Algoma Power Inc.

Distribution System Plan

2025 Cost of Service Application

Historical Period: 2020 - 2024

Forecast Period: 2025 - 2029

May 2024

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List of Acronyms

ACA	Asset Condition Assessment
ACR	Agawa Canyon Railway
AMI	Advanced Metering Infrastructure
AMP	Asset Management Plan
API	Algoma Power Inc.
APS	Area Planning Study
AVW	Annual Vegetation Workload
BBFA	Building Broadband Faster Act
CE	Customer Engagement
CHI	Customer-Hours Interrupted
CI	Customer-Hours
CN	Canadian National
CVOR	Commercial Vehicle Operator's Registration
DAI	Data Availability Index
DER	Distributed Energy Resources
DSC	Distribution System Code
DSP	Distribution System Plan
ELS	East Lake Superior
ESA	Electrical Safety Authority
ECI	Lakeside Environmental Consultants, LLC
EV	Electric Vehicle
EY	Ernst & Young
FNP	Flexnet Network Portal
FRP	Flexnet Remote Portal
FTTH	Fiber to the Home
HVAC	Heating, Ventilation, Air Conditioning
HI	Health Index
HONI	Hydro One Network Inc.
HOSSM	Hydro One Sault Ste. Marie
ISP	Internet Service Provider
LOS	Loss of Supply
MECP	Ministry of Environment, Conservation & Parks
MED	Major Event Day
MNRF	Ministry of Natural Resources & Forestry
MUS	Mobile Unit Station
O&M	Operating & Maintenance
OEB	Ontario Energy Board
OMS	Outage Management System
PCB	Polychlorinated Biphenyls
REG	Renewable Energy Generation
RIP	Regional Infrastructure Plan

ROW	Right of Way
RRFE	Renewed Regulatory Framework for Electricity Distributors
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory, Control And Data Acquisition
TGB	Tower Gateway Base
VM	Vegetation Management
VMP	Vegetation Management Program

List of Appendices

5.0 Introduction

Algoma Power Incorporated ("API") has prepared this Distribution System Plan ("DSP") in accordance with the Ontario Energy Board's ("OEB's") Chapter 5 Consolidated Distribution System Plan Filing Requirements dated December 15, 2022 (the "Filing Requirements") as part of its 2025 Cost of Service Application (the "Application").

This DSP was prepared by API employees and is supported an Asset Management Program ("AMP"), an area planning study ("APS") prepared by API employees and an Asset Condition Assessment ("ACA") completed by an independent third-party expert, METSCO Energy Solutions.

5.0.1 Objectives & Scope

API's DSP is a stand-alone document, updated on a 5-year cycle and filed in support of API's cost of service applications. API's DSP describes and substantiates API's AMP and Capital Expenditure plan for the 2025-2029 period. The DSP documents the practices, policies and processes that are in place to ensure that investment decisions support API's desired outcomes in a cost-effective manner and provide value to customers.

API's DSP is formulated to support achievement of the four key OEB established Renewed Regulatory Framework ("RRF") performance outcomes:

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

5.0.2 Outline of the Report

This is API's third DSP prepared in accordance with OEB's Filing Requirements. This DSP describes how API has developed, managed, and maintained its distribution system equipment to provide a safe, secure, reliable, efficient, and cost-effective service to its customers. The DSP identifies major initiatives and projects to be undertaken over the planning period. The DSP spans a 10-year period, with the historical period covering 2020-2024 (2024 being the Bridge Year) and the forecast period of 2025-2029 (2025 being the Test Year).

The DSP contents are organized into the following five sections:

- Section 5.0 provides a brief introduction and outline of the DSP report.
- Section 5.1 provides a high-level overview of API's distribution system, the customers it supplies and the category drivers for API's DSP identified projects.

- ❖ Section 5.2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvements.
- ❖ Section 5.3 provides an overview of API’s asset management practice, including an overview of the assets managed, asset lifecycle optimization policies and practices, and an overview of the system capability for Renewable Energy Generation and Distributed Energy Resources (“DER”).
- ❖ Section 5.4 provides a summary of API’s capital expenditures plan, including an overview of the capital expenditure planning process, a variance analysis of historical expenditures, an analysis of forecasted expenditures and material justification for projects exceeding the materiality threshold.

API’s materiality threshold is $175,000 and detailed descriptions of specific projects and programs exceeding this threshold are provided in Section 5.4.2.

API’s DSP is focused on providing the most viable, value-added operating environment possible for its consumers over the long term, with a short-term focus on continuation of reliable and safe service. API intends to execute its Capital Expenditure plan in full within the timeframe presented. The projects comprising the plan have been prioritized within the context of an overall investment strategy.

The DSP is organized using the same section headings indicated in the OEB’s Filing Requirements and addresses the information outlined in each section. Other relevant information is included in separately identified sections and is intended to complement the prescribed data.

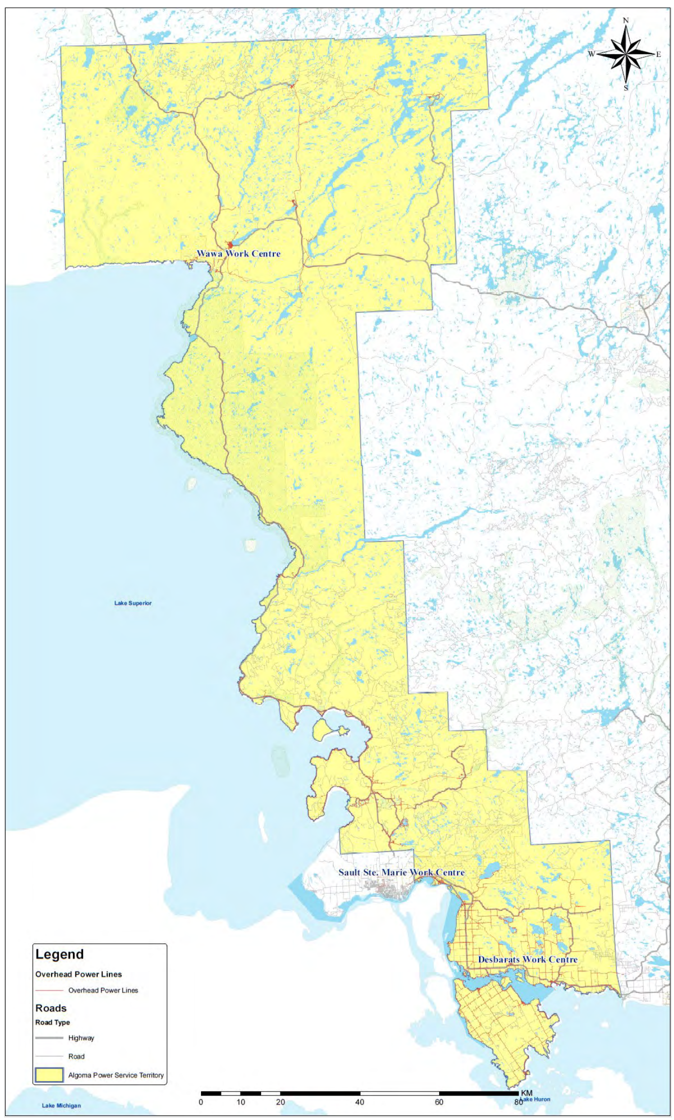
5.1 Algoma Power Distribution System

5.1.1 Description of the Utility

API is an OEB-licensed electricity distributor (ED-2009-0072) serving approximately 12,500 customers with a 14,400 km^2 service territory located in the Algoma District in Northern Ontario. API's distribution system extends approximately 93 km East of the city Sault Ste. Marie towards the Municipality of Huron Shores, and approximately 255 km North of the city of Sault Ste. Marie towards the Township of Wawa and Dubreuilville.

API operates a rural and remote distribution system, with power lines that are geographically dispersed within a large service territory and located along a predominantly forested backline. The following map illustrates the size of API's service territory (shaded in yellow).

Figure 1.1: Map of API's Service Territory



Within API's service territory, API has eight transmission supply connections, each supplying distinct distribution systems that are geographically separated and mostly isolated from one another. The following table provides a summary of these systems:

Table 1.1: Summary of API distinct distribution systems

Distribution Systems	Transmission Supply Connection(s)	# Distribution Stations	# of Customers Served[2]	Approximate Circuit KM
East of Sault	Echo River TS	4	6183	1,125
Sault Industrial	Northern Ave TS	0	6	7
Goulais	Goulais TS	1[1]	3153	372
Batchawana	Batchawana TS	0	833	123
Montreal River	Andrews TS	0	61	90
Mackay	Mackay TS	0	8	2
Wawa	Watson TS	2	1664	208
No. 4 Circuit	Circuit Limer	3	636	192

1. API owns an Autotransformer inside the Goulais TS, which is configured like a distribution station.
2. The total quantity of customers served is based on metered services.

5.1.1.1 Core Values

API has established seven (7) values that all employees should strive to promote and comply with each working day:

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 API 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 your customers' needs by listening. When you can meet those 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.

5.1.1.2 Customers Served

In 2023, API served approximately 12,500 electricity distribution customers across its service area. Historically, API has observed a minimal increase in its customer base. In 2020, API acquired the electrical distribution system in the Township of Dubreuilville, and with it approximately 350 customers, resulting in a moderate one-time increase in customer count. Table 1.2 highlights API's historical customer base and the growth observed.

API's low number of customers relative to its vast distribution service territory results in a very low population density. Historically, much of API'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. Therefore, API's system is characterized by long radial lines serving very few customers.

API distributes electricity to widely dispersed residential, seasonal, commercial, and industrial customers including remote First Nations communities. Organized townships are governed by 14 separate municipal governments and the seven First Nation reserve locations are governed by four First nations. Apart from property owned by businesses or individuals, API's territory also consists of significant parcels owned by large resource-based companies or provincial parks.

Table 1.2: Customer Base

Customer Class	2019	2020	2021	2022	2023
Residential (Residential R1(i))	7,698	7,925	8,205	8,361	8,485
General Service < 50 kW (Residential R1(ii))	961	951	969	999	1,025
General Service >= 50 kW (Residential R2)	40	41	43	46	47
Seasonal	3,039	2,990	2,925	2,849	2,793
Total	**11,736**	**11,906**	**12,141**	**12,253**	**12,350**

5.1.1.3 Peak System Load

Table 1.3 below highlights API's aggregate annual peak demand seasonally over the past 5 years based on 5-minute peak interval data.

Table 1.3: Peak System Load

Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2015	44,710	26,190	32,284
2016	40,591	29,413	31,617
2017	41,840	29,103	31,381
2018	44,182	34,492	35,232
2019	48,304	33,373	36,879
2020	44,860	36,660	36,273
2021	45,245	36,402	38,653
2022	50,393	38,745	39,881
2023	47,551	38,450	40,128

API experiences its peak demand mostly within the winter months due to lack of natural gas heating, a high penetration of electric heating, and a relatively low penetration of central air conditioning in much of its service territory. Variances in seasonal peaks are attributable to the varying weather conditions experienced in Northern Ontario. Table 1.4 highlights the annual peak demand seasonally as measured from API's eight distinct supply connections.

Table 1.4: API Seasonal Peak Demand by Distinct Supply Connection

Supply Connection	Peak Demand (kW)	2019	2020	2021	2022	2023
East of Sault	Winter	15,314	13,108	14,161	15,349	15,690
	Summer	11,238	11,980	12,700	12,139	12,160
Sault Industrial	Winter	2,410	2,380	2,222	2,176	2,046
	Summer	2,184	2,053	1,854	1,841	1,718
Goulais	Winter	8,126	7,414	7,707	9,021	8,232
	Summer	4,833	5,691	5,468	5,360	5,910
Batchawana	Winter	1,676	1,592	1,573	1,806	1,723
	Summer	1,497	1,680	1,672	1,563	1,594
Montreal River	Winter	304	220	217	265	224
	Summer	194	252	213	237	243
Mackay	Winter	46	46	38	39	37
	Summer	38	36	31	27	24
Wawa	Winter	8,553	7,758	7,751	8,468	8,159
	Summer	5,004	5,790	5,278	5,713	6,248
No. 4 Circuit	Winter	14,031	15,054	15,342	17,068	17,054
	Summer	12,859	13,283	15,068	15,823	15,866

Table 1-5 highlights API's distribution system losses in the historical period. Consideration of system losses in API's system planning process is discussed further in 5.2.3.5.

Table 1.5: System Losses

Customer Class	2019	2020	2021	2022	2023
Total kWh Delivered to API	253,100,740	250,571,206	263,158,051	277,849,319	278,754,157
Total kWh Delivered by API	235,800,481	229,140,220	244,314,344	256,287,580	259,742,424
Total kWh Distribution Losses	17,300,260	21,430,986	18,843,707	21,561,739	19,011,733
Loss Factor	1.0734	1.0935	1.0771	1.0841	1.0732

5.1.2 Background and Drivers

The Filing Requirements outline four categories of investments into which projects and programs must be grouped. The drivers for each investment category align with those listed in the Filing Requirements. For reporting purposes, a project or program involving two or more drivers associated with different categories is included in the category corresponding to the trigger driver. To note, all drivers of a given project or program were considered in the analysis of capital investment options and are further described in Section 4 of the DSP.

Table 1.6: API Category Drivers for DSP Identified Projects

Category	Driver	Capital Investment
System Access	Customer connections/upgrades, New Subdivisions	Service connection/expansions Transformers Meters
	Third-party requests	Road relocations Joint-use make-ready projects
System Renewal	Failure	Replacement due to asset failure, storm damage, vehicle accident, etc.
	End-of-Life (Failure Risk)	Targeted pole replacement Line rebuilds Substation rebuilds Other asset replacements
	End-of-Life (functional, performance, reliability)	Voltage conversion Substation rebuilds/replacements
System Service	Reliability, capacity, operating efficiency, loss reduction	Voltage conversion Substation upgrades, reconfiguration
	Reliability improvements	Distribution automation Protection & Control upgrades Fault indicators Wildlife guards
General Plant	System maintenance and investment support	IT Hardware/Software Fleet Tools and Equipment Communication assets Facility renovations Land rights, easements;
	Business operations efficiency	IT Hardware/Software Business system integration/upgrades Electric vehicles

System Access

These investments are modifications to the distribution system API is obligated to perform to provide a customer or group of customers with access to electricity services via API's distribution system. This category also includes relocations and system upgrades driven by third-party requests in accordance with applicable legislation.

System Renewal

These investments involve replacing assets that are at end of life and/or refurbishing system assets to extend the original service life, thereby maintaining the ability of API's distribution system to provide customers with safe and reliable service.

System Service

These investments are modifications to API's distribution system to ensure the distribution system continues to meet API's operational objectives and its customer's expectations with respect to reliability.

General Plant

These investments are modifications, replacements or additions to API's assets that are not part of the distribution system; including land and buildings, tools and equipment, and electronic devices and software used to support day-to-day business and operations activities.

5.2 Distribution System Plan

Section 5.2.1 provides an overview of the DSP, Section 5.2.2 summarizes coordinated planning activities with third parties, and Section 5.2.3 covers performance measurements to continuously improve asset management and Capital Expenditure planning processes.

5.2.1 Distribution System Plan Overview

The distributor must provide a high-level overview of the information filed in the DSP and is encouraged not to unnecessarily repeat details contained in the rest of the DSP. The overview should include capital investment highlights and changes since the last DSP. A distributor should list the objectives it plans to achieve through this DSP, which will be used as a baseline comparison in the performance measurement section below. This DSP will be used to inform and potentially support any requests for incremental capital module (ICM) funding during the 5-year DSP forecast period.

This section provides the OEB and stakeholders with a high-level overview of the information filed in the DSP, including key elements of the DSP, an overview of customer preferences and expectations, sources of expected cost efficiencies, the period covered by the DSP, the vintage of the information, an indication of important changes to API's asset management processes, and aspects of the DSP that are contingent on the outcome of ongoing activities or future events.

5.2.1.1 Capital Investment Highlights

The fundamental objective of API's planning processes is to manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets prudently and efficiently in a sustainable manner that maximizes safety and customer reliability, while optimizing asset lifecycle 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's DSP consolidates API's AMP with a 5-year capital investment plan that considers and balances the following inputs:

- ❖ Responding to the preferences of API's customers, as identified through customer engagement activities, and summarized in Section 5.2.3.2.
- ❖ Addressing system performance and energy needs in consideration of forecasted electricity demand, based on the results of API's APS.
- ❖ Improving system reliability and critical asset contingencies.
- ❖ Enabling innovation, electrification, and clean energy technologies.
- ❖ Addressing asset end of life replacements, based on the results of API's ACA.
- ❖ Addressing and support API's unique features, as described in Section 5.2.1.2
- ❖ General plant investments sufficient to support the identified distribution system capital investments and asset maintenance requirements, and to support API's daily operations activities.

Since the last DSP, API's objectives have remained relatively consistent, and key programs have also remained relatively stable. API continues to plan for the prompt and compliant completion of customer requests including new and upgraded services. API has consulted with external stakeholders to inform its budgets for these projects. A new challenge in recent years is presented by increased third party attachment work related to broadband expansion projects, which is expected to peak in 2025, and then return to previous levels. API has reflected the completion of externally driven customer requests primarily in the System Access investment category.

API continues to plan towards a sustainment approach for its line rebuilds and subtransmission rebuilds, as well as various other programs to replace ageing assets. As with the prior DSP, API has consulted an ACA in developing its plans. A new program for the 2025-2029 DSP relates to the replacement of ageing Smart Meters and related infrastructure. API has planned for sustainment programs primarily in the System Renewal investment category.

Additionally, as with the most recent DSP, API has completed an APS to identify areas of the system requiring attention due to capacity constraints, potential voltage issues, etc. The APS also incorporates sensitivity analysis relating to load growth. Greater focus has been considered in this DSP on the long-term electrification and energy transition's potential impacts to API's distribution system. Further analysis has been completed through the System Reliability Study. The recommended projects from both of these studies are generally reflected through projects in the System Service investment category.

One further change compared to the 2020-2024 DSP is the impact of COVID-19. The 2020 DSP was developed entirely prior to the COVID-19 Pandemic and therefore could not anticipate the unusual supply chain delays, work scheduling requirements, and material price increases to come. Some of these effects are still expected to prevail into the coming DSP period, for example longer delivery times for certain equipment (vehicles, smart meters, transformers, etc.); higher levels of pricing compared to pre-pandemic, and ongoing challenges with availability of skilled third-party contract labour. The primary impact of these changes to the 2025-2029 DSP is an increase in per-unit pricing assumptions, consistent with recent historical actual pricing trends.

Table 2.1 presents the Capital Expenditures by investment category and the system Operations and Maintenance (O&M) costs for both the historical and forecast period.

Table 2.1: Historical and Forecasted Capital Expenditures and System O&M

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

1 – 2024 listed expenditures are based on the bridge year forecast

Capital spending by category is designed to meet both customer-driven and asset-driven requirements. API has prepared a plan that is based on sustaining asset replacement, reliability improvement and meeting the overall expectations of both new and existing customers. API anticipates that the O&M investments to support its system are expected to generally remain consistent through the forecast planning period and has for illustrative purposes included annual budget from 2026-2029 based on an annual inflationary increase of 2.75%.

System Access spending is based on historical actual levels required to meet regulatory obligations for connections, upgrades and plant relocation driven by customers and third parties. System Renewal spending levels are driven by sustaining proactive asset replacement programs, mainly driven by pole replacement, but also include a station refurbishment project. Target replacement rates are based on consideration of the number, type, age, and condition of in-service assets. System Service spending is focused on reliability-driven projects, which are prioritized based on outage analysis and consideration of the impact of contingency scenarios. These investments enable improvements in overall system hardening when confronted with adverse weather and climate change. Finally, spending in the General Plant category is focused on ensuring that adequate tools, equipment, and systems are in place to support the day-to-day operations of API's business. Much of this category comprises levelized annual spending on items such as tools, equipment, fleet, information technology, SCADA, land rights and ROW Access.

The 2025-2029 DSP was developed with the objective of not only addressing the short-term needs but to ensure that the system can continue to achieve safe and reliable distribution in the long term based on effective AM planning. The DSP is a product of inputs from multiple initiatives, processes and documents involving several stakeholders. These input sources include the following:

- API's Asset Management Program
- Planning Studies (Area and Reliability)
- Asset Condition Assessment
- Customer Engagements
- Regional Planning

5.2.1.2 Unique Features

In operating a rural and radial distribution system in Northern Ontario, API has unique features that require consideration when managing and planning its programs and projects as well as when measuring performance.

5.2.1.2.1 Vegetation Management

Being in rural Northern Ontario, one of the characteristics of API's service territory is that it is predominantly located in forest zones with dense vegetation. API's service territory extends through two forest zones. The southern part is in the Great Lakes-St. Lawrence Forest zone, characterized by red and sugar maple, yellow birch, red oak, hemlock, red and white pine. The northern part is in the Boreal Forest zone, characterized by black and white spruce, tamarack, aspen, white birch, balsam fir, and jack pine. North of Wawa and east of the Montreal River area is the approximate transition area between the two forest zones.

Figure 2.1: Ontario's Forest Regions

API manages Right-of-Ways (ROWs or ROW) to support its 2,100 kilometers of distribution line. Approximately 85% of API's power lines have treed edges averaging 490 trees per km with an average height 20.7m (68ft). Greater than 23% of API system has forested edges on both sides of the ROW (i.e. cross-country and double-sided ROW - see Figure 2.2). The remainder of API's ROWs are mainly comprised of front yard trees (residential) and farmland and other natural areas containing brush and shrubs.

Figure 2.2: Examples of Forested Backlines in API's Service Territory

The remote and geospatial separation of customers necessitates long runs of distribution lines through very remote areas. For this reason, as well as the access challenge detailed in 5.2.1.2.5, API must maintain a very robust and comprehensive Vegetation Management Program ("VMP") to maintain and improve system reliability.

Vegetation can interfere with the safe and reliable operation of API's electrical system. Trees and brush growing in the vicinity of electrical wires increases the risk of making contact or arcing with power lines. There are a variety of ways for vegetation to contact with powerlines. Vegetation may grow naturally towards the conductors, may sag or swing into the lines during ice or snow-build up, or may sway into lines during severe windstorms. Trees or branches falling on power lines are also a major cause of power interruption whether through natural tree health decline or loading forces on trees, such as wind, snow and ice. Vegetation in direct contact or within proximity to powerlines can become a wildfire hazard due to the potential ignition source it creates, particularly during dry or windy conditions. Vegetation can also impede the efforts of staff to locate, inspect, maintain and repair disruptions to electrical service.

API's VMP was developed to not only address the legal obligations to protect the public through a safe and reliable power system but also recognizes the value and importance of a thriving and sustainable environment. Through its VMP, API endeavors to preserve and protect the environment and engages property owners to encourage the placement of compatible species near power lines at an appropriate distance. To meet its vegetation management ("VM") challenges with greater effectiveness, API has steadily improved its VMP and associated work practices. API has included its VMP as Appendix B.

The overall objective of API's VMP is to manage vegetation in proximity to electrical equipment on a regular schedule to:

- ❖ Avoid vegetation caused outages through system hardening to achieve sustainable reliability performance
- ❖ Decrease risk of wildfire ignition and spread by reducing the likelihood of tree contact with powerlines and eliminating volumes of fuel source wood

- Enhance public safety near electrical equipment
- Allow worker accessibility to the system
- Secure infrastructure resiliency by reducing impact caused by extreme weather events
- Manage and plan vegetation work activities in a least cost sustainable manner.

5.2.1.2.2 Low Customer Density

The OEB scorecard focuses on three measures related to cost control: efficiency assessment, total cost per customer, and total cost per km of line.

The efficiency ranking is produced by a total cost benchmarking model developed by Pacific Economics Group LLC on behalf of the Ontario Energy Board. API's unique attributes as a rural and remote distributor, particularly its low customer density, result in API being an extreme outlier in the data set used to develop the model. Some of API's largest cost drivers, including customer density and the degree of forestation along its distribution line rights of way, are not appropriately reflected in the benchmarking model. As a result of the extremely rural and low-density nature of API's system in relation to other Ontario distributors, API management believes that the total cost per km of line metric provides a more appropriate measure of API's efficiency and cost control.

Based on OEB yearbook and scorecard results, API consistently places in the top ten distributors in Ontario in terms of lowest total cost per km of line. Conversely, API's total cost per customer is consistently an outlier in the OEB's dataset, since a significant portion of its total costs are related to its extensive distribution system (i.e. costs associated with maintaining and replacing approximately 2,100 km and costs of establishing and maintaining the associated ROW) are spread over a relatively small number of customers when using this metric.

The low customer density also results in longer overall response time during outages due to the distance that needs to be travelled from one of API's work centres to the outage location. This coupled with API's rural and remote access challenge as detailed in 5.2.1.2.5 results in a greater challenge for responded to outage and restoring power. For these reasons, API has included forecasted expenditures for the continued installation and integration of SCADA-capable devices for station and feeder automation. These devices will give API better visibility on system conditions during outage events and in areas where looped configuration exists, could allow for automatic restoration.

5.2.1.2.3 Limited Localized Distribution

For clarity, the term localized distribution is being used to describe the components of API's distribution system to which individual residential, seasonal, and commercial customers are connected. Localized distribution may either extend directly from a transmission delivery point or may be connected to an express line by way of a step-down transformer.

Due to the rural, rugged, and remote nature of API's service territory, there is a very limited clustering of customers. Clustering of customers in close geographical proximity to each other, allows for an economically configured distribution network consisting of primary lines, distribution transformers and a secondary distribution system connecting multiple customers to a single, centrally located distribution transformer. This type of distribution network is typical of many Ontario distributors; however, it is not typical for API. For API, clustering of customers is basically limited to the community of Wawa and small communities east of Sault Ste. Marie. Otherwise, customers are sparsely located and connected by relatively long runs of primary distribution lines with customers normally connected to distribution transformers with a one-to-one ratio. Secondary distribution is rare due to geographical separation of customers.

5.2.1.2.4 Land Management

Community, Government and Agency Interaction:

API's service territory contains many types of land ownership, governance and interests; private lands, First Nation reserve lands, indigenous traditional territory, organized townships, municipalities, unorganized townships, provincial crown land managed by the Ministry of Natural Resources and Forestry ("MNRF"), provincial parks managed by the Ministry of Environment, Conservation and Parks ("MECP"), resource companies and environmental land trusts.

Townships and Municipalities

In contrast to other utilities, API's service territory covers over one-hundred townships, with a mix of organized and unorganized governance. Organized townships are controlled by 14 separate municipal governments. Annually, API attends council meetings and holds road supervisor meetings with each municipal government to discuss upcoming projects and gather information about upcoming municipal projects and planned road works. Additionally, multiple departments at API maintain relationships with staff from each municipality for land permissions, coordination of work activities, collaboration on engineering design and emergency issues.

Unorganized townships present API with unique challenges, as there is no municipal government to liaise with. In some cases, unorganized townships have a local roads board which API works with on land related permissions and coordination of work activities where work is occurring within the limits of a road. Unorganized townships lack a governance structure to create and enforce building permit requirements and zoning by-laws. This results in a lack of oversight and enforcement with respect to the building code including building setbacks in relation to power lines. As a result, property owners may construct buildings within the limits of approach to the power line; a serious safety issue of which API is not aware until routine line inspections are completed, or an electrical service request is made for the new construction. There is normally little recourse for API apart from the relocation of the power line to address the serious safety concern.

First Nation Reserve Land

With respect to First Nation reserve lands, API is unique as a distributor in that it services and/or runs across seven reserve locations, governed by four First Nations. As in many areas in the province land, claims and settlements are continually occurring within API's service territory. Successful land claims result in land being transitioned into a First Nation reserve. In cases where API services are located on these transitioning lands, API must enter into negotiations with the First Nation and Canada to secure land rights under Section 28(2) of the Indian Act to have valid tenure over the area to be added to reserve resulting in additional legal costs. API expects the land claim and addition to reserve process to affect areas of its service territory for the foreseeable future.

Indigenous Traditional Territory

API has been advised that its service territory overlaps portions of land identified as traditional territory by eight indigenous groups. Batchewana First Nation, Chapleau Cree First Nation, Garden River First Nation, the Metis Nation of Ontario, Michipicoten First Nation, Missanabie Cree First Nation, Red Sky Metis, and Thessalon First Nation. Meetings, collaboration and learning from indigenous groups are important to API. Protection of medicinal and food plants, increased protections to natural environment and working collaboratively to address environmental concerns are issues indigenous communities have advised API are of importance to them.

Resource Companies

Apart from the typical property interest commonly owned by businesses or individuals, API's service territory also consists of vast parcels including multiple townships, owned by large resource-based companies.

MNRF

Approximately thirteen percent of API's service territory falls upon Crown Lands owned by the government of Ontario managed by two district MNRF offices: Sault Ste. Marie and Wawa. Dealing with two separate offices often leads to different interpretations of Land Use and Environmental Planning policies. Land rights for API's power lines on these lands are managed through a multi-site land use permit. API works with MNRF staff on permissions for new ROW, access permissions, work permits and species at risk review.

Land Challenges:

API's unique distribution system traverses approximately 2,100 kilometers of rugged Canadian Shield comprised of exposed bedrock, lakes, bogs interspersed with small pockets of farmland. The nature of this topography has resulted in a somewhat haphazard configuration of land fabric and road systems in contrast to areas of southern Ontario which have more standard grid configurations.

System Construction

Portions of API's system were historically designed so the connection of a dwelling was a minimal distance from the power line. The goal was to provide the lowest possible cost for a customer to connect. Unlike most distribution utilities, this has resulted in power line locations which do not follow roadways, instead travelling cross-country and running through many properties. This routing has resulted in access issues for maintaining and replacing power lines located well onto private properties. Additionally, as areas of the region developed, power lines pre-dated road access. Roads were constructed in locations which were out of sync with the previously constructed power lines creating off road ROWs and access issues.

Land Division

Identifying the limits of private property is also a challenge in API's service territory. The rural nature of the area leads to little observable delineation between properties, especially for large, forested parcels. Often property owners themselves are unaware of the exact boundaries of their land.

Registrar's compiled plans are the most frequent property plans available from the Algoma Land Titles office. These plans are representative of the shape and location of lots, but do not include information on accurate lot size or monumentation necessary to relate to observable conditions. Reference plans which are required for severances, easements, other types of right-of-way creation, are informative but not available for all properties. A small fraction of properties in API's territory have been created by subdivision plan with surveyed and monumented property boundaries and clearly established road boundaries. More common are property boundaries defined by metes and bounds descriptions referencing the bearing and distance of the perimeter of the property. These descriptions are usually attached to the original deed of the land.

Road boundaries in API's territory can also be challenging. Many local roads originated by trespass, where little concern was given to surveying the limit of the road and establishing a proper parcel to be transferred to a public authority. In other cases, an original property deed sets out a portion of the parcel as a road allowance, but the actual boundaries of the allowance may not have been delineated by plan and survey monumentation.

New Construction Challenges

API faces challenges with constructing new lines or relocating existing lines within highway right-of-way and road allowance. The Ministry of Transportation, municipalities and local roads boards require API to locate new and relocated lines near the edge of the road allowance as they are sensitive to the areas required for their current and future road and drainage requirements. As a result, API's ROW clearing standards for vegetation management result in a power line ROW which impacts the private properties abutting the road all along the length of the new or relocated line. As a result, API must negotiate easements for these ROWs to ensure clearing rights and access for future vegetation management.

5.2.1.2.5 Rural and Remote Access Issues

API's distribution system has been designed and built to reach into all areas of its service territory to provide electricity service. By necessity, the design of the distribution system requires long runs of distribution line (known as express feeders) through uninhabited and undeveloped tracks of land in northern Ontario.

The express feeders are often situated on the most direct route from the transmission system delivery point to the customers, not normally along roadways or other forms of public ROWs. To the extent possible, when express feeders come due to be rebuilt, consideration is given to relocating the line along a roadway versus rebuilding along the existing right-of-way. In most cases the roadway is a significant distance from the existing ROW.

Even in locations where the power line is built within the highway right-of-way, API is faced with access issues. Rock outcroppings, common with the Canadian Shield geography of the service territory, pose a challenge when trying to access API's distribution system. These types of locations, as shown in the pictures below, cannot be accessed by aerial lifts and/or radial boom derrick trucks but instead, workers carrying the required equipment must climb the rock to the power line and then complete the work manually. For example, workers must climb a pole to complete repairs or climb a tree to trim for clearance.

Figure 2.3: Example of Access Challenge

When access to API's off-road system is required, a formal access agreement with property owners becomes necessary. Often travel over several different properties is needed to reach the power line.

API owns several power lines, both submarine and overhead, providing power to islands in its service territory. Generally, boats are used to access these locations and often the point at which the power line contacts the island is not a suitable landing site for watercraft. Alternative locations for docking must be made and, in some cases, formal agreements are arranged.

5.2.1.3 Overview Customer Preferences and Expectations

API employs a variety of communication channels to inform and engage with its customers, employees, communities, other interest groups and third parties on a regular basis. This includes regular bill inserts, presence on social media platforms, website updates, customer portals, community and contractor meetings, participation in regional planning efforts, and participation in community events.

As part of the Application, API worked with Innovative Research Group ("IRG") to develop a Customer Engagement ("CE") strategy and approach in order to engage with customers. A series of customer "workbook" surveys were used to gather customer preferences on program expenditures in the upcoming five-year period. The "workbook" survey was deployed to all API customers with an email address and promoted on API's website and social media platforms.

The surveys provided different levels segmentation that would help identify factors that may influence customer needs and preferences. Customers were segmented based on region, consumption quartile, bill impact on finances, general sector perceptions and vulnerable consumer status.

The results of the survey indicate broad support across API draft planned expenditures, with the majority (50-55%) of respondents indicating support for the planned expenditures. Between 21% and 33% of respondents also indicated support for increasing API's draft planned expenditures. Table 2.2 below provide summary of CE results of major projects/programs in the draft plan:

Table 2.2: CE Planning Placemat

	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

In setting priorities, the majority of respondents rated the following as the three most important:

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

Table 2.3: 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

The customer base does look at changes through the lens of costs and therefore has a deep desire to keep costs low. However, they also expect high standards of operation and reliability. While the number one suggestion was for API to keep costs reasonable, a large percentage of customers believe that API should also focus on items related to safety, reliability (particularly outage duration), and continued opportunities for conservation.

Details surrounding API's CE activities and the outcomes related to DSP capital expenditure investments are provided in section 5.4.1.3. Additionally, the full CE report is provided in Appendix F.

5.2.1.4 Anticipated Sources of Cost Savings

API's capital investments over the 2020-2024 historical period, combined with the proposed investments over the 2025-2029 forecast period are expected to result in the following sources of cost savings:

Reduction in System Losses

All else being equal, converting the distribution system in the Goulais area from 7.2/12.5kV to 14.4/25kV will reduce API's overall system losses. As part of API's line rebuild program, conductor upgrades are included that balance cost-benefit of material cost to the system loss improvement, while also ensuring the resulting system capacity exceeds forecasted demand. API notes that reductions in system losses will have a direct decreasing effect on customers' bills in the long term.

Proactive vs. Reactive Asset Replacements

API's Line Rebuild program is the core of API's sustaining asset replacement strategy and is predicated on the proactive approach to 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.

Efficiency and Operational Improvements from Business Systems

Advancements in business system platforms and increased integration between systems continues to provide several efficiency and operational improvements:

- Integration between Advanced Metering Infrastructure ("AMI") and Outage Management System ("OMS") has increased awareness of power outages and improved visibility into the likely source of the outage locations, allowing more efficient deployment of field crews and more effective communication with customers. Mobile tools allowing operational crews to directly access this information in the field will be tested to further improve outage response.
- Increased integration between metering data systems and engineering analysis software allows for more accurate assessment of system loading and performance, increasing API's ability to align investments between asset end of life requirements and investments aimed at addressing loading or performance issues.
- API's 2024 pole testing program is piloting the use of a mobile data entry interface that will upload results directly into the GIS system, reducing manual effort, improving data quality and consistency, and improving API's ability to analyze results for system planning purposes.
- Cloud-based solutions are being explored to increase the performance and cost-effectiveness of various IT systems and to reduce IT hardware costs.

5.2.1.5 Period Covered by DSP

The planning horizon for this DSP covers ten years with a 5-year historical period from 2020 to 2024, where 2024 is the Bridge Year, and a 5-year forecast period from 2025 to 2029, where 2025 is the Test Year.

5.2.1.6 Vintage of the Information

All asset inspection/condition assessment data is current per the inspection intervals described in the Section 5.3 Asset Management Process.

Unless otherwise noted, all information contained in the DSP is current as of December 31, 2023.

5.2.1.7 DSP Contingencies

API is currently working with Hydro One Sault Ste. Marie ("HOSSM") on the refurbishment project of the Goulais Bay TS, which is described in detail in section 5.2.2.1.4.3. This project was originally scheduled to begin in 2024 with a 2025 in-service date but was put on hold by HOSSM. Current discussions with HOSSM are centered around the timing and scope of the project, especially in consideration of API's Goulais Voltage Conversion project, are described in section 5.4.2.4.3.1. Based on these discussions, API has included a forecast capital expenditure in 2029 to capture cost associated with reconfiguring API's supply connection to HOSSM as part of the project, as well as to capture the cost associated with upgrading the supply voltage to support API's Goulais Voltage Conversion project and API's request for second feeder position. As a result of the interdependencies with HOSSM, the yet unclear scope of work, and the relatively late timing of this project within the DSP period, API considers this project cost and timing relatively uncertain.

API is currently in discussions with an applicant for a large commercial load that is proposed to be located in one of the more remote communities in API's service territory. API has not factored into the 2025-2029 capital expenditures the potential one-time connection cost of this load. To the extent that any such loads proceed with connections that require expansion to API's distribution system, those expansions would be undertaken in accordance with the relevant provision in the DSC and Transmission System Code ("TSC").

5.2.2 Coordinated Planning with Third Parties

A distributor must demonstrate that is has coordinated infrastructure planning with customers (e.g., large customers, subdivision developers, and municipalities), the transmitter (e.g., Regional Infrastructure Planning), other distributors, the Independent Electrical System Operator (IESO) (e.g., Integrated Regional Resource Planning) or other third parties where appropriate. A distributor should explain whether the consultation(s) affected the distributor's DSP as filed and, if so, provide a brief explanation as to how. For consultations that affect the DSP, a distributor should provide an overview of the consultation and relevant material supporting the effects the consultation has on the DSP.

5.2.2.1 Summary of Consultations

5.2.2.1.1 HOSSM Consultations

Purpose:	Planning meetings with HOSSM to address projects identified under Regional Plan, as well as annual work schedule.
Outcome:	API and HOSSM coordinate work plans, planned outages, monitor projects.
Who Initiates:	API or HOSSM.
Other Participants:	HOSSM.

From 2020-2023, API has had numerous working and planning meetings with HOSSM that were related to specific local projects that were identified in the previous regional planning process and consultations. These projects and the associated consultations are described under the regional planning process below.

API also meets with HOSSM annually to review their planned work schedule in the upcoming year. During this meeting, API reviews their planned outage dates, timeframe and supply locations and advises on opportunities to coordinate work plan, and where timing may need to be considered.

5.2.2.1.2 Consultations with Telecommunication Entities

Purpose:	Planning with Telecommunications companies for upcoming projects- both regular and BBFA-related.
Outcome:	API has been able to coordinate work and has obtained information used in its projections for Third Party Relocations in the System Access investment category.
Who Initiates:	API or telecommunications entities.

Other Participants:	API attends on a one-on-one basis with each telecommunication entity.

From 2020-2023, API has had about 50 meetings with one specific telecommunication entity that operates within API's service territory regarding their programs and projects for which they submitted formal requests for joint use permit applications. During these meetings, API and the telecommunication entity generally review the status and progress of each permit in the context of the review and approval steps and subsequent completion of identified utility make-ready.

Starting in 2023, significant effort has gone toward supporting the anticipated broadband designated projects for telecommunication entities that have been awarded lots under the BBFA. This effort is expected to continue into 2024 and 2025.

API researched the internet service providers awarded funding for programs in the Algoma Region under the BBFA in order to identify which ISPs to consult, in addition to working with the ISPs API already knew to be operating within its service territory based on prior joint use work. API has also engaged with the technical assistance team established to support the BBFA.

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As part of API's planning process described in section 5.3.1, API reviews identified projects with the current joint-use telecommunication entities attached to API poles develops. This review provides an initial notice of the project, which is followed by a request to transfer at the later stages of the project.

The outcomes of the discussions described above have not influenced API's planned capital expenditures.

5.2.2.1.3 Consultations with First Nations, Township & Municipalities

Purpose:	Planning and coordinating work with Communities within API's service territory.
Outcome:	API has been able to assess some of its System Access projections based on the high-level feedback received, however no material projects were identified based on recent consultations.
Who Initiates:	API requests an invitation to each First Nation, township, and municipality.
Other Participants:	Typically, API and members of First Nation, municipal council and/or other community leaders.

On an annual basis, API meets with townships and municipalities as a delegation to review upcoming work plans and initiatives. These delegation meetings are generally held during a regularly scheduled council meeting or specific meeting with appropriate First Nation's staff. During these meetings, API puts forth a request for any information regarding community developments and whether there is any work being completed towards community energy planning.

These consultation efforts have not identified any material developments requiring individual projects in API's DSP- rather API expects the levels of requests in the planned System Access projects will incorporate any items identified through these consultations.

5.2.2.1.4 Regional Planning Process

Purpose:	Regional Planning for the East Lake Superior region.
Outcome:	Please see the six projects listed below.
Who Initiates:	Regional Transmitter, HOSSM.
Other Participants:	HOSSM, IESO, Chapleau PUC, Hydro One Networks Inc. (HONI), Sault Ste. Marie PUC.

API is part of the East Lake Superior ("ELS") region for regional planning purposes. The East Lake Superior Region is the region that extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel.

HOSSM initiated the second cycle of regional planning for the ELS region with Needs Assessment on April 16th, 2019. API, along with several other LDCs and the IESO participated in the Needs Assessment process. The second cycle Regional Infrastructure Plan ("RIP") report, which was published on October 1st, 2021, outlined the following transmission projects over the next 10 years for which API will be involved.

1) Echo River TS – Transmission Supply Reliability and end of life breaker
2) Batchawana TS – End of Life Component Replacement
3) Goulais TS – End of Life Component Replacement
4) Northern Ave TS – T1 End of Life Replacement
5) Anjigami/Hollingsworth TS – Transformer Overload
6) Hollingsworth TS – End of Life Protection Replacement

A copy of the RIP report is included in Appendix I. The recommended action plan documented in the RIP for the above outlined projects is the following:

Table 2.4: Recommended Action Plans over the Next 10 Years (API specific)

Need	Recommended Action Plan
Echo River TS – Transmission Supply Reliability and end of life breaker	Install 'hot' spare transformer and replace end of life breaker
Batchawana TS – End of Life Component Replacement	Refurbish Batchawana TS with MUS provision
Goulais TS – End of Life Component Replacement	Refurbish Goulais TS with MUS provision
Northern Ave TS – T1 End of Life Replacement	Replace end of life T1 with smaller MVA unit and protection relays per current standard
Anjigami/Hollingsworth TS – Transformer Overload	Build new 115/44kV Station – HOSSM to work with API to continue to develop solutions
Hollingsworth TS – End of Life Protection Replacement	Replace end of life protections

A detailed summary and progress of the identified needs in Table 2.4 is provided in the sections that follow.

As outlined below, there are no inconsistencies between the DSP and the current Regional Plan, however there is currently no plan for the Northern Ave TS T1 EOL replacement. Further, API's load projections have changed since the RIP was developed approximately five years ago.

5.2.2.1.4.1 Echo River TS Spare Transformer Project

This project involved the addition of a second transformer at the Echo River TS as the preferred solution to resolve limitations to the contingency supply to API's East of Sault 34.5 kV system due to limitations on API's NA1 feeder. This represents a situation where a transmission investment was determined to be an overall superior and more cost-effective solution to resolving a capacity issue.

This project was completed and placed into service in 2023. API has included in section 5.4.1.1.3 a summary of the business case decision for this project as well as a detailed variance analysis.

5.2.2.1.4.2 Batchawana TS Refurbishment Project

This project initiated by HOSSM involved the refurbishment of the Batchawana TS. Through the regional planning process, the refurbishment of this station (along with the Goulais TS) was determined to be the alternative with the best cost and operational benefits, as described in the HOSSM Local Planning report (Appendix L) and the API Greenfield Study Report (Appendix K).

As part of the project, HOSSM requested that API relocate its feeder connection and wholesale revenue metering equipment. From the Greenfield Study Report, it was identified that converting the Batchawana and Goulais systems to 25kV would result in the following benefits:

- Significant reliability improvement through a reinforced distribution tie-line between this station and the Goulais TS;
- Decrease the overall system losses within this area of API's distribution system; and
- Enable API to provide increased capacity connections (such as EV charging infrastructure along the Highway 17 corridor, North of Sault Ste. Marie.

As a result, API requested formally that HOSSM estimate the cost to provision the station to operate initially at 12.5kV but be capable to convert to 25kV in the future.

A description of this project has been included in section 5.4.1.1.3

5.2.2.1.4.3 Goulais TS Refurbishment Project

This project initiated by HOSSM involves the refurbishment of the Goulais TS. Through the regional planning process, the refurbishment of this station (along with the Batchawana TS) was determined to be the alternative with the best cost and operational benefits, as described in the HOSSM Local Planning report (Appendix L) and the API Greenfield Study Report (Appendix K).

This project was initially scheduled to begin in 2024 and be placed into service in 2025. In 2023, API was informed that the project would have to be postponed until 2028/2029. Like the Batchawana TS refurbishment project, API has requested that HOSSM estimate the cost to provision the station to operate at 12.5kV initially but be capable to convert to 25kV in the future. In consideration of the project postponement and the results of the APS, API is now seeking to have this station operate at 25kV at the onset of this project. This will result in the same benefits list under Section 5.2.2.1.4.2

API has included a project narrative in section 5.4.2.4.3.3

5.2.2.1.4.4 Northern Ave TS T1 Replacement Project

This project involves the replacement of T1 at the Northern Ave TS. API has had a handful of discussions with HOSSM regarding the status and timing of this project, but at this time the project schedule is uncertain.

5.2.2.1.4.5 Hollingsworth TS Protection Replacement Project

This project involves the replacement and upgrade of protection equipment at the Hollingsworth TS. API would be involved to the extent that HOSSM's protection scheme will need to be coordinated with API's protection scheme.

5.2.2.2 Renewable Energy Generation (REG)

API is anticipating that the quantity of 2025-2029 REG connections will be limited to a small number of net metering and load displacement projects (see 5.3.4 for more details). API has assessed its distribution system and has not identified any concerns with accommodating any such projects, and as a result has not included any REG-specific investments in this DSP.

The IESO has commented in recent rate applications that no letter of comment is required from the IESO in circumstances where a distributor is not proposing REG investments during the DSP forecast period, and API has therefore not requested IESO comments.

5.2.3 Performance Measurement for Continuous Improvement

Distributors are expected to summarize objectives for continuous improvement (e.g., reliability improvement and other desired outcomes) the distributor set out to address in its last DSP, and to discuss whether these objectives have been achieved. For objectives not achieved, a distributor should explain how it affects the current DSP and, if applicable, improvements a distributor has implemented to achieve the objectives set out in Section 5.2.1.

5.2.3.1 Distribution System Plan

API compiles and submits a variety of performance-based reports for internal analysis and/or submission to the OEB on a regular basis. This includes items such as reliability statistics and Electricity Service Quality reports. As these reports are compiled, they are reviewed to determine if any failure to meet target performance levels, any trend in performance requires corrective action, or any adjustments to future capital or maintenance programs. Performance measures that are reported are mandated by the OEB and assist API with continuous improvement and meeting customer expectations. The measures are divided into three groups:

- Customer oriented performance;

- Cost efficiency and effectiveness; and
- Asset/system operations performance

The performance measures included on the scorecard establish minimum levels of performance expected to be achieved (API Target). The scorecard is designed to track API's historical performance, to identify trends in performance and whether targets are met, and to present results and trends in a manner that is easy for customers to understand. The associated Management Discussion and Analysis requires API to provide additional explanation related to the results and trending for each scorecard performance metric. Performance levels as compared to targets and historical trends are considered in API's AM process.

Table 2.5 below summarizes API's performance measures and Targets, with additional detail corresponding to Sections 5.2.3 of the Chapter 5 Filing Requirements provided for each specific performance measure throughout Sections 5.2.3.2-5.2.3.5.

Table 2.5: Performance Measures and Targets

Performance Outcomes	Performance Categories	Measures	Target
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	90.00%
		Scheduled Appointments Met on Time	90.00%
		Telephone Calls Answered on Time	65.00%
	Customer Satisfaction	First Contact Resolution	No Target
		Billing Accuracy	98.00%
		Customer Satisfaction Survey	No Target
Operational Effectiveness	Safety	Level of Public Awareness	No Target
		Level of Compliance with Ontario Regulation 22/04	C
		Serious Electrical Incidents / Rate per 10, 100, 1000 km of line	0 / 0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted	5.54
		Average Number of Times that Power to a Customer is Interrupted	2.54
	Asset Management	Distribution System Plan Implementation Progress	No Target
	Cost Control	Efficiency Assessment	No Target
		Total Cost per Customer	No Target
		Total Cost per KM of Line	No Target
Public Policy Responsiveness	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed on Time	No Target
		New Micro-embedded Generation Facilities Connected on Time	90.00%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	No Target
		Leverage: Total Debt (includes short-erm and long-term debt) to Equity Ratio	No Target
		Profitability: Regulatory Return on Equity (deemed, included in rates)	No Target
		Profitability: Regulatory Return on Equity (achieved)	No Target

Table 2.6 below provides a summary of API's performance measurement from 2019-2023, based on the measures and targets set in API's previous DSP. The 2020-2024 Targets shaded in green indicate the target set in the previous DSP was met in the recent years. API met or exceeded (and in many cases significantly exceeded) the performance targets set in the last DSP.

With respect to system losses, the previous DSP did not specify a numerical target, however the DSP indicated that API was not planning significant investments in the 2020-2024 DSP in programs which would further reduce losses; however as shown in the table below, losses in the most recent DSP period have increased compared to the prior trending. A further discussion of API's performance in this measure, and the projects that will support a loss factor improvement, is included in section 5.2.3.3 below.

Table 2.6: DSP Performance Measures

Performance Outcomes	Performance Category	Measure	2019	2020	2021	2022	2023	Industry Target	API 2020-2024 Target	API 2025-2029 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%	90.0%
		Scheduled Appointments Met On Time	100.0%	100.0%	100.0%	100.0%	100.0%	90.0%	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%	65.0%
		First Contact Resolution	100.0%	99.9%	100.0%	100.0%	99.9%	no target	95.0%	95.0%
		Billing Accuracy	99.9%	99.9%	99.8%	99.9%	99.9%	98.0%	98.0%	98.0%
		Customer Satisfaction Survey Results	95.0%	94.0%	93.0%	97.0%	90.0%	no target	81.0%	exceed Ontario Benchmark
Operational Effectiveness	Safety	Level of Public Awareness	83.0%	83.0%	83.0%	82.0%	82.0%	no target	80.0%	80.0%
		Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	C	C	C
		Serious Electrical Incident Index- Number of General Public Incidents	-	-	-	-	-	-	-	-
	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	5.42
		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	2.47
	Asset Management	Line Losses	1.0734	1.0935	1.0771	1.0841	1.0732	N/A	Maintain	Maintain or improve
	Cost Control	Total Cost per Customer	$ 2,235	$ 2,212	$ 2,338	$ 2,479	$ 2,825	no target	Improving Efficiency Trend per PEG Model	Improving Efficiency Trend per PEG Model
		Total Cost per Km of Line	$ 12,107	$ 12,203	$ 13,025	$ 14,501	$ 16,653	no target		
		O&M Cost per Customer *	$ 1,047	$ 1,120	$ 1,118	$ 1,132	$ 1,130			
		O&M per km of line *	$ 5,672	$ 6,077	$ 6,200	$ 6,595	$ 6,632			
		O&M per kW of average peak capacity *	$ 333	$ 368	$ 352	$ 349	TBD			

5.2.3.2 Service Quality and Reliability

5.2.3.2.1 Service Quality

API measures and reports on an annual basis on each of the service quality requirements set out in the Distribution System Code ("DSC"). Failure to meet minimum service quality targets, or declining trends in performance, would result in measures being taken to realign performance with DSC service quality standards. Three service quality measures are included on the OEB scorecard: New Residential/Small Business Services Connected on Time, Scheduled Appointments Met on Time and Telephone Calls Answered on Time. All these measures are self-explanatory in nature, and all relate to API providing connection services as well as quality customer service. API is committed to meeting and exceeding all targets found in the Service Quality performance measure group.

API confirms the data below is consistent with the scorecard, and with Appendix 2-G.

Table 2.7 presents the historical results for the service quality measures tracked and reported by API.

Table 2.7: Performance Measures – Service Quality

Indicator	OEB Minimum Standard	2019	2020	2021	2022	2023
Low Voltage Connections	90.0%	97.10%	100.00%	100.00%	99.09%	100.00%
High Voltage Connections	90.0%	N/A	N/A	N/A	N/A	N/A
Telephone Accessibility	65.0%	81.61%	84.84%	88.36%	85.46%	78.32%
Appointments Met	90.0%	100.00%	100.00%	100.00%	100.00%	100.00%
Written Response to Enquires	80.0%	100.00%	100.00%	99.88%	100.00%	100.00%
Emergency Urban Response	80.0%	N/A	N/A	N/A	N/A	N/A
Emergency Rural Response	80.0%	93.33%	94.44%	90.48%	95.65%	94.12%
Telephone Call Abandon Rate	10.0%	6.73%	2.03%	1.25%	2.38%	5.07%
Appointment Scheduling	90.0%	99.76%	99.86%	99.88%	99.56%	100.00%
Rescheduling a Missed Appointment	100.0%	N/A	N/A	N/A	N/A	N/A
Reconnection Performance Standard	85.0%	100.00%	100.00%	100.00%	100.00%	100.00%

API has consistently exceeded targets with respect to service quality measures and expects to continue to meet or exceed these targets throughout the forecast period. API has not seen any material changes in the service quality over the most recent five-year period. The Table above is OEB Appendix 2-G and is consistent with the values on API's scorecard.

5.2.3.2.2 Customer Satisfaction

Customer Satisfaction performance measures reported by API include: First Contact Resolution, Billing Accuracy and Customer Satisfaction Survey Results. API's target for Billing Accuracy is aligned with OEB's target of 98%.

API measures First Contact Resolution performance by tracking the number of escalated calls as a percentage of total calls taken by the customer service center. API strives to have less than 1% of total calls escalated, consistent with historical performance.

API conducts annual customer surveys and engages in a large variety of consultation activities with customers and stakeholders. The feedback obtained through these activities provides API with a sense of customer preferences that can be considered in both short-term and long-term plans. API's target is to exceed the Ontario benchmark for customer satisfaction in its annual surveys. API strives to meet the needs and identified priorities of its customers as identified through surveys and engagement. API considers historical performance and Ontario benchmarks in evaluating its annual satisfaction scores. As summarized in Section 5.2.1.3 and further detailed in Section 5.4.1.3, in addition to annual satisfaction surveys, API conducted more extensive customer engagement surveys specific to this DSP and the results of those surveys have informed the development of the DSP.

Customers continue to rate API very high in terms of overall customer satisfaction, and API consistently exceeds the applicable OEB targets for customer satisfaction, as illustrated in the following table.

Table 2.8: Performance Measures - Customer Satisfaction

Measures | Target	2018	2019	2020	2021	2022
First Contact Resolution | No Target	98.63%	97.10%	100.00%	100.00%	98.64%
Billing Accuracy | > 98%	100.00%	100.00%	100.00%	100.00%	100.00%
Customer Satisfaction Survey Results	86.06%	81.61%	84.84%	88.36%	85.46%

API has consistently exceeded targets with respect to First Contact Resolution and Billing Accuracy metrics and expects to continue to meet or exceed these targets throughout the forecast period.

Further details of the recently completed customer engagement surveys specific to this DSP, along with discussion of how API's planned investments for the 2025-2029 forecast period have considered the needs of its customers, are provided in Section 5.4.1.3

5.2.3.3 Operational Effectiveness

5.2.3.3.1 Safety

Safety is a core value at API for employees, contractors working on behalf of API, and the public. API provides necessary training for its employees to maintain safety as a priority. Any incidents or accidents that do occur are reported, reviewed, and communicated within the organization with a goal of improving processes and procedures to prevent further incidents. Communication may be through additional training and bulletins to bring awareness of historical incidents.

ESA annually reports several safety-related metrics to the OEB for inclusion on LDC scorecards. The safety measures reported by ESA include:

- Public Awareness of Electrical Safety
- Compliance with Ontario Regulation 22/04
- Serious Electrical Incident Index

API continues to be compliant with Ontario Regulation 22/04 and has reported zero serious incidents throughout the historical period. API will continue to maintain its core value of safety and will continue to reinforce the importance of safety throughout all aspects of its business. Furthermore, through public education programs such as First Responders presentations and its school safety program, API will continue to bring public awareness of the safety risks its assets present to customers, how to avoid incidents, and how to appropriately respond should an incident occur. In 2022, UtilityPulse was engaged to complete surveys in relation to "Public Awareness of Electrical Safety". Province-wide scores ranged from 68% to 99.5%, with both average and median Index scores of 83%. API's score of 82% suggests that members of the public are generally well-informed about the safety hazards associated with electrical distribution systems, but also that further education and engagement would be beneficial.

Table 2.9: Performance Measures – Safety

Measures | Target	2018	2019	2020	2021	2022
Level of Public Awareness	82.00%	83.00%	83.00%	83.00%	82.00%
Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C
Serious Electrical Incident Index	0	0	0	0	0

API considers safety as a key objective in its asset management process – from project scoping to project construction and close out. It is API's intention to continually improve on its high level of safety performance.

5.2.3.3.2 System Reliability

System reliability is an indicator of the quality of electricity supply received by the customer. System reliability and performance is monitored on a monthly and annual basis. Periodic reports produced by API's OMS allow for the tracking and analysis of reliability performance.

The reliability of supply is primarily measured by internationally accepted indices SAIDI and SAIFI as defined in the OEB's Electricity Reporting & Record Keeping Requirements dated March 8, 2023. SAIDI, or the System Average Interruption Duration Index, is the average outage duration that customers experience in the year, expressed as hours per customer per year. It is calculated by dividing the total customer hours of sustained interruptions over a given year by the average number of customers served. SAIFI, or the System Average Interruption Frequency Index, is the number of outages each customer experiences in the year on average, expressed as the number of interruptions per year per customer. It is calculated by dividing the total number of sustained customer interruptions over a given year by the average number of customers. An outage is considered sustained if it lasts for at least one minute.

$$SAIDI = \frac{Total\ customer\ hours\ of\ sustained\ outages}{Average\ number\ of\ customers\ served}$$

$$SAIFI = \frac{Total\ customer\ outages}{Average\ number\ of\ customers\ served}$$

Loss of supply ("LOS") outages occur due to problems related to transmission assets that are not owned by API. API tracks SAIDI and SAIFI including and excluding LOS. Major Event Days ("MED**"**) are calculated using the IEEE Standard 1366 approach (the preferred method indicated in the Canadian Electricity Association's Major Event Determination Reference Guide). MEDs are then confirmed by assessing whether interruption meets the remainder of the qualitative criteria in the OEB's Electricity Reporting & Record Keeping Requirements, for example whether the incident was beyond the control of API, and whether the event caused exceptional and/or extensive damage to assets.

API's Distribution System Interruption Reports form, which is completed for every outage contain detailed information on the outage location, cause, equipment involved, and customers impacted. There is also a section where recommendations and comments can be made by the operational staff involved in outage response where they believe that follow up by other departments is warranted. As the outage records are populated in API's outage database, copies are also circulated to any department flagged for follow up action. This ensures that specific issues of concern (e.g. repeated failure of a certain type of equipment, forestry concerns on a specific line section, etc.) are routed to the department that can most adequately resolve the issue.

API's reliability indices for 2019-2023 are shown in the figures below.

Figure 2.4: Performance Measure - SAIDI

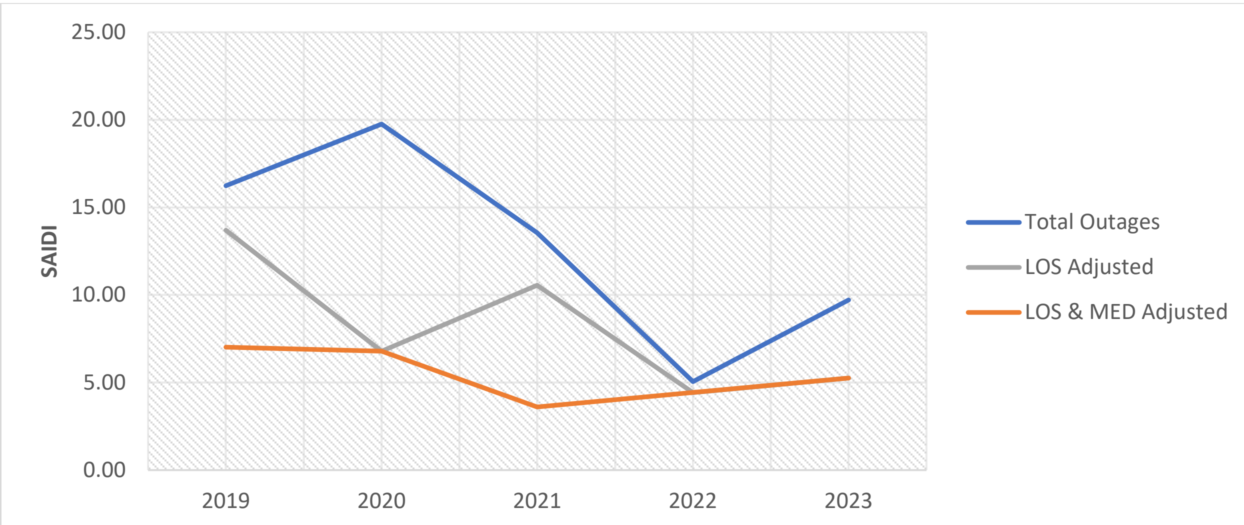
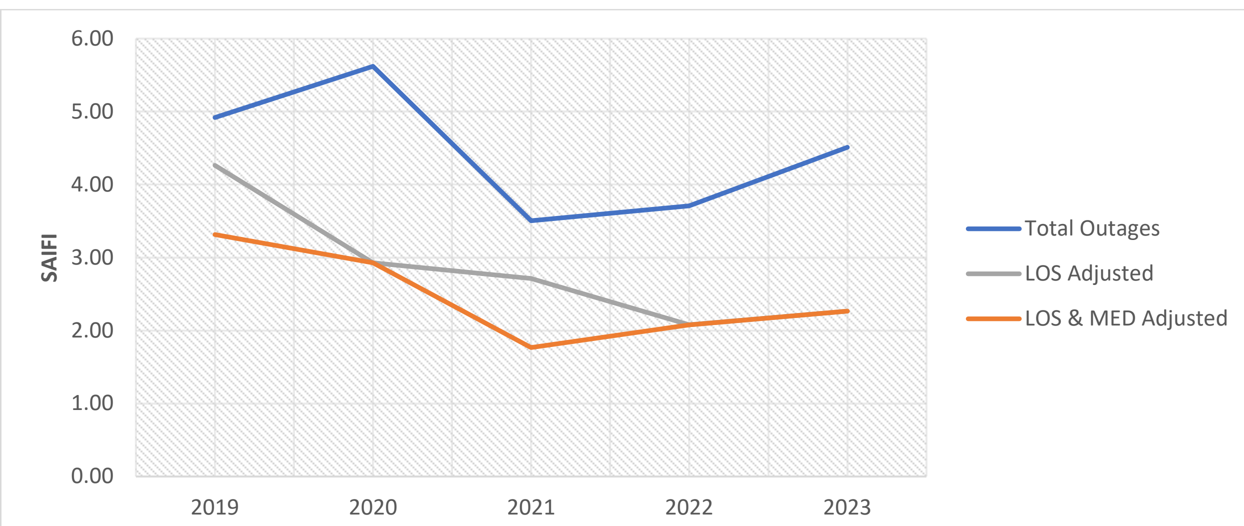


Figure 2.5: Performance Measure - SAIFI



The calculated reliability values are shown in Table 2.10. API has improved its reliability over the historical period, exceeding the performance targets set in the prior DSP.

Further, API has planned investments in the budget to continue to improve the reliability service for the benefit of its customers. Since 2015, API's OMS has leveraged outage information available from smart meters to allow API to more accurately record customers impacted and outage durations. The OMS has also assisted with consistency in applying the appropriate outage cause code. Over the past five years when outage data is adjusted for MED and LOS, SAIFI is averaging 2.47 and SAIDI is averaging 5.42.

Table 2.10: 2019-2023 Reliability Metrics

Metric	2019	2020	2021	2022	2023	Average
Total Outages						
SAIDI	16.23	19.76	13.55	5.05	9.71	12.86
SAIFI	4.92	5.62	3.5	3.71	4.51	4.45
Loss of Supply Adjusted						
SAIDI	13.7	6.79	10.55	4.43	5.25	8.14
SAIFI	4.26	2.93	2.71	2.08	2.27	2.85
Loss of Supply and Major Event Adjusted						
SAIDI	7.3	6.79	3.61	4.43	5.25	5.42
SAIFI	3.39	2.93	1.77	2.08	2.27	2.47

Table 2.11 presents a summary of outages that have occurred within API's service territory. The summary provides three different categorizations for counting outages. The table highlights a slight decreasing trend of outages with API's service territory, excluding MED and LOS outages. Further breakdown by cause codes is provided in the subsequent subsections.

Table 2.11: Outage Summation 2019-2023

Categorization	2019	2020	2021	2022	2023
All Outages	612	575	623	680	511
All Outages excluding LOS	604	559	607	670	495
All Outages excluding LOS and MED	513	559	513	670	495

API experienced MEDs in 2019 and 2021. The outages attributed to a variety of cause codes. Table 2.12 provides the summary overview the MEDs contributed by number of outages, number of customers out and customer hours of interruptions.

Table 2.12: Major Event Details 2019-2023

Major Event Details	2019	2020	2021	2022	2023
Number of Outages	**91**	**-**	**95**	**-**	**-**
0-Unknown	0	-	1	-	-
1-Scheduled Outage	1	-	0	-	-
2-Loss of Supply	0	-	1	-	-
3-Tree Contacts	29	-	88	-	-
5-Defective Equipment	1	-	2	-	-
6-Adverse Weather	59	-	3	-	-
9-Foreign Interference	1	-	0	-	-
Number of Customer Interrupted	**10,218**	**-**	**12,206**	**-**	**-**
0-Unknown	0	-	344	-	-
1-Scheduled Outage	2,279	-	0	-	-
2-Loss of Supply	0	-	631	-	-
3-Tree Contacts	2,412	-	10,819	-	-
5-Defective Equipment	3	-	7	-	-
6-Adverse Weather	5,523	-	405	-	-
9-Foreign Interference	1	-	0	-	-
Number of Customer Hours Interrupted	**74,077**	**-**	**85,010**	**-**	**-**
0-Unknown	0	-	625	-	-
1-Scheduled Outage	1,557	-	0	-	-
2-Loss of Supply	0	-	158	-	-
3-Tree Contacts	50,926	-	83,677	-	-
5-Defective Equipment	21	-	266	-	-
6-Adverse Weather	21,564	-	284	-	-
9-Foreign Interference	9	-	0	-	-

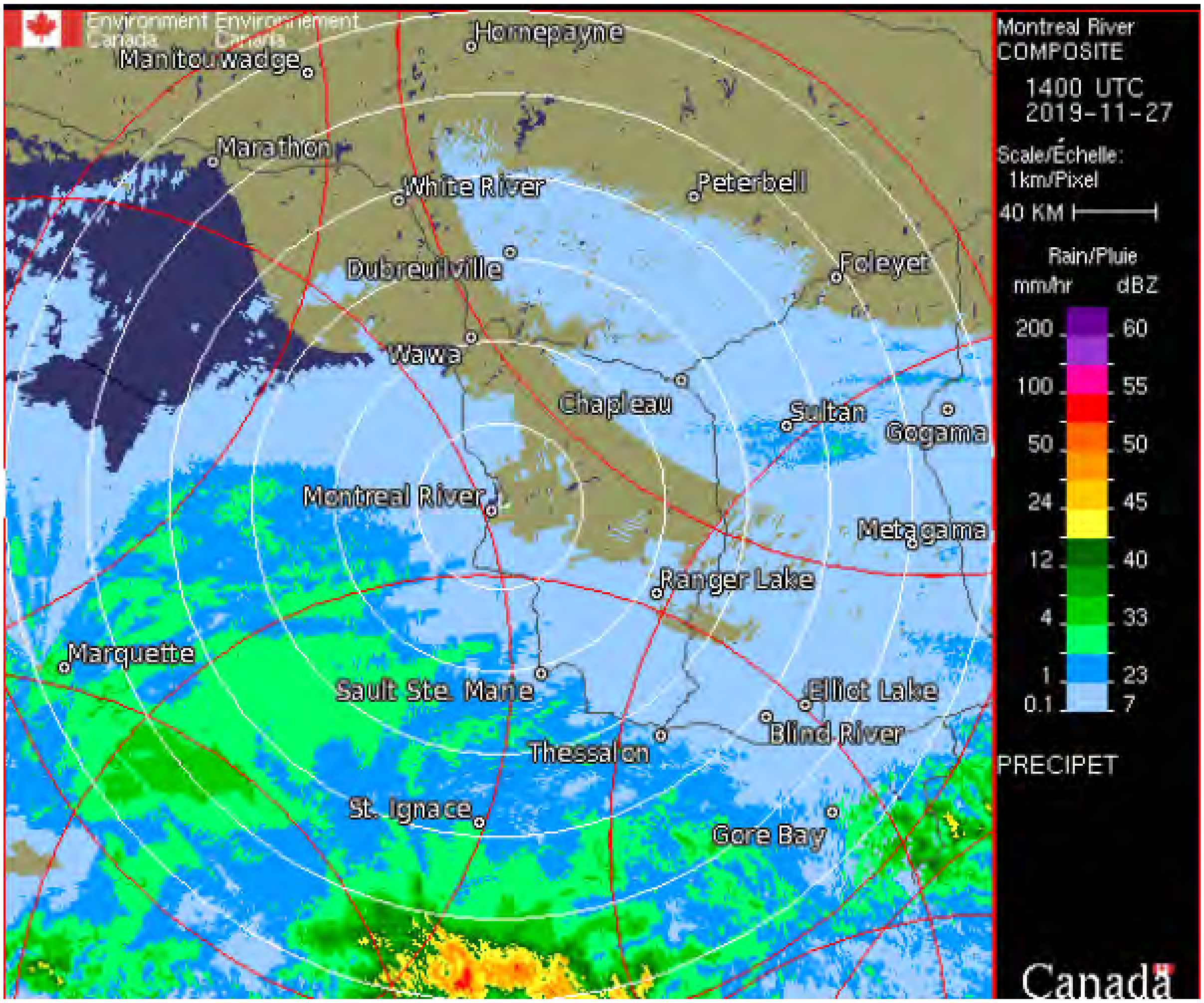
In 2019, API experienced 2 Major Events

November 27, 2019

An early winter storm descended upon the Algoma region on November 27th, bringing rain, heavy wet snow, freezing rain and winds gusting up to 78km/h. The most significant impact was experienced by the trees and power lines in the area being laden with heavy, wet snow. Although all regions within API's service territory felt the effect, the most affected area was east of Sault Ste Marie. The Goulais and Batchawana areas north of Sault Ste Marie did have some large-scale outages as well.

It took approximately 11 hours to restore 90% of the customers who were interrupted. For the outages affecting the remaining 10%, several had a duration longer than 24 hours.

Figure 2.6: Radar Image of November 27, 2019



<u>December 29 & 30, 2019</u>

On December 29th, a winter storm hit the API service territory east of Sault Ste Marie, primarily on St. Joseph Island. With mild temperatures hovering right around the zero-degree mark, precipitation that occurred during this and the following days had a heavy impact on the region. Significant periods of freezing rain and heavy, wet snow – combined with some episodes of gusty winds up to 50+ km/h – contributed to the overall impact of the storm.

The freezing rain and snow caked on to trees, weighing them down to the point of bowing over to the ground or breaking off altogether. These trees impacted the power lines in the area, which resulted in many outages – multiple interruptions on the same feeders in some instances.

The heavy snow and ice load on vegetation, coupled in some cases with some gusty winds, caused trees to fall onto power lines and cause damage and interruptions.

It took approximately 71 hours to restore 90% of the customers who were interrupted. As crews triaged the areas of concern and focused their efforts for maximum effectiveness, large groups of customers were restored several times over the first two days of crew response only to lose power again as further tree contacts and damage occurred.

Also, response times were hampered by the significant effort required simply to get to affected areas, as crews had to remove trees and debris from roads in order to pass through to the locations of some of the outages.

Figure 2.7: Radar Image of December 29, 2019

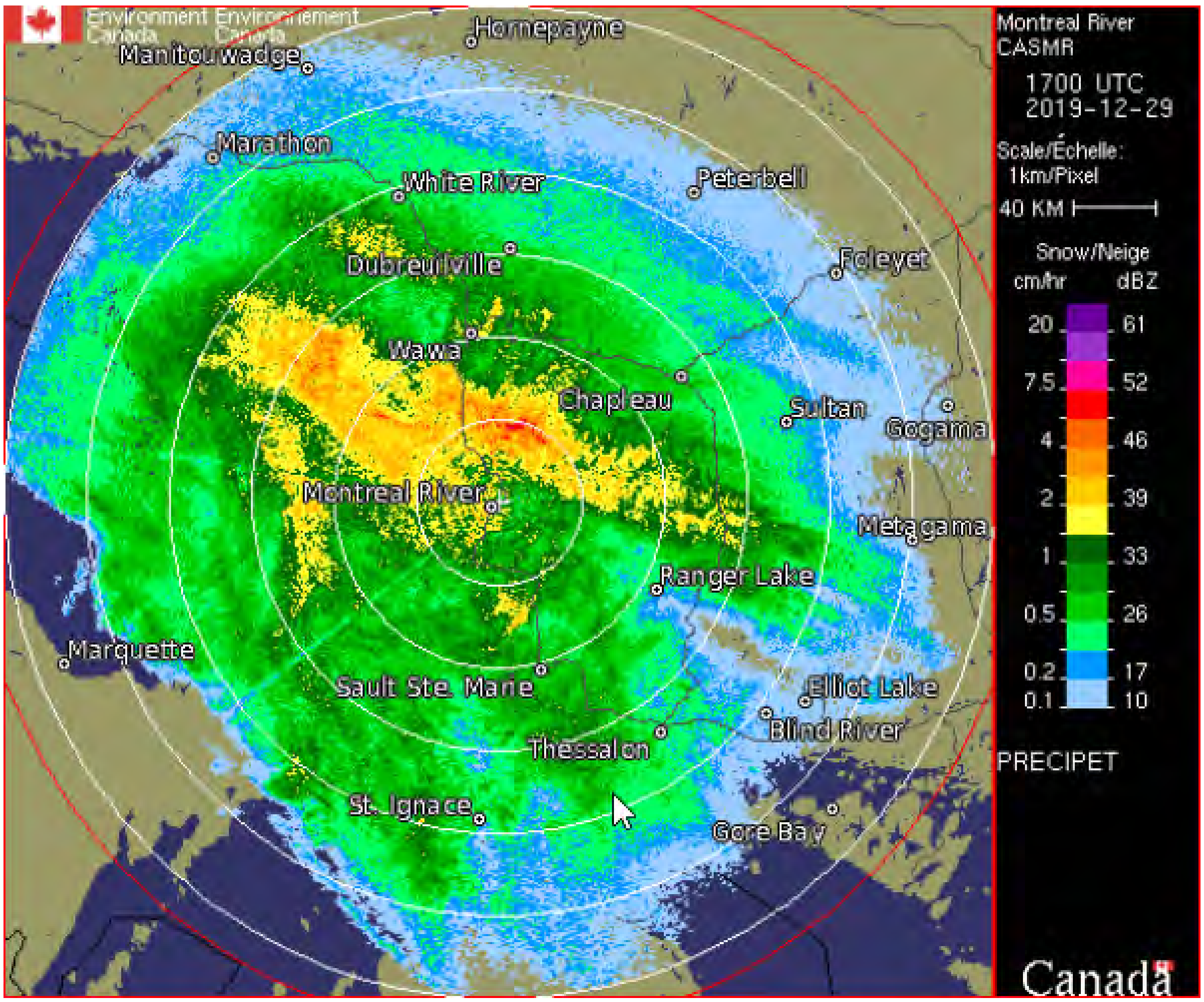
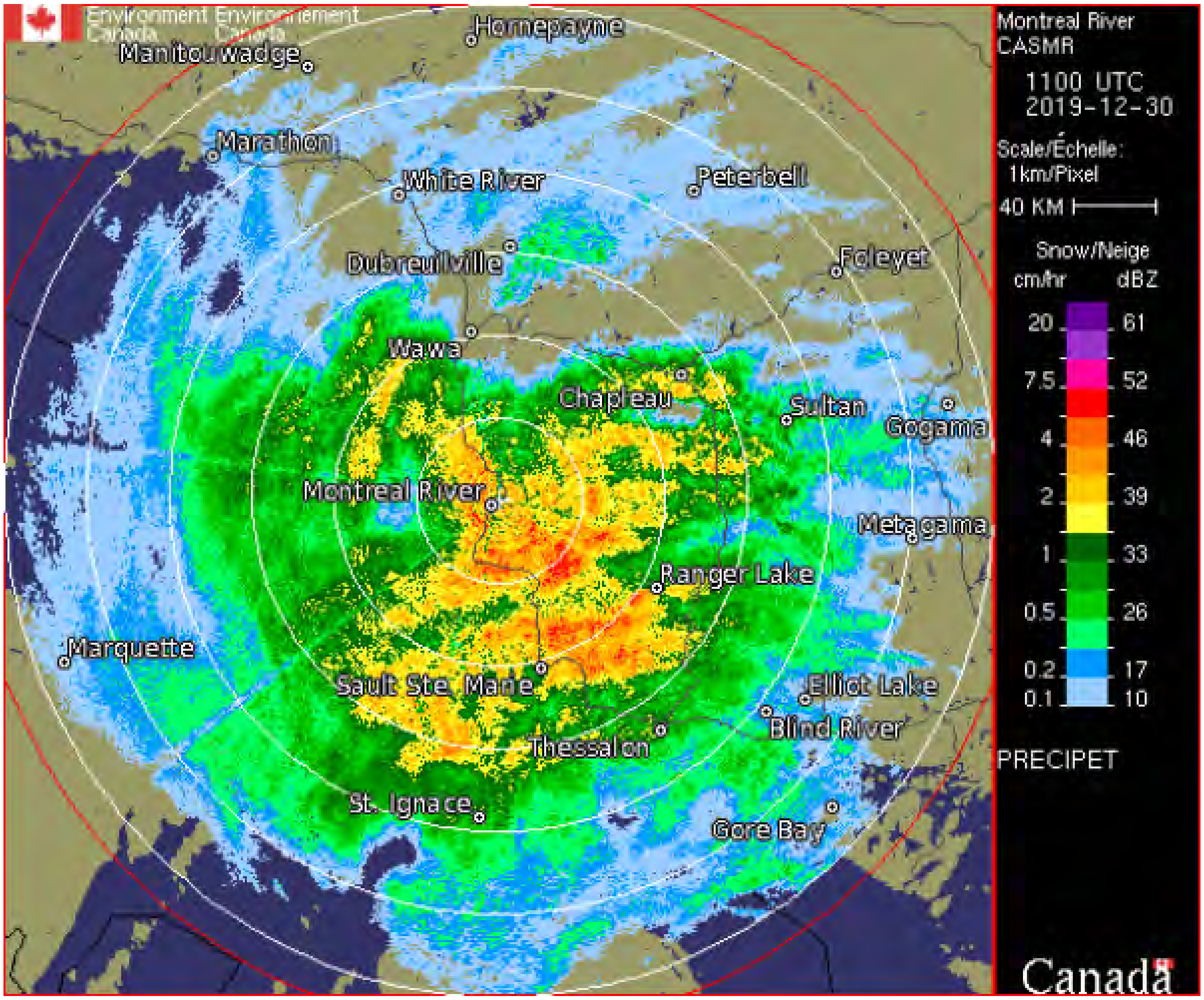


Figure 2.8: Radar Image of December 30, 2019



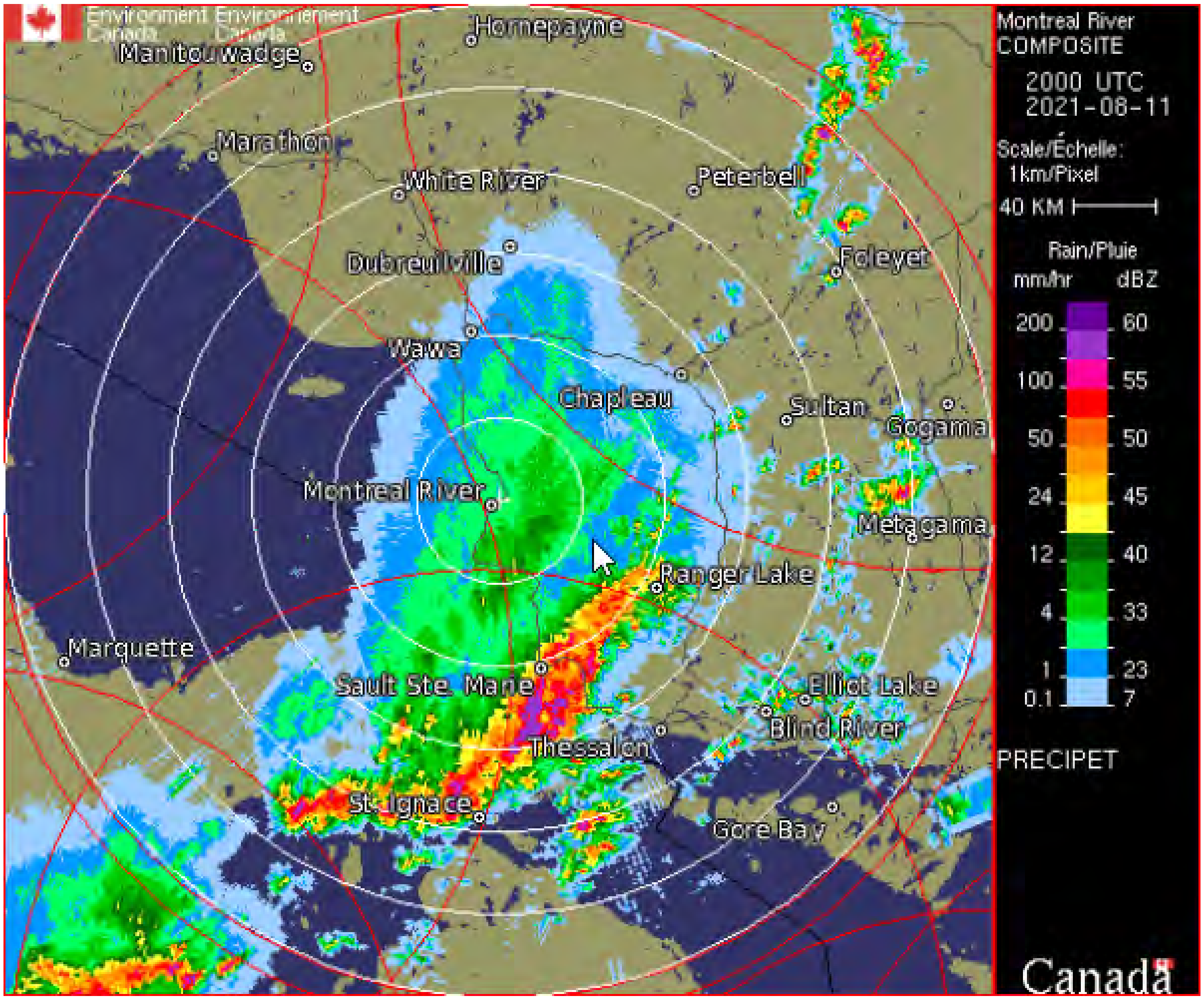
In 2021, API experienced 3 Major Events

<u>August 11, 2021</u>

On the afternoon of Wednesday August 11, 2021, severe thunderstorms moved through the API service territory – mostly to the east of Sault Ste Marie. This severe weather brought heavy winds and rain, and caused damage to API infrastructure and customer property, as many trees were brought down onto poles and lines.

It took approximately 27.7 hours to restore 90% of the customers who were interrupted. As the outages did not start happening until later in the day, it took time to mobilize additional crews (beyond the regular on-call crew for the area) and deploy all available resources. Also, for the health and safety of the crew, they were taken off duty at the end of the day (at 11:30pm) and re-engaged at dawn the next morning. Finally, notifications of a few of the events did not come in until the last two hours of the day, so crews were not assigned to those areas until the next day.

Figure 2.9: Radar Image of August 11, 2021

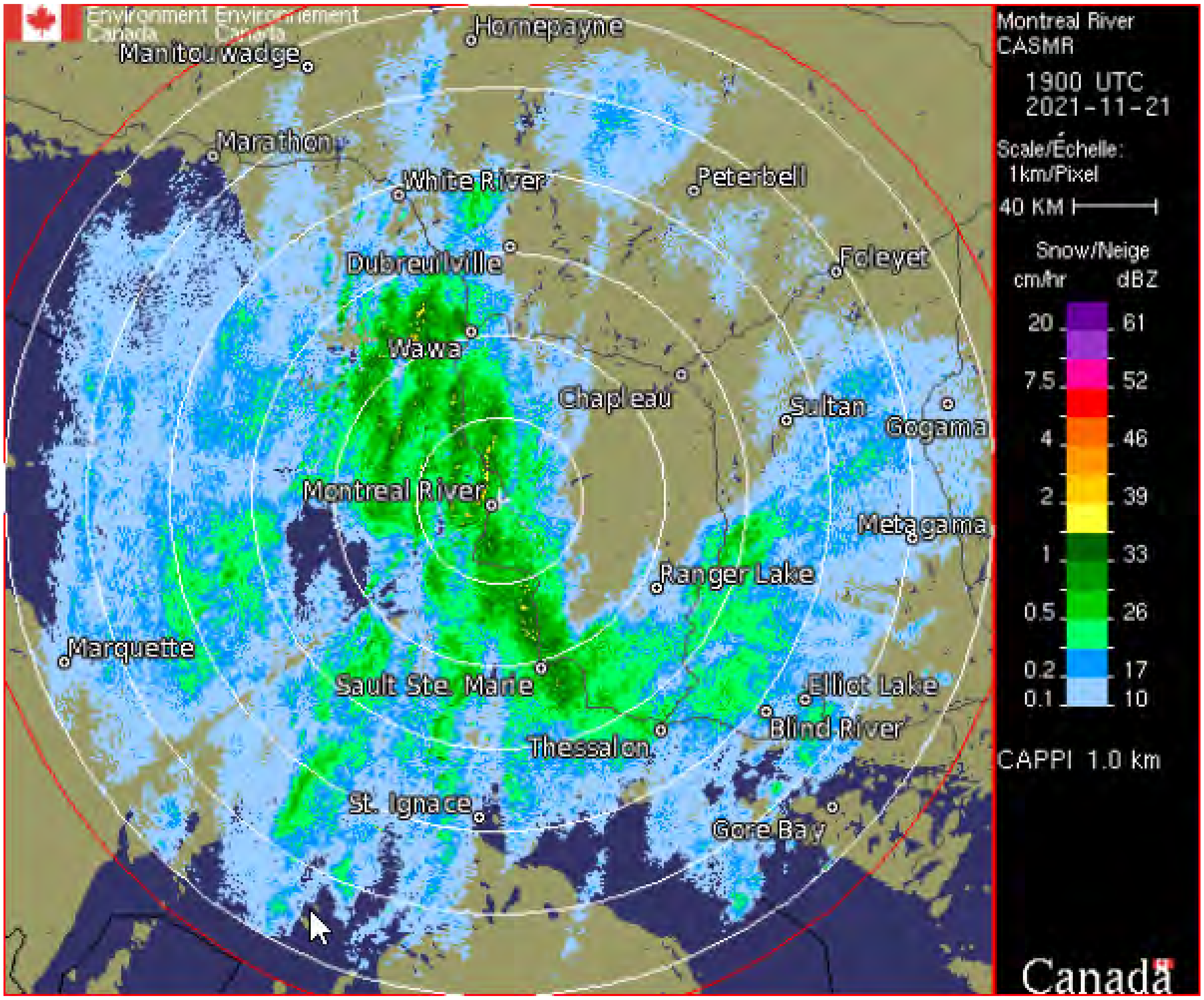


November 21, 2021

On Sunday November 21, 2021, a significant winter storm descended upon the API service territory, bringing heavy snow and high winds. This resulted in unsafe travel conditions (portions of area highways were even closed for periods of time during the event), and multiple trees falling onto and damaging API line infrastructure. Severe winter weather started in the area at 6:00pm, with sustained winds of 44-58 km/h and gusts registering up to 86 km/h throughout the rest of the day, along with blowing snow.

It took approximately 14.85 hours to restore 90% of the customers who were interrupted. As a large number of the overall customers affected came from an interruption that started after several significant initial outages that crews were already engaged in, and ran through the overnight, which contributed to response and restoration delays.

Figure 2.10: Radar Image of November 21, 2021

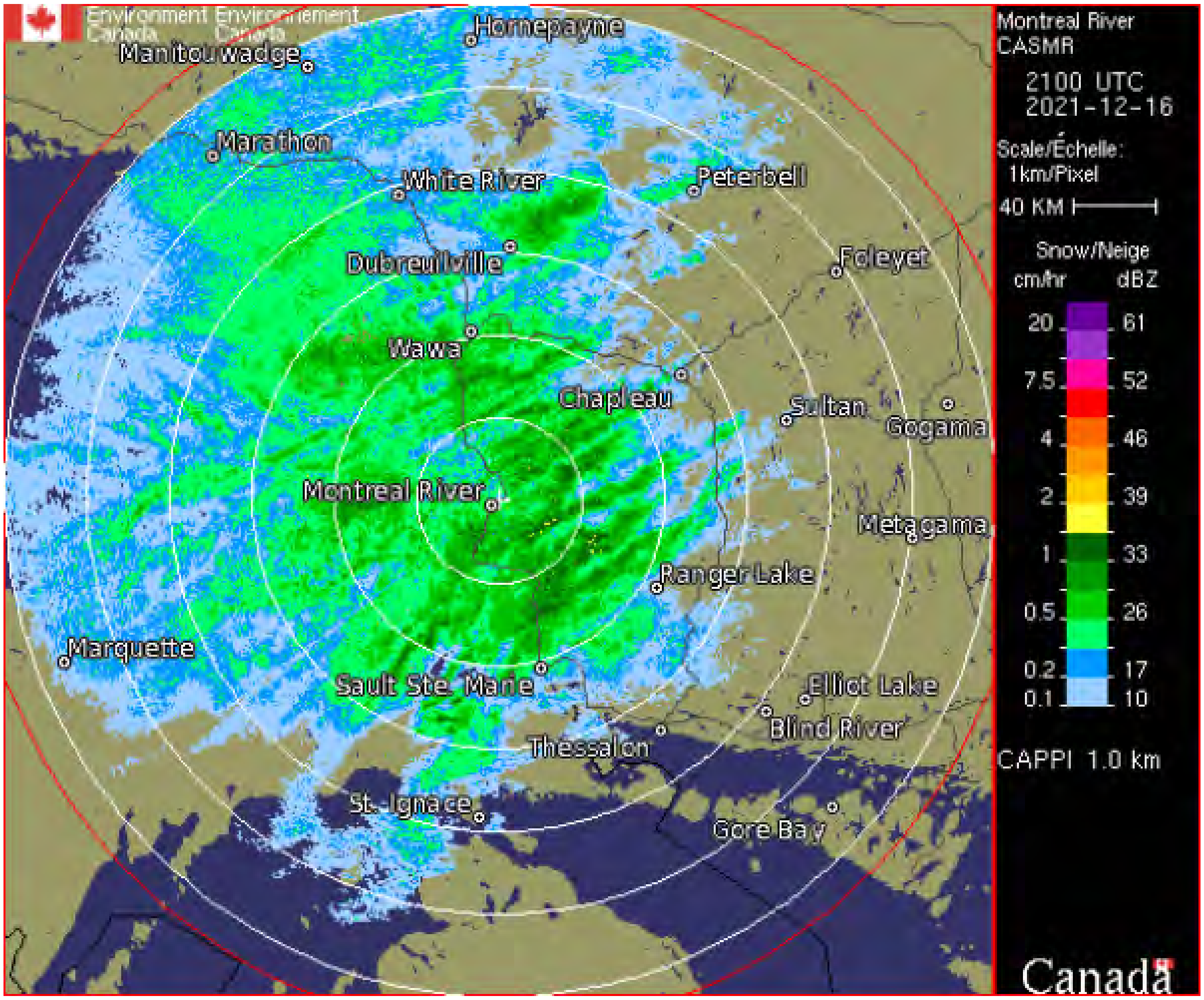


<u>December 16, 2021</u>

On Sunday December 16, 2021, a substantial storm occurred throughout the API service territory. Blustery conditions and declining temperatures brought a mix of rain, sleet and snow, as well as heavy winds with gusts up to 84 km/h, which resulted in numerous power interruptions due to trees falling onto power lines. Storm conditions started early in the day, with wind and rain at the onset. The precipitation changed from rain, to sleet, and eventually to snow as temperatures dropped throughout the day. Winds remained sustained, with significant gusts.

It took approximately 20.87 hours to restore 90% of the customers who were interrupted.

Figure 2.11: Radar Image of December 16, 2021



Outage Details for Years 2019-2023

The following sections provide the breakdown of historical outages for the years 2019-2023 regarding the number of outages, number of customers interrupted, and number of customer hours experienced by the outages. Tracking outage performance by cause code provides API information on specific outage causes that need to be addressed should an undesired trend develop. As with the reliability indices, the 5-year historical average is used as a target.

Table 2.13 presents the count of outages broken down by cause code. The number of outages is an indication of outage frequency and impact customers differently based on customer class. For example, residential customers may tolerate several outages with shorter duration while commercial and industrial customers can tolerate less outages with longer duration thereby reducing overall impact on production and business disruption.

Table 2.13: Number of Outages by Cause Codes 2019-2023 - Excluding MEDs

Cause Code	2019	2020	2021	2022	2023	Total Outages	Percent Share	Linear Slope
0-Unknown/Other	51	72	79	98	76	376	13.4%	7.6
1-Scheduled Outage	80	83	91	169	135	558	19.8%	19.6
2-Loss of Supply	8	16	15	10	16	65	2.3%	1
3-Tree Contacts	161	203	156	170	93	783	27.8%	-16.9
4-Lightning	20	15	17	28	21	101	3.6%	1.5
5-Defective Equipment	135	112	104	130	87	568	20.2%	-7.8
6-Adverse Weather	28	8	7	13	4	60	2.1%	-4.3
7-Adverse Environment	3	2	4	5	2	16	0.6%	0.1
8-Human Element	1	0	0	0	1	2	0.1%	0
9-Foreign Interference	39	63	52	57	76	287	10.2%	6.8
Total	**526**	**574**	**525**	**680**	**511**	**2,816**	**100%**	**7.6**

Figure 2.12: Total Number of Outages by Year - Excluding MEDs

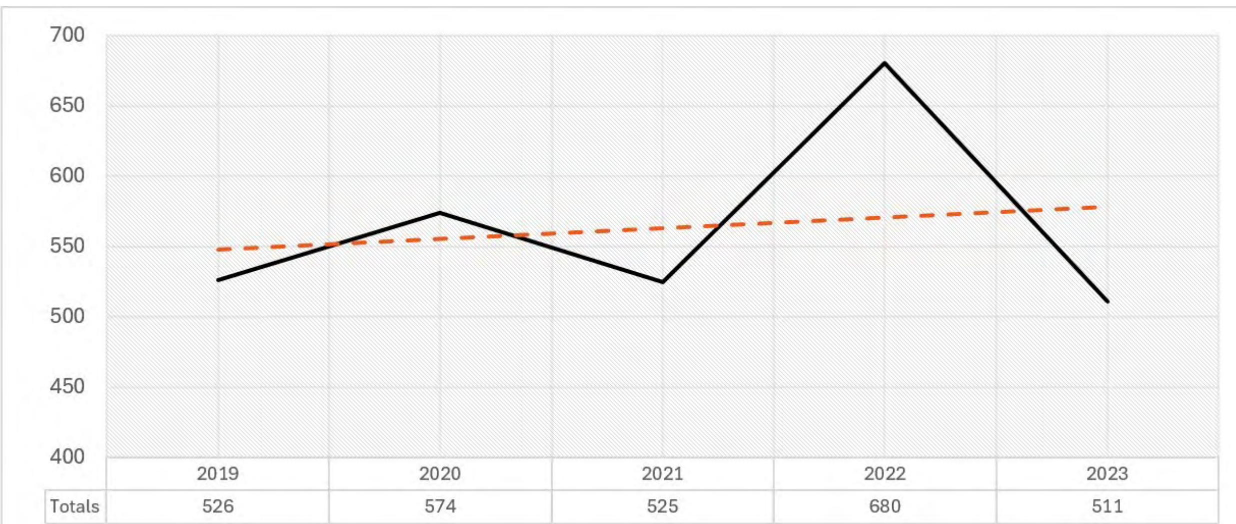
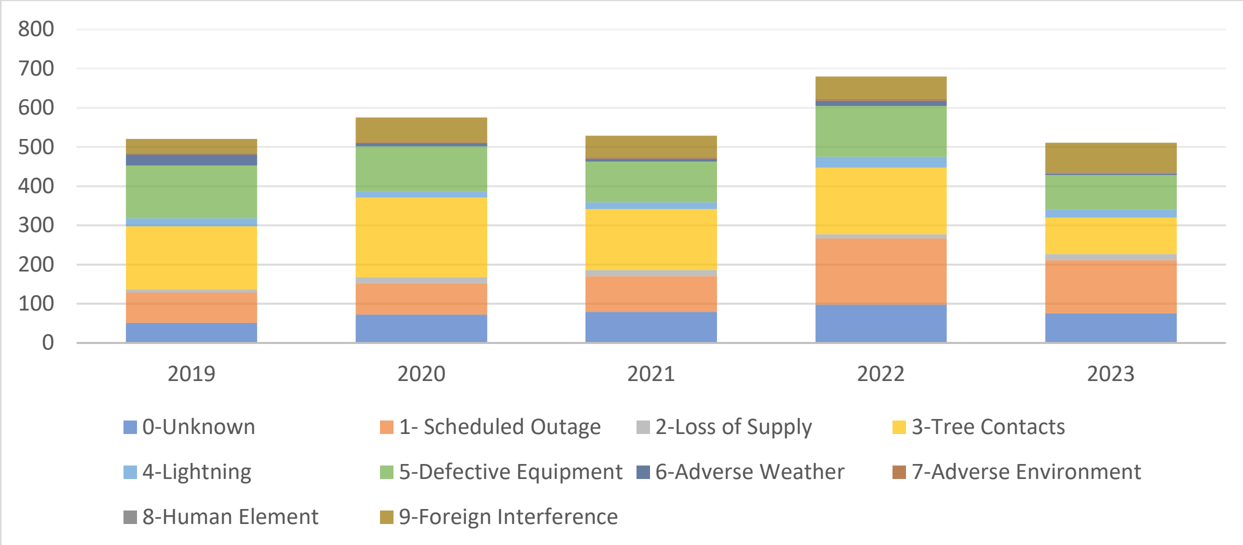


Figure 2.13: Total Number of Outages by Year and Cause Category - Excluding MEDs



The total number of outages experienced over the historical period at API exhibits an increasing trend. Within the historical period, API experienced a high of 680 outages and a low of 511 outages. This translates to an average range of 1.4 to 1.9 outages per day. The linear slope provides the average annual change based on the linear regression model. In 2022 and 2023, the quantity of scheduled outages has increased significantly due to line rebuild and planned maintenance work. The performance tied to tree contacts, defective equipment and adverse weather has seen a downward trend.

The number of customers interrupted ("CI") is a measure of the extent of outages, whereas the number of customer-hours interrupted ("CHI") is a measure of outage duration and the number of customers impacted.

Table 2.14 and Table 2.15 present the number of CI and CHI broken down by cause code.

Table 2.14: Customers Interrupted by Cause Codes 2019-2023 - Excluding MEDs

Cause Code	2019	2020	2021	2022	2023	Total Outages	Percent Share	Linear Slope
0-Unknown/Other	1,198	1,521	1,601	2,900	3064	10,284	4.1%	511.1
1-Scheduled Outage	10,557	9,838	6,814	3,388	4515	35,112	14.2%	-1,853.4
2-Loss of Supply	7,708	32,623	9,027	20,051	27,913	97,322	39.2%	2,783.8
3-Tree Contacts	11,643	11,820	6,876	10,436	6,200	46,975	18.9%	-1,227.0
4-Lightning	2,349	1,865	1,121	1,349	270	6,954	2.8%	-467.4
5-Defective Equipment	9,277	8,615	4,456	6,195	11,888	40,431	16.3%	280.2
6-Adverse Weather	1,416	927	441	330	823	3,937	1.6%	-178.3
7-Adverse Environment	55	34	9	34	6	138	0.1%	-9.8
8-Human Element	2,279	0	0	0	258	2,537	1.0%	-404.2
9-Foreign Interference	1,070	877	344	924	1,142	4,357	1.8%	19.1
Total	**47,552**	**68,120**	**30,689**	**45,607**	**56,079**	**248,047**	**100%**	**-545.9**

Figure 2.14: Total Number of Customers Interrupted by Year - Excluding MEDs

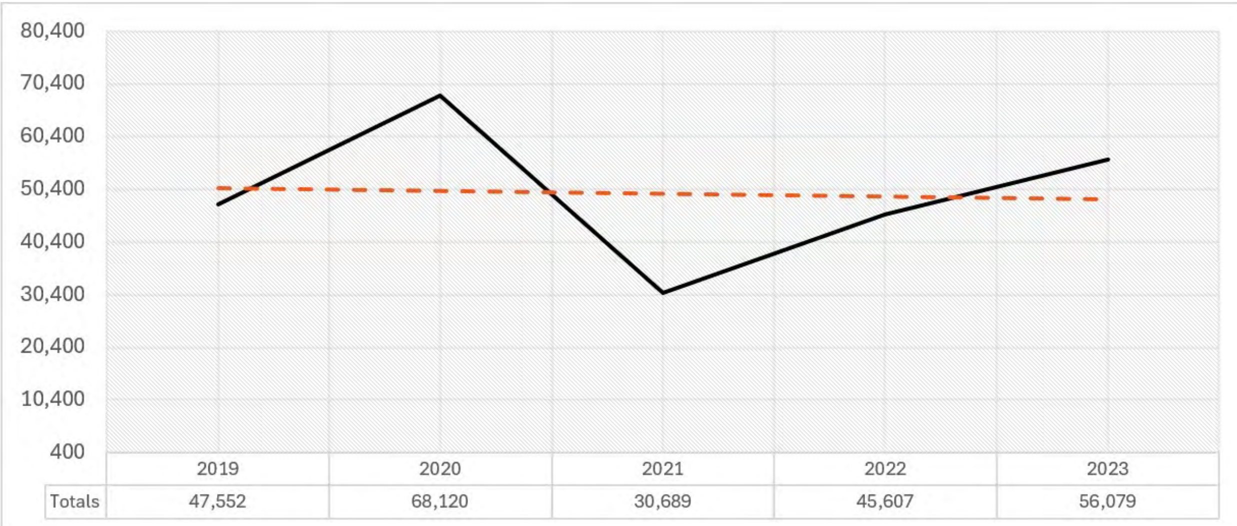
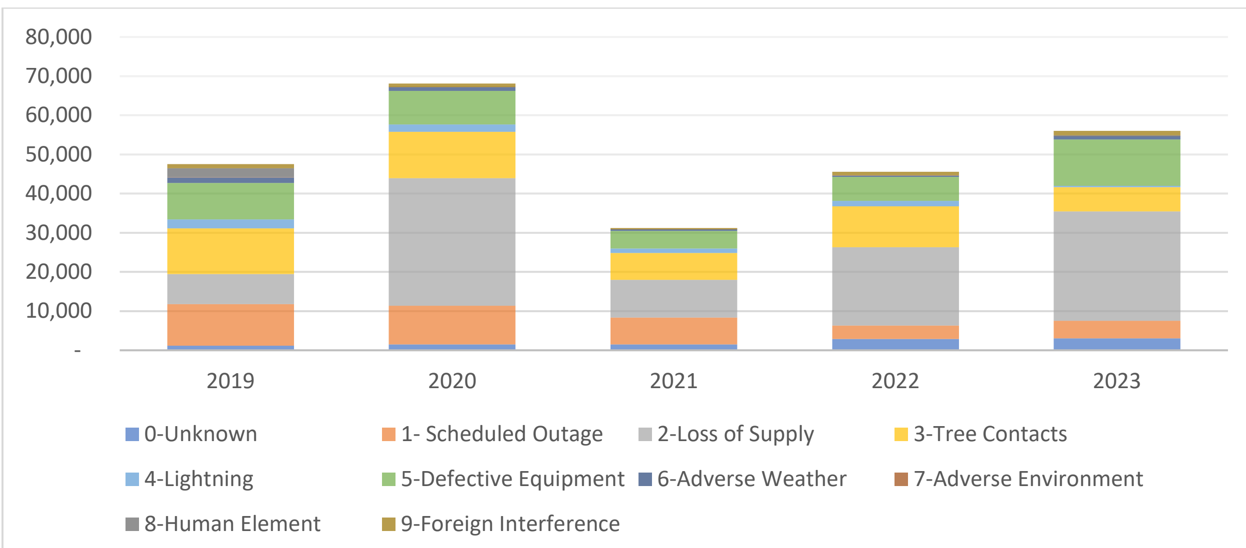


Figure 2.15: Total Number of Customers Interrupted by Year and Cause Category – Excluding MEDs



The number of CI has had a downward trend over the historical period, which can be mainly to the result of the decrease in tree-related outages and lessened impact (lower number of customers affected) during tree outages. This decrease is mainly attributed to the success of API's VM program and practices. The CI impact associated with scheduled outages also has a decreasing trend, which is a combination of more efficient work practice and location of work. API's VM practices have also positively contributed to the overall decreasing CI trend. Loss of supply CI impact has increased over the historical period. The loss of supply outages has been relatively consistent year-over-year, so the increase in CI is attributed to the outage occurring at supply station connected a larger quantity of customers.

Table 2.15: Customer-Hours Interrupted by Cause Codes 2019-2023 - Excluding MEDs

Cause Code	2019	2020	2021	2022	2023	Total Outages	Percent Share	Linear Slope
0-Unknown/Other	1,858	2,536	4,094	4,658	5,766	18,912	3.1%	993.7
1-Scheduled Outage	29,283	38,204	18,891	11,806	17,020	115,204	18.6%	-5,092.4
2-Loss of Supply	30,522	157,165	36,557	7,711	55,523	287,478	46.4%	-9,945.2
3-Tree Contacts	29,091	24,419	11,645	23,296	11,741	100,191	16.2%	-3,582.3
4-Lightning	3,484	1,994	2,172	1,128	456	9,234	1.5%	-692.3
5-Defective Equipment	14,803	12,291	6,171	9,594	27,118	69,978	11.3%	2,193.2
6-Adverse Weather	3,816	1,612	726	2,262	1,231	9,646	1.6%	-451.9
7-Adverse Environment	918	10	12	83	10	1,033	0.2%	-174.4
8-Human Element	190	0	0	0	357	547	0.1%	33.4
9-Foreign Interference	2,615	1,230	346.6	1,577	1,638	7,407	1.2%	-160.7
Total	**116,581**	**239,460**	**80,614**	**62,115**	**120,860**	**619,630**	**100%**	**-16,878.7**

Figure 2.16: Total Number of Customer-Hours Interrupted by Year - Excluding MEDs

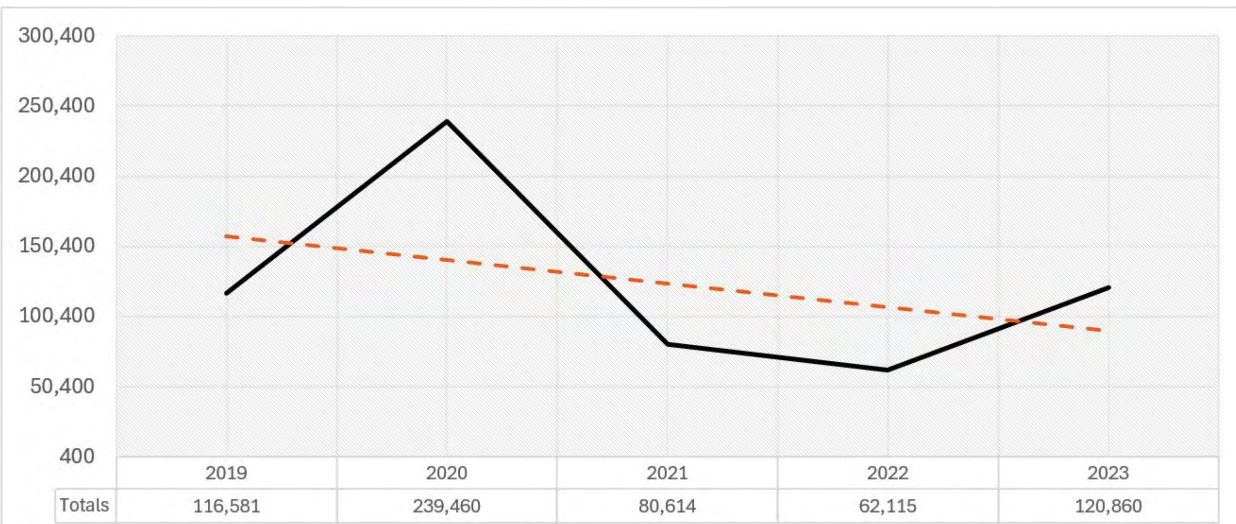
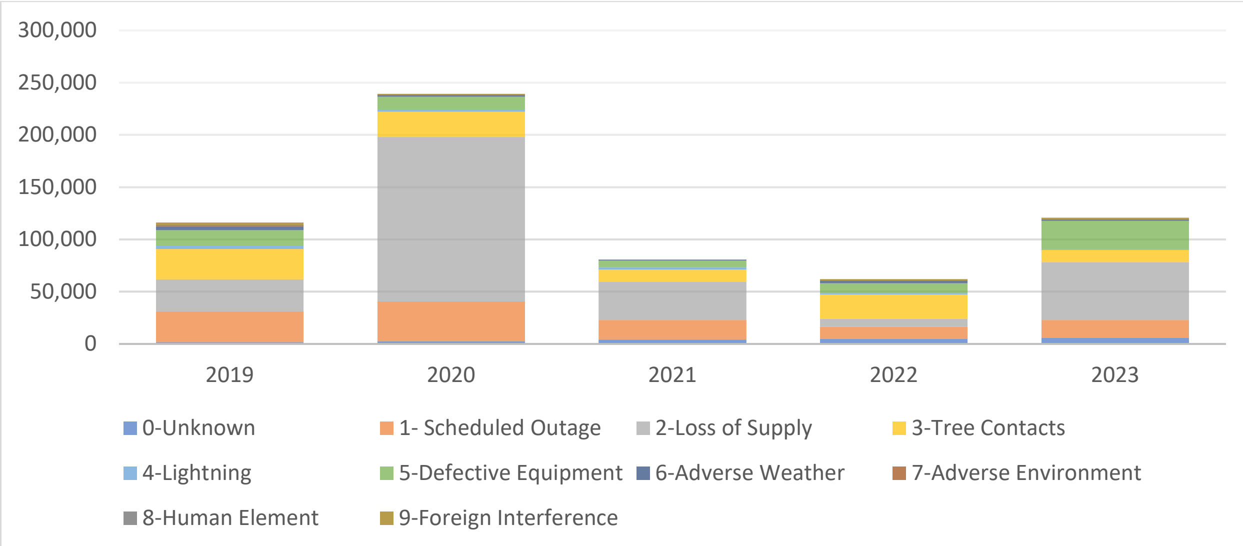


Figure 2.17: Total Number of Customer-Hours Interrupted by Year and Cause Category – Excluding MEDs



The number of CHI has had a decreasing trend over the historical period, which can be similarly attributed to the decrease in tree-related outages and lessened impact during tree outages. The CHI impact associated with scheduled outages also has a decreasing trend, which is a combination of more efficient work practice and location of work.

Overall, even though API is seeing an increasing trend in the number of outages, the customer impact and customer-hour impact of those outages has decreased over the historical period, which ultimately indicates that API is continuing to see general improvement in reliability, especially for the items in which API has control.

API has planned investments to continue managing the impact of outages on the total CI and CHI and has specifically targeted investment that will reduce the impact of loss of supply related outages. API follows a preventative VM program to address the surrounding vegetation near its distribution system. The program is described in Appendix B. In addition to the VM program, API's System Renewal investments targets the proactive replacement of assets with a higher probability of failure, and its System Service investments target reduction in outage duration, contingency risk, and increasing the supply efficacy of API's supply connections. Tools such as the ACA will assist with providing additional granularity in the prioritization of asset replacements. Supporting studies assist API with capital planning that can mitigate the effects of outages due to defective equipment or any other outage cause. Lastly, API continues to plan proactive capital and O&M activities to have a minimal impact to customers by addressing multiple work orders in an area at once rather than multiple times over an extended period. Additionally, API attempts to schedule such work, where possible, at times that will have lower impact on the customers affected. API communicates planned outages in advance to affected customers. While these efforts are not reflected in the reported reliability metrics, they can have an overall benefit on customers' experience, by reducing the inconvenience of an outage, or otherwise allowing customers to plan in advance for an outage.

API undertook a reliability study to provide historical outage analysis, identify major outage causes and to recommend system enhancements to improve the reliability of API's distribution system. The reliability study (attached as Appendix E) identifies that most LOS outages are associated with single supply connection – Goulais TS. Approximately 62% of the CHI impact of supply outage were associated with this supply connection. Additionally, a worst performing feeder analysis was completed, which ranked feeders by CHI impact. The top three feeders from this analysis were identified as feeders 5120, 3600 and ER2. Feeder 5120 is supplied by Goulais TS, while feeder 3600 and ER2are supplied by Echo River TS. The results of this study have been considered in prioritizing investments in this DSP.

Achieving and maintaining a high level of distribution reliability is one of API's key objectives. While API has observed an improving trend in overall reliability, API believes there is some reliability risk which would result in additional material projects. Capital reliability investments are aimed at:

- Proactively upgrading deteriorating, at end-of-life facilities;
- Adding system redundancy, where possible and practical, so that customers can be supplied from alternate paths in emergency or planned outage situations; and
- Investing in grid modernization to continue gaining visibility on the state of the distribution system, to allow for improved overall response and restoration times.

API understands that reliability of electrical service is a high priority for its customers and continues to invest in programs and projects that support its reliability objectives.

Maintenance programs and operational practices are also designed with reliability in mind. For example, API maintains an industry standard systematic VM program to ensure that appropriate clearances are maintained between power lines and surrounding vegetation. In forced outage situations, outage response efforts focus on locating and repairing the faulted areas promptly so that affected customers can be restored. When system components must be taken out of service for planned maintenance, switching is carried out to minimize disruption to customers. API reviews 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.

Ongoing review of reliability statistics and the results of customer feedback show that customers continue to prioritize reliability. As a result, certain information revealed through historical outage analysis has been a significant driver in the development of the DSP. Recommendations derived from the recently completed Reliability Study include:

- Consider opportunities to minimize or eliminate outages, such as using live-line techniques or increasing crew size. Coordinate scheduled work with Hydro One to the extent possible;
- As part of the Transmitter's supply station refurbishment plans, consider opportunities to optimize the supply configuration through supply redundancy, optimized work planning and improved outage response;
- Review of VM practices for specific areas, look for area trends that may warrant a more area-specific strategy; and

- ❖ Continue the proactive replacement of aged infrastructure, with increased emphasis on critical supply feeds. Identify any gaps in and ensure that preventative maintenance on major assets is completed.

5.2.3.3.2.1 Distributor Specific Reliability Targets

API's target for its reliability during this DSP forecast period is to maintain or improve its reliability performance compared to the most recent five (5) years' history, as it relates to SAIDI and SAIFI adjusted for MED and LOS. API's approach aligns with the OEB's standard treatment for reliability targets on the distributor scorecard.

Accordingly, and consistent with the statistics presented in Table 2.10, This would currently result in the SAIDI and SAIFI targets below, (based on 2019-2023 performance).

Draft SAIDI Target, 2025-2029: 5.42 (excluding LOS and MED)

Draft SAIFI Target, 2025-2029: 2.47 (excluding LOS and MED)

The reduced SAIDI and SAIFI target compared to the prior 2020-2024 targets below indicate a significant improvement in recent reliability performance compared to the prior 5 years. API's reliability performance in 2020-2023 was consistently favourable to the prior DSP target.

2020-2024 (Prior DSP) SAIDI Target: 7.36

2020-2024 (Prior DSP) SAIFI Target: 3.16

API acknowledges that, consistent with past practice, the scorecard target will be updated once 2024 data is available so that the new scorecard measure is the 5-year average beginning with 2020 and ending with 2024.

API sets targets annually for its reliability performance, which normally involve a set percentage improvement over a multi-year rolling average performance. This target therefore incentivizes continuous improvement in reliability performance.

5.2.3.4 Asset Management & DSP Implementation Measure

5.2.3.4.1 Distribution System Plan Implementation- Annual Scorecard Assessment

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 System Access customer 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".

5.2.3.4.2 System Renewal Project Variance

While API's capital programs for sustaining replacement are based on estimated unit costs (e.g. cost/pole), more specific project-level estimates are prepared during the detailed design stage. In advance of committing to a scope of work and budget for any individual project within a program, the detailed designs and estimates are issued to the operations group in charge of construction for review and commitment to the scope and budget. This process assists with ensuring that all project-level estimates are realistic, and that ongoing actual vs plan cost analysis is meaningful. Projects costs are also reviewed on completion to ensure that any significant variances from planned costs are justifiable (e.g. due to shallow rock not identified during the initial design, due to increased travel time caused by inclement weather, etc.). The analysis of these costs and variances also ensures that the unit cost estimates used for future program-level planning continue to be reasonable. API targets for programs and projects to be completed as originally identified for the project year.

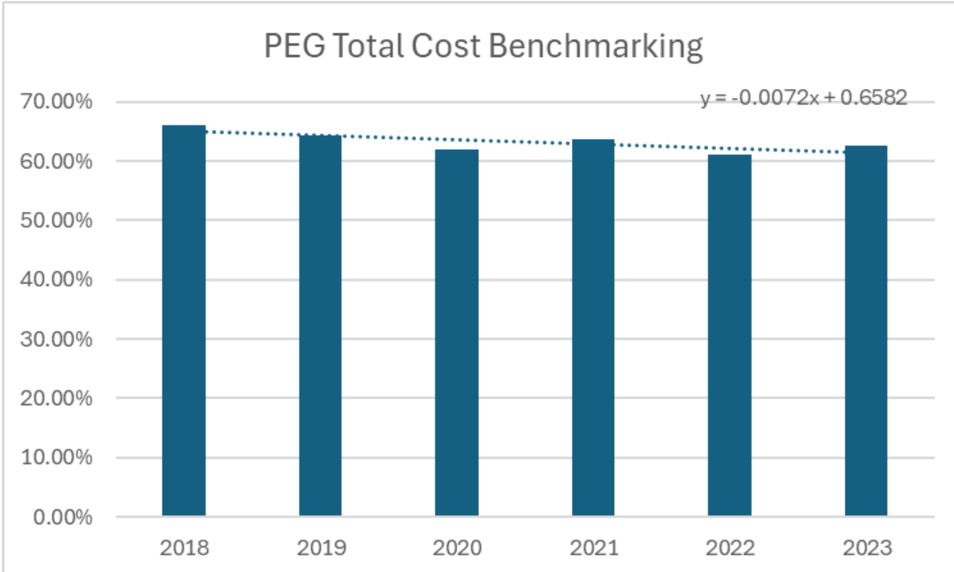
Members of the operations, forestry, engineering, finance, and procurement departments also meet on a monthly basis to review progress (physical and financial) on the annual capital program. This process ensures that all departments are aware of any issues that may impact project timing or budgets and allows for rescheduling or reprioritization of various items within the annual plan to ensure efficient use of resources and completion of overall annual targets. This process also helps to identify opportunities for improvement in the execution of the capital plan. For example, monthly meetings in recent years have identified that issues with Species at Risk legislation have affected the timing of many projects in specific areas of API's system. As a result, API has worked with the MNRF to proactively identify Species at Risk issues earlier in the design process and has also advanced the design process in relation to the timing of construction to allow more opportunity to schedule activities around timing restrictions imposed by the MNRF.

API has historically completed most of the individual projects identified in the System Renewal category. API strives to complete all identified projects within each planning year, however factors beyond API's control such as weather-related access restrictions occasionally result in projects being deferred. Occasionally, projects are also reprioritized within a planning year due to emerging risks identified through ongoing inspections and testing that were not apparent at the time of initial project prioritization, as well as increased non-discretionary work under the System Access category.

5.2.3.4.3 Cost Control

Total Cost is assessed annually by the Pacific Economics Group on behalf of the OEB. This total cost can be divided by the number of customers and kilometers of line to provide the total cost per customer and total cost per kilometer of line. In terms of API's target to improve its efficiency trend per the PEG benchmarking model, most recently assessed five years show relatively consistent year-over-year efficiency assessment improvements, as shown below.

Figure 2.18: PEG Total Cost Benchmarking



API's goal is to continue the improving trend, however API is aware that cost pressures related to the unique features described in section 5.2.1.2 may disproportionately affect API, as compared to the typical Ontario distributor. For example, increases in contractor rates and effort requirements related to API's Vegetation Management Program is expected to have a significant impact on API's OM&A in the Test Year, whereas the impact to other utilities' overall budgets is expected to be less material.

5.2.3.5 System Losses

API currently reports on the amount of loss it experiences on its system annually. API manages system design and operation to decrease system loss, as defined in the OEB Practices Relating to Management of System Losses.

API's system losses over the historical period are show in table below:

Table 2.16: System Losses

Customer Class	2019	2020	2021	2022	2023
Total kWh Delivered to API	253,100,740	250,571,206	263,158,051	277,849,319	278,754,157
Total kWh Delivered by API	235,800,481	229,140,220	244,314,344	256,287,580	259,742,424
Total kWh Distribution Losses	17,300,260	21,430,986	18,843,707	21,561,739	19,011,733
Loss Factor	1.0734	1.0935	1.0771	1.0841	1.0732

API's distribution loss factor profile range was between 7.2% - 9.35% and is above the OEB 5% threshold. API's high loss factor is the result of the low customer density, long radial distribution lines, and the overall distance between the transmission supply connection and the end customers.

API's relatively high demand loss can be largely attributed to the long runs of primary distribution lines with low customer and load density. Approximately 75% of API's primary distribution are also single phase, which tends to lead to more unbalanced feeders.

API has included several projects resulting from the recommendations of the APS that will have the added benefits of improving API's overall system losses. The projects and programs that are expected to result in a reduction in system losses are the following:

- The Goulais Voltage Conversion program
- Projects to extend API's 3-phase systems at specific feeder locations to better balance the distribution load and improve the voltage under API's *Protection, Automation & Reliability* program.
- Line Rebuild projects that specifically include conductor replacement.

Despite these projects, developments outside of API's control in API's system can contribute to the worsening of API's distribution system losses. For example, in 2024 API is anticipating a total of 8MW in incremental load to be connected to a remote section of the distribution system, relatively far from the nearest supply point. The significant incremental load is expected to be associated with relatively higher losses due to the relatively longer distance the electricity must travel to reach the load customers.

Another example of a factor that may worsen losses is the transferring of supply loads from one supply point to another, which may temporarily increase losses as the same customers are supplied from a further supply point than typical.

5.3 Asset Management Process

A distributor must use an asset management process to plan, prioritize, and optimize expenditures. The purpose of the information requirements set out in this section is to provide the OEB and stakeholders with an understanding of the distributor's asset management process, and the links between the process and the expenditure decisions that comprise the distributor's capital investment plan.

This section of the DSP provides an overview of API's asset management process, an overview of the assets managed by API, and a summary of API's asset lifecycle optimization policies and practices. The information is presented in accordance with Section 5.3.1 of the OEB's Chapter 5 Filing Requirements and describes the direct links between API's asset management process and the capital expenditure decisions and justifications that comprise the distributor's capital investment plan.

A copy of API's AMP is included as Appendix A.

5.3.1 Planning Process

The distributor must provide an overview of its planning process that has informed the preparation of the distributor's five-year capital expenditure plan (a flowchart accompanied by explanatory text may be helpful). A distributor should provide a summary of any important changes to the distributor's asset management process (e.g., enhanced asset data quality or scope, improved analytic tools, process refinements, etc.) since the last DSP filing. This includes a distributor's capital expenditure planning process, which was previously under Section 5.4 of the Distribution System Plan.

API's asset management and capital expenditure planning processes are founded the on objectives and principles that link the OEB's four identified categories of *Renewed Regulatory Framework for Electricity Distributors* ("RRFE") performance outcomes with API's organizational core values. The asset management process leverages asset records and condition information, as well as additional analysis and studies completed by API staff or third parties, to determine the pacing and prioritization of future capital and O&M programs and projects.

5.3.1.1 Planning Objectives

The fundamental objective of API's planning processes is to manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets prudently and efficiently in a sustainable manner that maximizes safety and customer reliability, while optimizing asset lifecycle 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, VMP and DSP which outlines operating and capital processes, activities, and expenditures to ensure that API continues to provide safe, reliable, and cost-effective distribution of electricity to its customers.

There are three key principles that are integral to API's AMP:

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

These key principles are derived from safety considerations, acts, regulations, cases, guidelines, good utility practice, and customer expectations. These are reviewed annually and adjustments to the plan are made based on changes in legislation, system performance reviews, safety assessments, infrastructure studies, and customer feedback through customer engagement activities.

Table 3.1 below illustrates how the asset management objectives and principles identified above, as well as API's core values (as identified in *Core Values*), relate to each other and to the RRFE performance outcomes established by the Board.

Table 3.1: Asset Management Objectives

RRFE Performance Outcome	API AMP Objectives/Principles	API Core Values
Customer Focus	1) Meet the needs and expectations of its customers, as identified through regular customer engagement; 2) Provide safe, reliable, and high-quality service; 3) Minimize long-term costs to be borne by ratepayers	Respect for People Diversity, Equity, and Inclusion Customer Service/Engagement Community Involvement Safety and the Environment
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/Engagement Diversity, Equity and Inclusion Productivity
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*	Diversity, Equity and Inclusion Productivity Financial Success

In addition to the customer focus measures outlined above, for this DSP, API specifically requested customer feedback on six (6) key DSP programs. Further details regarding the detailed feedback received are summarized in section 5.2.1.3, and the Customer Engagement report is included as Appendix F, however API confirms that the approach taken for each of the six programs is consistent with the feedback received from the majority of customers.

5.3.1.1.1 Planning Criteria and Assumptions

API utilizes the following criteria and assumptions for each OEB category:

<u>System Access</u>

System Access expenditures are primarily customer-driven and are relatively consistent year over year. Expenditure planning is based on budgeting annual amounts to meet customer expectations, as well as regulatory requirements in relation to new connections, service upgrades, and plant relocations. API budgets future amounts based on a 5-year rolling average of historical amounts and expects this method to be appropriate over the planning period. Adjustments are occasionally made for known future changes, such as above average relocation requests that API becomes aware of through the stakeholder consultation processes described in Section 5.2.2, as well as costs associated with one-time connection of large industrial customers. At the time of preparing this DSP, no unusual relocation activity was forecast, and any potential large industrial customer connections remained in a preliminary stage of assessment. As such, the historical rolling average is used to forecast System Access expenditures for the planning period. API notes that per the OEB's Accounting Order (001-2022) issued July 7, 2022, all costs and revenues related to Ontario Regulation 410/22 (Electricity Infrastructure- Designated Broadband Projects) are to be recorded in the requisite sub-account of regulatory asset account 1508. Accordingly, the costs related to this program are not shown under system access and not included in the forecasts for in-service capital at all.

System Renewal

System Renewal expenditures are driven by sustaining proactive asset replacement programs, primarily driven by the Line Rebuild and Station Rebuild programs, but also includes priority replacement of one-off items because of failure or high-risk issues identified during inspection and maintenance programs. An example of one-off replacements would be the replacement of a failed in-service recloser. An example of an unbudgeted event that could require reprioritization within this category would include the replacement of a new substation transformer due to sudden failure. Forecasted costs in this DSP are based on budgeting enough on a 5-year basis to meet the long-term sustainment and replacement requirements of major assets. In its system renewal budgeting process, API also considers the optimal efficient use of both internal and external resources in completing capital replacement programs. In doing so, API's aim is to lower overall costs to complete the necessary work by optimizing the capitalization of labour and reducing reliance on external contractors. Target replacement rates and plans are based on consideration of the number, type, age, and condition of in-service assets. Regarding the Line Rebuild programs, API sets a target replacement of 500 poles per year. Given the relatively small number of substations in relation to other asset types, substation rebuilds are prioritized on a case-by-case basis, based on the results of inspection and maintenance activities, as well as other analysis and reporting steps that are described in API's AM process.

System Service

System Service expenditure planning is based on prioritizing projects associated with improving overall system reliability, with considerations of contingency analysis, historical outage data and forecasted system impacts from planning studies. System Service investments in this DSP are informed by the internally developed APS and reliability study, whilst also taken into consideration regional planning projects identified in section 5.2.2.1.4.

General Plant

General Plant expenditures are focused on ensuring that adequate tools, equipment, and systems are in place to support the day-to-day operations of API's business. Additional investment in business systems is also budgeted based on opportunities to improve processes, realize efficiencies, and respond to customer preferences (e.g. Improved communications in a more timely and effective matter). All General

Plant investments are targeted at maintaining or improving the efficiency of the day-to-day operations at API.

5.3.1.2 Important Changes to Planning Processes Since Last DSP

As part of the previous DSP, API had planned to implement some of the recommendations in the ACA for improved data collection. The recommendations were geared towards collecting and keeping conditions records consistent for all assets inspected rather than checking for a pass/fail criterion, and to incorporate a five-level grading scheme for any asset condition inspection, where applicable, and be generally consistent with ISO55000 practices.

API began to implement these recommendations in 2020, focusing more on critical assets, such as power transformers, regulators, ratio-bank transformers and reclosers. API has not yet fully implemented this recommendation for all distribution asset managed but plans to over the next 5 years with a target completion year of 2029.

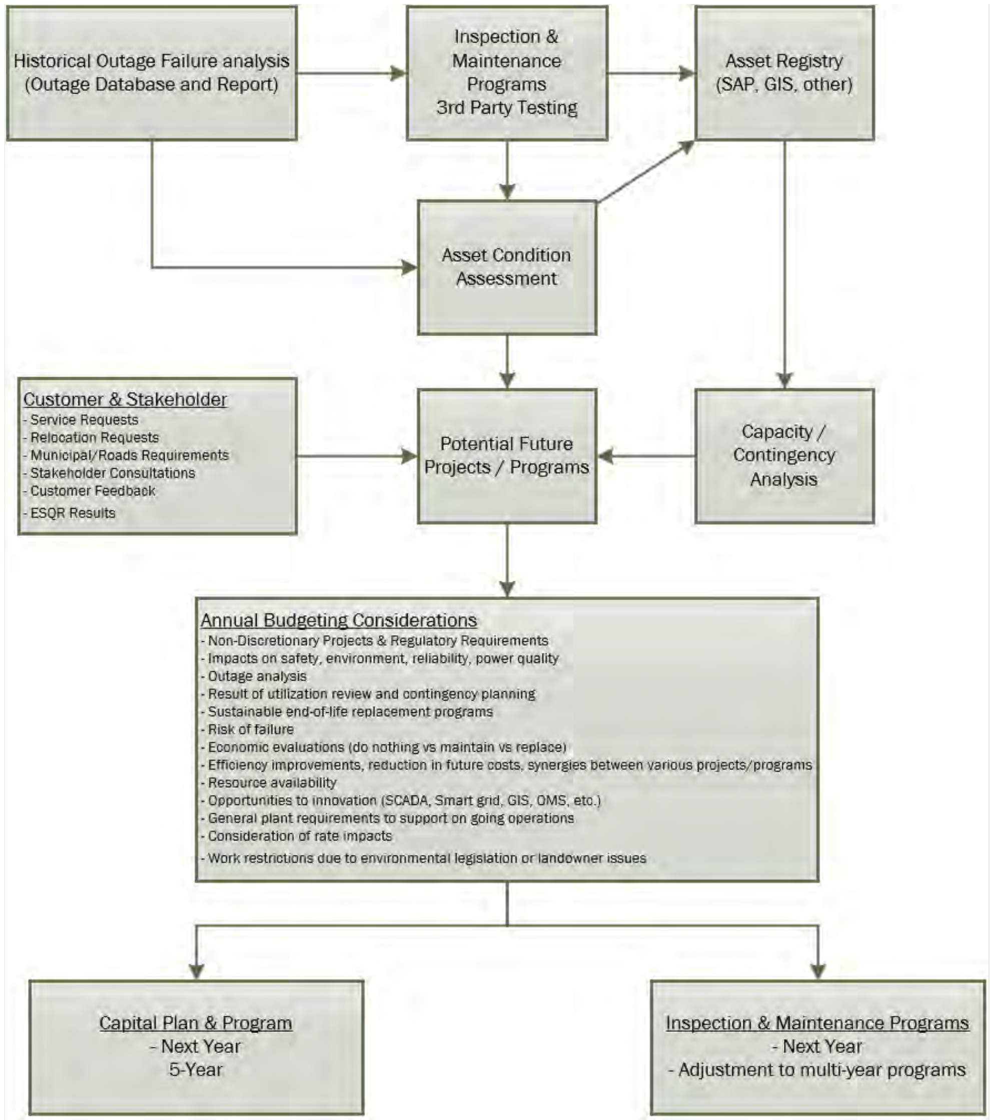
In 2024, API has begun tracking asset condition data directly in our GIS, rather than through other databases, such as Microsoft Access or Excel. The reason for this shift is that it will allow for the asset condition dataset to be attached directly to the asset record. Currently, asset records and asset condition data and in separates databases, which has presented challenge with merging the two datasets. By the end of 2029, API will have created appropriate asset condition fields for all assets in our GIS, and any condition report associated with that asset will be recorded in these fields going forward.

API's SCADA implementation program has allowed for the collection of system data that wasn't available previously. Realtime system information (voltages, currents, etc.) will allow API to better understand actual trends in system and feeder demand, which in turn will feed into the AM process defined above.

5.3.1.3 Components of the API's Planning Processes

The following figure illustrates the inputs, outputs, and overall flow of API's asset management process.

Figure 3.1: Asset Management Process



Sources of information providing input to the process described above include asset registers (primarily SAP and GIS, with some external databases), results of prior inspection, maintenance, and 3rd-party testing activities (databases and paper-based reports), and historical outage information (reports from OMS and spreadsheets with more detailed reporting/analysis).

The top half of the flowchart above illustrates multiple information flows between various data sources (asset register, OMS, test results, etc.) and API's inspection and maintenance programs. This information ultimately drives asset condition assessments and capacity/contingency analysis processes, which in turn inform the development of a list of potential future projects and programs. Potential future projects are also informed by customer/stakeholder input, such as requests for new services, requests for plant relocations, feedback from customers, and feedback from stakeholder consultations. This approach allows API to seek opportunities to coordinate and prioritize work plans to ensure project implementation is more seamless and to minimize overall project cost.

Results of the ACA and capacity/contingency analysis occasionally flow back to other data sources in the form of record updates or immediate adjustments to inspection or maintenance programs due to identification of high-priority repairs, or requirements for additional testing.

On an annual basis, API evaluates potential projects/programs, with consideration of the factors listed in the “Annual Budgeting Consideration” section of the above flowchart. This process is the primary driver of development of future capital and inspection/maintenance programs.

Priority in project selection is given to non-discretionary projects that are required to meet regulatory obligations, for example, service connections, plant relocations and the unexpected replacement of failed in-service equipment. Programs to replace certain end-of-life assets in advance of failure are also given high priority to allow for a paced and sustainable replacement program which levelizes annual spending by asset type to the extent possible, and results in efficient use of internal resources. Consideration is then given to general plant items, to ensure that annual spending on critical items such as fleet, buildings, computer hardware/software, tools, and test equipment, etc. is sufficient to support day-to-day business and operations activities. Any remaining projects that are more discretionary in nature are evaluated according to any applicable criteria listed in the “Annual Budgeting Consideration” section of the above flowchart. A final list of projects is selected, based on consideration of these criteria in relation to the overall costs, benefits and risks of particular projects or programs.

Non-discretionary activities such as customer demand work and relocations are generally budgeted based on a 5-year rolling average of historical activity and costs. The same approach is taken for budgeting most general plant items, such as tools, test equipment and small capital items related to offices and work centres. The resulting budgets are reviewed for reasonability and adjustments are made for known future changes, or past irregularities. For example, costs associated with one-time connection of a large industrial customer would be excluded from historical averages in determining future customer demand budgets.

Sustainment programs such as the Line Rebuild programs are generally budgeted based on the target replacement rate, times an estimated replacement cost per unit which in turn is based on analysis of historical costs. System Service programs are generally considered as added value to the distribution system that can improve the reliability and/or efficiency of API’s distribution system and/or reduce capacity and/or reliability risk. System Service investments will allow for completion of projects to address API’s most pressing reliability-driven needs.

Capital investments are selected for execution based on relative priority within each investment category and program. Projects or programs developed to address an external driver are prioritized based on execution timing requirements and resource availability. These projects are typically customer, municipally / regionally, or third party driven (e.g. service connection, plant relocation, etc.). In order to meet the regulatory requirements associated with these types of projects, these investments are considered to be non-discretionary.

Programs to replace certain end-of-life assets in advance of failure are also given high priority to allow for a paced and sustainable replacement program that levelizes annual spending by asset type to the extent possible, and results in efficient uses of internal resources. For these projects the prioritization focuses on asset replacement timing based on ACA and the risk and consequence of asset failure.

Consideration is then given to General Plant items, to ensure that annual spending on critical items such as fleet, buildings, computer hardware/software, tools, and test equipment, etc. is sufficient to support day-to-day business and operations activities.

Other projects or programs identified based on drivers such as reliability are prioritized based on the identified benefit vs. cost of execution (including a consideration of the potential risks of proceeding or not proceeding with individual programs) and alignment with API's AM objectives, which include consideration of the needs and expectations of its customers. The benefit of a given project or program execution is evaluated based on the adherence to API's project justification criteria. API identifies a primary "trigger" or driver for selected project alternatives while also identifying the applicable justification criteria.

The justification criteria identify whether the project positively impacts:

- Safety
- Customer Value
- Operational Efficiency
- Reliability
- Coordination / Interoperability
- Economic Development
- Cyber-Security / Privacy
- Environmental Objectives

5.3.1.4 Distributed Energy Resources

In 2023, API implemented the Distributed Energy Resource ("DER") Connection Procedure in accordance with the OEB's Notice of Amendment to the DSC to facilitate the connection of distributed energy resources (OEB File No.: EB-2021-0117). Since its implementation, API has received a minor amount of interest and subsequent applications (mainly for net-metering connections less than 10kW).

API considers requests for the connection of DER as system access investments which are non-discretionary. While API does not expect significant customer interest in connecting DER over the forecast period, investment prioritization for enabling connection of DER shall follow the same method and criteria outlined in Section 5.3.1.3.

5.3.1.5 Non-Distribution System Alternatives to Relieving System Capacity

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 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, API will be in a much better position to not only consider non-wire solutions but be able to implement non-wire solutions.

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 once they are finalized.

5.3.1.6 System Modernization & Innovation

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 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. As API continues further with these and other improvements over the DSP period, API expects to take advantage of further efficiencies.

5.3.1.7 Distribution Resiliency and Climate Change Adaptation

The effects of climate change, including the intensity and frequency of extreme weather and changing weather patterns, continues to cause damage to the power system. These climate risks are projected to increase into the future and compounding the situation when the reliability and resiliency of the grid is more critical than ever to society due to electrification of transportation.

In 2023, API has participated in recent study performed by a consulting company Ernst & Young ("EY") that would provide an overview of how climate change risks and impact of extreme weather could potentially impact the power system. As one of the distribution participants, API submitted the asset data (poles, transformers, lines, cables, and substations) within grids representing 15% of its service territory with highest customer density. EY overlaid the asset data with the location-based climate risk exposure data derived from a prediction model they developed for this study. The goal of the study is to identify the asset-specific vulnerability ratings to a set of climate hazards due to inherent attributes of asset in question. The climate hazards considered in this study include heat stress/waves, extreme cold events, higher or lower ambient temperatures, wildfire, flooding, strong winds, snow/ice storms, and water stress. For each climate hazard category, the prediction model forecasts its change to a specific location under both RCP 2.6 (low emissions) and RCP 8.5 (high emissions) scenarios. This study is still in progress, and as a result, no direct results have been incorporated into API's 2025-2029 capital expenditure plan.

However, API does have several programs and projects that support distribution resiliency in the context of worsening climate change. API follows the definition of resilience as defined in the report to the Ministry of Energy, *Improving Distribution Sector Resilience, Responsiveness and Cost Efficiency*. Namely that distribution resilience is the ability of the electricity distribution network to respond to high-impact/low-frequency disruptions by adequately preparing for, withstanding, rapidly recovering from, and adapting to these events.

The following list represents API's planned programs and project that have a direct impact on API's distribution resilience:

- API's line rebuilds programs (distribution and subtransmission), target in general the most vulnerable poles in API's service territory. These rebuild will result in a stronger distribution network.
- API's Subtransmission reliability program is centered around automating API's 34.5kv express feeders to improve problem detection and system restoration.
- API's VMP has a significant role in distribution resilience at API, specifically as it relates to wildfire mitigation. Within the program, API managed brush within established ROWs, which ensures that brush height is not exceeding certain distance and encroaching into the powerline. The VMP also manages danger trees that pose a risk to API's powerline (these trees are outside the ROW and are identified as having the potential to fall into the powerline, either because of a heavy lean, signs of deterioration, decay, etc.)

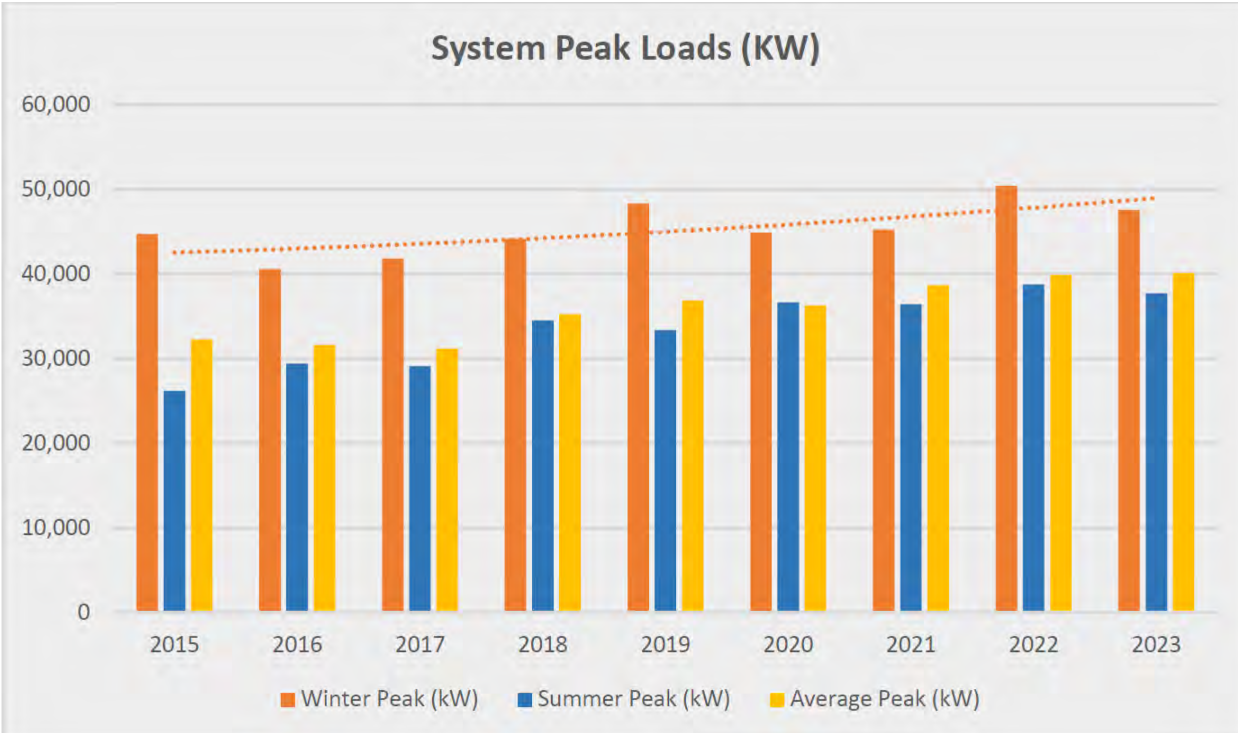
Given the nature of API's service territory, API is very aware of potential risks associated with wildfires. As a result, API is in the process of developing a wildfire mitigation plan and strategy, that will outline the protocols that would be followed to further mitigate the wildfire risks.

Following the conclusion of the study being performed by EY, API expects that the recommendations will become an additional input into planning processes outlined in section 5.3.1.1.

5.3.1.8 Future Capacity Consideration for Electrification

As can be seen in Table 1.3, API's average system demand has maintained a moderately increasing trend over the past 8 years. No significant increase in demand has been seen over the years. The figure below shows the trend of API's System Demand.

Figure 3.2: System Average and Peaks Loads 2015 to 2023

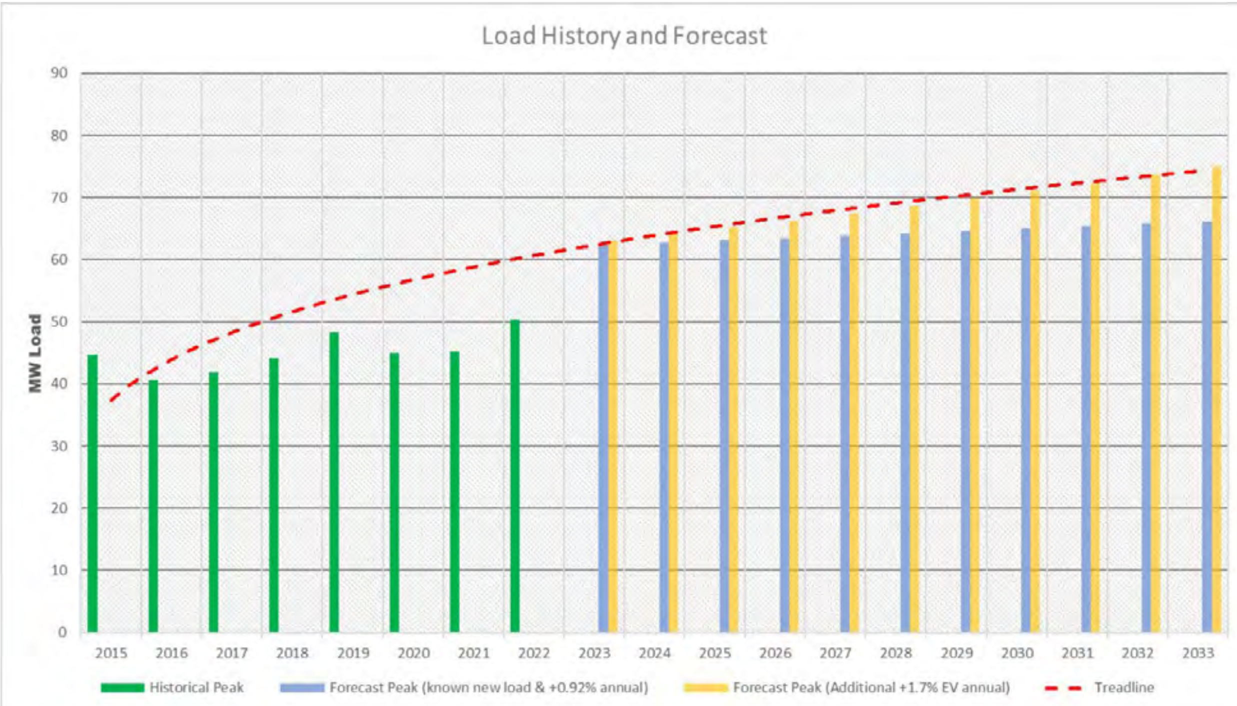


As part of API's APS, a load project was projected under two (2) main load increase scenario:

1. Known new load (tied to large industrial customer in 2023, with an annual growth increase of 0.92%.
2. Same as above, with the addition of an annual increase of 1.7% associated with EV charging and electrification.

These load projections are depicted in Figure 3.3. API's consideration of an additional 1.7% annual load increase is based on the projected growth indicated in the IESO's 2021 Annual Planning Outlook report.

Figure 3.3: API Load History and Forecast 2015 to 2033



To gauge customer preferences to EV readiness, API included in its CE workbook survey a question pertaining to preparing for increased electricity demand. In this survey question, API's approach was centered around proactively replacing distribution transformers. Historically, API's standard practice for supplying residential and seasonal services have been through smaller capacity transformers. This approach was appropriate at the time, given the size of the services and types of loads being connected. As API customers move into a period of increased demand due to EV charging and overall electrification, these smaller capacity transformers will no longer be able to support to demand. API had proposed a do-nothing approach because there was still uncertainty around the timing of when these load increase would be realized and would give API an opportunity to monitor growth tied to these increases.

As is indicated in Table 2.2, the result of the survey indicates that about 43% of respondents preferred API's approach, while about 40% of respondents preferred the 25% proactive replacement. As a result, API has included in its Capital Expenditure plan the proposed do-nothing approach. Given the higher level of respondents supporting the proactive approach, API will consider opportunities to install larger capacity transformer when installing new or needing to replace an existing through other means (e.g. End-of-Life replacement).

In addition to the above scenarios, API also performed a sensitivity analysis in the APS to test the robustness of the distribution system in dealing with extreme loading conditions. The load scenarios are summarized in detail in section 5.3.2.4

5.3.1.9 Conservation Activities to Address System Needs

API has not proposed any distribution-funded Conservation and Demand Management programs for the purpose of deferring any distribution infrastructure investments under this DSP. API will continue to consider such solutions (including demand response and energy storage) on a case-by-case basis where the implementation of such activities may address operational or reliability issues in a more cost-effective and value-added manner than a traditional "wires" investment.

API notes that since the last DSP, its role in the conservation and demand management provincial framework has changed, with LDCs no longer expected to be directly involved in the delivery of the provincial framework, and this responsibility rather being assigned to the IESO. As a result of this change, API no longer has direct access to information regarding the planned and/or implemented conservation and demand management activities undertaken within its service territories. Previously API had access to this information through its involvement and through detailed IESO reporting. Currently, API may receive this information from participating customers, at the customers' discretion. To the extent that API would normally be able to consider these activities in its distribution system planning, API has experienced a decrease in the availability of relevant information.

5.3.2 Overview of Asset Managed

5.3.2.1 Description of the Service Territory

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.

API confirms it does not have any transmission or high voltage assets previously deemed by the OEB as distribution assets, nor is API requesting the OEB to deem high-voltage or transmission assets as distribution assets in this Application.

There are three distinct characteristics of the API distribution system. First, the service territory is vast and heavily forested. Second, the distribution system's configuration is required to distribute electricity to an extremely dispersed customer base. Third, the climatic conditions often limit and dictate access to distribution facilities and customers' premises.

API's service territory spans across approximately 14,200 square kilometres, or 3.5 million acres, of land, comprised of organized and unorganized townships and First Nations lands. The southern and northern limits of the service territory can be found 93 km east and 255 km north of the City of Sault Ste. Marie. API's service territory lies upon the Canadian Shield; a rugged and unyielding expanse of rock, lakes, muskeg, and trees. Being a rural and remote distributor in Northern Ontario, one of the characteristics of API's distribution service area is that it is located predominantly in forest zones with dense vegetation. API's distribution service area extends through two forest zones. The southern part is in the Great Lakes – St. Lawrence forest zone, characterized by red and sugar maple, yellow birch, red oak, hemlock red and white pine. The northern part is in the Boreal forest zone, characterized by black and white spruce, tamarack, aspen, white birch balsam fir, and jack pine. North of Wawa and east of the Montreal River area is the approximate transition area between the two forest zones. With the exception of Hydro One Networks Inc. ("HONI"), no other LDC in the province has a service territory as large as API's.

Due to the vast expanse of the API service territory together with the geographic dispersion of its customers, the distribution system has been designed and constructed to mimic an integrated transmission and distribution utility. This type of configuration is atypical to that of the general population of electricity distributors in Ontario. The API distribution system is a network of express distribution lines (or sub-transmission lines), long runs of distribution lines with sparsely connected customers and more localized distribution systems in locations where customers are more clustered.

Express distribution lines serve load centers and have been built not along highway corridors but along the most direct route in a similar manner to transmission construction. As with transmission lines, API maintains wider ROW's, access and utilizes specialized vehicles to maintain the express feeders, not normally used by other LDCs. An outage on an API express line is akin to an LDC embedded in HONI's sub-transmission system having an outage, in that a large proportion of downstream customers may be affected by these outages.

API has a "localized" distribution system to which individual residential, seasonal and commercial customers are connected. Localized distribution may either extend directly from a transmission delivery point or may be connected to an express line by way of a step-down distribution transformer. Generally, customers are sparsely located and connected by relatively long runs of primary distribution lines with customers normally connected to distribution transformers with a one-to-one ratio.

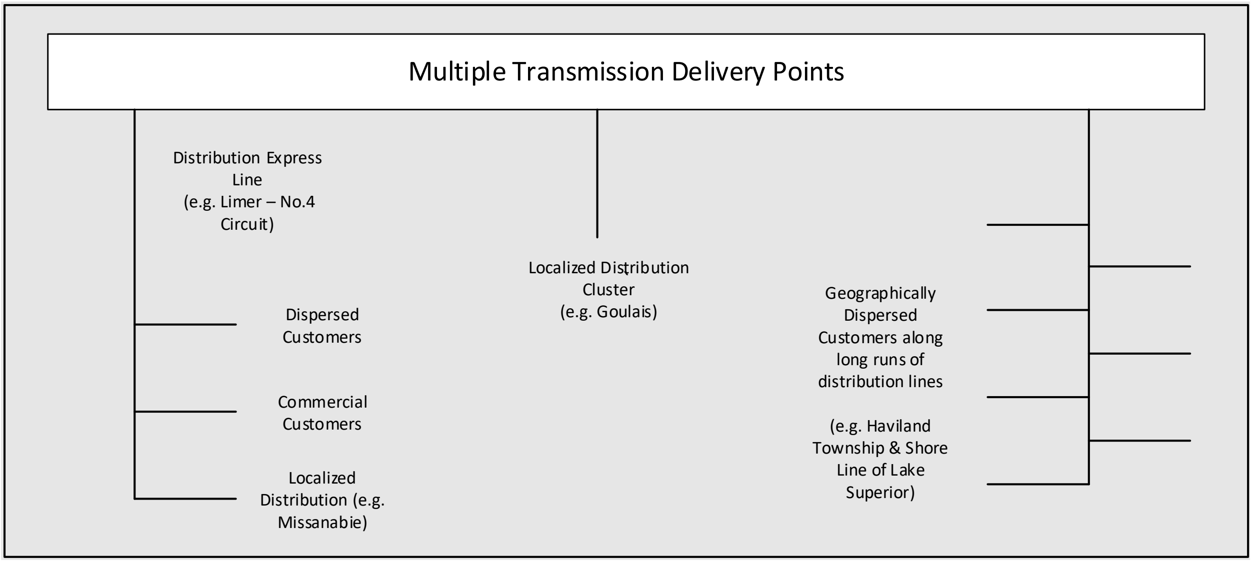
API's service territory is challenged by the climatic traits of the Northern region. The entire API service territory is located near the shore of the Great Lakes and impacted by prevailing winds. As a result, the region is prone to lake effect precipitation and severe weather which often limits API's ability to access portions of its service territory. For example, it is not uncommon for a large stretch of Highway 17 between Sault Ste. Marie and Wawa to be closed to all traffic during the winter months due to snow squalls and poor visibility. These closures typically last from several hours to several days, with no detours available to most of the area. The most recent closure of this highway was on January 14, 2024. The highway remained closed for 4 days, finally reopening on January 18, 2024. This severely hampers both outage response activities, and access for planned work during this time of year.

5.3.2.2 Summary of System Configuration

To distribute electricity to widely dispersed residential, seasonal, commercial, and industrial customers including remote First Nations communities, API had to construct and maintain a unique distribution system. The API distribution system is made up of multiple transmission delivery points which include:

- a network of express distribution lines (or sub-transmission lines)
- long runs of distribution lines with sparsely connected customers and
- more localized distribution system in locations where customers are more clustered as shown below.

Figure 3.4: API High Level System Configuration Diagram



API confirms is neither an embedded distributor nor a host distributor.

API's express line sections mimic the "transmission" component in API's distribution system. Essentially, API's distribution system is a network of eight independent distribution areas fed from eight delivery points which connect these individual distribution areas to the IESO controlled grid as depicted in the single line representation of API's distribution system.

Figure 3.5: API Distribution System - Single Line Diagram

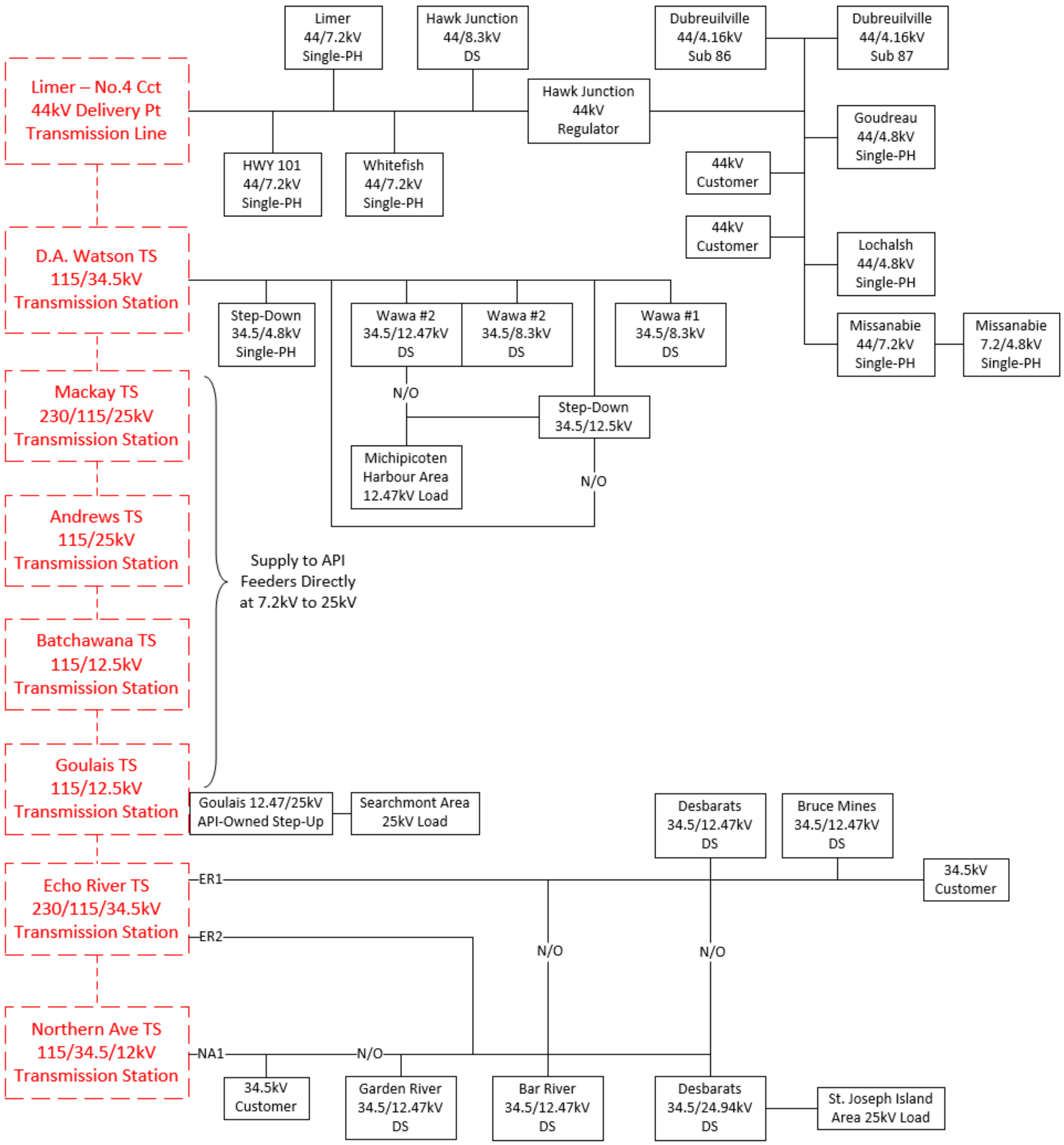


Table 3.2 provides a summary of API's total primary distribution line distance by voltage level, overhead vs. underground construction, and by number of phases.

Table 3.2: Line KM Summary

Voltage Level	Km	Overhead vs. Underground	Km	# of Phases	Km
< 5kV	29	Overhead	1,778	1 Phase	1,359
5-25kV	1,548	Underground	21	2 Phase	23
34.5 – 44kV	201			3 Phase	417
Total	1,778	Total	1,799	Total	1,799

Section 2 of API's AMP provides detailed descriptions of its distribution systems in each of its service areas, including service area and system maps, voltage levels in use, substations, capacity, and a number of additional considerations. The following tables, reproduced from the AMP, summarize the configuration and capacity of substations owned by API, and the number of feeders supplied from each substation. Total capacity values listed in these tables represent the sum of the highest nameplate rating (i.e. the fan-cooled rating where applicable) of all transformers unless otherwise noted.

Table 3.3: Algoma Power Distribution Stations

Station	Secondary Voltage	Quantity of Transformers	Transformer Age	Total Capacity (MVA)	Quantity of Feeders
Garden River DS	34.5-12.5 kV Wye	2	1992, 2007	6	2
Bar River DS	34.5-12.5 kV Wye	1	2001	10	2
Desbarats DS	34.5-12.5 kV Wye 34.5-25 kV Wye	2	2010, 2013	18.3	4
Bruce Mines DS	34.5-12.5 kV Wye	2	1993, 2024	13.3	2
Goulais TS	12.5-25 kV Wye	1	1989	7.5	1
Wawa #1 DS	34.5-8.32 kV Wye	1	2008	8.3	2
Wawa #2 DS	34.5-8.32 kV Wye	1	1979	8.3	2
Hawk Junction DS	44-8.32 kV Wye	2	1985 (2)	2	1
Dubreuilville Sub 86	44-4.16 kV Wye	2	2021 (2)	6	2
Dubreuilville Sub 87	44-4.16 kV Wye	1	1991	1	1

In response to a significant transformer failure in 2018, which had a total response time of approximately 22 hours, API included in its previous DSP, a capital investment plan and strategy to improve API's station transformer contingency at each of its stations.

API's East System includes Garden River DS, Bar River DS, Desbarats DS and Bruce Mines DS. All East System DS's are normally served from HOSSM's Echo River TS at 34.5 kV. Each of these stations have full transformer redundancy at the end of 2024. The Garden River DS is a fully redundant, dual transformer DS operating at 34.5 to 12.5 kV. The Bar River DS has a single power transformer within the station, with a platform-mounted transformer bank nearby providing redundancy. The Desbarats DS has two single power transformers; T2 operates at 34.5 to 25 kV to feed St. Joseph Island and T1 operates at 34.5 to 12.5 kV to feed the local Desbarats area. API has an on-potential platform-mounted transformer bank at this station, permitting full redundancy. The Bruce Mines DS, which is currently being rebuilt on the greenfield property will be a fully redundant, dual transformer DS operating at 34.5 to 12.5 kV.

API's North System includes Wawa #1, Wawa #2, Hawk Junction, Dubreuilville Sub 86, Dubreuilville Sub 87, and the Goulais TS Autotransformer. API also supplies a 12.5kV area load in Wawa through a platform-mounted transformer bank (Wawa Ratio Bank). Wawa #1 T1 and Wawa #2 T1 split the town of Wawa's 8.32kV demand, approximately by a half. Each of these transformers can supply the entire 8.32kV load. Hawk Junction has fully redundant power transformers and voltage regulator on site. Dubreuilville Sub 86, which was rebuilt greenfield in 2021 is now a fully redundant two transformer station, which supplies the main town of Dubreuilville demand. The Wawa Ratio Bank does not have on- potential spare, but rather a cold spare that can be mobilized from the Wawa work centre to site in the event of a contingency. With the Wawa #2 DS planned for a refurbishment in 2027, adding additional 12.5kV transformation has been included in the overall rebuild plan. The Dubreuilville Sub 87, which supplies a very small commercial/industrial park does not currently have a site spare. API has included in this DSP, the plan to purchase spare transformation that can be pole mounted. API has a cold spare for the Goulais TS Autotransformer, which requires it to be mobilized to site if needed. The Autotransformer currently supplies a larger seasonal load as well as a small pocket of distribution residential load. There exists a backup supply through a limited load transfer switch for the residential load, but it is not sufficient to supply the larger commercial load that operates on a seasonal basis. As part of HOSSM's Goulais TS refurbishment project and coinciding with API's Goulais Voltage Conversion program, API has proposed to eliminate the need for this Autotransformer by 2029 (the supply from HOSSM will be increased to 25kV, matching the output voltage of the Autotransformer).

Express Lines

API's Express lines were originally constructed at a time when resource industries such as forestry and mining were being developed in the region. There are five express lines in API's service territory as described in the following table.

Table 3.4: Description of Express Line Feeders

	Harbour Circuit 12.47kV	Searchmont 25kV	East 34.5kV & SJI 25kV	Wawa 34.5kV	No.4 Circuit 44kV & 7.2kV	Total Express Feeders
Delivery Point(s)	D.A. Watson TS	Goulais TS	Echo River TS; Northern Ave TS	D.A. Watson TS	Limer - No.4 Circuit	
Line km	5.3	25.1	112.5	26	88	256.9
Line km %	2.06%	9.77%	43.79%	10.12%	34.25%	
Customers	48	199	6,234	1,681	654	8,816
Customer %	0.54%	2.26%	70.71%	19.07%	7.42%	

As an illustrative example, the Limer No. 4 circuit is a 44kV express line which extends 88 kilometers through a vast expanse of wilderness from Limer, a rail siding established for the forestry industry, to serve small pockets of mostly residential and seasonal customers in Hawk Junction, Goudreau, Dubreuilville, Lochalsh, and Missanabie, as well as large industrial loads.

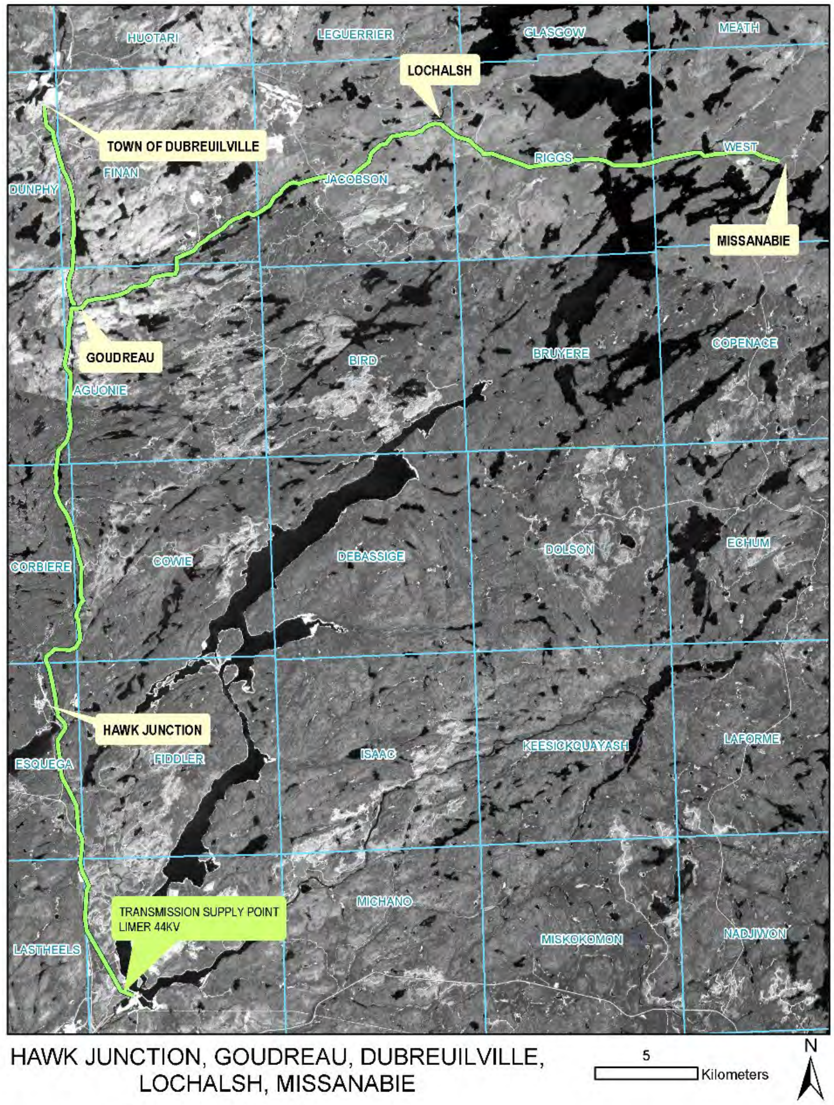
Table 3.5: Description of Customers Supplied via API's Limer - No. 4 Circuit

Location along API's No. 4 Circuit	Quantity of Customers
Limer	81
Hawk Junction	147
Goudreau	15
Dubreuilville	355
Lochalsh	9
Missanabie	44
Mining & Transportation	3

Limer, Hawk Junction, Goudreau, and Lochalsh are residential areas which historically were associated with industrial development in the early 1900's and are now home to a mix of 252 Seasonal and Residential R1 customers. Dubreuilville is a town that hosts a forestry industry and a mix of 355 residential and commercial customers. Missanabie is a community with 44 customers.

The No. 4 Circuit is an express line that is purely radial. Each of the communities and commercial customers are dependent on it for safe and reliable service. The route taken by the No. 4 Circuit is shown below, where each square depicted on the map is a township (typically an area measuring approximately 10 kilometers by 10 kilometers). Approximately two-thirds of the circuit does not follow a roadway and is only accessible by all-terrain equipment or helicopter. Prior to 2009, many of these sections were accessible via rail through informal agreements between API (or its predecessor companies) and Algoma Central Railway ("ACR"). Rail cars would generally be provided on a cost basis for both forced outage situations and for planned work. Following the acquisition of ACR by Canadian National ("CN") Rail, API has been unable to obtain reliable rail access to these sections. In 2021, Watco purchased this rail line from CN, and since then API has had discussion with Watco regarding establishing agreements to use the rail but has not yet been able to obtain formal rail access to these sections.

Figure 3.6: Route Taken by the No. 4 Circuit Express Feeder



Below is a photograph of the No. 4 Circuit North of Hawk Junction, which illustrates the type of terrain and environment that are typical over its length. Note the rail corridor, not roadway below API's lines cannot reliably be used by API for access.

Figure 3.7: Remoteness and Ruggedness of API's No.4 Circuit Express Feeder

In total, express lines are approximately 257km in length, representing 12% of API's total length of distribution line, servicing 38% of the annual demand and 70% of API's customers. The express lines essentially perform the role of a transmission line and therefore are normally built to a higher standard of construction. Also, the associated ROWs are cleared and maintained to a higher standard than the typical distribution feeder serving less customer and load and commonly constructed along easily accessible roadway. This increased emphasis is in part due to the criticality of these assets; a single failure could result in a prolonged outage for a significant number of customers. The other important consideration is the remoteness of the express line; these were typically constructed to meet the needs of the customer base present during their construction. The system followed the best access routes of the historical time to service customers (e.g. rail access, access roads for logging, mining, etc.) Due to the radial nature of settlement and road establishment, in many locations access remains limited to either rural or remote roadway systems, seasonal roads and trails, and in some location by natural occurring waterways.

5.3.2.3 Result of Asset Condition Assessment

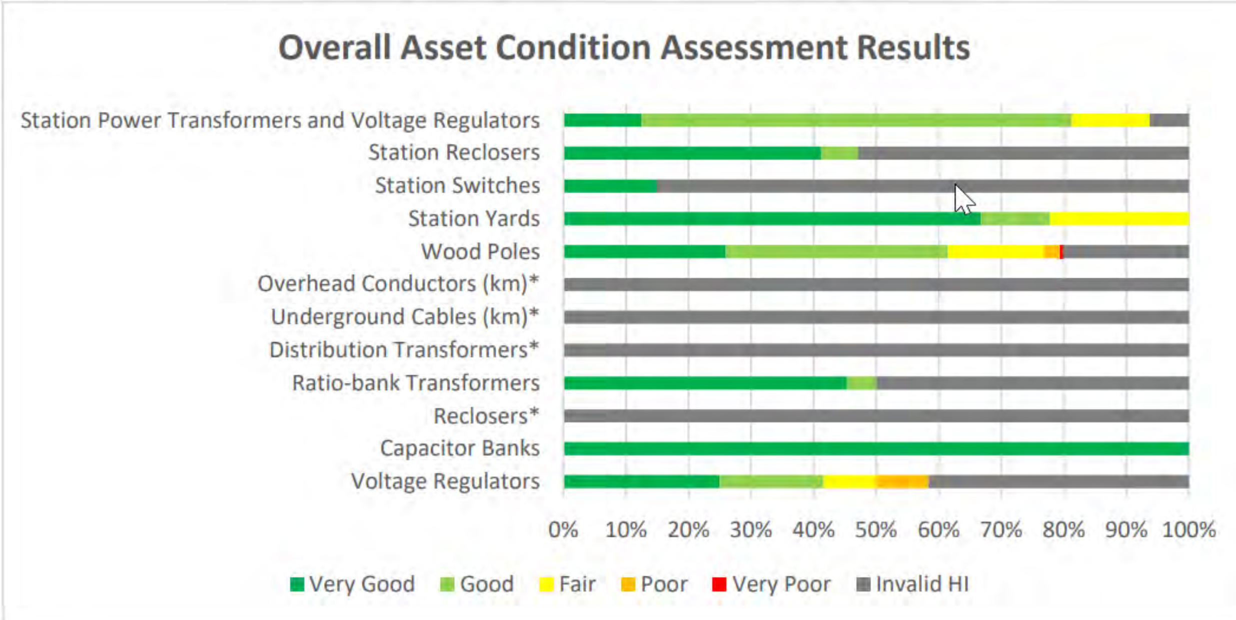
An ACA study was carried out by METSCO for API with the objective of assessing the health and condition of distribution assets. The ACA report is provided in full in Appendix D and is based on asset data compiled to the end of December 2022. Table 3.6 and Figure 3.8 present the summary results of the ACA. Data collection for the purpose of assessing each asset was collected through API's current inspection and maintenance procedures, such as visual inspections and pole testing.

Table 3.6: API Health Index Distribution

Asset Category	Population	Health Index Distribution (%)						Average Health Index
		Very Good	Good	Fair	Poor	Very Poor	Invalid HI	
Station Assets								
Station Power Transformers and Voltage Regulators	16	2	11	1	1	0	1	83%
Station Reclosers	17	7	1	0	0	0	9	61%
Station Switches	67	10	0	0	0	0	57	63%
Station Yards	9	6	1	2	0	0	0	100%
Distribution Assets								
Poles	28,931	7,512	10,272	4,440	718	157	5,832	95%
Ratio-Bank Transformers	44	20	2	0	0	0	22	95%
Capacitor Banks	4	4	0	0	0	0	0	99%
Voltage Regulators	12	3	2	1	1	0	5	79%
*Overhead Conductors (km)**	2,965	-	-	-	-	-	-	4%
*Underground Cables (km)**	34	-	-	-	-	-	-	33%
*Distribution Transformers**	5,233	-	-	-	-	-	-	99%
*Reclosers**	110	-	-	-	-	-	-	-

* No Health Index formulation

Figure 3.8: API Health Index Distribution



Station Power Transformers and Voltage Transformers

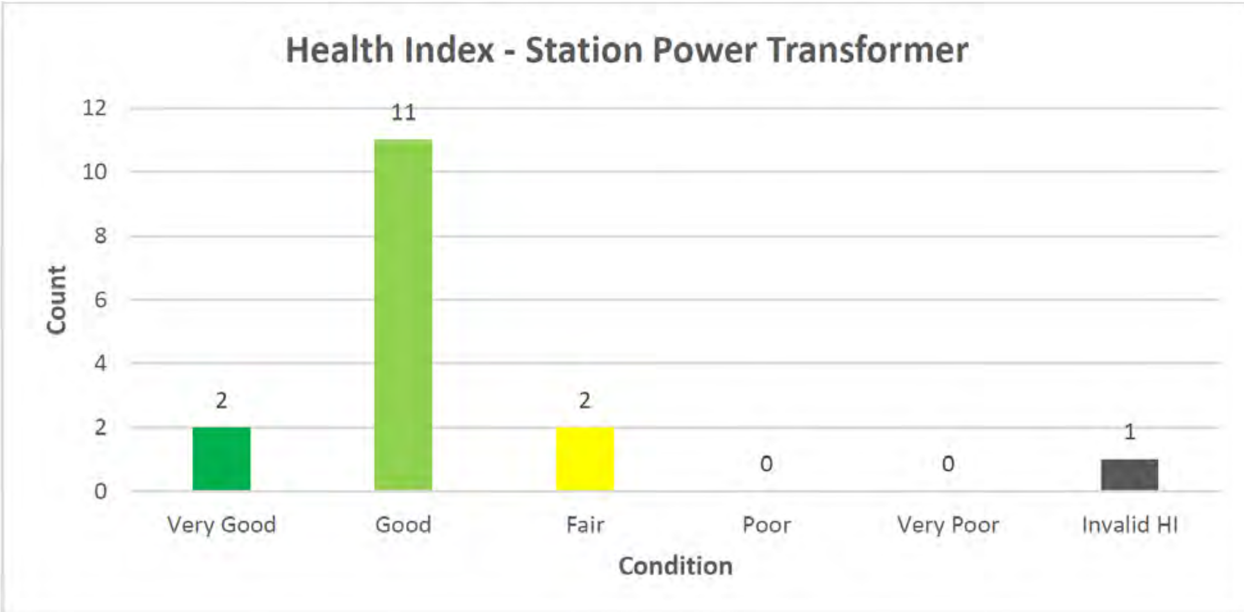
API currently has 14 power transformers and 2 voltage regulating transformers in-service, located within API's distribution stations. Of API's sixteen total assets, fifteen had sufficient data to form a health index, two of which were in Fair or worse condition. The breakdown of station transformer and voltage regulator assets, their data availability index ("DAI"), and their calculated Health Index("HI") is presented in Table 3.7.

Table 3.7: Health Index Breakdown - Station Transformer and Voltage Regulator

CO#	Station	Designation	DAI (%)	HI Score (%)	Condition
7549	Bar River DS	T1	100%	92%	Very Good
8600	Wawa #1 DS	T1	100%	90%	Very Good
8971	Desbarats DS	T2	100%	85%	Good
5236	Hawk Junction DS	T2	88%	83%	Good
8224	Garden River DS	T2	100%	82%	Good
9318	Desbarats DS	T1	80%	81%	Good
5108	Bruce Mines DS	T1	80%	78%	Good
4633	Hawk Junction DS	T1	78%	77%	Good
	Dubreuilville Sub 87	T1	76%	76%	Good
5496	Goulais TS	T1	94%	76%	Good
C-4710-1	Dubreuilville Sub 86	T1	70%	71%	Good
C-4710-2	Dubreuilville Sub 86	T2	70%	71%	Good
6843	Hawk Junction DS	VR1	98%	71%	Good
6095	Garden River DS	T1	80%	64%	Fair
4039	Wawa #2 DS	T1	100%	56%	Fair
VR2	Hawk Junction DS	VR2	20%	--	--

The transformer in Fair condition, at Garden River DS, has reached a more advanced age (31 years in service) and scored poorly on the dissolved gas analysis and very poorly on the oil quality analysis. The transformer in Fair condition, at Wawa #2, is of a significantly advanced age (44 years in service) and has serious deficiencies in its physical condition. There is evidence of an oil leak on the conservator tank, damage to relays and paint, and significant corrosion of its control wiring.

Figure 3.9: Health Index - Station Transformer and Voltage Regulator



<u>Recommendations:</u>

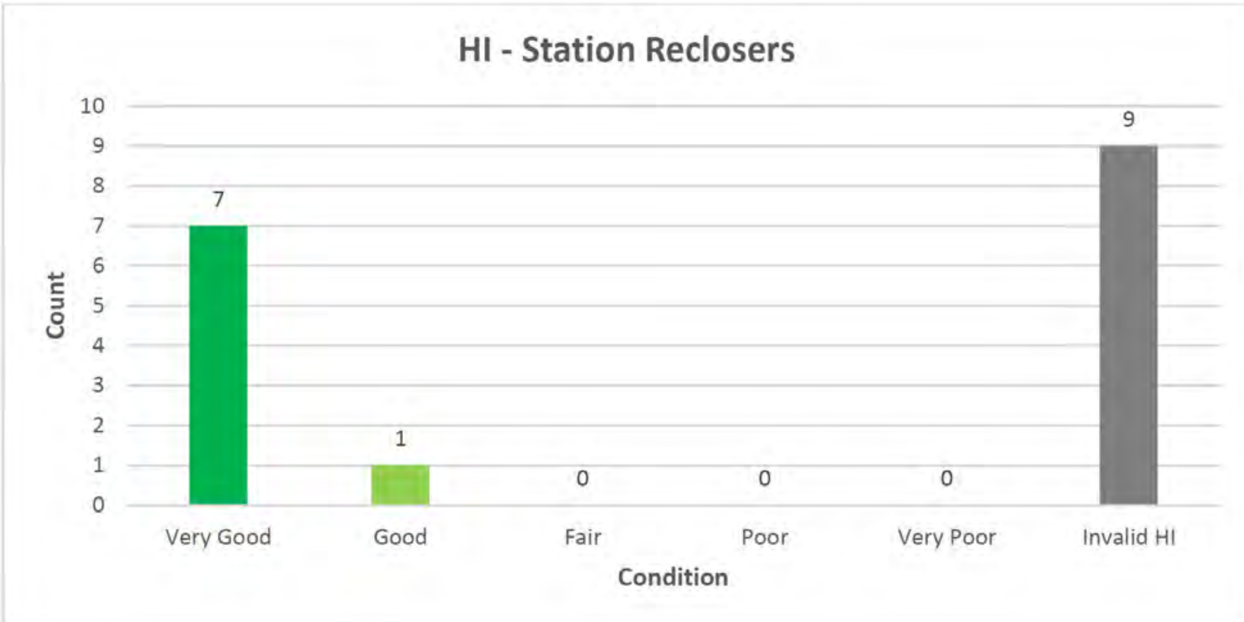
It is recommended to enhance and add to the data that is being collected for power transformers and voltage regulating transformers to improve the formulation of this health index. The information that is proposed is based on a combination of more granular visual inspections and detailed testing of each transformer.

Station Reclosers

API owns and operates 17 station reclosers, 15 of which are located inside distribution stations and 2 are located outside. For the purposes of defining station reclosers, the two located outside are included in the station recloser group.

Of the 17 station recloser, 8 had enough data to form a valid health index, seven of which were assessed as being in Very Good condition and one as being in Good condition. The results are presented in Figure 3.10.

Figure 3.10: Health Index - Station Reclosers



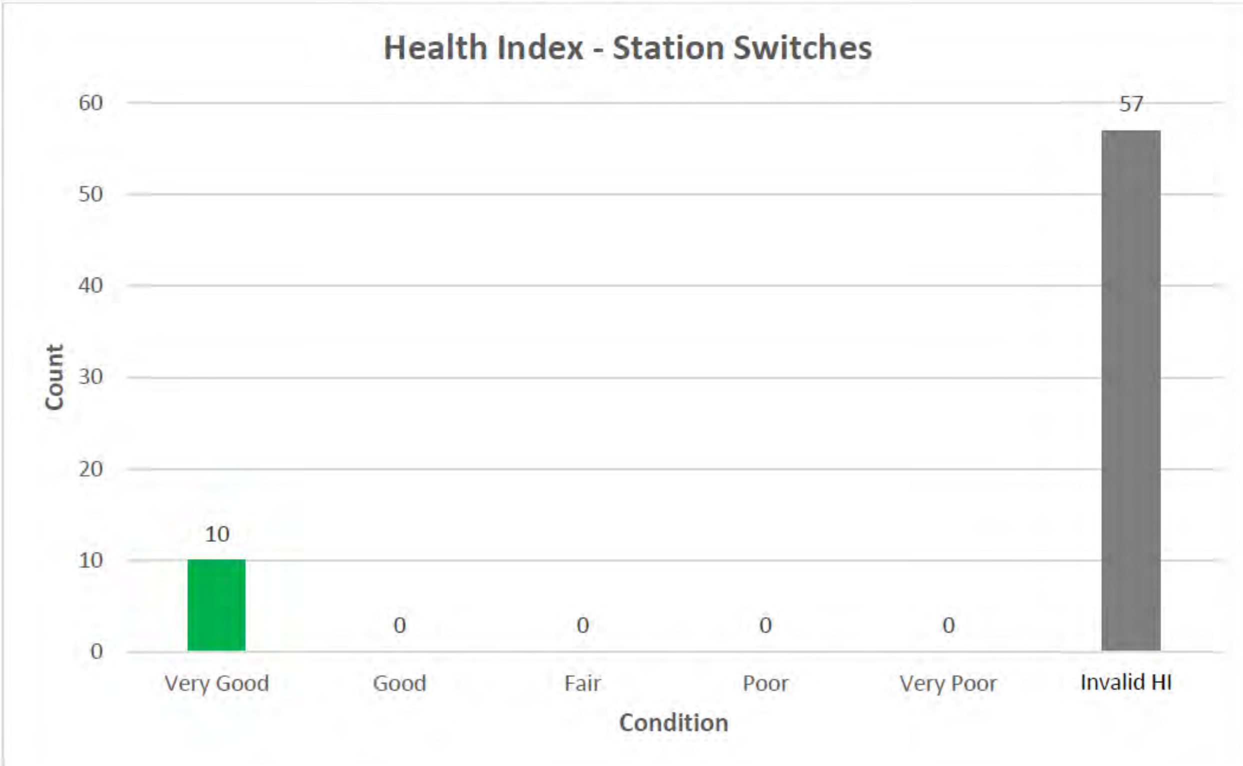
Recommendations:

It is recommended to enhance and add to the data that is being collected for the station reclosers to improve the formulation of this health index. The information that is proposed is based on a combination of more granular visual inspections and detailed testing of each recloser.

Station Switches

API owns and operates 67 station switches within its distribution stations. These switches are either group-operated or single-phase operated air-break or load-break switches. Of the 67 station switches, only 10 have a sufficient amount of data to form an asset health index. The results are presented below in Figure 3.11.

Figure 3.11: Health Index - Station Switches



<u>Recommendations:</u>

It is recommended to enhance and add to the data that is being collected for the station switches to improve the formulation of this health index. The information that is proposed is based on a combination of more granular visual inspections and detailed testing of each switch.

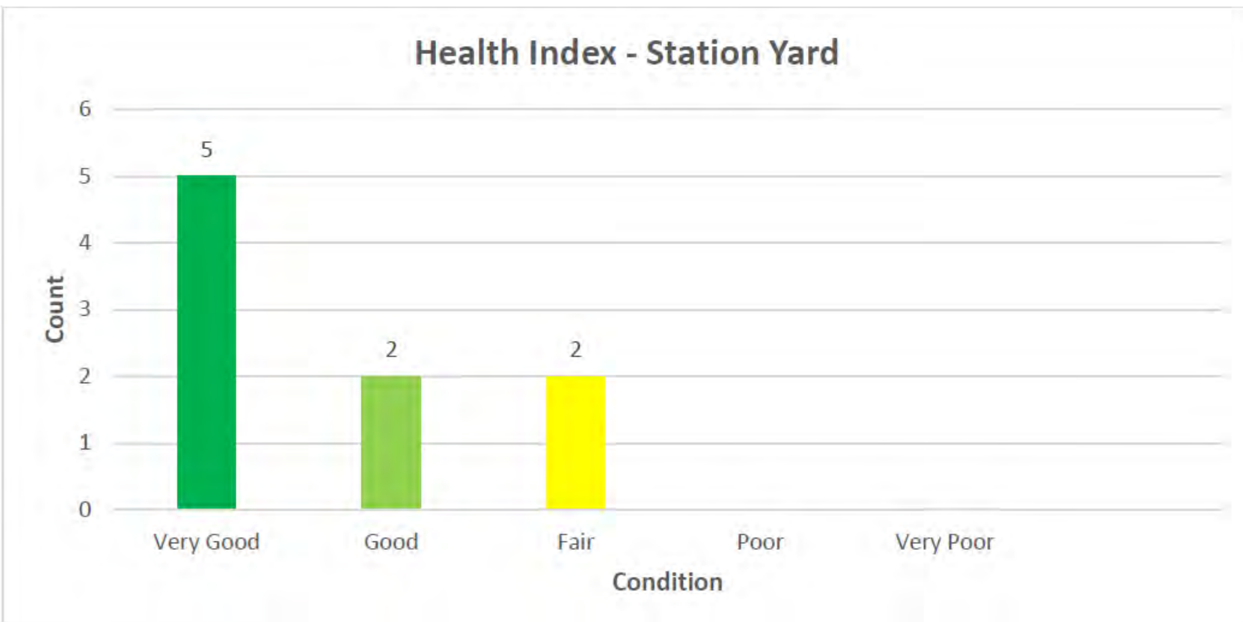
Station Yards

API owns nine station yards (one for each of its distribution stations). Of the nine station yards evaluated, two were found to be in Fair condition. The breakdown of HI results is presented below in Table 3.8 and Figure 3.12.

Table 3.8: Health Index Breakdown - Station Yards

Station Yard	HI Score (%)	Condition Rating
Dubreuilville Sub 86	100%	Very Good
Hawk Junction DS	100%	Very Good
Bar River DS	96%	Very Good
Dubreuilville Sub 87	88%	Very Good
Wawa #1 DS	88%	Very Good
Garden River DS	82%	Good
Desbarats DS	75%	Good
Bruce Mines DS	59%	Fair
Wawa #2 DS	57%	Fair

Figure 3.12: Health Index - Station Yards



The two yards in Fair condition, Bruce Mines DS and Wawa #2 DS are possible candidates for remedial work or replacement, depending upon their criticality. Bruce Mines has deficiencies in its fence condition, fence signage, and yard condition. Wawa #2 DS has deficiencies in its fence condition, gate condition, and yard condition.

<u>Recommendations:</u>

No recommendations to improve the health index formulation of the station yards.

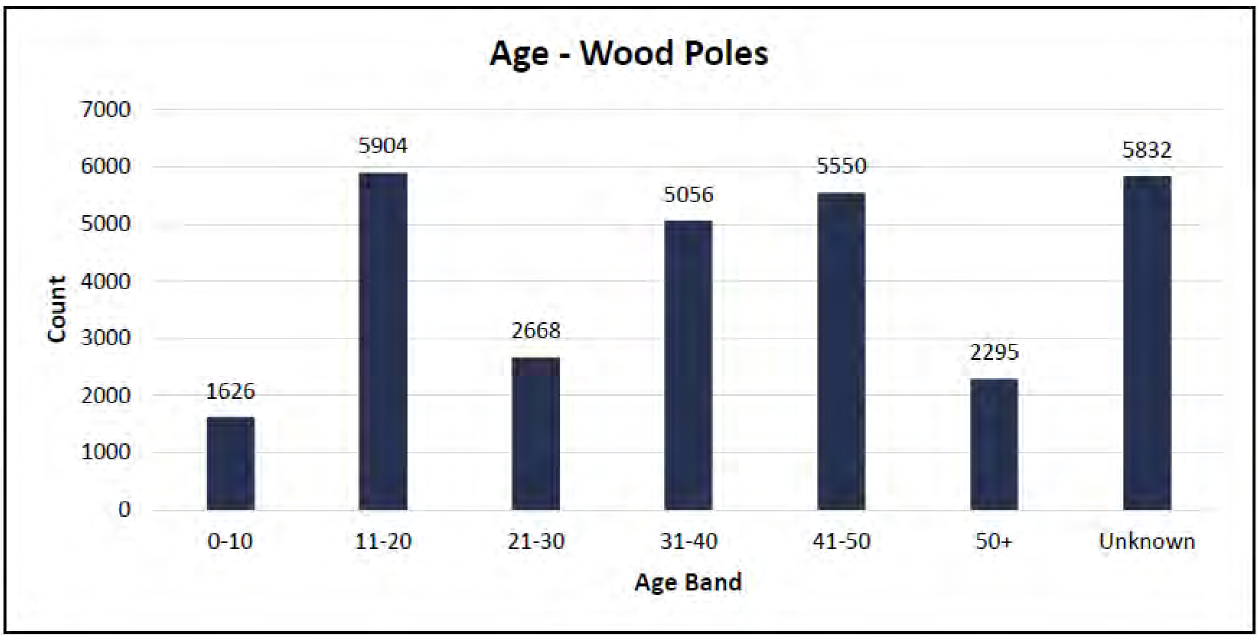
Wood Poles

API owns and manages 28,931 poles within its service territory. Poles condition is determined through data collected via inspections and testing. As part of API's AMP, API tests approximately 10% of its poles annually, which over time has provided a good accumulation of wood pole data and creates a sampling of data that use to effectively assess API's population of wood poles.

To interpret the wood poles data, pole testing records from 2015-2022 were used as reference. Over this time, API has collected 23,227 inspection records, representing approximately 80% of API's total poles. Given that some of the pole testing data is as much as 10 years old, METSCO use a linear degradation method to approximate the loss of pole strength based on current pattern of degradation.

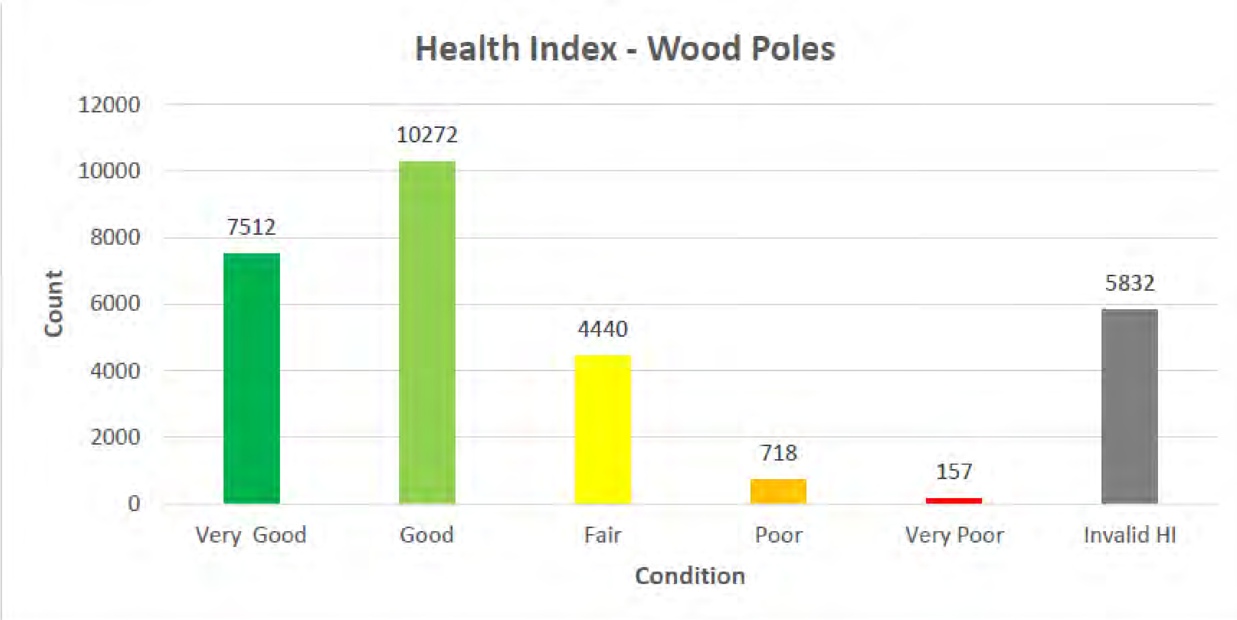
Figure 3.13 presents the age distribution for in-service wood poles. For the purposes of this ACA, uninspected wood poles were deemed to have an unknown age, for a total of 5,704 wood pole assets with an unknown age. An additional 128 inspected poles did not have sufficient information to formulate a valid HI. These wood poles were also deemed to have an unknown age. As a result of this, a total of 5,832 wood poles could not formulate a valid HI.

Figure 3.13: Age Distribution of Wood Poles



The breakdown of HI results is presented below in Figure 3.14.

Figure 3.14: Health Index - Wood Poles



<u>Recommendations:</u>

No recommendations to improve the health index formulation of the wood poles.

Overhead Conductors

API owns and operates approximately 1,800 km of overhead <u>primary</u> circuit kilometers within its service territory. API currently has replaced most of its small gauge ACSR conductor, which aids in eliminating failure risks due to conductor breakdown and lowers overall line losses across the system. Age and inspection data are not currently being collected for API's overhead conductor, however replacement programs currently in place seek to replace conductor segments to circumvent age-related degradation.

<u>Recommendations:</u>

No recommendations to improve the health index formulation of the overhead conductors.

Underground Cables

API owns approximately 21.1km of non-overhead primary cable within its service territory, of which approximately 9.6km is submarine type and the remaining 11.6km is of underground type. There is no age information available on underground and submarine primary cable segments.

<u>Recommendations:</u>

It is recommended to enhance and add to the data that is being collected for the underground cables to improve the formulation of this health index. The information that is proposed is based on a combination of more granular visual inspections and detailed testing of underground cables.

Distribution Transformers

API owns and operates a total of 5,723 distribution transformers – 5,507 pole-mounted transformers (POL) and 222 pad-mounted transformers (PAD). Of this total number of transformers, 5,233 are currently installed (5,066 POL and 167 PAD), 352 are available in a spare capacity (320 POL and 32 PAD), and 138 are designated for other purposes. Only assets in service were assessed. Of the 5,233 in-service transformers assessed, 5,170 had available age information. As only age data was available for distribution transformers, no HI was formulated for these assets.

Recommendations:

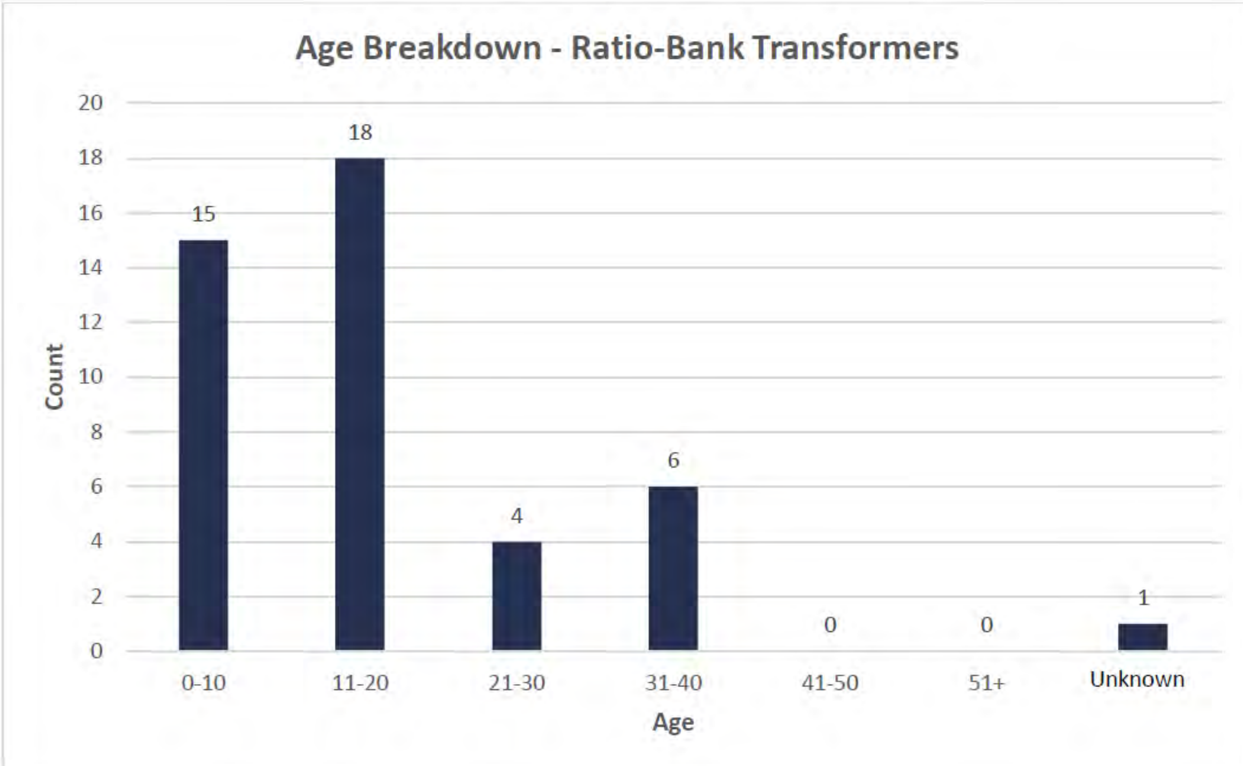
It is recommended to enhance and add to the data that is being collected for the distribution transformers to improve the formulation of this health index. The information that is proposed is based on a combination of more granular visual inspections of distribution transformers.

Ratio-Bank Transformers

API has a total of 44 ratio-bank transformers installations. Ratio bank transformers are specialized transformers that connect a higher voltage system to a lower voltage system, similar to a station power transformer. Ratio-bank transformers are generally installed along distribution feeders, either pole-mounted or platform-mounted. In locations where API has a 3-phase distribution system, the ratio-bank installation is made up of three transformers (one for each phase).

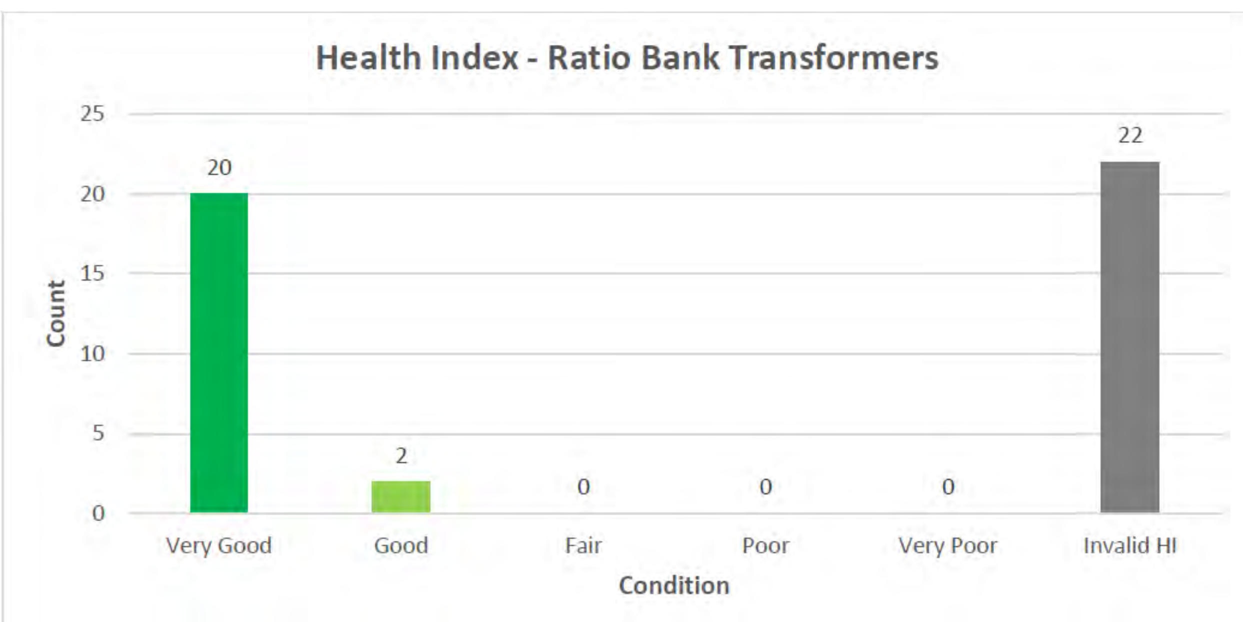
The breakdown of age is presented in Figure 3.15.

Figure 3.15: Age Distribution of Ratio-Bank Transformer Installations



22 of API's ratio-bank transformers have enough data to construct a valid health index, 20 of which of which are currently installed. The average health index of installed units is 95%. Figure 3.16 shows the HI results for this asset class.

Figure 3.16: Health Index - Ratio-Bank Transformer Installations



<u>Recommendations:</u>

No recommendations to improve the health index formulation of the ratio bank transformers.

Reclosers

API owns and operates 110 in-service recloser installations throughout its service territory. Within the last 10 years, API has replaced a significant portion of the older hydraulic type recloser with a relay-controlled vacuum interrupter. API currently has a mix of hydraulic recloser, electronically controlled vacuum interrupters and relay-controlled vacuum interrupters.

No recloser condition data was available to formulate a health index.

<u>Recommendations:</u>

It is recommended to enhance and add to the data that is being collected for the reclosers to improve the formulation of this health index. The information that is proposed is based on a combination of more granular visual inspections of reclosers.

Capacitor Banks

API owns and operates four capacitor banks throughout its service territory, each having a shunt connection type. The inspection and condition data allowed for the formulation of a health index, which is shown in Figure 3.17

Figure 3.17: Health Index - Capacitor Banks

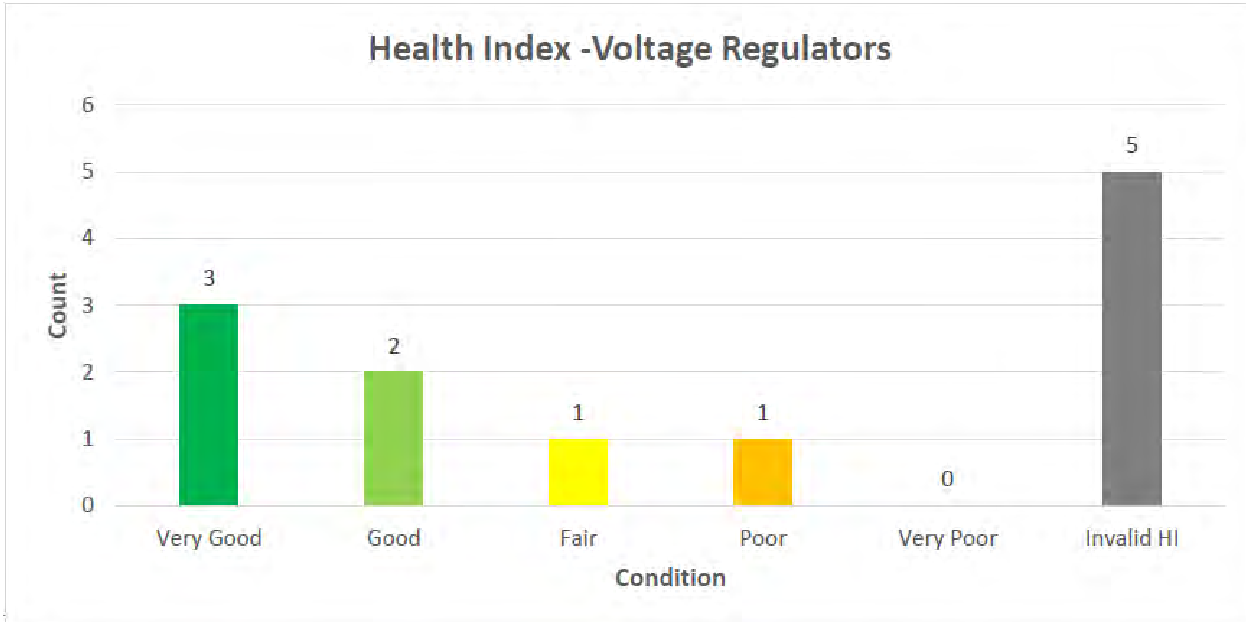
Recommendations:

No recommendations to improve the health index formulation of the capacitor banks.

Distribution Voltage Regulators

API owns and operates 12 in-service voltage regulators and spare voltage regulators. Limited amount of condition data is available for the spare voltage regulators and so only the installed units were assessed. The health index for voltage regulators is shown in Figure 3.18.

Figure 3.18: Health Index - Voltage Regulators



Recommendations:

No recommendations to improve the health index formulation of the voltage regulators.

5.3.2.4 System Utilization

Distribution Asset Capacity Utilization

Historically, API has had difficulty in evaluating the exact utilization of distribution assets. In recent years, API leveraged smart meter data for planning study purposes, but also for assessing individual distribution transformer loading on a case-by-case basis as needed. In 2022, API commissioned an internal area planning study (attached in Appendix C) in which a load flow study was conducted using API's GIS model and reported on the capacity and utilization of all equipment. The summary table is shown Table 3.9. The planning study identified several devices that would experience thermal capacity violations in the short to long term forecast horizon. API has included projects within the in 2025-2029 investment plan to address the capacity issues identified. Addressing the issues identified either through equipment replacement, or through other means (i.e. load balancing) will ensure that the equipment is appropriately sized and could prevent a premature equipment failure.

In general, the average loading of the substation power transformers are below their 50% capacity utilization although an increase has been observed over the years. The seasonal / momentary peaks observe a similar increasing trend, and some power transformers are well above their 50% capacity utilization.

The summarized capacity utilization table for substation transformers are as follows:

Table 3.9: Distribution Station Utilization

Distribution Substation	Transformer	HV kV	LV kV	Capacity (kVA)	# Customers	Winter Peak (kVA)	% Capacity Utilized[1]
Garden River DS	T1	34.5Δ	12.47Y/7.2	3000	406	1,010	33.67%
	T2	34.5Δ	12.47Y/7.2	3000	137	509	16.97%
Bar River DS	T1	34.5Δ	12.5	6000	1375	3,231	53.85%
Desbarats DS	T1	34.5Δ	12.5	6000/8000/10000	1141	2,782	27.82%
	T2	34.5Δ	24.94Y/14.4	5000/6667/8333	1969	4,030	48.36%
Bruce Mines DS	T1	34.5Δ	12.47Y/7.2	5000	334	716	14.32%
	T2	34.5Δ	12.47Y/7.2	5000/6667/8333	862	1,847	22.16%
Goulais TS (API Transf.)	T1	25	12.5	7500	200	2,276	30.35%
Wawa #1 DS	T1	34.5	8.3Y/4.792	5000/6667/8333	687	2947	35.37%
Wawa #2 DS	T1	34.5	8.3Y/4.792	5000/6667/8333	672	1674	20.09%
Hawk Junction DS	T1	44	8.3Y/4.792	1000	See Note 2		
Hawk Junction DS	T2	44	8.3Y/4.792	1000	147	296	29.60%
Dubreuilville Sub 86	T1	44	4.16Y/2.4	3000	221	1,260	42.00%
	T2	44	4.16Y/2.4	3000	127	865	28.83%
Dubreuilville Sub 87	T1	44	4.16Y/2.4	1000	7	99	9.90%

1. Capacity utilization is based on the first cooling stage for applicable transformers
2. T1 is a redundant spare power transformer within the Hawk Junction DS

Transmission System Capacity Utilization

In 2023, API conducted a review of peak load vs capacity on all transmission delivery points, based on 2023 loads. The following table provides a summary of capacity utilization by delivery point.

Table 3.10: Transmission Station Utilization

Delivery Point	HV kV	LV kV	Capacity (kVA)	# Customers	Peak Demand (kVA)[4]	% Capacity Utilized
Andrews TS	115	25	5000	62	369	7.38%
Batchawana TS	115	12.5[2]	7500	829	2,081	27.75%
D.A. Watson TS[1]	115	34.5	75000	1,649	9,221	12.29%
Echo River TS	230	34.5	25000	6,107	18,433	73.73%
Goulais TS	115	12.5	15000	3,123	10,849	72.33%
Limer - No.4 Circuit	44	44	28000	641	27,099	96.78%
Mackay TS	115	14.4	25000	9	68	0.27%
Northern Ave 34.5kV	115	34.5	26700	2	See Note 3	
Northern Ave 12kV	34.5	12	10000	6	2,508	25.08%

1. The large available capacity of Watson TS is a result of a large amount of generation connecting at 34.5kV
2. The noted configuration for the Batchawana TS is based on the supply configuration planned to be placed into service in 2024.
3. The Northern Ave 34.5kV feeder normally supplies < 100 kVA to a single customer; however, it occasionally supplies a portion of the East of Sault load that is normally supplied from Echo River TS
4. Peak loads are extracted from the Load Allocation in the APS

System Utilization under Load Scenarios in the APS

Under the APS, the following four different load growth scenarios were considered:

Scenario 1 9.6% accumulative general load growth (0.92%/annum over 10 years) plus 18% accumulative EV growth (1.7%/annum over 10 years)

Scenario 2 20% accumulative general load growth (1.84%/annum over 10 years) plus 10% EV penetration rate

Scenario 3 20% accumulative general load growth (1.84%/annum over 10 years) plus 20% EV penetration rate

Scenario 4 20% accumulative general load growth (1.84%/annum over 10 years) plus 40% EV penetration

The results of these load scenarios are summarized in the table below:

Table 3.11: Load Allocation Scenario per the APS

	Allocation Load (MW)			
Delivery Point	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
Andrews TS	0.4	0.44	0.48	0.54
Batchawana TS	2.13	2.97	3.89	5.17
DA Watson TS	10.14	10.9	11.6	12.81
Echo River TS	20.89	24.44	29.26	36.2
Goulais TS	11.32	13.42	16.05	19.94
Limer – No.4 Circuit	25.85	26.27	26.85	27.74
Mackay TS	0.076	0.078	0.085	0.093
Northern Ave 34.5kV	0.039	0.056	0.075	0.075
Northern Ave 12kV	2.86	2.65	2.65	2.66

Potential System Constraints

Andrews TS: This distribution does not have any constraints identified under the four load scenarios.

Batchawana TS: Under the four scenarios, the distribution system in Batchawana shows certain levels of non-standard voltage and voltage non-convergence. The system is vulnerable to any significant measurable growth. API intends to monitor load growth in this region, and upgrade portions of the distribution system from single-phase to 3-phase under API's line rebuild program. API intends to revisit a voltage conversion program for Batchawana in its next rate filing.

DA Watson TS: This distribution system performs well under the first three scenarios and is fully capable of supporting the projected loads. Under scenario 4, the distribution system will begin to encounter decreasing voltage levels as well as conductor over-capacity. API intends to monitor growth and revisit its load projection in the next planning study to evaluate if a remediation measure needs to be advanced.

Echo River TS: Under the first two scenarios, this distribution system displays certain levels of non-standard voltage, while under the 3rd and 4th scenario, the distribution system displays certain levels of voltage non-convergence. These constraints are generally associated with long runs of single-phase line operating at 7.2kV. API has included in its capital investment plan projects to expand several single-phase systems to three-phase to support improved load balance and voltage stability. The detail of this program is provided in section 5.4.2.4.3.2.

Goulais TS: Under the four scenarios, the distribution system in Goulais shows certain levels of non-standard voltage and voltage non-convergence. The system is

	quite vulnerable to any significant measurable growth. API intends to leverage the upcoming Goulais refurbishment project led by HOSSM to increase the supply voltage and perform a voltage conversion. The detail of this program is provided in section 5.4.2.4.3.1.
Limer – No.4 Circuit:	This distribution system performs well under the first three scenarios and is fully capable of supporting the projected loads. Under scenario 4, the distribution system will begin to encounter decreasing voltage levels as well as conductor over-capacity. API intends to monitor growth and revisit its load projection in the next planning study to evaluate if a remediation measure needs to be advanced.
Mackay TS:	This distribution does not have any constraints identified under the four load scenarios.
Northern Ave 34.5kV:	This distribution does not have any constraints identified under the four load scenarios.
Northern Ave 12kV:	This distribution does not have any constraints identified under the four load scenarios.

5.3.3 Asset Lifecycle Optimization Policies and Practices

5.3.3.1 Asset Lifecycle Optimization Policies and Practices

API's asset lifecycle optimization practices include consideration of overall inspection, maintenance, repair, and replacement requirements for each type of asset over its expected life. The optimal balance of these activities will depend on factors such as:

- The number, type, condition, and criticality of the assets in service;
- Minimum inspection and maintenance requirements according to DSC requirements, manufacturer's recommendations and Good Utility Practice;
- Health, safety and environmental requirements;
- Risk of Failure (safety, environmental, reliability, cost etc.);
- Availability of spare equipment and evaluation of contingency plans;
- Analysis, by asset type, of available options to refurbish vs. replace existing assets;
- Replacement prior to end of life due to factors beyond API's control (e.g. storm damage, vehicle accidents, vandalism, changes to standards or new regulations unexpected customer demand work, road relocations, etc.)

Additional programs such as infrared scanning, pole testing and transformer Dissolved Gas Analysis ("DGA") are used to identify the condition and the probability of failure more accurately for more critical assets. Where the results of inspections identify issues requiring immediate attention, corrective maintenance and/or asset replacement is undertaken. Less immediate issues are addressed through future maintenance or capital programs.

API's preventative maintenance programs consist of regularly scheduled activities based on manufacturer's recommendation and Good Utility Practice. This includes activities such as removing equipment from service for replacement of consumable components, detailed electrical testing, cleaning, lubrication, etc. Details of API's major in-service distribution assets, as well as full details of the inspection and maintenance programs in place for each type of asset can be found in API's AMP. Section 5 of API's AMP describes how the output of the inspection and maintenance programs supports the continuous reassessment of future Capital and Maintenance plans.

API sustains its planning process through the lens of long-term (15-year), medium-term (5-year), and short-term (1-year) planning. Annual review of these plans allows the utility to prioritize investments and reach decisions regarding repair vs. replace, new-builds, or allow for reallocation of funding to higher priority investments. The long-term approach focuses on high-level reviews, such as system planning studies, in conjunction with load growth and voltage data to assure that the system will retain its level of access, reliability, and safety for the customer. Medium-term planning is driven by customer, municipal, First Nation, health, safety, environmental, regulatory, reliability, and other needs that API must service. The medium-term planning also allows for the incorporation of new information from short-term planning, as well as being used to review the effectiveness of maintenance programs to allow for adjustments as they may be required. Short-term planning addresses short-term needs, such as customer connection, or reaction to external events. The inputs to short term planning include current budget year projects, customer-driven asset development, municipal and developer asset development, and other short-term projects.

The target number of replacements is determined by considering the number, type, age and condition of assets in service, in comparison to the expected useful life of these assets, to determine a replacement rate that is sustainable in the long-term. The Line Rebuild Program is broken out into Distribution and Subtransmission rebuilds in recognition that both the planning requirements and the cost per poles may be different between the two types of line. This prevents an inflated average cost per pole from being used in the future Line Rebuild budgeting as the Express Feeder rebuilds continue to taper off. The Pole Replacement Program is budgeted based on an annual target replacement rate of 500 poles per year.

5.3.3.2 Asset Lifecyle Risk Management Policies and Practices

The optimal balance of inspection, maintenance, repair, and planned replacement will vary by asset type and sub-type. Critical assets, such as substation transformers, will be the subject of frequent inspection and preventative maintenance programs throughout their life. On the other hand, assets such as insulators and most pole hardware are visually inspected in accordance with the DSC mandated frequencies but are not otherwise inspected or maintained. These assets are generally replaced on failure, or at the time of the planned replacement of the associated pole. The following section describes API's lifecycle optimization practices by asset type.

Poles

API conducts visual inspections of its distribution feeders on a minimum 6-year cycle, in accordance with DSC requirements for rural systems. Inspections are carried out more frequently for certain express feeders, due to the criticality of those feeders and the access issues associated with many of those sections that make response to forced outages extremely difficult to conduct and extremely costly. The visual inspections are carried out by internal resources.

In addition to minimum inspection requirements, API also retains a third-party contractor to perform more detailed pole testing. This includes remaining strength calculations based on resistograph testing. The target test rate is approximately 10% of the total pole population per year. With approximately 80% of the total pole population being examined over the historical period, API is on track to sustain this level of inspection and compile system-wide pole records by the end of the forecast period. Detailed pole testing assists API in the following activities:

- Identifying poles at high risk of failure for immediate replacement in the current year;
- Identifying groups of poles (e.g. by area, vintage, type, or combination of these factors) that are showing common signs of premature decay or other issues that require reprioritization within the Line Rebuild Program;
- Identify poles of lower criticality that can be deferred for replacement due to the existence of more critical poles of equal condition score that would have a much greater impact of failure on the entire distribution system.

The regular internal inspection and testing programs are consistent with Good Utility practice with respect to the lifecycle management of wood poles. Western Red Cedar poles used by API are naturally resistant to many types of decay, fungi and insects. This translates the associated poles maintaining good remaining strength scores well into the later years of their typical useful lives. Due to the high number of in-service poles, and the consequence of failure, API employs a proactive replacement strategy. The target planned replacement rate is 500 poles per year. This is intended to replace the majority of poles prior to in-service failure or remaining strength that is below relevant CSA specifications. This also ensures that the associated components (insulators, hardware, crossarms, grounding, guying, etc.) remain intact without major issues for the lifecycle of each pole. Reducing the replacement rate would be expected to result in more poles or associated components failing in-service than are currently observed, meaning potentially large outages and public safety issues, and higher incremental costs for reactionary repair and replacement work.

Overhead Conductor

Conductors are inspected as part of the regular feeder inspections mandated in the DSC. Other than visual inspections, there are few options for additional in-service testing or maintenance of overhead conductors. Conductors are generally repaired via splices as they fail. An example of a cause for a failure necessitating this type of repair would be tree contact.

In previous rate applications, it was identified that much of API’s in-service low gauge ACSR conductor posed a high risk of in-service failure. In response, API created the High-Risk Conductor Replacement program, initiated in 2003 and finished 2014. In addition, many of the poles associated with these conductors were also replaced, in conjunction with the Pole Replacement Program in place at that time. With the transition of the system’s conductor away from low gauge ACSR conductor, API’s ongoing strategy for overhead conductor lifecycle management will be run-to-failure, expect under the following conditions:

- During proactive pole replacement projects that involve a large majority of poles on a given line section, factors such as age, condition, loading, loss analysis, and risk of failure would be evaluated to determine whether it would be economical to replace the conductor in conjunction with the pole replacement.

- ❖ Where inspections or outage analysis identifies specific subsets of the conductor population with above-average risk of failure, this conductor will be considered for replacement. Examples would be where visual inspections identify many splices in a given segment of line. Alternately, if cases emerge where statistically higher failure rates are noticed in relation to a given type, size, or location of conductor, but visual inspection of the conductor does not lend to insight into the mechanisms of failure, API may proceed with laboratory testing to determine if a larger replacement program is required. In most of these cases, API expects that the conductor replacement on any given line section would require significant replacement of poles and associated hardware in order to meet safety standards. Conductor replacement under these conditions would therefore be considered as a factor in the prioritization of line sections into the Pole Replacement Program.

Underground and Submarine Cable Assets

Less than 1% of API's conductor system is underground. Underground assets have been installed as early as 1991. Submarine cable assets feed several islands, the largest submarine cable installation is the express 25 kV feeder crossing between Kensington Point and Campement D'Ours Island, which serves the communities located on St. Joseph Island. These assets are inspected on frequencies mandated by the DSC. Issues or deficiencies are noted and corrected as required. As the age of this asset group increases and issues are identified through regular inspections, API will review available options for life-extending maintenance and will make the appropriate decisions to maintain vs replace at that time.

Pole Line Hardware

This group of assets includes items such as crossarms, insulators, hardware, fused cutouts, anchoring and guying components, grounding components, etc. These assets are inspected during visual feeder patrols. These components are normally run to failure or replaced in conjunction with planned pole replacements. Often, these components will provide reliable service from the initial pole installation to the time of planned total pole replacement. On occasion, groups of components are identified that require proactive replacement outside of being replaced with the associated pole. An example would be where manufacturing defects or design issues are identified in certain lots or types of material that pose higher risks of failure or exhibit safety issues to workers or the public for the in-service asset.

Distribution Transformers

Overhead transformers are inspected visually during the 6-year feeder patrols, as well as on an ad-hoc basis during other planned work such as service connections or disconnections.

Due to the large number of in-service distribution transformers, it would be extremely impractical to closely monitor and maintain pole-top and pad-mount transformers in the same fashion as substation power transformers, and the expense of such a program would far exceed its utility.

The consequence of failure of any individual pole-top or pad-mount transformer is relatively low, as API typically has very few customers connected to each transformer, often one-to-one. API also maintains an adequate inventory of spare transformers which allows for immediate replacement of failed units. As a result, distribution transformers are mainly replaced using a run-to-failure strategy.

There are however situations where API will proactively replace distribution transformers that have not failed in-service:

- ❖ Voltage conversion – transformers are replaced as required for voltage conversions. The units removed from service are tested and the majority are returned to stock for use elsewhere in API's service territory. In cases where line rebuild projects occur in areas for upcoming planned voltage conversions, any existing single-voltage distribution transformers are replaced with dual-voltage transformers during the line rebuilds. This allows for a more efficient voltage conversion at a future date with reduced overall costs and planned outage durations.
- ❖ Overloading – distribution transformers identified as being overloaded, or those that would have a high probability of future overloading due to the connection of new services or service upgrades are proactively exchanged for a larger size transformer.
- ❖ Near end-of-life – transformers at end of life, or those containing PCB's are removed from service during otherwise planned activities. This eliminates the higher future costs associated with a one-time trip for the sole purpose of exchanging a failed or PCB-contaminated transformer.

Transformers that are replaced for reasons unrelated to end of life (voltage conversion and potential overloading) are inspected and tested. If the transformer is in good condition and otherwise suitable for re-use, it is returned to inventory as a spare for future use. In consideration of current and future load projections, API will optimize the capacity of any new transformers to be installed.

Reclosers, Capacitors, Voltage Regulators, Gang-Operated Switches

The assets in this category are relatively small in number, expensive and critical to the proper operation of the distribution system. In-service failure could result in widespread outages, power quality issues, as well as potential safety or environmental issues. As a result, there are inspection and preventative maintenance programs associated with these assets.

The more critical assets in this category are subjected to corrective maintenance based on the outcome of infrared scanning. Where equipment can by bypassed, regular operational checks (i.e. manually verifying proper operational capability) are also conducted on a semi-annual basis. In addition, many of these assets are removed from service for more detailed testing, repairs, and overhauls, as required. Specific details on the inspection and maintenance programs in place for each type of asset can be found in Section 4 of API's AMP (Appendix A).

Due to the costs associated with both the initial purchase and ongoing maintenance of these assets, decisions to replace vs repair the assets are often required. For example, hydraulic reclosers are removed from service for testing and preventive maintenance on a 6-year cycle. Should any time-consuming repairs or replacement components be required, then it may be more economical to replace the unit. API has found that replacement units often provide improved functionality (more accurate timing, ability to change parameters to replace multiple variations of legacy equipment, SCADA-ready, etc.) and also require less future maintenance than a repaired unit. As a result, API budgets an annual capital amount for replacement of these assets where the replacement option is superior to the repair option.

Substation Power Transformers and Station Voltage Regulators

Substation power transformers and station voltage regulators are generally among the most expensive distribution assets. They also have a high consequence of failure in terms of potential safety and environmental impacts, outage impacts and replacement costs. A single transformer failure could result in a prolonged outage to thousands of customers, with extensive restoration time if the outage impacts an area with no interconnection to other systems. The combination of the high value, criticality, and small number of in-service assets, justifies more intensive inspection and maintenance programs for this group of assets.

Power transformers and voltage regulators are inspected at least every 6 months as required by the DSC. Overall condition is observed, and readings of gauges are recorded. Annually, all substation assets are scanned using infrared cameras and have oil samples taken for DGA. Any issues identified during an inspection process are noted and prioritized for corrective maintenance as required. Where these units can be removed from service without significant outage impact, they will be subjected to detailed inspections, adjustments and testing over a 6-year cycle.

These assets are generally replaced proactively when results of inspection and maintenance activities suggest that there is an increasing probability of failure in the near future. API has included in its Capital Investment plan under section 5.4.2.4.2.5, a rebuild project at the Wawa #2 DS. As part of this project, API intends to replace the current three-phase 8.32kV transformer and install a contingency three-phase 12.5kV transformer.

Substation Switching and Protection Assets

API's substations are relatively simple configurations consisting of 1-2 incoming express feeders (34.5 or 44 kV), 1-2 power transformers or voltage regulators, and 1-3 outgoing feeders. Protective and switching devices include power fuses and the same types of reclosers and gang-operated switches as those used on overhead lines. These assets are inspected on 6-month cycles, in accordance with DSC requirements. Further inspection and maintenance programs for these devices are anticipated to be similar to the programs in place for the overhead line switching assets, as described above. Full details of API's substation inspection and maintenance programs can be found in Section 4 of API's AMP (Appendix C). Only one of API's substations currently has a control building and DC system, and no substations contain circuit breakers, or metal clad switchgear.

Other Substation Assets

This group of assets includes the general substation site, fencing, structures, and foundations, buswork, insulators, hardware, etc. These items are inspected on a 6-month cycle in accordance with the DSC. Annual infrared scanning is also conducted to identify issues such as loose connections or thermal variations on equipment. Any issues identified during routine inspections are noted and prioritized for corrective maintenance as required. API also budgets an annual amount for small capital replacements in substations that are required to correct deficiencies or high-risk issues identified during inspection and maintenance activities.

Metering Assets – AMI

API utilizes the Sensus FlexNet AMI system in order to meet the requirements of the provincial smart metering mandate. The AMI communications network currently consists of the following equipment:

- 8 Tower Gateway Base stations
- 23 Repeaters – with more being added as required to reach remote meters

Tower Gateway Base ("TGB") stations are relatively expensive assets that comprise complex transceiver units housed in weatherproof enclosures, with integrated heating, ventilation, and air conditioning

(“HVAC”) systems and battery backup. Each TGB typically reads thousands of meters, either directly or via repeaters. As part of the long-term AMI contract with Sensus, these units are remotely monitored on a 24/7 basis, and preventive maintenance activities are performed by Sensus on a 6-month basis. Maintenance includes changing air filters, verifying correct operation of all HVAC and power systems, and firmware upgrades as required. Sensus is responsible for any repairs to these units during the term of the AMI contract.

Repeaters are pole-mounted devices that are used to read meters beyond TGB coverage areas. One type of repeater is used to effectively extend the reach of a nearby TGB to read meters in “dead-zones”, or areas that are just beyond the reach of TGB’s. Another type of repeater is effectively a “mini-TGB”, with a direct backhaul link, and is used in place of TGB’s for extremely remote and low-density areas, where deployment of TGBs would be impractical and uneconomical. These devices are monitored for communication uplink availability, with alarms sent to API in the event that communications are lost. Given the relatively low number of meters relying on each repeater, issues are corrected only as identified. In most cases, a simple reset of the communication link may restore connectivity. In other cases, a complete replacement of the repeater or associated antenna hardware is required. In this case, spare equipment is readily available, and replacement can generally occur prior to the loss of any Time-of-Use (“TOU”) consumption data.

Meters and Instrument Transformers

Meters follow a certification maintenance program as they are subject to re-verification regulations made under the Electricity and Gas Inspection Act. API samples meters in accordance with regulatory requirements and will keep meters in service if they continue to meet regulatory requirements. Other than periodic verification of large/poly-phase services, meters are not subject to any additional inspection or maintenance programs.

Instrument transformers that are associated with large poly-phase services are inspected and tested in conjunction with the associated meters during the periodic verifications of these services.

Wholesale metering installations are subject to the requirements of the IESO’s Market Rules. API’s Meter Service Provider (MSP) manages the periodic re-verification and replacement of meters as required to meet Market Rules. The MSP also reviews data from these meters and flags any potential data integrity issues for further investigation.

Fleet

In order to support the day-to-day activities of the three work centres in its service territory, as well as to enable access to remote areas of its system across challenging terrain, API maintains a relatively large and diverse fleet, consisting of:

- 11 aerial devices (bucket trucks, radial boom derricks)
- 20 pickup trucks
- 2 Forestry Utility truck
- 8 snowmobiles
- 5 off-road vehicles
- 2 forestry chippers
- 2 forklift

- 17 trailers (open & enclosed) – for transporting poles, heavy materials, snowmobiles and off-road vehicles

API has developed and implemented a preventative fleet maintenance plan in its SAP work management system that complies with manufacturers recommendations and prescribed regulations.

Maintenance of booms for hoisting and man lifts (buckets) includes requirements for a variety of one month, 3 month, 6 month and annual inspections, including dielectric testing. Cab and Chassis have separate inspection requirements that are similar in frequency. Additionally, regulations prescribe annual commercial, vehicle operator's registration ("CVOR") inspections and emissions testing.

Maintenance of pick-up trucks generally includes 3-month service requirements and annual Safety Inspections. Heavier pickups are subject to CVOR inspections and emissions testing.

Annual allowance is made for replacement of one aerial device, as well as about three pickup trucks and a variety of other items as required. This results in approximate replacement cycles of 12 years for aerial devices and five plus years for pickup trucks. Condition assessment and evaluation of future maintenance costs may extend the in-service life of some pickup trucks beyond 5 years. Replacement of lower-value items such as snowmobiles and off-road vehicles is based mainly on evaluation of the overall condition.

Rights of Way (ROW)

The objective of the API VM plan is to manage Annual Vegetation Workload (AVW) in proximity to electrical equipment on a regular schedule to enhance and sustain reliability and worker accessibility to the system, while minimizing hazards created by vegetation in proximity to energized equipment.

Achieving this objective requires ongoing investment in maintenance programs that include brush removal, herbicide application, tree trimming and hazard tree removal. In 2023, API contracted Lakeside Environmental Consultants ("ECI") to complete a comprehensive review of the status of API's ROWs, as well as to quantify recommendations for future activities that would ultimately lead to a lowest-cost, sustainable VM plan. The full report summarizing the exercise undertaken by ESI is provided in Appendix L. The results of the report are critical to the fundamental review process of API's VM programs, and the establishment of future maintenance plans.

The end goal of removing the AVW is to provide a least-cost program for vegetation removal to realize the lowest practical incidence of tree-related outages. Through the creation and review of cyclical maintenance programs for brush removal, herbicide application, tree trimming, and hazard tree removal activities, API strives to hold AVW in equilibrium and maintain minimum ROW clearance standards. The O&M funding for API is based heavily on AVI specific to its densely forested service territory. The VM plan is provided in Appendix B.

ROW Access

ROW Access allows crew and equipment access to the express lines and are maintained in a similar manner to those used for the transmission system in Ontario. At the time of the express feeder construction, much of the ROW containing these lines were accessible by combinations of rail, access roads used for logging and mining activities, or recreational trails.

Once an access trail system has been established, annual inspections are performed to ensure maintenance requirements are identified and included in the current maintenance program. Maintenance activities, under the current year's program, would address vegetation growth, repair washouts, remove fallen vegetation off the ROW access trail, and address vegetation growth within the ROW access that would impact API's usage of the trail system.

5.3.4 System Capability Assessment for Renewable Energy Generation

As of January 31, 2024, API has 3 FIT connections with a total capacity of 334 kW as well as 128 microFIT connections with a total capacity of approximately 1,195 kW. All these connections were completed between 2009 and 2017. API has also connected 14 Net-Metered services, which have a combined total generation capacity of 70 kW.

5.3.4.1 Applications Over 10 kW

API has a single DER application over 10kW for load displacement. At the time of submitting this DSP, the DER application process was not yet finalized.

5.3.4.2 Forecast of REG Connections

Since the IESO ceased accepting new applications under the FIT and microFIT programs, API has seen a significant decrease in interest in connecting REG projects to its distribution system. Currently, settlement options for any new embedded generation project are limited to net metering, load displacement, or settlement as an embedded retail generator under the Retail Settlement Code. In recent years, API has seen a limited number of new net metering installations (which typically export very little power to API's system) and load displacement installations (which generally do not export power to API's system).

5.3.4.3 Capacity Available

In the absence of the Northeast Zone transmission constraints, API expects that a maximum of approximately 22 MW could be connected throughout its service area (under ideal conditions of project location). In the absence of both Northeast Zone constraints and all local transmission line/station constraints, API expects that upwards of 150 MW could be connected (again under ideal conditions of project location on each distribution feeder).

5.3.4.4 Constraints – Distribution and Upstream

As mentioned above, the Northeast Zone transmission constraints severely limit any large REG projects in API's service area. Local transmission line and station constraints are also limiting in some cases. Due to the overriding limitation of the Zone constraint, API has not provided a complete listing of local transmission constraints.

API does not currently have any restricted feeders in relation to the system capability for renewable energy generation and distributed energy resources. The current planned investment which will result in overall increased distribution system capability will further increase API's ability to connect these types of services.

5.3.4.5 Constraints – Embedded Distributor

API does not have any embedded distributors, therefore the connection of future generation will have no impact on available capacity for any existing embedded distributor.

5.3.5 CDM Activities to Address System Needs

As outlined above, API now has relatively limited access to information regarding CDM activity within its service territory, as a result of changes implemented in 2019 and beyond which transferred any responsibility for the provincial conservation framework from LDCs to the IESO. In discussion with the IESO, the IESO is no longer able to provide customer-specific or distributor- specific information regarding the level of current or planned conservation programs with LDCs. As a result, API has lost a significant degree of visibility as it relates to CDM programs in its service territory. Previously, API would have had direct and robust information and was able to take this information into consideration for system planning and rate-setting purposes.

Based on its engagement with customers, communities and other stakeholders, API is not aware of any planned significant CDM programs undertaken within its service territory which would need consideration in API's system planning (ex: CDM programs that would allow API to defer or alter a planned investment).

API is not proposing any distribution funded CDM programs to address system needs with this DSP. API will continue to consider CDM opportunities to address system needs. In doing so, API will consider the relative costs and benefits associated with a CDM option. When the OEB's Benefit Cost Analysis is finalized, API will implement it as required by the OEB.

5.4 Capital Expenditure Plan

The capital expenditure plan should set out and comprehensively justify a distributor's proposed expenditures on its distribution system and general plant over a five-year planning period, including investment and asset-related O&M expenditures.

A distributor's DSP details the system investment decisions developed on the basis of information derived from its planning process. It is critical that investments be justified in whole or in part by reference to specific aspects of that process. As noted in section 5.2 above, a DSP must include information on the historical and forecast period.

This section describes API's 5-year Capital Expenditure plan over the historical and forecast period, including:

- ❖ A summary of capital expenditures over a 10-year period, including five historical years and five forecast years (Section 5.4.1);
- ❖ Justification for forecasted capital expenditures and material investments (Section 5.4.2).

5.4.1 Capital Expenditure Summary

5.4.1.1 Capital Expenditure Variances Over the Historical Period

The following sections provide variance analysis and explanations of the actual in-service capital investments (forecast for the 2024 bridge year) against the 2020-2024 planned capital investment identified in API's 2020-2024 Distribution System Plan.

The table below outlines API's capital expenditures over the 10-year period covered by this DSP, and is consistent with Appendix 2-AB

Figure 4.1: API's Capital Expenditures over the 10-Year Period

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2020			2021			2022			2023			2024			2025	2026	2027	2028	2029
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	903	1,519	68.1%	963	2,488	158.2%	930	2,082	123.8%	906	12,989	1333.1%	906	3,295	263.5%	1,465	1,489	1,511	1,534	1,557
System Renewal	6,023	4,052	-32.7%	4,700	5,139	9.3%	4,822	7,567	56.9%	6,494	4,102	-36.8%	4,616	12,397	168.6%	5,752	5,822	10,494	5,998	6,088
System Service	562	259	-54.0%	7,978	980	-87.7%	472	32	-93.3%	461	11,393	2371.9%	461	1,684	265.3%	1,054	1,110	652	753	1,310
General Plant	1,357	1,425	5.0%	1,238	819	-33.9%	13,980	16,386	17.2%	1,178	2,241	90.2%	1,098	1,901	73.2%	2,039	1,718	1,855	1,787	1,785
TOTAL EXPENDITURE	8,846	7,254	-18.0%	14,879	9,425	-36.7%	20,205	26,067	29.0%	9,039	30,725	239.9%	7,081	19,278	172.3%	10,310	10,139	14,513	10,071	10,740
Capital Contributions	- 102	- 168	65.4%	- 100	- 472	372.3%	- 100	- 264	163.7%	- 100	- 272	171.8%	- 100	- 5,252	5152.1%	- 100	- 102	- 104	- 106	- 108
NET CAPITAL EXPENDITURES	8,744	7,086	-19.0%	14,779	8,953	-39.4%	20,105	25,804	28.3%	8,939	30,453	240.7%	6,981	14,026	100.9%	10,210	10,037	14,409	9,965	10,632
System O&M	7,015	7,078	0.9%	7,186	7,171	-0.2%	7,294	7,388	1.3%	7,404	7,605	2.7%	7,515	7,883	4.9%	9,275	9,530	9,792	10,061	10,338

Figure 4.2: API's Capital Expenditures over the 2025-2029 DSP Period

CATEGORY	Forecast Period (planned)				
	2025	2026	2027	2028	2029
	$ '000				
System Access	1,465	1,489	1,511	1,534	1,557
System Renewal	5,752	5,822	10,494	5,998	6,088
System Service	1,054	1,110	652	753	1,310
General Plant	2,039	1,718	1,855	1,787	1,785
TOTAL EXPENDITURE	10,310	10,139	14,513	10,071	10,740
Capital Contributions	- 100	- 102	- 104	- 106	- 108
NET CAPITAL EXPENDITURES	10,210	10,037	14,409	9,965	10,632
System O&M	9,275	9,530	9,792	10,061	10,338

Further, the spending by project is outlined in the table below, which is consistent with Appendix 2-AA

Figure 4.3: API's Project Capital Expenditures over the 10-Year Period

Projects	2020	2021	2022	2023	2024 Bridge Year	2025 Test Year	2026	2027	2028	2029
Reporting Basis	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE
System Access										
Meters	$ 302,112	$ 83,982	$ 137,956	$ 110,307	$ 132,952	$ 129,294	$ 131,246	$ 133,214	$ 135,213	$ 137,241
Service Connections	$ 981,859	$ 1,506,238	$ 1,284,929	$ 12,463,740	$ 2,998,014	$ 1,150,988	$ 1,167,403	$ 1,184,913	$ 1,202,686	$ 1,220,728
Transformers - SA	$ 51,982	$ 248,886	$ 278,992	$ 317,632	$ 154,000	$ 160,000	$ 162,400	$ 164,836	$ 167,309	$ 169,818
Relocation/Joint-Use	$ 182,808	$ 648,395	$ 380,336	$ 97,786	$ 10,000	$ 25,000	$ 28,114	$ 28,536	$ 28,964	$ 29,398
System Access Gross Expenditures	$ 1,518,760	$ 2,487,501	$ 2,082,212	$ 12,989,466	$ 3,294,967	$ 1,465,281	$ 1,489,163	$ 1,511,499	$ 1,534,172	$ 1,557,185
System Access Capital Contributions	$ 144,984	$ 472,311	$ 33,820	$ 141,704	$ 5,252,085	$ 100,000	$ 102,000	$ 104,040	$ 106,121	$ 108,243
Sub-Total	$ 1,373,776	$ 2,015,190	$ 2,048,392	$ 12,847,762	-$ 1,957,118	$ 1,365,281	$ 1,387,163	$ 1,407,459	$ 1,428,051	$ 1,448,942
System Renewal										
Storm Capital	$ 78,102	$ 100,323	$ 37,690	$ 16,323	$ -	$ -	$ -	$ -	$ -	$ -
Small Lines/Station Capital	$ 494,240	$ 317,612	$ 3,204,676	$ 408,238	$ 423,625	$ 430,224	$ 435,523	$ 441,854	$ 448,277	$ 454,793
Recloser, Regulator Replacements	$ 65,673	$ -	$ 16,219	$ 48,785	$ 62,100	$ 90,000	$ 91,350	$ 92,720	$ 94,111	$ 95,523
Distribution Line Rebuilds	$ 3,198,061	$ 4,364,427	$ 4,234,143	$ 3,153,365	$ 5,454,691	$ 3,720,947	$ 3,765,636	$ 3,822,121	$ 3,879,452	$ 3,937,644
Subtransmission Line Rebuilds	$ 57,830	$ 206,603	$ 11	$ 249,775	$ 1,994,380	$ 964,493	$ 977,272	$ 991,932	$ 1,006,811	$ 1,021,913
Transformers - SR	$ 157,891	$ 150,133	$ 74,390	$ 225,373	$ 116,800	$ 140,000	$ 142,100	$ 144,232	$ 146,395	$ 148,591
Dubreuilville DS Rebuild	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Replacements	$ -	$ -	$ -	$ -	$ -	$ 406,509	$ 410,468	$ 416,625	$ 422,875	$ 429,218
Bruce Mines DS Rebuild	$ -	$ -	$ -	-$ 0	$ 4,345,863	$ -	$ -	$ -	$ -	$ -
Wawa #2 DS Rebuild	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,584,465	$ -	$ -
System Renewal Gross Expenditures	$ 4,051,798	$ 5,139,098	$ 7,567,129	$ 4,101,858	$ 12,397,459	$ 5,752,173	$ 5,822,349	$ 10,493,949	$ 5,997,921	$ 6,087,682
System Renewal Capital Contributions	$ 23,480	$ -	$ 2,024	$ 31,153	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total	$ 4,028,318	$ 5,139,098	$ 7,565,105	$ 4,070,705	$ 12,397,459	$ 5,752,173	$ 5,822,349	$ 10,493,949	$ 5,997,921	$ 6,087,682
System Service										
Transformers - SS	$ -	$ 115,963	$ 30,979	$ 179,697	$ 55,000	$ -	$ -	$ -	$ -	$ -
Hawk Junction DS	$ -	$ 856,045	$ 699	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Goulais Voltage Conversion	$ -	$ -	$ -	$ -	$ -	$ 296,560	$ 302,370	$ 308,417	$ 314,586	$ 320,877
Protection, Automation, Reliability	$ 255,092	$ 8,118	$ -	$ 11,213,244	$ 1,484,971	$ 757,301	$ 807,144	$ 343,918	$ 437,971	$ 309,491
Desbarats DS Upgrades	$ 3,487	$ -	$ -	-$ 0	$ 143,911	$ -	$ -	$ -	$ -	$ -
Goulais TS Refurbishment	$ -	$ -	$ -	-$ 0	$ 0	$ -	$ -	$ -	$ -	$ 680,000
System Service Gross Expenditures	$ 258,579	$ 980,125	$ 31,678	$ 11,392,940	$ 1,683,882	$ 1,053,861	$ 1,109,514	$ 652,335	$ 752,557	$ 1,310,368
System Service Capital Contributions	$ -	$ -	$ 227,852	$ 98,993	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total	$ 258,579	$ 980,125	-$ 196,174	$ 11,293,947	$ 1,683,882	$ 1,053,861	$ 1,109,514	$ 652,335	$ 752,557	$ 1,310,368
General Plant										
ROW Expansion	$ 105,630	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tools & Equipment	$ 29,186	$ 83,318	$ 59,546	$ 164,421	$ 90,000	$ 91,800	$ 93,177	$ 94,575	$ 95,993	$ 97,433
Business Systems	$ -	$ 15,575	$ 9,179	$ 66,409	$ 485,448	$ 82,437	$ 83,479	$ 84,731	$ 86,002	$ 87,292
Land Rights	$ 29,425	$ 62,085	$ 63,601	$ 76,710	$ 39,336	$ 33,420	$ 33,783	$ 34,290	$ 34,804	$ 35,326
Communication & SCADA	$ -	$ -	$ -	$ -	$ -	$ 125,564	$ 146,127	$ 138,210	$ 70,487	$ -
Transportation & Work Equipment	$ 784,824	$ 499,513	$ 138,882	$ 1,145,318	$ 584,674	$ 1,207,470	$ 957,509	$ 1,139,721	$ 1,129,936	$ 1,189,752
IT Hardware/Software	$ 61,070	$ 124,961	$ 240,475	$ 106,934	$ 58,933	$ 59,067	$ 59,824	$ 60,722	$ 61,632	$ 62,556
Buildings, Facilities & Yards	$ 135,485	$ 53,185	$ 165,728	$ 25,498	$ 154,147	$ 213,866	$ 216,898	$ 173,934	$ 176,542	$ 179,191
Sault Facility	$ -	$ -	$ 15,708,824	$ 640,323	$ 200,622	$ -	$ -	$ -	$ -	$ -
ROW Access Program	$ 279,359	-$ 19,969	$ -	$ 15,000	$ 288,217	$ 225,549	$ 127,295	$ 129,204	$ 131,142	$ 133,109
General Plant Gross Expenditures	$ 1,424,978	$ 818,668	$ 16,386,235	$ 2,240,612	$ 1,901,377	$ 2,039,174	$ 1,718,092	$ 1,855,387	$ 1,786,538	$ 1,784,659
General Plant Capital Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total	$ 1,424,978	$ 818,668	$ 16,386,235	$ 2,240,612	$ 1,901,377	$ 2,039,174	$ 1,718,092	$ 1,855,387	$ 1,786,538	$ 1,784,659
Miscellaneous										
Total	$ 7,085,650	$ 8,953,081	$ 25,803,558	$ 30,453,026	$ 14,025,600	$ 10,210,489	$ 10,037,118	$ 14,409,130	$ 9,965,067	$ 10,631,651
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*										
Total	$ 7,085,650	$ 8,953,081	$ 25,803,558	$ 30,453,026	$ 14,025,600	$ 10,210,489	$ 10,037,118	$ 14,409,130	$ 9,965,067	$ 10,631,651

5.4.1.1.1 System Access

API's System Access investments from 2020-2024 are outlined in the table and figures below. Table 4.1 provides an overall summary of the investment drivers. API's prior DSP did not include specific categorization of the net planned investments; therefore, variances are discussed in the context of the major drivers of overall System Access investments, it is evident that significant investments occur in the response of connecting services to API's distribution system.

Table 4.1: System Access Historical (2020-2024) Variance Summary ($000's)

System Access	Net Plan	Gross Actual	CIAC	Net Actual	Net Variance
Service Connections	3,402	19,235	(5,474)	13,761	10,359
Meters[1]	308	767	-	767	459
Transformer – SA[1]	384	1,051	-	1,051	667
Relocation/Joint-Use[1]	14	1,319	(571)	748	734
Total	**4,108**	**22,373**	**(6,045)**	**16,328**	**12,220**

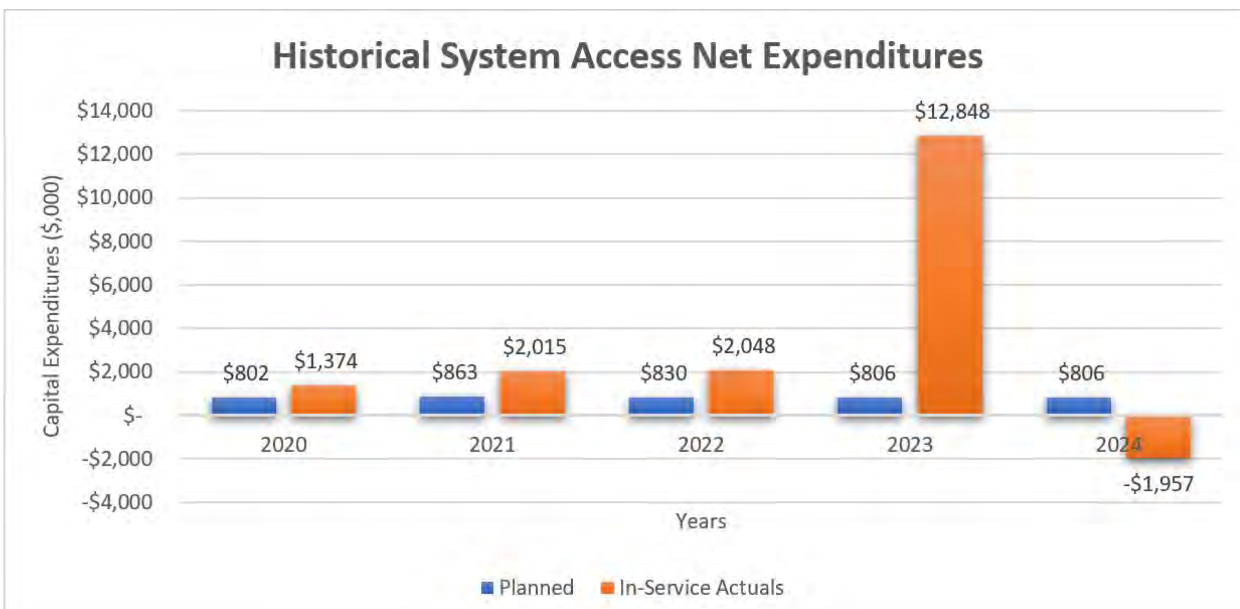
1 – In API's 2020-2024 DSP, these line items were grouped under *Total Items Less Than Materiality*

At the time of filing its previous DSP, API hadn't identified any increasing trend in new or upgraded service requests, and so based its plan on 5-year rolling averages. API had been aware of the connection of a potential new large industrial mining customer, but the timing, load projection and scope of request and associated system upgrades were still uncertain.

Instead of seeing previous levels of residential, seasonal, and small commercial service requests, API experienced a surge of new and upgraded service connections that started in mid-2020 and continued over 2021 to 2023.

As depicted in Figure 4.4 below, API incurred significant capital expenditures in 2023 and significant contributions in 2024 (based on the net negative expenditure). This is mainly the result of a one-time large industrial connection (the "No.4 Circuit 10 MW Project") that required a substantial system expansion ("44kV Expansion"), which consisted of upgrading approximately 11.3 km of 44kV Subtransmission lines along API's No.4 Circuit. API was also required to relocate a portion of its existing 44kV line. The relocation added significant effort with regards to permitting, clearing and establishing a new ROW and required the installation of two large water crossings that required specialized foundation and structural design and engineering. The scope of the system expansion upgrade and resulting project was significant and as a result skews API's historical in-service actual. API notes that portions of the 44kV line were already approaching the end of their useful life and would have been replaced in the coming years. Accordingly, API has applied the cost sharing contemplated in Section 3.1.7A of the Distribution System Code in relation to these components of the project, subject to the OEB's approval of this treatment. API further notes that by completing the related replacement, it has increased available capacity in this section of the distribution by 2MW.

Figure 4.4: Historical System Access Net Expenditures



In the context of all expenditures exclusive of the large expenditures associated with the 44kV expansion noted above, API has included a summary of in-service actuals. Table 4.2 provides this summary, while Figure 4.2 provides a comparison of annual in-service additions relative to planned expenditures. API notes that capital contributions for the project were collected and recorded in 2024, however the project was in-service in 2023.

Table 4.2: System Access Historical (2020-2024) Variance Summary (less 44kV Expansion) ($000's)

System Access	Net Plan	Gross Actual	CIAC	Net Actual	Net Variance
Service Connections	3,342	6,272	(322)	5,950	2,608
Meters[1]	308	767	-	767	459
Transformer – SA[1]	384	1,051	-	1,051	667
Relocation/Joint-Use[1]	14	1,319	(571)	748	734
Total	**4,048**	**9,410**	**(893)**	**8,517**	**4,469**

1 – In API's 2020-2024 DSP, these line items were grouped under *Total Items Less Than Materiality*

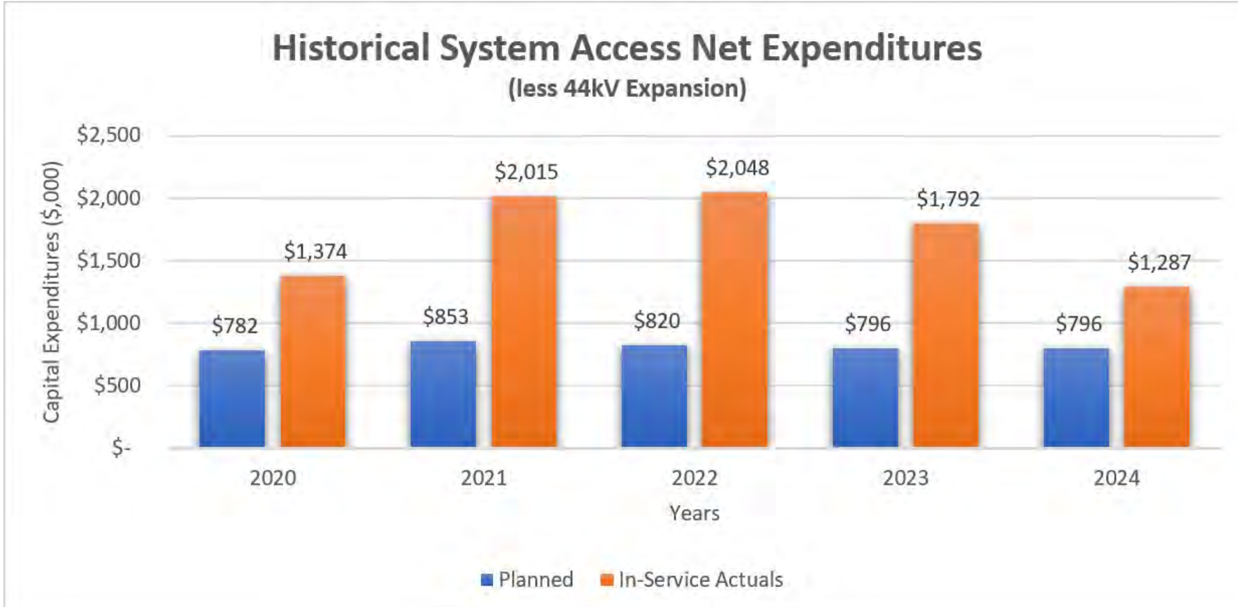
At the time of filing its previous DSP, API was also unaware of any major third-party plans, especially regarding broadband and fiber-to-the-home ("FTTH") telecommunication projects by Internet Service Providers ("ISP"), however the following volume of requests materialized beginning in 2020:

- 2020: 42 permits to connect to 1,117 API poles
- 2021: 7 permits to connect to 137 API poles
- 2022: 10 permits to connect to 365 API poles
- 2023: 9 permits to connect to 434 API poles
- 2024: 8 permits to connect to 297 API poles (as of March 2024)

API anticipates that numerous additional permits to connect broadband will be received in 2024 and 2025 in meeting the objectives set out in the Building Broadband Fast Act ("BBFA"). API is currently working closely with two ISPs and expects a minimum of an additional 1800 poles to be connected. API has not received detailed information and therefore cannot yet estimate the total number of poles to be connected under the BBFA at the time of this submission, but it expected to be in the 4000-8000 range. API notes that BBFA-related increases have not been reflected in the Bridge and Test year capital in-service projections, as these costs will be recorded in a regulatory asset.

Along with the increased levels of service connections, API was also required to procure a higher level of transformers to facilitate those connections. Historically, it was API standard to use a minimum 15kVA transformer for single services. However, with the onset of electrification and electric vehicles charging requirements, API has increased its standard to 25kV and 37kVA (where the size is based on the type of dwelling and the level of occupancy expected). The larger capacity transformers have resulted in increased costs. Transformer manufacturers have also incurred COVID-19 inflationary pressures, which they have passed on to utilities. It has been common to see the price per unit increase in the 30-50% range.

Figure 4.5: Historical System Access Net Expenditures (less 44kV Expansion)



5.4.1.1.2 System Renewal

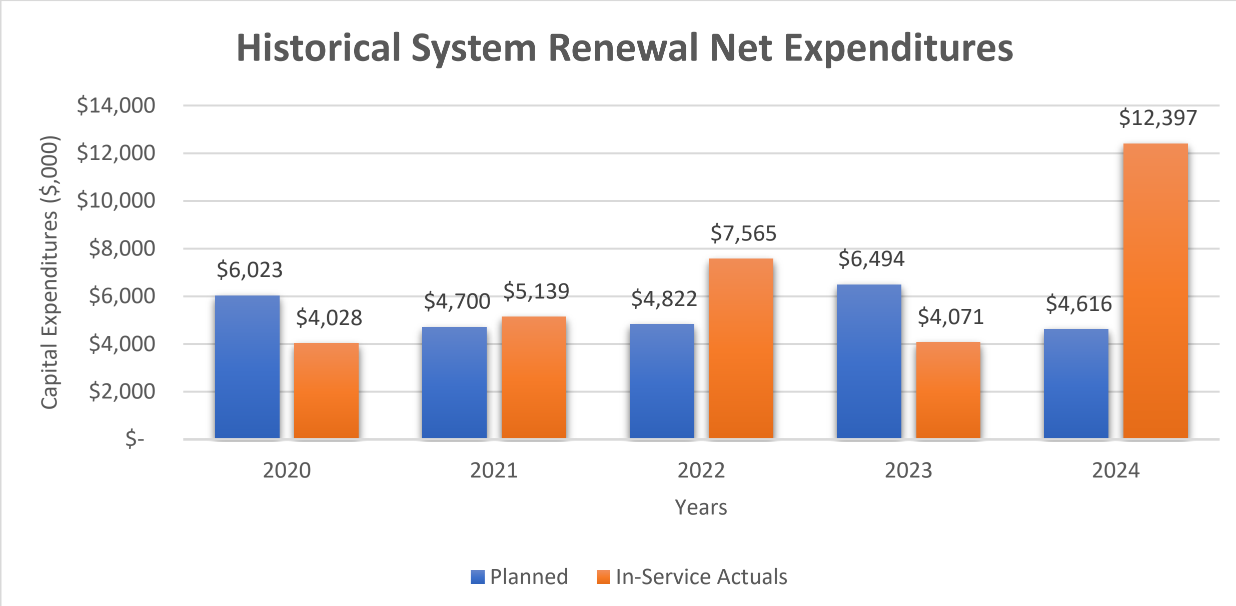
Net System Renewal investments exceeded API's 2020-2024 plan as summarized in the following table. For major projects and programs included in API's prior DSP, variances are discussed at a project/program level. For the balance of System Renewal investments (i.e. the category total, less the total of material projects outlined in the prior DSP); variances are discussed in the context of various other investment drivers.

Table 4.2: System Renewal Historical Period (2020-2024) Variance Summary ($000's)

System Renewal	Net Plan	Gross Actual	CIAC	Net Actual	Net Variance
Storm Rebuilds	794	232	-	232	(562)
Small Priority Replacements – Lines/Stations	1,964	1,992	(51)	1,941	(23)
Distribution Line Rebuilds	14,783	20,405	(2)	20,403	5,620
Express Feeder Rebuilds	4,912	2,509	(3)	2,505	(2,407)
Dubreuilville Sub 86 Rebuild	1,496	2,856	-	2,856	1,360
Bruce Mines DS Rebuild	2,000	4,346	-	4,346	2,346
Transformer – SR[1]	384	725	-	725	341
Recloser, Regulator Replacements[1]	322	193	-	193	(129)
Total	**26,655**	**33,257**	**(57)**	**33,201**	**6,546**

1 – In API's 2020-2024 DSP, these line items were grouped under *Total Items Less Than Materiality*

Figure 4.6: Historical System Renewal Net Expenditures



As can be seen from Table 4.2, API's actual in-service system renewal expenditures exceeded the DSP plan by about $6.5 M. This variance is mainly the result of the four (4) major projects/programs indicated in the table. A variance analysis for each is provided below:

Distribution Line Rebuilds

As identified in API's previous DSP, distribution line rebuilds represents the most significant portion of API's sustaining pole replacement and line rebuild program, with a goal of achieving a sustainable replacement rate for poles that is balances the cost of the replacement program to the cost, reliability impact and safety aspects associated with reactive replacements. The distribution Line Rebuild program target for 2020-2024 is approximately 400 poles per year at an overall budget of $14.8 M. API's actual net program expenditure over the historical period was about $20.4 M with a total overspend variance of $5.6 M.

Overall, from 2020 to 2024, API will have replaced 1,996 poles as part of this program, just four (4) shy of the total target of 2000 poles. The main cost driver for the noted variance for this program have been due to the following:

- Material and Contractor cost increases that began to be experienced during and following the COVID-19 pandemic. These increases are well beyond inflation and consumer price index ("CPI") and have generally been sustained up to the date of this DSP. For example, the material price per pole increased between 10.5% and 15.6% per year from 2020 to 2023. By comparison, the annual average change in CPI during the same time frame was between 0.7% and 6.8%.
- Several rebuilds within the program included expanding the distribution line from single-phase to 3-phase. In particular, a portion of the distribution line between the Batchawana TS and Goulais TS has been upgraded to 3-phase in accordance with API's Greenfield Study report and subsequent HOSSM's East Lake Superior Local Area Planning Report

- ❖ API also captured the one-time in-service addition of the Dubreuilville line upgrade cost that were captured in regulatory accounts in accordance with the OEB's decision and order EB-2017-0303.

Express Feeder Rebuilds

As identified in API's previous DSP, express feeder rebuilds is a subset of API's overall sustaining pole replacement and line rebuild program, that is targeted specifically at the express feeders within API's service territory. These feeders are unique in that they are generally built along off-road, remote locations and function as a Subtransmission feeder. These ROWs are like Transmission ROWs, requiring significant additional planning, permitting and equipment to access and complete the required work. The program target for 2020-2024 was approximately 100 poles per year, at an overall budget of about $4.9M. API's actual net program expenditure over the historical period was about $2.5 M with a total underspend variance of $2.4 M.

Overall, from 2020 to 2024, API will have replaced 201 poles as part of this program, which is about 40% of the total target of 500 poles. The main drivers for the variances for this program have been due to the following:

- ❖ Increased cost for Materials and Contractor, similar to what has been noted under the Distribution Line Rebuild variance explanation.
- ❖ Balancing the increased cost associated and prioritization of identified work within the distribution line rebuild program.
- ❖ Balancing the quantity of poles that were required to be replaced along the No.4 circuit as part of the connection of the large industrial load request.

Dubreuilville Sub 86 Rebuild

This project involved rebuilding Dubreuilville Substation 86 (previously known as the #2 substation), the main distribution supply station in the town of Dubreuilville. Initially, API identified a need to replace/rebuild this station in its 2017 Dubreuilville Status Report issued to the OEB as part of case number EB-2017-0153. Subsequent to this report, as part of API's 2020-2024 DSP, API identified the need to build a new 44kV distribution supply station to replace the existing station. API's total planned expenditure for this project was approximately $1.5 M and was based on building a two-element station, complete with modern protection relays and oil containment.

This project began in 2020 and was based on a station specification for a modular-style transformer and switchgear. API received higher cost quotes for the required material and made the decision to revise the station specification to a more traditional style station. This decision led to postponing the project to 2021. The construction of the station began in 2021 with construction awarded to a third party under a design-build contract. As a result of construction complications late in the year, API was not able to place the station into service until January 2022.

API's actual net project expenditure was about $2.8 M with a total variance of about $1.3 M. The main drivers for the variances for this program have been:

- ❖ There were unplanned costs associated with the initial site preparation, including tree clearing and the relocation of a telecommunication line. API was also required to relocate three distribution poles on the North side of the station that conflicted with the designed perimeter fencing.
- ❖ There were unplanned costs associated with the 44kV pole line that were required in reconfiguration and extension from its current location to the new station location.
- ❖ The total design-build contractor cost was higher than originally planned. API attributes a portion of this cost differential to the impacts of the COVID-19 Pandemic, specifically cost increases beyond the levels forecasted at the time of preparing the last DSP.

Bruce Mines DS Rebuild

This project involved rebuilding the Bruce Mines distribution substation, located just North of the town of Bruce Mines. This station is the main supply to the town of Bruce Mines, as well as a portion of rural customers within the East of Sault system. As part of API's previous DSP, API planned to rebuild the Bruce Mines DS on a new property to API current station standard and retire the current station. The project construction was originally planned to begin and be completed in 2023, but due to the higher construction cost, API made the decision to postpone the project construction start to early spring 2024.

At the time of finalizing this DSP, the Bruce Mines DS Rebuild remains in progress, but is planned to be complete and in-service before the end of 2024. API's projected total cost of the project is about $4.3 M, with a total variance of $2.3 M.

The main drivers for the variances for this program have been:

- ❖ The total design-build contractor cost was substantially higher than originally planned. In comparing the design-build contract for this project to the Dubreuilville Sub 86 project, the total design-build cost is about 64% higher.
- ❖ Material cost was higher than originally planned for the major material purchases, such as the power transformer and protection relays.
- ❖ As with the previous projects, the original DSP budgets were prepared at pre-pandemic pricing levels, so unforeseen levels of inflation contributed to the variance.

5.4.1.1.3 System Service

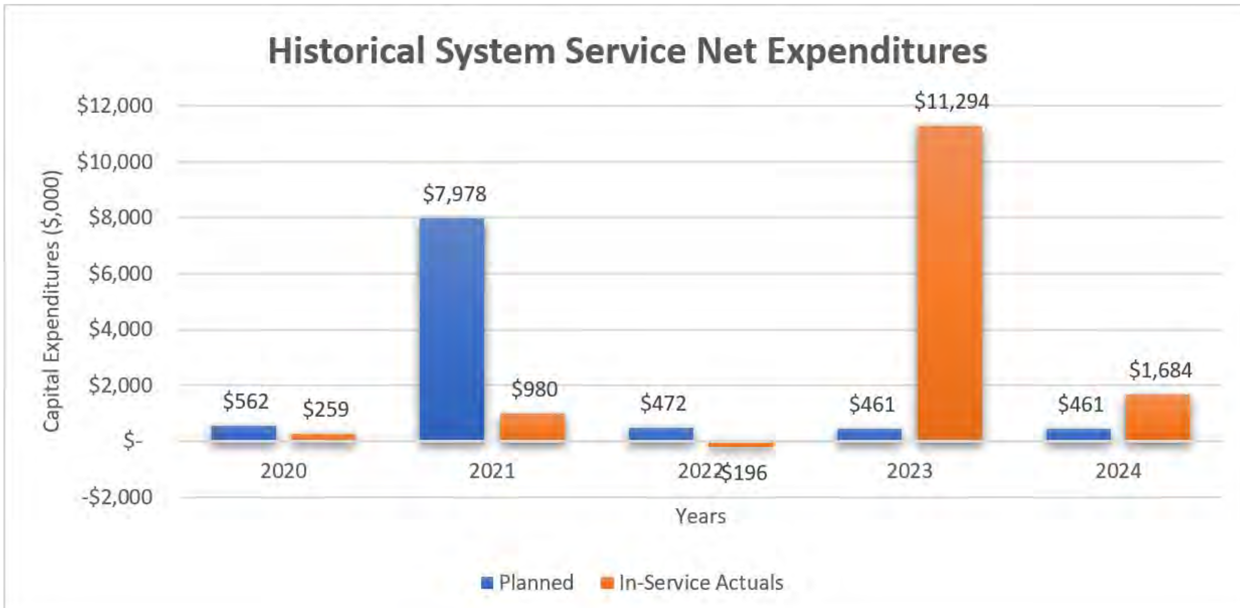
Net System Service investments exceeded API's 2020-2024 plan as summarized in the following table. For major projects and programs included in API's prior DSP, variances are discussed at a project/program level. For the balance of System Service investments (i.e. the category total, less the total of material projects outlined in the prior DSP), variances are discussed in the context of various other investment drivers.

Table 4.3: System Service Historical Period (2020-2024) Variance Summary ($000's)

System Service	Net Plan	Gross Actual	CIAC	Net Actual	Net Variance
Protection, Automation, Reliability	1,582	1,955	(99)	1,856	274
Desbarats DS Upgrades	660	147	-	147	(513)
Echo River TS	7,500	11,006	-	11,006	3,506
Hawk Junction DS	-	857	(228)	629	629
Transformers-SS[1]	192	382	-	382	190
Total	**9,934**	**14,347**	**(327)**	**14,020**	**4,086**

1 – In API's 2020-2024 DSP, these line items were grouped under *Total Items Less Than Materiality*

Figure 4.7: Historical System Service Net Expenditures



As can be seen from Table 4.3, API's actual in-service system service expenditures exceeded the DSP plan by about $4.1 M. This variance is mainly the result of one major project indicated in the table. A variance analysis for this project is provided below each is provided below:

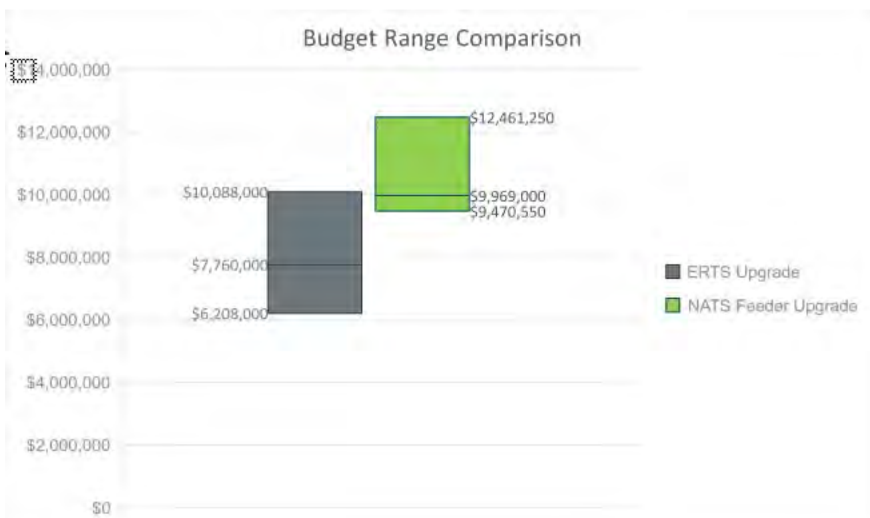
<u>Echo River TS</u>

As part of API's previous DSP, API had included a proposal for an Advanced Capital Module ("ACM") for the Echo River TS Second Transformer project. API has included a planned project cost of $7.5 M based on discussion with HOSSM and the high-level estimate range that HOSSM had provided. As part of API's previous COS Settlement Agreement, API committed to provide information and business case analysis that incorporates the updated forecast cost responsibility for the project based on the outcome of Hydro One's detailed engineering study and cost estimate process. The project variance analysis below also includes the information and business case analysis.

In 2020, API engaged a third-party Engineering consultant (CIMA+) to develop and provide a report on a distribution alternative to address the supply contingency risks associated with the transformer failure at the Echo River TS. This report has been included in Appendix M. The report confirmed API's previous analysis that while supplied entirely by Northern Ave TS and under winter peaking conditions, the voltage levels in API's East of Sault system decreases below acceptable levels because of the smaller conductor between the Northern Ave TS and API's Bar River DS. The most effective distribution alternative to address this issue was to reconductor approximately 31km of 34.5kv Subtransmission lines. This alternative was estimated to be $9.97 M.

In December 2020, API received the HOSSM estimate for the procurement and installation of a second transformer at the Echo River TS. HOSSM provided a final class 3 estimate of $7.76 M. HOSSM also confirmed that the project would not be considered part of the connection pool, and therefore API would bear 100% of the cost responsibility. After receiving this estimate and having completed the distribution alternative analysis, API further engaged CIMA+ to develop a business case analysis that would compare the cost and operational benefits of the distribution alternative to the transmission alternative. This business cases analysis is included in Appendix J. When comparing the cost of each alternative, the transmission alternative was the least cost option. Figure 4.8 depicts the cost range for both alternatives (note that ERTS Upgrade refers to the Transmission, while the NATS Feeder Upgrade refers to the Distribution alternative). While there was an overlap of about $500k between both alternatives, the transmission appeared to be the least risk cost option. API also notes that the analysis considered an "all-in" cost for ERTS, incorporating project management and administration, while the budget estimate for NATS Feeder Upgrade excluded these items., therefore the fulsome cost of the NATS project would be expected to exceed the levels shown in the table below.

Figure 4.8: Echo River TS - Alternative Analysis Cost Comparison



As described in the business case analysis, the non-monetary benefits and challenges of each alternative are the following:

Distribution Alternative:

Benefits:

- Diversification of the supply of power
- This alternative can support a load increase of 15% (or 2.3MW)

Challenges:

- If the entire East of Sault load is being supplied by Northern Ave TS (such as during an outage

- Some poles that are required to be replaced may already need replacement based on the condition of the pole

at Echo River TS). The 6000 customers load would be under a single contingency situation.

- Whilst being supplied by Northern Ave TS, system losses would be excessive, even after the conductor has been replaced (this is mainly due to 75%+ of the customer load being located 50-70 km from Northern Ave TS.

Transmission Alternative:

Benefits:

- Transformer redundancy at the Echo River TS
- Supports long term load growth in the area.
- Construction is all within an existing station
- No off-road construction
- Turn-key solution for API

Challenges:

- The Echo River TS would still be susceptible to a total 230kV supply outage (affecting both transformers)
- A catastrophic event could theoretically damage equipment at the Echo River TS
- The construction time for this project is two years (longer than the distribution alternative)

The recommendation to API in the business cases analysis was to pursue the Transmission alternative based on the lower expected cost and overall better operational benefits.

In May 2021, API proceeded to execute the connection and cost recovery agreement (“CCRA”) with HOSSM for $7.76 M, formalizing the direction to proceed with the project to install a second transformer. Per the terms of CCRA, API split the payment in half, paying 50% of the required contribution in May 2021 and the remaining 50% in May 2022.

In July 2022, API was notified by HOSSM that due to supply chain issues, that additional funding by API would be required to cover engineering and material price increases. HOSSM indicated that an additional $1.83 M would be required. API requested clarification as to the cost increase drivers to substantiate this notification. The following clarification was provided:

Increased Engineering cost associated with:

- ❖ Additional resources required to address issues identified deficiencies in grounding study
- ❖ Unexpected delay in transformer drawings and test reports held up completion of engineering, extending schedule and support required from resources

Increased Construction cost associated with:

- ❖ Delay in completion of Issue for Construction drawings, which extended construction schedule into winter seasons, and resulted in incurring additional heating & preservation expenses
- ❖ Higher quotes for equipment rentals
- ❖ New soil management regulations introduced additional soil sampling and handling costs (Ontario Regulation 406/19)

- ❖ Incremental scope/quantities of material were added to address deficiencies (as noted in the Engineering section)
- ❖ Temporary pad had to be built to support the Transformer delivery timeline and delayed construction start (resulting from the delay in Issue for Construction drawings
  - o Additional craning and lifting costs are incurred as the transformer will have to be rigged into its permanent location from its temp pad
- ❖ Laydown area is now outside the compound, as space is required for transformer temporary pad inside compound, requiring additional areas to be prepared and maintained for material handling

At the time of receiving this notice, API revisited the business case analysis to confirm the impact of this cost increase in the context of the cost-benefit of the two alternatives considered. Using Q2 2022 Project Status report, API was given indication that the project cost actual cost to date (March 31, 2021) was $3.13 M. As these are actual project costs, API would not be reimbursed if API decided to cancel the project and pursue the distribution alternative. As a result, the amount would be in addition to the estimated cost of the distribution option. In addition, given that the distribution option estimate was prepared based on pre-COVID pricing and inflation assumptions, API estimated an adjusted base cost for the Distribution option, using relevant recent pricing on a comparable project, as well as general inflation adjustments.

Table 4.4: Echo River TS Project-Estimate Update July 2022

Alternative	Original Estimate	Updated Estimate (as of July 2022)	Increase explanation
Distribution	$9,969,000	$14,300,000	HOSSM non-reimbursable project cost and updated price escalation estimates.
Transmission	$7,766,000	$9,600,074	Variance as explained above

Based on the difference in overall updated costs for each alternative, API was confident that the transmission remained the least-cost alternative option, with the difference between the two alternatives being about $4.7M.

In September 2022, API received another notice from HOSSM that additional funding would be required by API as a result of increased cost of procurement and project management. Overall, HOSSM indicated that an additional $767k would be required as part of the project.

At the time of receiving this notice, API had not yet received a quarterly project status report. API opted to use the previously provided project cost of date and revisit the cost-benefit analysis that was performed in July 2022. Factoring this additional cost increase to the Transmission alternative update estimate, the following comparison was made:

Table 4.5: Echo River TS Project-Estimate Update September 2022

Alternative	Original Estimate	Updated Estimate (as of Sept 2022)	Increase explanation
Distribution	$9,969,000	$14,300,000	HOSSM non-reimbursable project cost and updated price escalation estimates.
Transmission	$7,766,000	$10,367,419	Variance as explained above

The difference in the two alternatives (about $3.9M) and the expectation that the actual project cost to date would be higher than what was reported at the end of June, API continued with this alternative as it remained the least-cost alternative.

Below is a summary of the project status reports provided throughout the project:

Table 4.6: Quarterly Echo River TS Project Update Summary

Year/Quarter	Budget/Estimate	Actual to Date	Forecast
2021 Q1	$7,766,000	$1,287,636	$7,766,000
2022 Q1	$7,766,000	$2,228,356	$7,766,000
2022 Q2	$7,766,000	$3,125,301	$9,600,074
2022 Q3	$7,766,000	$4,674,843	$10,367,419
2022 Q4	$7,766,000	$6,658,252	$10,367,188
2023 Q1	$7,766,000	$8,488,887	$10,367,188

For its second quarter 2023 report, HOSSM provided an update via email in anticipation of placing the new transformer into second in July. In the email report, HOSSM indicated that further additional funds would be required to cover increased cost for commissioning. Overall, HOSSM indicated that an additional $99k would be required. Towards the end of 2023, API was provided final project costs and was subsequently invoiced for an additional <u>$2,984,195</u>. In total the overall project cost was:

Table 4.7: Summary of Echo River TS Project Variance

Cost Item	Budget	Total Actual Cost	Variance ($)
Cost payable to HOSSM/IESO	$7,500,000	$10,754,279	$3,254,279
API Internal Cost		$63,207	$63,207
Study Cost (for Alternative & Business Case		$181,111	$181,111
Modification required to API Wholesale Meter		$7,614	$7,614
Total	$7,500,000	$11,006,211	$3,506,211

<u>Hawk Junction DS</u>

In 2019, API's VR2 voltage regulator was damaged through external factors outside of API's control, which led to an unplanned investment to replace the winding coils inside the regulator. The evidence collected suggested that an internal fault occurred within one of the three winding coils inside the regulator following an event external to the substation. The result of this was catastrophic and led to significant amounts of dissolved gases in the oil and most importantly, measurable amounts of copper in the oil. API worked closely with the manufacturer of the regulator, who ultimately gave the recommendation to replace all three winding coils. API proceeded with the replacement and placed the regulator back into in 2021.

Batchawana TS Refurbishment

As part of the regional planning process as indicated in section 5.2.2.1.4.2, HOSSM had identified a need to refurbish their Batchawana TS. At the time of submitting its previous DSP, API was just beginning to discuss alternatives for refurbishment work at this station. In July 2019, API commissioned a Greenfield TS study, which considered the alternatives presented by HOSSM in the supply configuration in the Batchawana and Goulais region. The recommendation of this report was to pursue refurbishing both stations and indicated that there would be significant challenges in operating at the existing supply over the next 15 years. The report also included the recommendation to upgrade the supply to 25kV.

With the above report in hand, API formally requested that HOSSM provide API an estimate as part of the refurbishment program to upgrade the station to enable converting to 25kV within the next 10 to 15 years. This would support would the recommendation from the Greenfield TS Study report, allow API to plan for voltage conversion in the medium term and ensure that any investments in the station today would support the system needs for tomorrow. API received an estimate of about $391k and proceeded with executing the applicable CCRA with HOSSM.

Included in the scope of the refurbishment, API relocated its feeder point of connection with HOSSM and installed a new wholesale revenue meter and equipment. The relocation requirement was driven by HOSSM, and so API has executed a contribution agreement with HOSSM, and through that agreement identified the capital contribution HOSSM was required to pay API to facilitate the relocation. API has also made the decision as part of this project to install a new wholesale revenue meter and equipment rather than relocate the existing because the existing configuration was not compatible with the pole-mounted configuration that was planned.

5.4.1.1.4 General Plant

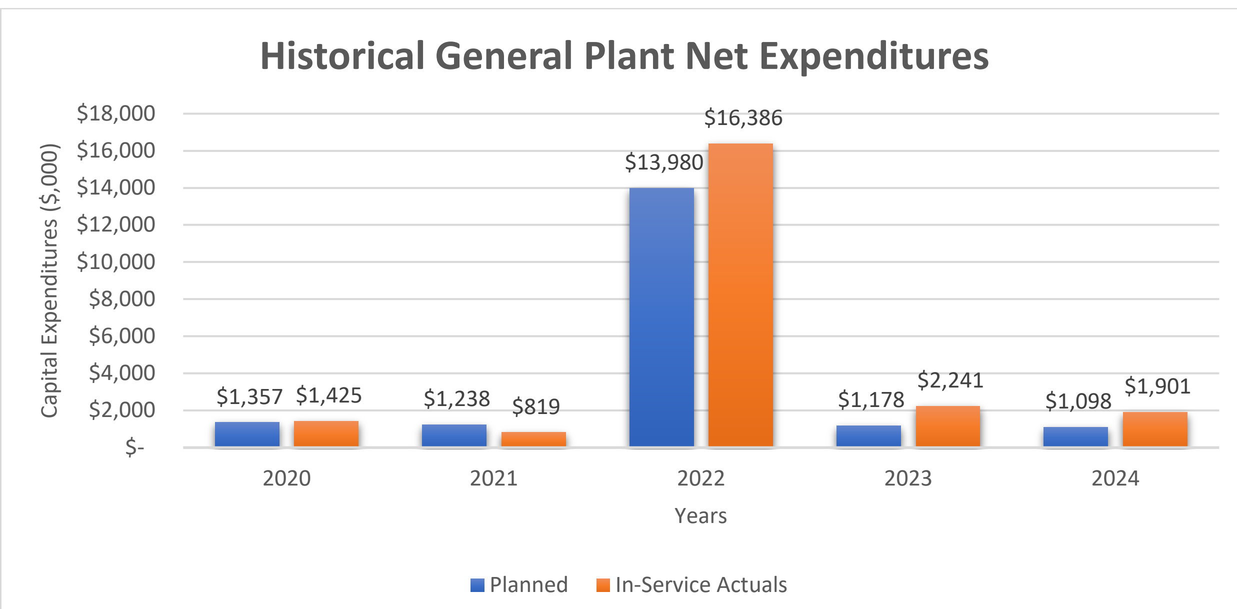
Net General Plant investments exceeded API's 2020-2024 plan as summarized in the following table. For major projects and programs included in API's prior DSP, variances are discussed at a project/program level. For the balance of General Plant investments (i.e. the category total, less the total of material projects outlined in the prior DSP), variances are discussed in the context of various other investment drivers.

Table 4.8: General Plant Historical Period (2020-2024) Variance Summary ($000's)

General Plant	Net Plan	Gross Actual	CIAC	Net Actual	Net Variance
ROW Expansion Program	-	106	-	106	106
Office Furniture & Equipment[1]	29	45	-	45	16
Buildings & Yards Improvements[1]	197	187	-	187	(10)
Sackville Leasehold Improvements[1]	2	18	-	18	16
Tools & Equipment[1]	456	426	-	426	(30)
Land Rights[1]	169	271	-	271	103
Business Systems (SCADA, GIS, OMS, etc.)	707	577	-	577	(130)
IT Hardware	527	566	-	566	39
IT Software[1]	55	26	-	26	(29)
Fleet	3,207	3,153	-	3,153	(53)
Desbarats Facility[1]	141	57	-	57	(84)
Wawa Facility[1]	171	227	-	227	56
Sault Facility Project	12,690	16,550	-	16,550	3,860
ROW Access Program	500	563	-	563	63
Total	**18,850**	**22,772**	-	**22,772**	**3,922**

1 – In API's 2020-2024 DSP, these line items were grouped under *Total Items Less Than Materiality*

Figure 4.9: Historical General Plant Net Expenditures



As can be seen from Table 4.8, API's actual in-service general plant expenditures exceeded the DSP plan by about $3.9 M. This variance is mainly the result of the Sault Facility. A variance analysis of this project is provided below:

<u>Sault Facility Project</u>

In 2022, API substantially completed construction and took occupancy of its new administration and operations centre, the Sault Ste. Marie Facility ("SSM Facility") project. Prior to the project's completion, API sub-leased its shared facilities at 2 Sackville Road from Hydro One Sault Ste. Marie (HOSSM). In its 2020 DSP, API had proposed a project cost in excess of $14M. In the Settlement Agreement to the 2020 COS, a total 12.69M was approved for the SSM Facility as an ACM project, with an understanding that API would be able to justify the prudence of any actual spending in excess of this amount in its next COS. Following due diligence regarding its options for its operational needs, API selected to purchase land and build an administration and operations facility at 251 Industrial Park Cres.

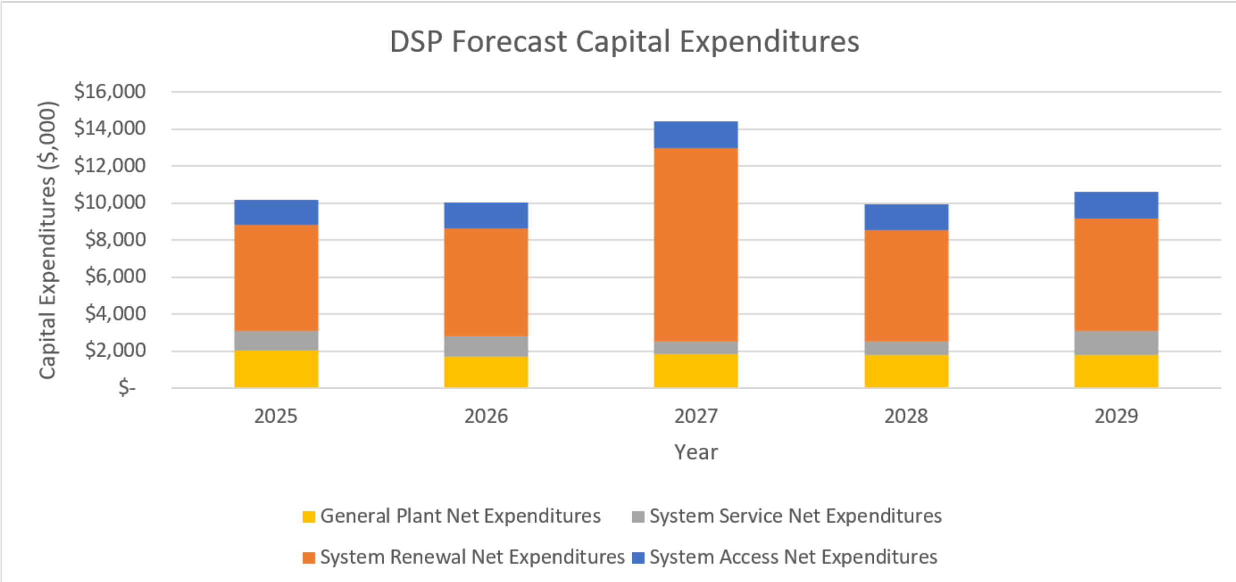
API undertook cost saving measures with the aim of completing the project within the ACM approved levels. These included entering into an innovative form of agreement on the land that would allow API to purchase only the size of lot it required, and reconvey a portion of the land to the original owner (saving on land costs). Additionally, API and the selected contractor identified over $2.3M in additional savings by making adjustments to the facility design.

Nonetheless, factors outside of API's control, such as unexpected geotechnical challenges and COVID-19 related factors increased the overall project price. Additionally, through the construction process, operational requirements beyond the original scope of the contract were identified, which were necessary for the optimal operational functionality of the facility. These requirements included such items as motorized doors and gates, the installation of an overhead crane, pole and transformer storage, and parking and driveway modifications. These Change Orders were reviewed with care, and each was determined to have significant long-term health and safety, operational efficiency, security and/or financial risk mitigation benefits.

5.4.1.2 Capital Expenditures Over the Forecast Period

The following figure summarizes the planned Capital Expenditures for the DSP forecast period. For projects with a life cycle greater than one year, API has indicated the total capital spending in the year the project is planned to be in-service. That is to say, the capital amounts in the forecast years reflect in-service additions. For material projects spanning more than one year, API may apply the OEB's prescribed CWIP account interest rate.

Figure 4.10: Forecast Capital Expenditures



5.4.1.2.1 System Access

System Access capital investments primarily relate to distribution system expansions, upgrades, and modifications that API is required to undertake to connect customers to its distribution system or accommodate changes to existing services. Starting in 2020, API has experienced a higher volume of new and existing upgrade connection requests, which has been sustained over the historical period. As a result, API has forecasted a higher level of service connection investments for the 2025-2029 period compared to 2020-2024.

System Access investments also include line rebuilds or relocations that are required to meet the needs of local road authorities in relation to road widening and relocation projects, as well of the needs of joint-use tenants in relation to expansions and upgrades of telecommunication systems attached to API's poles. These projects can result in significant annual variability in API's System Access investment levels.

Actual 2025-2029 System Access investments will depend on the level of customer and third-party demand. API is prepared to increase investments in this category as required, while maintaining investment levels in other categories and expects that an increase in demand work will result in increased Contributions in Aid of Construction ("CIAC") from customers and third parties, as well as increased distribution revenue for customer-driven work.

Table 4.9 provides a breakdown of API's System Access investments over the forecast period.

Table 4.9: 2025-2029 System Access Investment ($000's)

System Access Project/Program	2025	2026	2027	2028	2029
Service Connections	1,151	1,167	1,185	1,203	1,221
Meters	129	131	133	135	137
Transformers – SA	160	162	165	167	170
Third-Party Requests (Relocations/Joint-Use)	25	28	29	29	29
System Service Total (Gross)	**1,465**	**1,489**	**1,511**	**1,534**	**1,557**
System Access Capital Contributions	(100)	(102)	(104)	(106)	(108)
System Access Total (Net)	**1,365**	**1,387**	**1,407**	**1,428**	**1,449**

API notes that third-party requests in the table above do not reflect the increased volume of work related to the BBFA. While API anticipates the cost of this work will be significant in 2024 and 2025 (at which time API understands that BBFA projects are intended to be complete), the cost of the related work will be treated as a regulatory asset rather than in-service capital, in accordance with OEB Accounting Order 001-2022.

A unique feature of API's very rural service territory is that the vast majority of API's customer demand work is related to single-customer requests for connections to new residences, or for service upgrades to existing residences. Development of new subdivisions is relatively rare. As a result, most new services or service upgrades require a single new or modified connection to existing API plant. In many cases, this requires pole replacement, reframing, or other upgrades to meet the requirements of Ontario Regulation 22/04.

5.4.1.2.2 System Renewal

System Renewal investments involve replacing end of life distribution assets and refurbishing system assets to extend the original service life. These investments maintain the ability of API's distribution system to supply customers with safe and reliable electricity.

API's System Renewal investments are driven by sustaining proactive asset replacement programs, mainly API's distribution and subtransmission line and substation rebuilds. Target replacement rates and associated projects are mainly based in consideration of the total assets being managed, age of the asset and the overall asset condition. Annual budgets for smaller, non-discretionary items are based on historical 5-year averages and includes priority replacements of one-off items due to high-risk issues identified during inspection and maintenance programs.

API's System Renewal investments over the forecast period include the following:

- Distribution and express feeder line rebuilds, and line upgrades related to end-of-life asset replacement;
- Distribution line rebuilds associated with the Goulais voltage conversion efforts as described in, which are integrated with end-of-life asset replacement and other capital planning considerations;
- Targeted pole replacement based on pole testing results and feeder inspections;
- API has planned for the replacement of its smart meters over a five-year period, given the high risk that further seal extensions for these meters will not be possible.

- ❖ Replacement of other individual distribution line or substation assets where test results or deficiencies identify requirements for priority replacements; and,
- ❖ Transformer replacements due to failure, end of life or voltage conversion.

Table 4.10 provides a breakdown of API’s System Access investments over the forecast period.

Table 4.10: 2025-2029 System Renewal Investments ($000's)

System Renewal Project/Program	2025	2026	2027	2028	2029
Small Priority Replacements - Lines/Stations	430	436	442	448	455
Distribution Line Rebuilds	3721	3766	3822	3879	3938
Subtransmission Rebuilds	964	977	992	1007	1022
Replace End-of-Life Transformers	140	142	144	146	149
Wawa #2 DS Rebuild	0	0	4584	0	0
Smart Meter Replacements	407	410	417	423	429
Recloser, Regulator Replacements	90	91	93	94	96
System Renewal Total (Gross)	**5,752**	**5,822**	**10,494**	**5,998**	**6,088**
System Renewal CIAC	-	-	-	-	-
System Renewal Total (Net)	**5,752**	**5,822**	**10,494**	**5,998**	**6,088**

5.4.1.2.3 System Service

System Service investments involve modifications or additions to API’s distribution system to improve system reliability, improve power quality, and reduce system losses. Projects are prioritized based on outage and reliability analysis, load flow and area planning studies (see Appendix C and D, respectively).

API’s System Service investments over the forecast period include the following:

- ❖ Convert and upgrade portions of API’s distribution feeders in the Goulais region as part of the Goulais Voltage Conversion program;
- ❖ Installation of additional protection and control equipment and distribution automation schemes to improve reliability and outage response;
- ❖ Portions of voltage conversion activity that do not fall under the System Renewal category; and,
- ❖ Investments to reduce contingency risk as identified through area planning studies; and
- ❖ Support and upgrade API’s distribution connection at the Goulais TS as part of the HOSSM’s refurbishment project.

Table 4.11 provides a breakdown of API’s System Service investments over the forecast period.

Table 4.11: 2025-2029 System Service Investments ($000's)

System Service Project/Program	2025	2026	2027	2028	2029
Goulais Area Voltage Conversion	297	302	308	315	321
Protection, Automation, Reliability	757	807	344	438	309
Goulais TS Refurbishment	-	-	-	-	680
System Service Total (Gross)	**1,054**	**1,110**	**652**	**753**	**1,310**
System Service CIAC	-	-	-	-	-
System Service Total (Net)	**1,054**	**1,110**	**652**	**753**	**1,310**

5.4.1.2.4 General Plant

General Plant investments are modifications, replacements or additions to API's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities. Most of this category comprises levelized annual spending on items such as tools, equipment, fleet, IT and land rights, as well as programs related to VM.

API's General Plant investments over the forecast period include the following:

- End of life replacements of fleet, IT hardware and other equipment;
- Continued implementation of the SCADA program;
- Software upgrades and licensing;
- Development and construction of new access routes and trails;
- Business Systems (CIS, GIS, etc.) upgrades and development; and,
- Sustaining investments in facilities, buildings and yards.

Table 4.12 provides a breakdown of API's General Plant investments over the forecast period.

Table 4.12: 2025-2029 General Plant Investments ($000's)

General Plant Project/Program	2025	2026	2027	2028	2029
ROW Access Program	226	127	129	131	133
Tools & Equipment	92	93	95	96	97
Communication & SCADA	126	146	138	70	-
Transportation & Work Equipment	1,207	958	1,140	1,130	1,190
Facilities, Buildings & Yards	214	217	174	177	179
IT Hardware/Software	59	60	61	62	63
Other	116	117	119	121	123
General Plant Total (Gross)	**2,039**	**1,718**	**1,855**	**1,787**	**1,785**
General Plant CIAC	-	-	-	-	-
General Plant Total (Net)	**2,039**	**1,718**	**1,855**	**1,787**	**1,785**

5.4.1.3 Customer Engagement and Preferences Activities

This section summarizes how API engaged with its customers to inform the development of this DSP, and the results of those engagement activities. Customer engagement is one among many inputs to API's overall capital planning process, with must also consider API's AMP, non-discretionary projects, input from other stakeholders, and the results of system planning studies.

5.4.1.3.1 Customer Engagement

API employs a variety of communication channels to inform and engage with its customers, employees, communities, other stakeholders and third parties on a regular basis. This includes regular bill inserts, presence on social media platforms, website updates, customer portals, community and contractor meetings, participation in regional planning efforts, and participation in community events. API's customer engagement activities are summarized in various sections of its 2025 Cost of Service Application, as well as in the CE report prepared for API by Innovative Group Inc.

With regards to the recently completed CE workbook survey, the following is a summary of the outcomes and overall customer preferences are included in section 5.2.3.2.

The unique geography of API's roughly 14,200 square kilometers service territory presents challenges in reaching all the communities that it serves. API has developed a multi-channeled communication model to reach out and engage its customers, stakeholders and third parties with whom they do business. Below, these channels are described in more detail:

Bill Inserts

API sends bill inserts regularly to its customers with their monthly invoice. This includes the semi-annual newsletter "Making Connections" which provides information on specific customer initiatives, safety messages, community involvement efforts, distribution concerns, and current rate information.

Company Website

The website provides a single location for API's customers to gain access to a consolidated source of important information on distribution services, rates, regulatory matters and decisions, customer initiatives, corporate policy, community events, and relevant safety issues. API's website also provides customers with a mechanism to correspond with API directly. In 2024, API launched a public-facing outage map, through which customers can access details regarding current and restored outages. This measure was implemented based on feedback supporting such an initiative when customers were asked in prior surveys. API also intends to launch text message notifications for power outages.

Online Customer Surveys

Annual Customer Survey – API conducts an annual customer satisfaction survey. The survey is conducted by a third party (UtilityPULSE) and is comprised of several main questions which are repeated annually, and often features additional questions. UtilityPULSE also surveys customers throughout Ontario regarding aspects of their satisfaction with their local distributor, providing an "Ontario Benchmark" that API can compete against.

Public Awareness Safety Survey – API conducts the Public Awareness of Electrical Safety Survey every two years. The results of the study will be included in the Utility Scorecard. Most importantly, it will help API shape its electrical safety education program and help keep community members safe from electrical hazards.

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.

Annual Municipal Stakeholder Meetings

Annually, API sets an agenda of current customer service initiatives, public safety initiatives, conservation demand management updates (including incentives), and operations maintenance and capital projects. API attempts to meet annually with each of the 17 municipal councils, planning boards and First Nation councils within its service territory. Each presentation provides the councils with updates and encourages dialogue between council and API on several levels. The operational topics discussed are tailored to each party. Councils continue to comment positively on the value these presentations and discussions provide.

5.4.1.4 Modifications to Typical Capital Programs

In its Capital Expenditures Plan, API has included new programs that were not in API's previous DSP. The Smart Meter Replacement, which is aimed at replacing meters as required and in accordance with Measurement Canada guidelines. The voltage conversion program in the Goulais region, which has the objective of ensuring that API's voltage reliability and system capacity will be sufficient in support projected load forecasts.

5.4.1.5 Expenditures for Non-Distribution Activities

API has no planned expenditures for non-distribution activities over the forecast period.

5.4.2 Justifying Capital Expenditures

This section provides the necessary data, information, and analyses to support the 2025-2029 capital investments proposed in this DSP.

5.4.2.1 Overall Plan

API has arrived at an overall capital investment plan that balances the following drivers:

- 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)

The identified needs and preferences of API's customers, as determined through customer engagement activities, were considered in prioritizing investments within each category, as well as in pacing the overall annual level of investment considering rate impacts.

For each capital investment category, the sections below provide support for the overall level of investment included in this DSP by summarizing the following information listed in Section 5.4.3.1 of the Filing Requirements:

- Comparative expenditures by category over the historical period.
- The forecast impact of system investment on system O&M costs.
- The drivers of investments by category, including historical trend and expected evolution of each driver over the forecast period.

5.4.2.2 Historical to Planned Comparative Analysis of Capital Expenditures

Table 4.12 below, which reproduces OEB Appendix 2-AB, provides a summary of API's actual capital expenditures for the 2020-2024 historical period compared to the capital expenditure plan presented in its 2020-2024 DSP. Planned capital expenditures for the 2025-2029 forecast period are included in Table 4.14. For summary purposes, the entire costs of individual projects have been allocated to one of the four OEB investment categories based on the primary driver for the investment. The remainder of this section provides detailed variance analysis of planned vs. actual capital expenditures over the 2020-2024 historical period.

Table 4.13: Historical Capital Expenditures and System O&M

Category	Historical												Bridge Year		
	2020			2021			2022			2023			2024		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.*	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	903	1,519	68%	963	2,488	158%	930	2,082	124%	906	12,989	1334%	906	3,295	264%
System Renewal	6,023	4,052	-33%	4,700	5,139	9%	4,822	7,567	57%	6,494	4,102	-37%	4,616	12,397	169%
System Service	562	259	-54%	7,978	980	-88%	472	32	-93%	461	11,393	2371%	461	1,684	265%
General Plant	1,357	1,425	5%	1,238	819	-34%	13,980	16,386	17%	1,178	2,241	90%	1,098	1,901	73%
Total Expenditure, Gross	8,845	7,254	-18%	14,879	9,425	-37%	20,205	26,067	29%	9,039	30,725	240%	7,081	19,278	172%
Total Capital Contributions	(102)	(168)	65%	(100)	(472)	372%	(100)	(264)	164%	(100)	(272)	172%	(100)	(5,252)	5152%
Total Expenditure, Net	**8,744**	**7,086**	**-19%**	**14,779**	**8,953**	**-39%**	**20,105**	**25,804**	**28%**	**8,939**	**30,453**	**241%**	**6,981**	**14,026**	**101%**
System O&M		7,078			7,171			7,388			7,605			7,883	

Table 4.14: Planned Capital Expenditures and System O&M

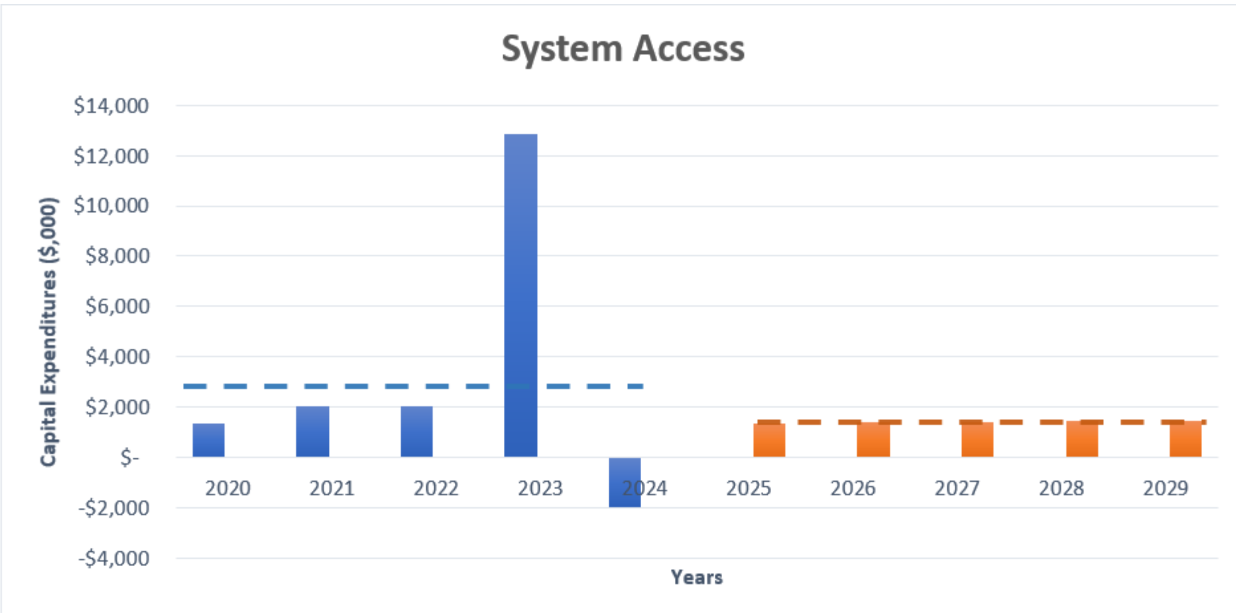
Category	Forecast				
	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	1,465	1,489	1,511	1,534	1,557
System Renewal	5,752	5,822	10,494	5,998	6,088
System Service	1,054	1,110	652	753	1,310
General Plant	2,039	1,718	1,855	1,787	1,785
Total Expenditure, Gross	10,310	10,139	14,513	10,071	10,740
Total Capital Contributions	(100)	(102)	(104)	(106)	(108)
Total Expenditure, Net	**10,210**	**10,037**	**14,409**	**9,965**	**10,632**
System O&M	9,275	9,530	9,792	10,061	10,338

5.4.2.2.1 System Access

The 5-year plan for System Access expenditures is based on ensuring API is able to meet the needs and expectations of its customers, as well as third-party entities, such as ISPs and road authorities. Planned expenditures are based on historical rolling averages, with consideration of larger one-off higher cost expansion connections.

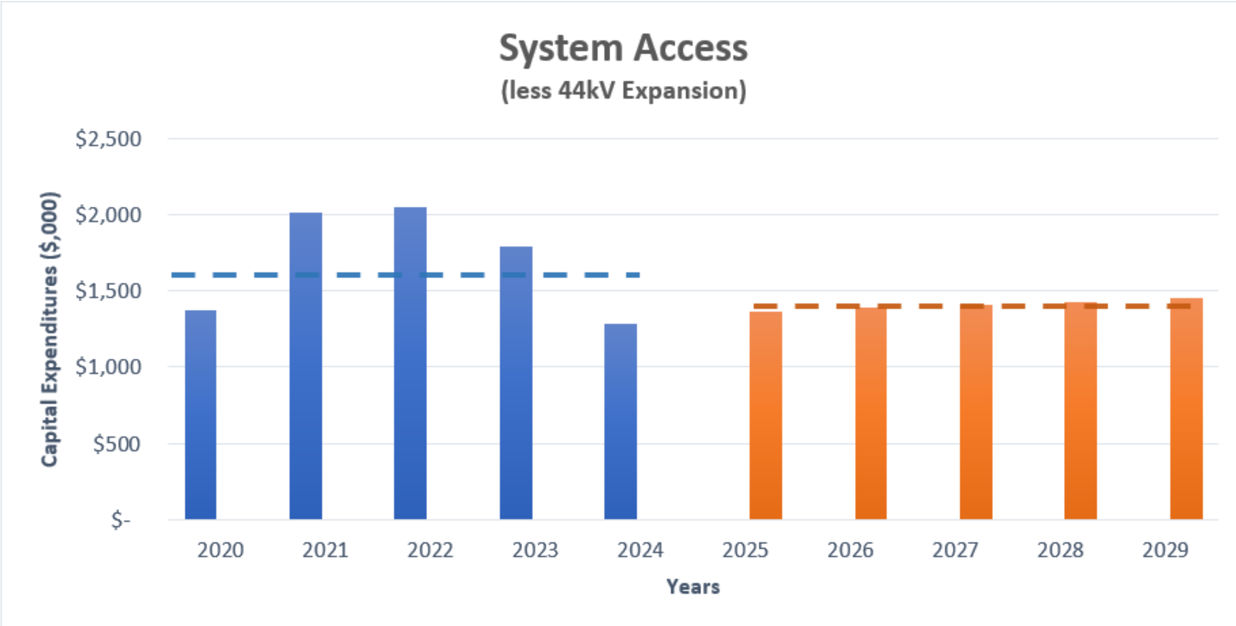
Figure 4.11 compares annual System Access investments over the historical and forecast periods. The dashed line represents the annual average in-service investments during the period.

Figure 4.11: 2020-2029 System Access Investments



To provide a more wholesome comparison and to avoid any skewing of the average expenditures, the project and capital investment required in connection with a large industrial load on API's 44kV Subtransmission system that required a system expansion, as described in 5.4.1.1.1 has been excluded and depicted in Figure 4.12.

Figure 4.12: 2020-2029 System Access Investments (less 44kV Expansion)



API has planned for net annual System Access levels of approximately $1.4 million over the forecast period, which represents a decrease compared to the historical period. This decrease is mainly attributed to an expected reduction in third-party requests, namely tied to joint use. API is aware of joint use that is associated with the broadband program, but the project cost will be tracked in a deferral account in accordance with the OEB Accounting Order #001-2022. API does not have any evidence to suggest that the levels of service requests experienced over the historical period will change, and so has allocated its planned budget for this work based on the historical average. Based on API's experience in managing surges in activity in the historical period and how API plans for and prioritizes its capital work, API is confident that it can ramp resources up or down as required to meeting fluctuating demand for this type of work.

The 5-year plan for System Access expenditures is generally consistent with historical spending when you exclude the higher cost associated with the broadband program and the cost related to the connection a large industrial customer. The planned expenditures currently account for about 13% of the planned net capital expenditures, compared to 19% over the historical period.

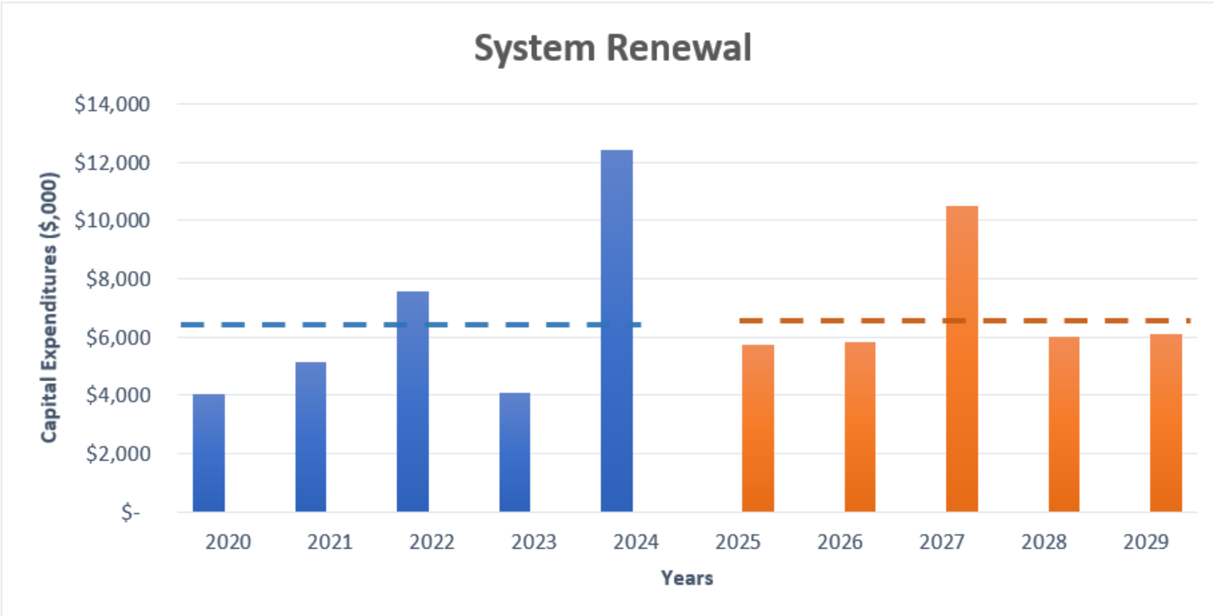
System Access investments generally have minimal impact on O&M, in some cases adding to the overall length of line that must be inspected and maintained.

5.4.2.2.2 System Renewal

The 5-year plan for System Renewal expenditures is based on sustained and proactive asset replacement that ensures API's is provide safe and reliable service, while minimizing long-term cost associated with the renewal of API's distribution system and with consideration of overall asset condition. These investments also support infrastructure resiliency in the light of more commonly occurring adverse weather.

compares annual System Renewal investments over the historical and forecast periods.

Figure 4.13: 2020-2029 System Renewal Investments



API has planned for net annual System Renewal levels of approximately $34.1 million over the forecast period, which represents an increase of $963k compared to the historical period. The category of investment balances the cost associated with asset replacements. Over the historical period, API completed two station rebuild projects, as well as its sustainable line rebuild program. Over the planned period, API has included a planned station rebuild project at the Wawa #2 DS in 2027, its smart meter replacement program as well as the continued line rebuild program.

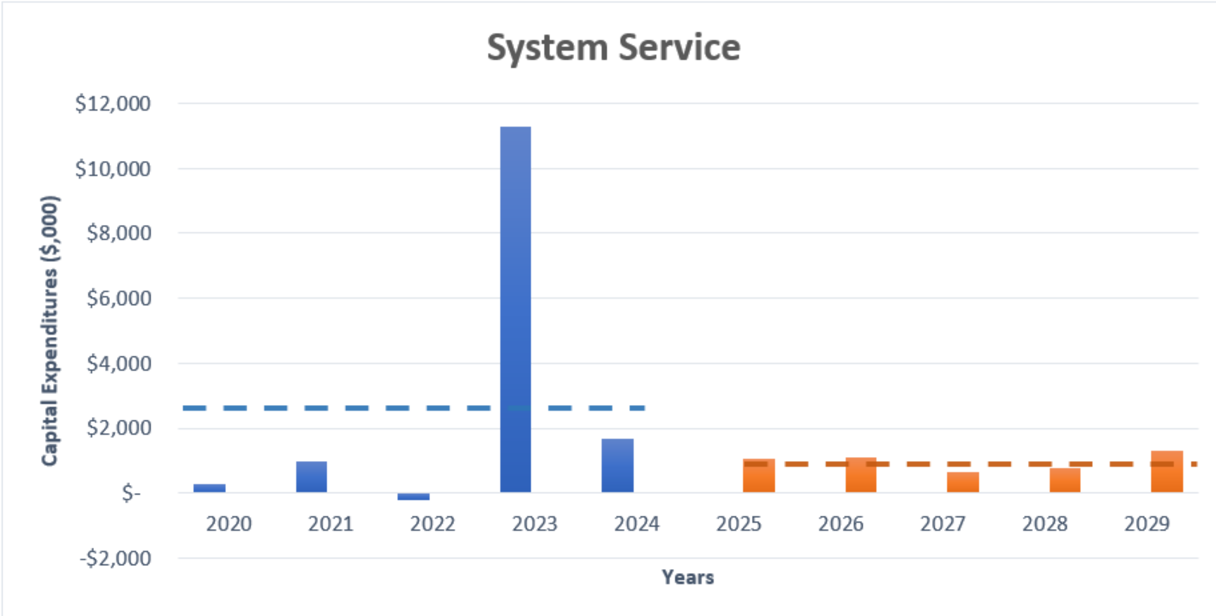
The 5-year plan for System Renewal expenditures is generally consistent with historical spending when factoring in the balance between the two historical station projects to API's planned project at Wawa #2 DS and its smart meter replacement program. The planned expenditure for this category currently accounts for about 62% of the planned net capital expenditures, compared to 39% over the historical period. This difference is largely the result of higher than average cost for two major projects in the historical period within the System Access and General Plant (44kV Expansion project and Sault Facility project).

5.4.2.2.3 System Service

The 5-year plan for System Service expenditures is based on addressing the potential system capacity constraints identified in 5.3.2.4 that consider load growth and long-term electrification as well as addressing poorer reliability performing supply and feeder systems. These investments will ensure that API will be able to continue provide high-quality service and meet its customers expectations with continue investment and focus on improving reliability.

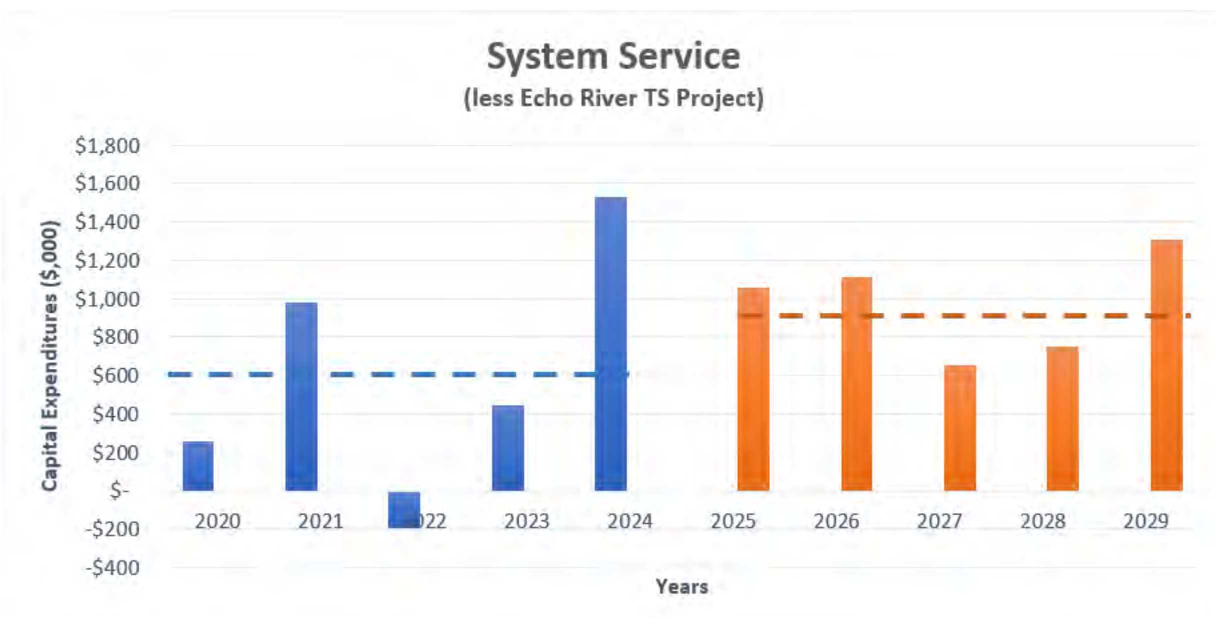
Figure 4.14 compares annual System Renewal investments over the historical and forecast periods.

Figure 4.14: 2020-2029 System Service Investments



To provide a more wholesome comparison and to avoid any skewing of the average expenditures, the project and capital investment required as part of the Echo River TS project, as described in section 5.4.1.1.3 has been excluded and depicted in Figure 4.15.

Figure 4.15: 2020-2029 System Service Investments (less Echo River TS Project)



API has planned for net annual System Service levels of approximately $4.9 million over the forecast period, which represents an increase of about $1.9 million compared to the historical period. The additional cost is mainly attributable to the voltage conversion program in Goulais and the associated refurbishment at the Goulais TS.

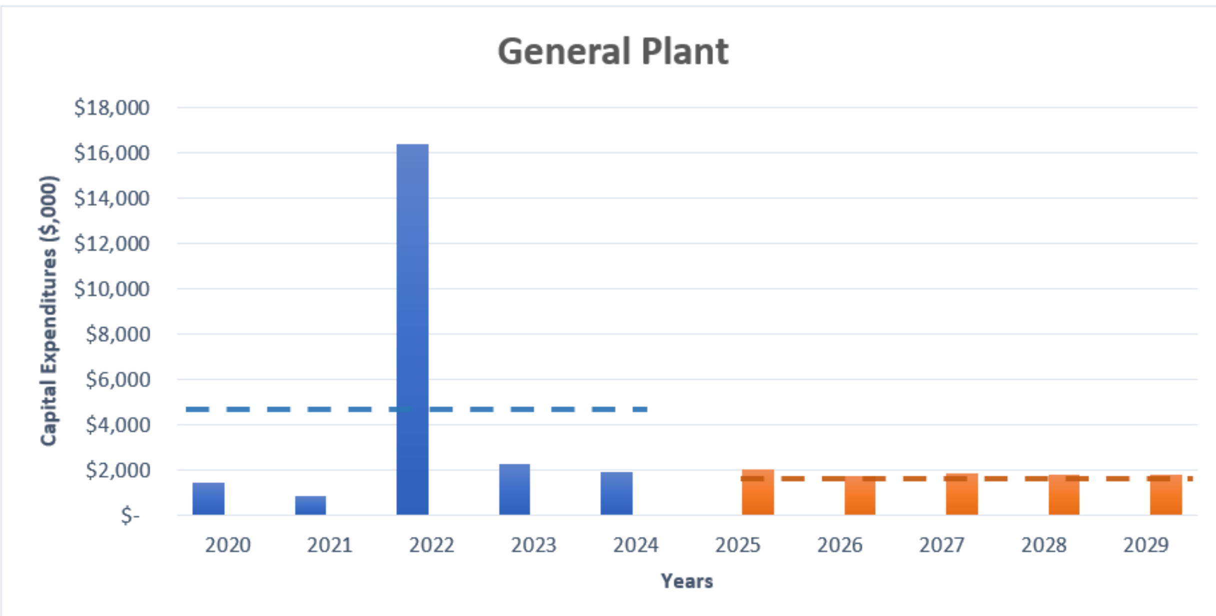
The 5-year plan for System Service expenditures has varied in the historical period, mainly due to the timing of certain projects. The planned expenditure for this category currently accounts for about 9% of the planned net capital expenditures, compared to 16% over the historical period.

5.4.2.2.4 General Plant

The 5-year plan for General Plant expenditures is based ensuring that API has the tools, equipment and overall means to meet its customers expectations in how it provides electrical service and manages its distribution system.

Figure 4.16 compares annual System Renewal investments over the historical and forecast periods.

Figure 4.16: 2020-2029 General Plant Investments



To provide a more wholesome comparison and to avoid any skewing of the average expenditures, the project and capital investment required as part of the SSM Facility project, as described in section 5.4.1.1.4 has been excluded and depicted in Figure 4.17

Figure 4.17: 2020-2029 General Plant Investments (less Sault Facility Project)

API has planned for net annual General Plant levels of approximately $9.2 million over the forecast period, which represents an increase of about $2.9 million compared to the historical period. This increase is mainly attributed to an increase in API's fleet capital replacement plan, which was driven by the material cost increases that were experience during and immediately following the COVID-19 pandemic.

The 5-year plan for General Plant expenditures has varied in the historical period, mainly due to the timing of certain projects. The planned expenditure for this category currently accounts for about 17% of the planned net capital expenditures, compared to 26% over the historical period.

5.4.2.3 Forecast Impact of System Investment on System O&M Costs

With the majority of spending in the System Renewal category, replacement of many assets is typically performed on a like-for-like basis therefore there would be little to no change in the future O&M costs associated with these assets. However, certain projects with this category will be upgraded beyond like-for-life and have positive impacts to API's operating expenses. Under API's line rebuild program, API is generally installing taller, stronger poles which will inherently result in better reliability and resilience. This improvement will result in decreased costs associated with outage response. Inspections and maintenance of assets will still be required to meet the requirements of the DSC and API's AMP.

Investment expenditures within the System Service category are centered around improving voltage and outage reliability as well as ensuring that the distribution system will be capable of supporting forecasted demand increases over time. The types of expenditures planned, such as the Goulais voltage conversion, continued implementation of SCADA, etc. will meet these objectives. Some of these programs and projects will inherently reduce expenses through system losses reductions. API's SCADA will save having to roll out staff to collect certain field information, improving efficiency. As API mentioned in its previous DSP, for some asset types, such as reclosers and switches, the newer assets generally require less maintenance than the assets being replaced.

Another capital investment that will impact the O&M costs is the ROW Access Program. Once a trail system has been established, annual inspections are performed to ensure maintenance requirements are identified and included in the current maintenance program. Maintenance activities, under the current year's program, would address vegetation growth, repair washouts, remove fallen vegetation off the ROW Access, and address vegetation growth within the ROW access that would impact API's usage of the trail system.

Over the 2026-2029 period covered by this DSP, API has forecasted that its total O&M costs will increase at a rate of 2.75% annually, reflecting inflationary increases, offset by moderate efficiency improvements.

5.4.2.4 Material Investments

The focus of this section is to support the material projects and programs comprising API's 2025-2029 capital investments.

API confirms that none of the currently planned projects is expected to require Leave to Construct approvals.

Most API's capital expenditures over the forecast period consist of multi-year programs or budget items where individual projects or areas of focus within these programs shift over time. API has assigned a priority ranking for each of the major programs and projects in the table listed below. Projects driven by external mandatory factors (such as System Access and some others) may be ranked as "Non-Discretionary". All remaining discretionary projects/programs have been assigned a numerical relative ranking. These rankings are intended to give a sense of the projects which API may consider deferring first (ie: lower-ranked discretionary projects) compared to others, if budget, resource availability or other factors were to require such consideration.

Table 4.15: Project Prioritization

Investment Category	Project/Program	Non-Discretionary or Priority Rank
System Access	Service Connections	Non-Discretionary
System Renewal	Smart Meter Replacement	Non-Discretionary
System Service	Goulais TS Refurbishment	Non-Discretionary
System Renewal	Small Lines/Stations Capital	Discretionary #1
General Plant	Transportation & Work Equipment	Discretionary #2
System Renewal	Wawa #2 DS Rebuild	Discretionary #3
System Service	Goulais Voltage Conversion	Discretionary #4
General Plant	ROW Access Program	Discretionary #5
System Renewal	Distribution Line Rebuilds	Discretionary #6
System Renewal	Subtransmission Line Rebuilds	Discretionary #7
System Service	Protection, Automation, Reliability	Discretionary #8
General Plant	Facilities, Buildings & Yards	Discretionary #9

API has provided the capital expenditure details required in Section 5.4.1.1 of the Filing Requirements at a program level for most budget items, with an additional annual breakdown of areas of focus within each program where applicable. For certain distinct projects, API has provided details at the project level under separate headings. Tables within each investment category indicate which programs/projects exceed API's materiality threshold, projects that are distinct for other reasons, and programs/projects that fall below API's materiality threshold.

In the remaining sections of this DSP, API has combined the following items from 5.4.1.1 of the Filing Requirements under a single heading for each material program/project for ease of review:

- Part A – General Information on the Project/Program
- Part B – Evaluation Criteria and Information Requirements for Each Project/Program

5.4.2.4.1 System Access

The following table summarizes API's planned System Access investments over the forecast period.

Table 4.16: Net System Access Investment Summary for the Forecast Period ($000's)

SA Project/Program	2025	2026	2027	2028	2029	Total	Materiality
Service Connections	1,063	1,079	1,095	1,111	1,127	5,476	> Threshold
Meters	129	131	133	135	137	666	< Threshold
Transformer – SA	160	162	165	167	170	824	< Threshold
Relocation/Joint-Use	13	14	14	14	15	70	< Threshold
System Access Total	**1,365**	**1,387**	**1,407**	**1,428**	**1,449**	**7,037**	

5.4.2.4.1.1 Service Connections

A. <u>General Information on the Project/Program</u>

1. **Overview**

This program includes all costs for the installation and replacement of API plant that is driven by customer requests for new services or service upgrades. Total investments over the 2025-2029 period are planned at approximately $1.2 million per year, for a total of $5.9 million. Individual customer-driven projects range from connecting or upgrading standard residential services that lie along API's existing distribution lines to expansions and upgrades required to connect larger commercial/industrial customers.

A unique feature of API's very rural service territory is that the vast majority of API's customer demand work is related to single-customer requests for connections to new residences, or for service upgrades to existing residences. Development of new subdivisions is relatively rare. As a result, most new services or service upgrades require a single new or modified connection to existing API plant. In many cases, this requires pole replacement, reframing or other upgrades to meet the requirements of Ontario Regulation 22/04.

This program also includes costs related to system expansions and upgrades required to connect commercial or large industrial services.

2. Key Project Timing

Start Date: January 1, 2025

In-Service Date: December 31, 2029

Key factors that may affect timing: Timing is subject to customer needs and when a request is made. Annual fluctuations in the volume of work are expected.

3. Total Expenditures

Table 4.17: Total Planned Expenditures - Service Connections ($000's)

	2025	2026	2027	2028	2029
Capex (Gross)	1,151	1,167	1,185	1,203	1,221
CIAC	(88)	(88)	(90)	(92)	(94)
Capex (Net)	1,063	1,079	1,095	1,111	1,127

4. Comparative Historical Expenditures

Table 4.18: Total Historical Expenditures - Service Connection ($000's)

	2020	2021	2022	2023	2024
Capex (Gross)	982	1,506	1,285	12,464	2,998
CIAC	(53)	(82)	(10)	(76)	(5,252)
Capex (Net)	928	1,424	1,275	12,387	(2,254)

5. Investment Priority

Non-Discretionary - This program is considered a high priority since it is a non-discretionary program driven by customers and is governed by regulatory compliance.

6. Alternatives Considered

Alternatives are considered on a case-by-case basis based on the request made. The alternative selected is based on consideration of safety, cost, reliability, site, conditions, regulatory compliance, and customer value.

7. Cost-to-Benefit Analysis

Not applicable

B. Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

Efficiency: In consideration of alternatives in the connection of a service, as described in A.6 above, API evaluates and determines the most –cost-effective solution for all parties. For each individual connection, API considers whether the connection or upgrade can be accommodated with a minimal scope of work (e.g. connection to existing secondary bus without anchoring or pole changes), while meeting the applicable safety requirements. Where a more involved scope is required to complete the connection, API assesses the possibility of incorporating additional related work (e.g. adjacent pole changes) to take advantage of fixed costs related to mobilization and excavation equipment.

Customer Value: This type of investment is a high priority for API, and it allows API to ensure it is responsive and is timely in connecting new and upgraded service to its distribution system.

Reliability: In general, there are no reliability impacts for this type of investment. To the extent that a system expansion may required a planned outage, these are generally one-offs, and are typically outweighed by the benefits that result from the upgrade.

2. Investment Drivers

The primary driver of this activity is customer service requests. This program allows API to satisfy its AM objective of meeting the needs of its customers, as well as meeting regulatory obligations under the DSC.

Safety: The design and construction of new or modified service connections is completed in accordance with API's Standards (API has adopted USF Standards) to meet the requirements of Ontario Regulation 22/04 and to ensure that no undue safety hazards exist.

Cyber Security: Customer connections requests are managed in accordance with relevant privacy legislation.

Grid Innovation: In general, driving grid innovation through customer connections is cost prohibitive. Where system constraints are identified in response to a larger service request, API considers non-wire alternatives to alleviate those constraints and facilitate connection.

Environmental: While the investment isn't inherently environmentally driven, API does strive to build efficiencies into the process by incorporating additional related work to take advantage of the mobilization of heavy equipment to the area. Reduced mobilization and set-up of this equipment minimizes emissions and potential impact on species at risk.

Statutory/Regulatory: Service connections are considered non-discretionary as there are regulatory obligations defined in the DSC, to process these requests within defined timeframes. API is also required to ensure that any work performed in the connection of a service is done in accordance with the safety standards defined under Ontario Regulation 22/04.

3. Investment Justification

Evidence of Accepted Distributor Practice: API follows a standard approach and procedure in response to receiving an application for a new or upgraded service. This internally approved procedure ensures that API is able to provide a timely plan for connection in accordance with the most current safety and design standard and with API's Conditions of Service.

Cost-to-Benefit Analysis: API considers alternatives in response to an application for a new or upgraded service, and the alternative selected is generally based on the most practical and cost-effective solution for API and the customer.

Historical Investments and Observed Outcomes: API has historically budgeted for and provided service connections as part of its capital expenditures. These investments and future investments will allow customers to access API's distribution system.

Substantially Exceeding Materiality Threshold: Not applicable.

5.4.2.4.2 System Renewal

The following table summarizes API's planned System Renewal investments over the forecast period.

Table 4.19: Net System Renewal Investment Summary for the Forecast Period ($000's)

SR Project/Program	2025	2026	2027	2028	2029	Total	Materiality
Small Lines/Stations Capital	430	436	442	448	455	2,211	> Threshold
Distribution Line Rebuilds	3,721	3,766	3,822	3,879	3,938	19,126	> Threshold
Subtransmission Line Rebuilds	964	977	992	1,007	1,022	4,962	> Threshold
Smart Meter Replacements	407	410	417	423	429	2,086	> Threshold
Wawa #2 DS Rebuild	-	-	4,584	-	-	4,584	> Threshold
Replace End-of-Life Transformers	140	142	144	146	149	721	< Threshold
Total Items less than Materiality	90	91	93	94	96	464	< Threshold
System Renewal Total	**5,752**	**5,822**	**10,494**	**5,998**	**6,088**	**34,154**	

5.4.2.4.2.1 Small Lines/Stations Capital

A. General Information on the Project/Program

1. **Overview**

This expenditure category includes the costs for priority replacement of individual line or station components that have failed, are defective, or have a high risk of failure, as identified during regular inspection and maintenance activities. Budgeting for these items allows for prudent decisions to be made on refurbishment vs replacement strategies, for assets that are not the focus of larger sustaining replacement programs.

Annual amounts are budgeted based on a 5-year average of historical costs. A risk of applying this budgeting approach to a future 5-year plan is that identification of any systemic issue with these assets during the next five years (e.g. identification of a high-risk lot or vintage of switch) may require the establishment of a priority replacement program at the expense of other asset replacement programs.

2. **Key Project Timing**

Start Date: January 1, 2025
In-Service Date: December 31, 2029
Key factors that may affect timing: In general, API does not expect any key factors that will affect timing. Any material that is required is pulled from stock and the work is completed by internal crews.

3. **Total Expenditures**

Table 4.20: Total Planned Expenditures – Small Lines/Stations Capital ($000's)

	2025	2026	2027	2028	2029
Capex (Gross)	430	436	442	448	455
CIAC	-	-	-	-	-
Capex (Net)	430	436	442	448	455

4. **Comparative Historical Expenditures**

Table 4.21: Total Historical Expenditures - Small Lines/Stations Capital ($000's)

	2020	2021	2022	2023	2024
Capex (Gross)	484	318	381	385	424
CIAC	(23)	-	-	(28)	-
Capex (Net)	461	318	381	385	424

5. **Investment Priority**

Discretionary #1 - While not completely non-discretionary, these Small Capital budgets are given a high priority due to the higher-than-average failure and/or performance risk of assets to be replaced. Replacements of assets that have already failed are non-discretionary. Replacement of assets that have been identified as having a high risk of failure is high priority because of the need to avoid unplanned replacement, which is typically associated with higher costs and longer outages due to API's inability to plan and coordinate the unplanned work.

6. Alternatives Considered

In general, a do-nothing approach is not a viable alternative as the inherent risks to workers and to the public in not replacing an asset that has deteriorated to the point of failure and/or performance is too great. Alternatives are typically based on a like-for like replacement approach and focus on the failed or near-failed component to minimize the scope of the replacement.

7. Cost-to-Benefit Analysis

Not applicable

B. Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

Efficiency:	Asset replacement within this activity is based on annual inspection and maintenance activities. As a result, API is replacing assets that are at end of life or have been identified as defective or as having a high risk of failure. This proactive approach ensures that API is addressing system needs before a failure occurs and a potential outage ensues.
Customer Value:	This type of investment is a high priority for API, and it allows API to ensure it is proactive in managing assets that have failed or are at risk of failure. A proactive approach improves the overall reliability of the asset in question and lessens the cost of replacement compared to reactively responding to a failure.
Reliability:	Replacing deteriorated assets prior to failure allows API to reduce or eliminate the outage impact of an unplanned outage.

2. Investment Drivers

The primary driver for this activity is the replacement of assets that have either reached end-of-life or have degraded to the extent that there is a high risk of failure/performance. This relates to API's AM objective of providing safe, reliable, and high-quality service. Specific replacement requirements in any given year are based on review of asset condition information obtained through regular inspection and maintenance activities or documented on interruption reports.

Safety:	The planned and proactive replacement of assets with high failure and/or performance risk is inherently safer than reactive

replacement as the working conditions can be controlled, and the optimal replacement plans can be determined in advance. This replacement approach also ensure that any hazards and risks to public safety that would result from an asset failure are mitigated. All design and associated construction are completed in accordance with USF Standards and meets the requirements of Ontario Regulation 22/04 and to ensure that no undue safety hazards exist.

Cyber Security: Not applicable

Grid Innovation: Not applicable

Environmental: Some assets requiring replacement involve oil-filled equipment. Proactive replacement of this type of equipment prior to in-service failure minimizes the risk of oil leaking to the environment.

Statutory/Regulatory: Not applicable

3. Investment Justification

Evidence of Accepted Distributor Practice: Assets replaced under this program are based on API's inspection and maintenance activities outlined in API's AMP.

Cost-to-Benefit Analysis: API considers the cost and operational benefits of proactive versus reactive asset replacements. In general, the cost of replacing an asset proactively will be lower compared to replacing that asset reactively (e.g. during an unplanned outage). Alternatives aren't typically considered when replacing an asset proactively, but rather is replaced in a like-for-like fashion. Certain situations may warrant a more detailed review of alternatives that are more the result of a legacy installation. Without this proactive approach, outages would be more prevalent.

Historical Investments and Observed Outcomes: API has historically budgeted to allow the replacement of assets resulting from inspection and maintenance activities. These investments and future investments will ensure that API is addressing and replacing asset that have a high risk of failure and/or high-performance risk.

Substantially Exceeding Materiality Threshold: Not applicable.

5.4.2.4.2.2 Distribution Line Rebuilds

A. General Information on the Project/Program

1. **Overview**

This program represents the most significant portion of API's sustaining asset replacement strategy. The objective of the Distribution Line Rebuild program is to achieve a sustainable asset replacement rate that is centered around proactively replacing poles near end of life, but prior to failure. The result of this objective is a balance between the cost of the replacement program and relatively larger costs, reliability impacts, and safety concerns associated with reactive replacement of these assets. The resulting levelized annual replacement rates also allow for efficient use of internal resources.

The sustainable asset replacement rate is largely based on factors associated with API's pole assets. Though age is not the only factor influencing the replacement priority, there is often a strong relationship between the age of a pole and the overall condition of the pole and associated line hardware. API has set an annual target replacement rate of approximately 400 poles per year under this program. The program's annual replacement target is based on the number, age, and overall condition of in-service poles, with consideration that poles are also being replaced in the Express Feeder rebuild program over the next five years. Annual program costs are based on rolling annual average cost from 2020-2023, approximately $9,300 per pole. Forecast program costs are similar to historical spending on the Line Rebuild program.

2. **Key Project Timing**

Start Date:	January 1, 2025
In-Service Date:	December 31, 2029
Key factors that may affect timing:	The key factors that may affect timing of work within this program include access constraints, permitting requirements and timing restrictions in accordance with species at risk and other applicable legislation.

3. **Total Expenditures**

Table 4.22: Total Planned Expenditures – Distribution Line Rebuilds ($000's)

	2025	2026	2027	2028	2029
Capex (Gross)	3,721	3,766	3,822	3,879	3,938
CIAC	-	-	-	-	-
Capex (Net)	3,721	3,766	3,822	3,879	3,938

4. **Comparative Historical Expenditures**

Table 4.23: Total Historical Expenditures – Distribution Line Rebuilds ($000's)

	2020	2021	2022	2023	2024
Capex (Gross)	3,198	4,364	4,234	3,153	5,455
CIAC	-	-	(2)	-	-
Capex (Net)	3,198	4,364	4,232	3,153	5,455

5. Investment Priority

Discretionary #6 - API considers the Line Rebuild program to be a critical part of an overall sustaining proactive replacement strategy that optimizes the overall lifecycle management of its assets. A minimum number of overall replacements are required over the course of the 5-year plan to sustain asset performance at current levels.

6. Alternatives Considered

Alternatives that were considered as part of this program were based on reducing or increasing the target replacement rate for poles by 10%.

7. Cost-to-Benefit Analysis

The cost-to-benefit analysis for this program is based on cost and operational benefits and ensuring that API is managing an efficient program.

Table 4.24: Cost-to-Benefit Analysis Line Rebuilds

Alternative	Target	Cost estimate (over 5-years)
Reduce Pace	Based on 360 poles per year	$17,213,220
Planned Pace	Based on 400 poles per year	$19,125,800
Accelerated Pace	Based on 440 poles per year	$21,038,380

With the alternatives in consideration, API anticipates that a reduction or accelerated alternative of 10% would result in costs that scale linearly. If API were to consider reducing the targeted replacement rate, API would need to be more selective and targeted, and would like result in having to replace poles more sporadically.

B. Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

Efficiency: By managing a robust line rebuild program, API is able to ensure efficiency in its use of resources and third-party services. The benefits of a line rebuild versus a pole replacement program for example, is that the cost per pole will increase dramatically when poles are replaced more sporadically. This is especially true for API as the size of the service territory increases the overall cost of mobilization.

Customer Value:	The line rebuild program at API is at the center of its sustaining asset replacement strategy. This strategy and the resulting program ensure that API is actively replacing its most vulnerable poles in a least-cost sustainable approach. By optimizing the asset lifespan of the poles, API is able to minimize early write-offs while also minimizing the need for costly and disruptive reactive repair/replacements. The levelized, proactive annual approach also allows API to plan to complete this work, where possible, through the use of internal resources. This approach allows API to optimally capitalize internal labour costs and minimize dependency on external, more costly support.
Reliability:	Poles and line hardware that are replaced under this program have generally been in service in excess of 50 years, well beyond the typical useful life for this asset. Poles are also typically shorter and smaller in class compared to what is installed today. This program inherently improves reliability as well as pole lines resilience in the context of adverse weather.

2. Investment Drivers

The primary driver of this program is the planned and sustainable replacement of end-of-life poles. Secondary drivers are maintaining reliability, optimizing the overall lifecycle costs associated with poles, as well as improved system performance. This program is based on the fundamental objective of API's AMP, which is "to prudently and efficiently manage the planning, 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 costs, in the short and long terms." API's asset register and the results of third-party testing programs are the primary sources of information driving this program.

A secondary driver for this program is that it will support and be a synergy to API's Goulais voltage conversion program. Some of the lines within the Goulais region that are included in the voltage conversion have reached end of life, and API can advance these lines as rebuild with understanding that it supports the objectives of both programs.

Safety:	Proactive replacement of poles, wires and hardware ensures that API's is progressively being brought up to more current and safe standards. Replacing older, more vulnerable, and weak poles in particular reduces the safety risks associate with downed powerlines.
Cyber Security:	Not applicable.
Grid Innovation:	Not applicable.

Environmental: For all API work activities under this program, the impact on the natural environment and significant natural areas is considered. Each project is thoroughly reviewed to identify any issues related to the natural environment or areas of cultural significance. Identified significant natural areas may require consultation with government, First Nation, and local agencies and/or landowners with regards to upcoming work activities. Considerations may include relocation of the power line to an alternative location, change in the project schedule and other mitigation measures to lessen the impact of the project on the significant natural area.

Statutory/Regulatory: Not applicable

3. Investment Justification

Evidence of Accepted Distributor Practice: API's Line Rebuild program began in 2015 and has become an essential program under API's sustaining asset replacement strategy.

Cost-to-Benefit Analysis: API has considered alternatives to the planned replacement rates, that would see either a reduction by 10% or an increase by 10%.

API has considered alternatives that involve increasing or decreasing the annual replacement target associated with this program. Based on the number of overall pole changes anticipated over the next five years through all capital projects and programs, API expects little change in the number of near end of life poles on completion of the 5-year plan. Over time, increasing the annual pole replacement targets would effectively decrease the average in-service pole age and the average age of poles being replaced. API does not believe this to be warranted based on the historical performance and failure rates of these assets. Decreasing the annual pole replacement targets would result in an increasing risk associated with high-risk in-service poles. This could quickly lead to a cycle where the increasing reactive replacement costs due to more frequent unexpected pole failures and a greater number of deficiencies identified during patrols lead to less budget room available for the proactive replacement, which further decreases the annual number of poles replaced proactively. Adopting this approach over a 5-year plan, could result in a bow-wave of future replacements, requiring both increased

	capital and O&M budgets at the time of API's next COS application.
Historical Investments and Observed Outcomes:	API has historically replaced around 400 poles per year through this program, which has led to a more robust and strengthened system. Historically, API has had few reactive pole failures in the field. Recently in 2023, API experienced a pole failure, which resulted in an outage of about 4.5 hours to 772 customers. The estimated cost of the reactive pole replacement was About $11,100. API believes its line rebuild projects have helped to avoid further instances of in-service pole failures.
Substantially Exceeding Materiality Threshold:	Yes

API considers the Line Rebuild program to be a critical part of an overall sustaining proactive replacement strategy that optimizes the overall lifecycle management of its assets. A minimum number of overall replacements are required over the course of the 5-year plan to sustain asset performance at current levels.

Though age is not the only factor influencing the replacement priority, there is often a strong relationship between the age of a pole and the overall condition of the pole and associated line hardware. The results of the ACA indicate that approximately 3.79% of the poles that were tested were of deteriorated condition (either poor or very poor). By comparison, API's previous ACA reported that 2.4%, which represents an increase of about 158%. This is likely the result of poles of fair condition degrading into poor and very poor condition. As is shown in Figure 3.14, API has about 4,440 that are deemed in fair condition. Over the next 5-years a certain level of these poles will have deteriorated to a poor condition and warrant replacement. API's Line Rebuild program and targeted replacement of 2,000 per over the next 5 years, ensures that will not be at risks of a substantial worsening condition of its poles.

Further evidence is supported through the CE effort. As is indicated in section 5.2.3.2, customers prefer and agree with API's planned approach for the targeted pole replacement rate.

Given the expansive nature of API's service area, the planned and programmatic replacement of groups of poles by line section is much more cost-effective than sporadic replacement of individual high-priority poles or reactive replacement of failed poles. Regular inspections and testing programs are designed to identify high-risk poles for proactive replacement prior to failure. API expects that the target replacement rates will maintain the status quo where one-off reactive replacement requirements are relatively rare. Any reduction in the overall replacement targets associated with this program will result in increased one-off replacements, at a higher cost per pole.

5.4.2.4.2.3 Subtransmission Line Rebuilds

A. General Information on the Project/Program

1. **Overview**

   This program represents a portion of API's sustaining asset replacement strategy. The objective of the Subtransmission Line Rebuild program is to achieve a sustainable asset replacement rate that is centered around proactively replacing poles near end of life, but prior to failure. The result of this objective is a balance between the cost of the replacement program and relatively larger costs, reliability impacts, and safety concerns associated with reactive replacement of these assets. The resulting levelized annual replacement rates also allow for efficient use of internal resources.

The sustainable asset replacement rate is largely based on factors associated with API's pole assets. Though age is not the only factor influencing the replacement priority, there is often a strong relationship between the age of a pole and the overall condition of the pole and associated line hardware. API has set an annual target replacement rate of approximately 100 poles per year under this program. The program's annual replacement target is based on the number, age, and overall condition of in-service poles, with consideration that poles are also being replaced in the Line Rebuild program over the next five years. Annual program costs are based on average cost per pole from 2020-2023, approximately $10,000 per pole.

2. Key Project Timing

Start Date:	January 1, 2025
In-Service Date:	December 31, 2029
Key factors that may affect timing:	The key factors that may affect timing of work within this program is access constraints, permitting requirements and timing restrictions in accordance with species at risk and other applicable legislation.

3. Total Expenditures

Table 4.25: Total Planned Expenditures – Subtransmission Line Rebuilds ($000's)

	2025	2026	2027	2028	2029
Capex (Gross)	964	977	992	1,007	1,022
CIAC	-	-	-	-	-
Capex (Net)	964	977	992	1,007	1,022

4. Comparative Historical Expenditures

Table 4.26: Total Historical Expenditures - Subtransmission Line Rebuilds ($000's)

	2020	2021	2022	2023	2024
Capex (Gross)	58	207	11	250	1,994
CIAC	-	-	-	-	-
Capex (Net)	58	207	11	250	1,994

5. Investment Priority

Discretionary #7 - API considers the Subtransmission Rebuild program to be a critical part of an overall sustaining proactive replacement strategy that optimizes the overall lifecycle management of its assets. A minimum number of overall replacements are required over the course of the 5-year plan to sustain asset performance at current levels.

6. Alternatives Considered

Alternatives that were considered as part of this program were based on reducing or increasing the target replacement rate for poles by 10%.

7. Cost-to-Benefit Analysis

The cost-to-benefit analysis for this program is based on cost and operational benefits and ensuring that API is managing an efficient program.

Table 4.27: Cost-to-Benefit Analysis Line Rebuilds

Alternative	Target	Cost estimate (over 5-years)
Reduce Pace	Based on 90 poles per year	$4,466,178
Planned Pace	Based on 100 poles per year	$4,962,420
Accelerated Pace	Based on 110 poles per year	$5,458,662

With the alternatives in consideration, API anticipates that a reduction or accelerated alternative of 10% would scale the associated costs linearly. If API were to consider reducing the targeted replacement rate, API would need to be more selective and targeted, and would like result in having to replace poles more sporadically (at a greater cost per pole).

B. Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

Efficiency: By managing a robust program, API is able to ensure efficiency in its use of internal resources and third-party services. The benefits of a rebuilding versus a pole replacement program for example, is that the cost per pole will increase dramatically when poles need to be changed more sporadically. This is especially true for API as the size of the service territory increases the overall cost of mobilization.

Customer Value: The subtransmission rebuild program at API is a core part of its sustaining asset replacement strategy. This strategy and the resulting program ensure that API is actively replacing its most vulnerable poles in a least-cost sustainable approach.

Reliability: Poles and line hardware that are replaced under this program have generally been in service in excess of 50 years, well beyond the typical useful life for this asset. Poles are also typically shorter and smaller in class compared to what is installed today. This program inherently improves reliability as well as pole lines resilience in the context of adverse weather.

Through the subtransmission rebuild program, API is able to mitigate the risk of reactive failures in the field, which are associated with unplanned outages that may last as long as eight (8) hours.

API notes that typically, a greater number of customers may be connected downstream of a given portion of the subtransmission system, therefore an asset failure on the subtransmission system has greater reliability risk (in terms of both SAIFI and SAIDI) compared to other portions of the system.

2. Investment Drivers

The primary driver of this program is the planned and sustainable replacement of end-of-life poles. Secondary drivers are maintaining reliability, optimizing the overall lifecycle costs associated with poles, as well as improved system performance. This program is based on the fundamental objective of API's AMP, which is "to prudently and efficiently manage the planning, 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 costs, in the short and long terms." API's asset register and the results of third-party testing programs are the primary sources of information driving this program.

Safety:	Proactive replacement of poles, wires and hardware ensures that API's is progressively being brought up to more current and safe standards. Replacing older, more vulnerable, and weak poles in particular reduces the safety risks associate with downed powerlines. A large portion of API's Subtransmission lines are located in remote, off-road locations. As a results, a failed poles pose significant safety risks associated with wildfires.
Cyber Security:	Not applicable
Grid Innovation:	Not applicable
Environmental:	For all API work activities under this program, the impact on the natural environment and significant natural areas is considered. Each project is thoroughly reviewed to identify any issues related to the natural environment or areas of cultural significance. Identified significant natural areas may require consultation with government, First Nation, and local agencies and/or landowners with regards to upcoming work activities. Considerations may include relocation of the power line to an alternative location, change in the project schedule and other mitigation measures to lessen the impact of the project on the significant natural area.

A large portion of API's Subtransmission lines are located in remote, off-road locations. As a results, a failed poles pose significant safety risks associated with wildfires.

Statutory/Regulatory: Not applicable

3. Investment Justification

Evidence of Accepted Distributor Practice: API's Subtransmission Rebuild program began in 2015 and has become an essential program under API's sustaining asset replacement strategy.

Cost-to-Benefit Analysis: Due to the number, condition, criticality, and location of the poles along API's Subtransmission lines, the reliability impacts of a "do-nothing" or run to failure would be significant. The costs associated with reactive replacement would also be high, and there could be significant worker and public safety risks associated with gaining access to certain line sections on an unplanned basis.

API has considered alternatives that involve increasing or decreasing the annual replacement target associated with this program. Based on the number of overall pole changes anticipated over the next five years through all capital projects and programs, API expects little change in the number of near end of life poles on completion of the 5-year plan. Over time, increasing the annual pole replacement targets would effectively decrease the average in-service pole age and the average age of poles being replaced. API does not believe this to be warranted based on the historical performance and failure rates of these assets. Decreasing the annual pole replacement targets would result in an increasing risk associated with high-risk in-service poles. This could quickly lead to a cycle where the increasing reactive replacement costs due to more frequent unexpected pole failures and a greater number of deficiencies identified during patrols lead to less budget room available for the proactive replacement, which further decreases the annual number of poles replaced proactively. Adopting this approach over a 5-year plan, could result in a bow-wave of future replacements, requiring both increased capital and O&M budgets at the time of API's next COS application.

Historical Investments and Observed Outcomes: API has historically replaced around 100 poles per year through this program, which has led to a more robust and

	strengthened system. API has avoided unplanned replacements due to failure of assets on the subtransmission system through its proactive approach, and therefore has avoided long-duration, costly outages affecting many end-use customers, as well as avoiding public and worker safety risk and reducing the need for costly unplanned repair/replacement work.
Substantially Exceeding Materiality Threshold:	Yes

API considers the Subtransmission Rebuild program to be a critical part of an overall sustaining proactive replacement strategy that optimizes the overall lifecycle management of its assets. A minimum number of overall replacements are required over the course of the 5-year plan to sustain asset performance at current levels.

Though age is not the only factor influencing the replacement priority, there is often a strong relationship between the age of a pole and the overall condition of the pole and associated line hardware. The results of the ACA indicate that approximately 3.79% of the poles that were tested were of deteriorated condition (either poor or very poor). By comparison, API's previous ACA reported that 2.4%, which represents an increase of about 158%. This is likely the result of poles of fair condition degrading into poor and very poor condition. As is shown in Figure 3.14, API has about 4,440 that are deemed in fair condition. Over the next 5 years a certain level of these poles will have deteriorated to a poor condition and warrant replacement. API's Subtransmission Rebuild program and targeted replacement of 500 per over the next 5 years, ensures that API will not be at risks of a substantial worsening condition of its poles.

Further evidence is supported through the CE effort. As is indicated in section 5.2.3.2, customers prefer and agree with API's planned approach for the targeted pole replacement rate.

Given the expansive nature of API's service area, the planned and programmatic replacement of groups of poles by line section is much more cost-effective than sporadic replacement of individual high-priority poles or reactive replacement of failed poles. Regular inspections and testing programs are designed to identify high-risk poles for proactive replacement prior to failure. API expects that the target replacement rates will maintain the status quo where one-off reactive replacement requirements are relatively rare. Any reduction in the overall replacement targets associated with this program will result in increased one-off replacements, at a higher cost per pole.

5.4.2.4.2.4 Smart Meter Replacements

A. General Information on the Project/Program

1. **Overview**

   In 2009-2010 API (like all Ontario LDCs), was required to install Smart Meters for all residential, seasonal, and small commercial customers. The meters available for the Smart Meter program were electronic meters and these new meters replaced existing electro-mechanical induction type meters that had registered low-volume customers' consumption for decades. As a result of the Smart Meter program, the residential meters at API went from a chronologically diverse population that were spread out over a 25-to-40-year lifespan, with a variety of installation dates, to a population with a single effective manufacture and seal date of 2009.

Industry Canada Bulletin E-26 defines the required reverification periods for electricity meters and metering installations. For meters with lengthened initial reverification periods, such as the meters at API, the net effect is that meters are subject to reverification statistical sampling on or before their 18th in-service year. For meters installed in 2009, this would be 2027. API anticipates that ten thousand (10,000) of the population of twelve thousand (12,000) meters will require resealing in 2027 and potentially replacement in the coming years.

API has developed a proactive Meter Replacement Plan that begins the process of meter reverification in 2025. The program provides for the purchase and installation of one thousand (1,000) new meters per year, starting in 2025 and ending in 2029 (5000 in total). The newly purchased meters will include eight hundred (800) direct replacements per year and, pending testing and approval, two hundred (200) Remote Disconnect Meters per year. The Remote Disconnect Meters that are planned to be deployed are approved federally, through Measurement Canada and can be used in Ontario. To meet API's equipment approval process, API will test the meters to ensure they are reliable and that the meter configuration meets API's metering requirements.

As part of the project in 2009, API chose the Sensus Flexnet Advanced Metering Infrastructure solution to meet its obligations to install Smart Meters. This system relied upon the installation and use of collector and repeater devices to form a meter communication network. Each meter broadcasts its meter readings, which are generally picked up by a single communication hub called a Tower Based Gateway ("TGB"), which then passes on the meter read to the Regional Network Interface ("RNI"). In addition to the TGB, the Sensus Flexnet system can transmit meter reads to the TGB or RNI via a repeater network. Two types of repeaters were available when API deployed the Flexnet system: the Flexnet Remote Portal ("FRP") and the Flexnet Network Portal ("FNP").

Given API's large service territory, the number of TGBs that might be required to read all meters directly could be expected to be large and the network expensive. However, using the Sensus developed "repeaters" that could effectively pass meter reads to the TGB or directly to the RNI using a variety of communication media, API was able to achieve the required meter read success rate without deploying a significant number of TGBs. API implementation included six (6) TGBs, ten (10) FRPs and fourteen (14) FNPs. API notes that this level of investment for a customer population of 12,500 is likely unusual in Ontario, however due to the low customer density, additional smart meter network communications investments were required relative to a higher-density utility.

The FRPs have effectively reached the end of their useful life and are no longer available from Sensus. As a result, API has included in this investment plan the purchase and installation of a new type of Sensus collector to replace the FRPs.

2. Key Project Timing

Start Date:	January 1, 2025
In-Service Date:	December 31, 2029
Key factors that may affect timing:	Delivery is subject to manufacturer scheduled and lead time.

3. Total Expenditures

Table 4.28: Total Planned Expenditures – Smart Meter Replacements ($000's)

	2025	2026	2027	2028	2029
Capex (Gross)	407	410	417	423	429
CIAC	-	-	-	-	-
Capex (Net)	407	410	417	423	429

4. Comparative Historical Expenditures

While API has not had a similar Smart Meter replacement program in the most recent years, the total cost of the initial smart meter implementation was $4.6M, including $4.5M in capital costs and $100k in OM&A. These costs do not include additional stranded meter costs.

Table 4.29: Total Historical Expenditures – Smart Meter Replacements ($000's)

	2020	2021	2022	2023	2024
Capex (Gross)	-	-	-	-	-
CIAC	-	-	-	-	-
Capex (Net)	-	-	-	-	-

5. Investment Priority

Non-Discretionary - Given the current level of meters that would require reverification in 2027 and the risk associated with a failure in the statistical sampling, API considers this a high priority.

6. Alternatives Considered

As the entire population was installed in a single year, a "do-nothing" approach risks a high failure rate in the statistical sampling of the reverification population (which could be 7000 meters in 2027).

In determining its proposed approach, API also took into consideration recent supply chain challenges in obtaining smart meters, brought about during the COVID-19 pandemic. While supply constraints may be gradually easing, API is aware of a potential demand-related risk with procuring smart meters. Specifically, given the implementation across Ontario of the Smart Metering Initiative (“SMI”), and the use of similar meters and similar suppliers among many Ontario LDCs, API is concerned that many other Ontario LDCs will likewise require a near-wholesale replacement of their smart meters in the coming medium term.

Such requirements could once again lead to shipment delays, which would negatively impact API’s ability to plan proactively for these replacements and likely lead to higher material and installation costs.

7. Cost-to-Benefit Analysis

Not applicable

B. Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value & Reliability

Efficiency:	The proposed replacement plan eliminates risks associated with a high failure rate in the statistical sampling of the reverification population. The objective is to gradually create 1000-meter annual reverification batches until a sustainable annual reverification program with a chronologically diverse batch size of about 1000 meters is re-established at API.
Customer Value:	Gradually creating smaller annual reverification batches will create a better, more optimized, and sustainable program. The remote disconnect meters, once deployed will enable API to remotely disconnect a service. This will in turn result in better operational efficiencies in performing this disconnect/reconnect activities.
Reliability:	Replacements of FRPs will ensure that the Sensus network is more reliable and minimizes the requirement for API to reset FRPs that fail to reinitialize after an outage.

2. Investment Drivers

The primary driver for this program is the replacement of smart metering asset that are at end-of-life and to ensure API is adhering Measurement Canada regulation requirements.

Safety:	Not applicable.
Cyber Security:	The implementation of this project considers cyber security and the risks associated with communication network for Smart Metering. During implementation, the new meters will not only ensure that API is meeting Measurement Canada requirement, but the newer device firmware and associated hardware will

	help support and mitigate any risks associated with Cyber Security threats.
Grid Innovation:	API is planning to purchase remote disconnect meters as a means of supporting and improving APIs disconnect/reconnect process.
Environmental:	Not applicable.
Statutory/Regulatory:	Meter reverification requirements are regulated by Measurement Canada. API has developed this program with the goal of maintaining compliance with Measurement Canada requirements.

3. Investment Justification

Evidence of Accepted Distributor Practice:	API's does not have any specific evidence of accepted practice. However, the plan is predicated on creating a sustainable reverification practice at the onset of having to reverify a large portion of Smart Meters.
Cost-to-Benefit Analysis:	API did not include any type of cost-to-benefit analysis, as it did not consider the do-nothing a viable alternative. The do-nothing alternative exposes API to a greater degree of planning and potential pricing volatility, as well as risking that API would have large batches of meters becoming non-compliant with Measurement Canada requirements.
Historical Investments and Observed Outcomes:	Not applicable.
Substantially Exceeding Materiality Threshold:	Not applicable.

The Smart Meter Replacement plan will have the following outcomes:

- Reduces the Supply Chain risks that have been experienced in recent years as API would be making annual requests for smaller quantities of meters at a time when all Ontario meters are beginning to come due for replacement.
- Increases the probability that the life of the existing meter stock can be extended based on the reverification testing process.
- Reduces annual capital costs if a batch fails (which is likely to happen more often as the meter population ages) by reducing the size of the failed batch to 1000; up to 2027 when the seals on every meter originally installed in 2009 (approximately 7000 meters at that time) expire and that population must be sampled and either reverified or replaced. Of note is the fact that API could retest all the 7000 meters in batches of 1000. Assuming that in 2027 the 7000 meters whose seals

expire undergo reverification and the meters are acceptable, the meters can be resealed for a period of six (6) years as defined in Annex D and Annex E of Industry Canada document S-S-06.

- Manages the need for qualified staff to complete this work by limiting the batch size and therefore both the need to remove existing meters from the field for sample testing and, if a batch failure occurs, the need to replace all the meters in the batch.

5.4.2.4.2.5 Wawa #2 DS Rebuild

A. General Information on the Project/Program

1. **Overview**

This project involves rebuilding the Wawa #2 DS in situ within the town of Wawa. This station supplies about half of the 8.32kV load, which is the bulk residential load in the town. The station serves as backup for API's 12.5kV feeder, which supplies the outskirts of Wawa. This station remains one of API's oldest stations and has shown signs of substantial deterioration in the past years. T1, the transformer that supplies the 8.32kV load from this station was manufactured in 1979.

As can be seen in Figure 3.9 and Figure 3.12, the main transformer and the station itself is in fair to poor condition. There are also working clearing challenges and lack of oil containment, which present substantial environmental risk in the event of a catastrophic failure. The risk of transformer failure at Wawa #2 DS is heightened based on the routine transformer maintenance that verified that the transformer is in fair condition due to the deterioration in the insulation of the transformer. Further, the station structure design cannot be operated, nor worked on using live line procedures. The entire structure must be de-energized to perform routine switching operations or to replace failed or deteriorated components on the structure.

The Town of Wawa load is served by two distribution stations, Wawa #1 DS and Wawa #2 DS. Each distribution station has a power transformer that operates at the 8.3kV level to supply the Town of Wawa load. Under normal operating conditions the town load is shared between the two stations. In the event of a catastrophic event at either station, the entire town load can be served by the remaining station. However, the lead time for replacement of a power transformer is currently 18 to 36 months, which risks leaving the Town of Wawa without back up for an extended period of time should the transformer at Wawa #2 DS fail. For this reason, API considered alternatives for increasing the transformer capacity in consideration of the forecasted load projections.

2. **Key Project Timing**

Start Date:	January 1, 2025
In-Service Date:	December 31, 2027
Key factors that may affect timing:	Delivery is subject to manufacturer scheduled and lead time.

3. **Total Expenditures**

Table 4.30: Total Planned Expenditures – Wawa #2 DS Rebuild ($000's)

	2025	2026	2027	2028	2029
Capex (Gross)	-	-	4,584	-	-
CIAC	-	-	-	-	-
Capex (Net)	-	-	4,584	-	-

4. Comparative Historical Expenditures

Table 4.31: Total Historical Expenditures – Wawa #2 DS Rebuild ($000's)

	2020	2021	2022	2023	2024
Capex (Gross)	-	-	-	-	-
CIAC	-	-	-	-	-
Capex (Net)	-	-	-	-	-

5. Investment Priority

Discretionary #3 - This investment is a high priority for API based on the overall condition of the station and the transformation equipment inside the station. This investment will also mitigate the risk that is associated with a transformer failure.

6. Alternatives Considered

While a do-nothing approach is typically considered for a project such as this, API considers this not acceptable given the current station configuration, asset age, lack of oil containment, criticality, and condition. In lieu of this, API did consider alternatives regarding the capacity of the 8.32kV power transformers that would be procured for the project. API considered three capacity alternatives:

- Alternative A – Like for Like Replacement – 5/6.67/8.33 MVA
- Alternative B – 50% Increased Capacity – 7.5/10/12.5 MVA
- Alternative C – 100% Increased Capacity – 10/13.3/16.6 MVA

7. Cost-to-Benefit Analysis

The cost-to-benefit analysis of the alternatives presented above are based on power transformer capacity consideration, and the risks associated with API being able to meet the forecasted load projections as outlined in the APS.

The 10-year load forecast in the APS in projected to be about 9,118 kVA. Given that the Typical Useful Life (TUL) for a power transformer was estimated at 45 years (with a maximum life of 60 years and a minimum life of 30 years) it would be prudent to consider the load requirements beyond 2033 when recommending a power transformer capacity for the new station.

- Alternative A – $4,322,356

This option is the like-for-like alternative. The power transformer that would be purchased would be sized to mimic the capacity of API's current power transformer. While this option is a consideration, during a contingency or during planned work, the transformer would not be able to supply the projected load requirements over the 10-year horizon.

❖ Alternative B – $4,584,000

This option considered increasing the capacity of the transformer by 50% relative to API's current transformer capacity. Building a new Wawa #2 DS with a power transformer rated at 12,500 kVA would allow such a station to operate below 50% of its nominal capacity if the estimated peak load calculated in the 10-year forecast becomes a reality.

❖ Alternative C – $4,850,877

This option considered increasing the capacity of the transformer by 100% relative to API's current transformer capacity. Building a new Wawa #2 DS with a power transformer rated at 16,600 kVA would allow such a station to operate below 50% of its nominal capacity if the estimated peak load calculated in the 10-year forecast becomes a reality.

Alternative B is proposed for this project as the 12, 500 kVA rating of the power transformer suitably strikes a balance between the uncertainty of the load forecast (which includes the uncertainty with respect to the load impacts - size and timing) of electric vehicles and electrification in the API service territory and the Typical Useful life of the asset. By choosing this alternative, API is potentially avoiding the need for costlier upgrades in the future if higher-than-projected levels of load growth (due to customer growth, electrification, etc.) occur.

B. Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

Efficiency:	Rebuilding the station and replacing T1 will result in a better station configuration for crews work in and operate. The replacement transformer will also benefit by being more efficient compared to the existing transformer.
Customer Value:	As indicated in section 5.2.3.2, API customers are mostly in favour of API's proposed 50% increase alternative. 50% of respondents were in favour of the 50% increase capacity alternative, while 33% of respondents favour the 100% increase capacity alternative.

Reliability:	The rebuild will address the condition concerns that have raised in the ACA and through preventative maintenance work. The rebuild will also incorporate oil containment, which will support mitigating risk associated with oil spills. To the extent that T1 were to fail, API would be required to operate with a backup contingency for a period of up to 18-36 months for the town of Wawa (one of the larger clusters of customers in API's service territory).

2. Investment Drivers

The primary driver for this program is asset renewal, reliability, and contingency performance. Secondary drivers are improved system performance, maintainability, and operability. This relates to API's AM objective of providing safe, reliable, and high-quality service. The proposed 50% capacity upgrade also supports load growth and electrification.

Safety:	The rebuild will address all the challenge associated with the existing structure. Currently API cannot operate any equipment in the structure live. The entire structure must be de-energized to perform routine switching operations.
Cyber Security:	To the extent that any new SCADA-operable devices are installed and integrated to API's SCADA system, the security of the communications link will be considered during the integration phase.
Grid Innovation:	API's standard station specification includes modern protection equipment and relay, which have the capability of connecting to API's SCADA, which in the future will allow API to see and operate these devices from a control room.
Environmental:	The station rebuild will be provisioned with oil containment, which will support mitigating environmental risks associated with an oil spill.
Statutory/Regulatory:	Not applicable.

3. Investment Justification

Evidence of Accepted Distributor Practice:	API stations are generally flagged for rebuild based on several different factors. Age of the station, age of the asset in the station, location, station constraints, load forecast, overall condition, etc. are all inputs into decision making on whether a rebuild should be pursued.

Cost-to-Benefit Analysis: The cost-to-benefit analysis for each alternative was the following:

- Alternative A – $4,322,356
- Alternative B – $4,584,000
- Alternative C – $4,850,877

A do-nothing alternative is deemed not viable given the risk of failure of T1.

Historical Investments and Observed Outcomes: API has completed two recent station rebuild projects, one in Dubreuilville and another in Bruce Mines. In both cases, the constructed station was a significant improvement in terms of layout, operability, access, containment, and contingency.

Substantially Exceeding Materiality Threshold: Yes

In addition to satisfying API's objective of providing safe, reliable, and high-quality service, this project will ensure that API is following good utility practice related to asset maintenance and replacement. The existing transformer, which will be 48 years old, poses a significant reliability risk and as a result should be replaced. The lack of oil containment, existing electrical clearances and access constraints to the station provide further justification for relocating the station.

While a do-nothing approach is typically considered for a project such as this, API considers this not acceptable given the current station configuration, asset age, lack of oil containment, criticality, and condition. To the extent that T1 were to fail, API would be required to operate with a backup contingency for a period of up to 18-36 months. The lack of oil containment also presents significant environmental risk, especially with the age of the transformer.

5.4.2.4.3 System Service

The following table summarizes API's planned System Service investments over the forecast period.

Table 4.32: Net System Service Investment Summary for the Forecast Period ($000's)

SS Project/Program	2025	2026	2027	2028	2029	Total	Materiality
Goulais Area Voltage Conversion	297	302	308	315	321	1,543	> Threshold
Protection, Automation, Reliability	757	807	344	438	309	2,656	> Threshold
Goulais TS Refurbishment	-	-	-	-	680	680	> Threshold
System Service Total	**1,054**	**1,110**	**652**	**753**	**1,310**	**4,879**	

5.4.2.4.3.1 Goulais Area Voltage Conversion

A. General Information on the Project/Program

1. **Overview**

This project involves upgrading portions of API's distribution system in the Goulais region to support converting to a higher voltage once HOSSM's TS refurbishment is complete. Through the regional planning effort, HOSSM identified that the Goulais TS is at end-of-life and requires replacement. Through this process API developed a Greenfield TS report, that considered different supply options with the objective of identifying API's long term supply needs. The recommendation from this report was to refurbish the existing Goulais TS and convert its distribution system to 25kV within the next 10-15 years.

Further to the Greenfield Study report and as part of this DSP, API developed its APS, which further confirms the need for API to operate at a higher voltage. The APS identified that the distribution system in Goulais is highly sensitive to load growth and that converting to 25kV will sustain its forecasted load increase and improve feeder end voltage levels.

HOSSM has recently indicated that the refurbishment plan will begin in 2025 and expects to be placed into service in 2028/2029. Details of API's investment plan around the refurbishment of the station itself are included in section 5.4.2.4.3.

The detailed implementation plan for this program is included below.

2. Key Project Timing

Start Date:	January 1, 2025
In-Service Date:	December 31, 2029
Key factors that may affect timing:	This program relies on procuring suitable distribution transformers, which is subject to manufacturer scheduled and lead time.

3. Total Expenditures

Table 4.33: Total Planned Expenditures – Goulais Voltage conversion ($000's)

	2025	2026	2027	2028	2029
Capex (Gross)	297	302	308	315	321
CIAC	-	-	-	-	-
Capex (Net)	297	302	308	315	321

4. Comparative Historical Expenditures

Table 4.34: Total Historical Expenditures – Goulais Voltage conversion ($000's)

	2020	2021	2022	2023	2024
Capex (Gross)	-	-	-	-	-
CIAC	-	-	-	-	-
Capex (Net)	-	-	-	-	-

5. Investment Priority

Discretionary #4 - This investment is a relatively high priority for API based on the forecasted system issues identified in the APS.

6. Alternatives Considered

Based on the results of the APS and the previous Greenfield Study report, API has deemed a do-nothing approach not feasible. In a do-nothing approach, API will risk that the distribution system will not be capable of supplying the demand over the 10-year horizon included in the study.

API considered three alternatives based on the scale of the area to be covered in the upgrades and conversion:

- Alternative A: A minimum level (25%) distribution system voltage conversion
- Alternative B: A medium level (50%) distribution system voltage conversion
- Alternative C: A full level (100%) distribution system voltage conversion

7. Cost-to-Benefit Analysis

The cost-to-benefit analysis for each alternative was the following:

Alternative A:

In this alternative, API considered converting approximately 25% (or 45 km) of the distribution system in the Goulais region. In this option, API's program would consist of approximately the following:

- Convert 45 km of primary distribution
- Upgrade 140 transformers
- Reinsulate 310 primary distribution poles
- Install 12 step-down transformers

This option would be API's lowest investment cost-alternative but would require the greatest number of step-down transformers to be installed to bridge the converted distribution system to the existing distribution system. Each step-down transformer would be required to be inspected annually in accordance with API's AMP. As a result, the overall inspection requirement and associated cost would be higher in this alternative. This alternative would result in the least amount of system loss improvement. This alternative is the most logistically feasible as it requires the least amount of work to "switch" the equipment once the supply from the Goulais TS is converted to 25kV.

The estimated capital investment cost for this alternative is **$1,495,597.**

Alternative B:

In this alternative, API considered converting 50% (approximately 76 km) of the distribution system in the Goulais region. In this option, API's program would consist of approximately the following:

- Convert 76 km of primary distribution
- Upgrade 205 transformers
- Reinsulate 532 primary distribution poles
- Install 7 step-down transformers

This option presents API's mid-level investment alternative, which strikes a balance between the cost and feasibility of implementation along with the increase in operating expenses. In this option, API would be required to install seven (7) step-down transformers to bridge the converted distribution system to the existing distribution system. Each step-down transformer would be required to be inspected annually in accordance with API's AMP. This alternative would result in greater system losses compared to Alternative A but less than Alternative C. This alternative is also feasible, like alternative A.

The estimated capital investment cost for this alternative is **$1,542,810.**

Alternative C:

In this alternative, API considered converting 100% (approximately 202 km) of the distribution system in the Goulais region. In this option, API's program would consist of approximately the following:

- Convert 202 km of overhead primary distribution
- Upgrade 891 transformers
- Reinsulate 1,948 distribution poles

This option presents API's highest-level investment alternative and represents API's ultimate vision and objective for the distribution system in the Goulais region. The high cost for the alternative is mainly attributable to the substantially larger quantity of transformers and hardware that would be required to be upgraded. The option would result in the greatest reduction in system losses, but also presents the greatest logistical challenge to implement. The large quantity of transformers would require the greatest amount of work to "switch" the equipment once the supply from the Goulais TS is cutover to the higher voltage. It is estimated that there would be about 4 times the level of work and associated coordination.

The estimated capital investment cost for this alternative is **$4,500,166.**

B. Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

Efficiency:	This capital investment program will support API's planned investment at the Goulais TS as part of the refurbishment project, which will allow API to remove its Autotransformer requirement and allow for an overall better configuration of that station. The program will also see a reduction in system losses. API intends to leverage previous investments under its Line Rebuild program, which saw API replace poles in the Goulais region. As part of these replacements, API replaced all hardware on the pole, which included the insulators. API has standardized on a 28kV insulation level, so to the extent that recently replace poles are included in the area to be converted, these poles would not require any insulator replacement.

Customer Value: This capital investment program will ensure that API's distribution system can supply the forecasted demand over the next 10 years, with consideration of EV and electrification load increases. This will support future customer supply needs.

Reliability: This capital investment program is centered around ensuring that the distribution system can support future load projections. Current load projections, included in Appendix C indicate that under the existing distribution system configuration, there is substantial risk associated with the reliability of the voltage supply as the system demand increases. This program will ensure that the supply voltage remains reliable and within an acceptable range.

2. Investment Drivers

The primary driver for this program is voltage reliability and system performance. Secondary drivers are asset renewal, maintainability, and operability. This relates to API's AM objective of providing safe, reliable, and high-quality service.

Safety: This program is driven by safety, but through detailed design and engineering, API will ensure that safety standards are followed during implementation.

Cyber Security: Not applicable

Grid Innovation: The conversion to a higher voltage will support API's capability to connected distributed energy resources.

Environmental: Not applicable

Statutory/Regulatory: Not applicable.

3. Investment Justification

Evidence of Accepted Distributor Practice: API does not have any recent programs or projects tied to voltage conversion work. However, API has in the past justified converting the distribution system to a higher voltage as part of overall system planning in consideration of load projections.

Cost-to-Benefit Analysis: The proposed plan is based on Alternative B, described above. In this alternative, API overall investment is incrementally unsubstantial compared to the lower-cost alternative A. The additional cost of Alternative B is

	balanced with the reduced cost and better system loss improvement.
Historical Investments and Observed Outcomes:	API does not have any historical investments tied to this type of work.
Substantially Exceeding Materiality Threshold:	No

This program, along with the Goulais TS Refurbishment project, is based on the area plan for this region and forecasted load increase outlined in API's APS. Within API's voltage conversion plan, it has planned for upgrading a sufficient level of the Goulais distribution such that it can be converted to 25kV once the supply from the Goulais TS is upgraded to 25kV. The Goulais TS refurbishment project will ensure that the Goulais TS can supply 25kV by 2029 so that API can complete its voltage conversion.

5.4.2.4.3.2 Protection, Automation, Reliability

A. General Information on the Project/Program

1. **Overview**

API's AM process includes analysis of historical outage data as well as an analysis of system capacity at current and 10-year forecasted loads and contingency plans. These analyses are all incorporated into the APS and Reliability Study (Appendix C and Appendix E). These studies identify projects that will improve outage and voltage reliability as well as contingency performance.

Many of these projects also have positive impacts on power quality, system maintainability, accommodation of REG/DER projects, future cost savings, and reduction of system losses. This program also ensures API is meeting customer expectations regarding continued reliability improvements.

The result of these studies and planning efforts have identified the following priority protection, automation & reliability projects in the 5-year plan:

- **Project A** – 34.5kV Switching Automation
  This project consists of installing SCADA-operable devices along API's 34.5kV Subtransmission system East of Sault Ste. Marie, and implementation a fault locating and system isolating and restoration scheme.
- **Project B** – 12.5kV Voltage Reinforcement
  This project consists of upgrading conductor and extending 3-phase circuits at specific locations along API's 12.5kV distribution.
- **Project C** – Install Second 3-Phase Circuit along Feeder 5120
  This project consists of constructing a second 3-phase feeder that supplies the distribution system south of the Goulais TS
- **Project D** – Upgrade the Primary Transformer Protections at the Bar River DS
  This project consists of replacing the existing transformer protections at the Bar River DS (power fuses) with a modern relay and breaker.

- **Project E** – Procure suitable contingency replacement for the power transformer at the Dubreuilville Sub 87.

2. Key Project Timing

Start Date: January 1, 2025

In-Service Date:

Project A – December 31, 2027
Project B – December 31, 2029
Project C – December 31, 2026
Project D – December 31, 2025
Project E – December 31, 2025

Key factors that may affect timing: Procurement of equipment and material is subject to manufacturer scheduled and lead time.

3. Total Expenditures

Table 4.35: Total Planned Expenditures – Protection, Automation, Reliability ($000's)

	2025	2026	2027	2028	2029
Capex (Gross)	757	807	344	438	309
CIAC	-	-	-	-	-
Capex (Net)	757	807	344	438	309

4. Comparative Historical Expenditures

Table 4.36: Total Historical Expenditures – Protection, Automation, Reliability ($000's)

	2020	2021	2022	2023	2024
Capex (Gross)	255	8	-	11,213	1,485
CIAC	-	-	-	(99)	-
Capex (Net)	255	8	-	11,114	1,485

5. Investment Priority

Discretionary #8 - Investments in this program are relatively discretionary as compared to most other projects and programs, and as a result are given less priority. While justifications could be made for many projects driven by reliability improvement and cost efficiencies, API is mindful of the associated rate impacts and resource requirements. Planned spending on this program is therefore relatively low in comparison to other programs and projects included in the 5-year plan.

6. Alternatives Considered

API considered alternatives for Project A in this program. Namely the implementation of the distribution automation on API's 34.5kV system. API considered the following options:

- Alternative A: Status Quo (do-nothing)

- Alternative B: Partial Implementation
- Alternative C: Full Implementation.

These options were included in the CE survey workbook, so that API could gauge customer preferences regarding balancing the investment levels to expected reliability improvement.

7. Cost-to-Benefit Analysis

API considered alternatives to the proposed implementation of the Distribution Automation scheme highlighted above, based on the level of implementation. Below is a summary of the cost-to-benefit analysis of these three alternatives:

Alternative A:

In this alternative, API would do nothing. The project would not proceed, and API's reliability and outage response would remain unchanged. Across this stretch of the system where this project is targeting, Algoma Power would continue to manually locate outages and restore power, typically taking between 4 and 8 hours on average.

The estimated capital investment cost for this alternative is $0.

Alternative B:

In this alternative, API would partially implement the distribution automation scheme by focusing the procurement and installation of remotely controllable switches along API's 34.5kv subtransmission feeder East of Sault Ste. Marie. The software purchase and installation would be deferred to a future cost of service. Across this stretch of the system where this project is targeting, Algoma Power will be able to remotely locate an outage, improving average estimated restoration times by about 50%.

The estimated capital investment cost for this alternative is $551,455.

Alternative C:

In this alternative, API would fully implement the distribution automation scheme. API would procure and install remotely controllable switches along API's 34.5kV subtransmission feeder East of Sault Ste. Marie, as well as the necessary distributed automation software. This alternative would see the same benefits as Alternative B; however, outage restoration times are reduced even further because power can be restored remotely.

The estimated capital investment cost for this alternative is $851,455.

B. Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

Efficiency:	These investments will support improved system visibility and operability, which will support API operations in responding to outage and/or power quality concerns.
Customer Value:	Customer value is based on the improvements in reliability.
Reliability:	Reliability is the primary driver for this program as a result the investment will ultimately improve API's outage and voltage reliability

2. Investment Drivers

The primary driver for this program is reliability. Secondary drivers are operational efficiencies, improved system performance, maintainability, and operability. This relates to API's AM objective of providing safe, reliable, and high-quality service. The selection, prioritization, and justification of individual projects in any given year will be based on the analysis of historical outage data as well as an analysis of system capacity and contingency plans that form part of API's AMP.

Safety:	The improvements to reliability and contingency performance due to these investments are expected to reduce the safety risks that may be associated with outage restoration efforts in unfavourable conditions due to weather, time of day, or other factors.
Cyber Security:	To the extent that any new SCADA-capable devices are installed and incorporated into API's SCADA integration plan, the security of the communications link will be considered during the integration phase.
Grid Innovation:	API proposed projects within this program have grid innovation in mind. While API's distribution system is simpler compared to other utilities, 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.
Environmental:	Reliability improvements resulting in a reduction of outage frequency would reduce the emissions associated with vehicles responding to after-hours outage events.
Statutory/Regulatory:	Not applicable.

3. Investment Justification

Evidence of Accepted Distributor Practice:	Annually, API reviews outage statistics with load flow studies to identify areas of improvement. Outage analysis

	helps to identify any trending and worst performing feeders, while load flow studies identify capacity and voltage constraints for forecasted load growth.
Cost-to-Benefit Analysis:	
Historical Investments and Observed Outcomes:	Historical investments in protection, automation and reliability have enabled API to gain increased visibility of system conditions and outage causes.
Substantially Exceeding Materiality Threshold:	Not Applicable

As discussed above, this program is relatively discretionary in comparison to other projects and programs within the current 5-year plan. As a result, considering a do-nothing approach for any specific project within this program would maintain the status quo in terms of reliability, costs, and contingency performance.

Given the significant benefits in terms of reliability, contingency response and operational efficiency associated with typical projects outlined in Section A above, API believes that the investment levels in the 5-year plan strike a reasonable balance between an overall do-nothing approach, and investment by customer feedback and operational effectiveness in response to the Board's RRFE performance outcomes. In addition, these projects are expected to incorporate advanced SCADA-capable equipment and technologies, providing for grid innovation advancements. These technologies will also improve operational efficiencies and AM practices.

5.4.2.4.3.3 Goulais TS Refurbishment

A. General Information on the Project/Program

1. **Overview**

This project, which is being led by HOSSM involved refurbishment the Goulais TS. This station and all the 115kV equipment inside the station is owned by HOSSM. The operational demarcation with API is such that API owns all the low-voltage distribution equipment within the station. API operates a 12.5kV low-voltage distribution system which supplies the Goulais River region. Within the Goulais TS, API also owns and operates a 12.5/25kv autotransformers, which supplies API's Searchmont express feeder.

Through the Regional Planning process, HOSSM identified that their equipment at this station has reached end-of-life and requires replacement. Given the current configuration and demarcation, HOSSM has worked closely with API to identify the optimal plan for replacement. HOSSM developed a Local Planning Report (see Appendix L), which identified that refurbishment of this station is the preferred solution to address identified needs.

Planning for this project is expected to begin in 2025 and be completed around 2028/2029. Through previous planning discussions with HOSSM, API is aware that the scope for the refurbishment will include at a minimum expanding the station footprint, replacing existing 115kV power transformer and provision for new protections in accordance with HONI standards. API's scope currently is expected to include relocating the distribution feeder connection point and removing all existing API equipment from the station.

From API's APS report and as is identified in the Goulais voltage conversion program identified above, API has planned to upgrade a portion of the distribution system in the Goulais area and convert to 25kV. This work is contingent upon the supply at the HOSSM Goulais TS also converting from 12.5kV to 25kV. As a result, API is currently in discussions with HOSSM to receive a 25kV supply at the end of the refurbishment project.

The investment plan is to cover the incremental cost associated of HOSSM upgrading the supply to 25kV (above a like-for-like replacement), a second feeder connection and upgrades to API's wholesale revenue metering equipment. As part of the planning process and as part of HOSSM planned station configuration, API will draft a relocation plan that will cover moving API's feeder connection.

2. Key Project Timing

Start Date:	January 1, 2025
In-Service Date:	To be determined, expected in 2028 or 2029 (subject to finalizing plan with HOSSM)
Key factors that may affect timing:	This is a HOSSM-led project and will be subject to their project plan and schedule.

3. Total Expenditures

Table 4.37: Total Planned Expenditures – Goulais TS Refurbishment ($000's)

	2025	2026	2027	2028	2029
Capex (Gross)	-	-	-	-	680
CIAC	-	-	-	-	-
Capex (Net)	-	-	-	-	680

4. Comparative Historical Expenditures

Table 4.38: Total Historical Expenditures – Goulais TS Refurbishment ($000's)

	2020	2021	2022	2023	2024
Capex (Gross)	-	-	-	-	-
CIAC	-	-	-	-	-
Capex (Net)	-	-	-	-	-

5. Investment Priority

Non-Discretionary – While the overall refurbishment project is HOSSM-led, API has identified investment associated with the overall voltage conversion in the region that would be incorporated in project plan. Given the interdependency with the Goulais Area Voltage Conversion program and the associated justifications for that program, this project is considered a high priority for API.

6. Alternatives Considered

Working with HOSSM, API has proposed upgrading the supply to 25kV as part of this project. An alternative to this approach would have been a like-for-like replacement. This alternative would require that API construct a distribution station for API's 12.5/25kV autotransformer, upgrading the conductor for numerous feeders, extending two and three-phase along existing single-phase feeders as well as the installation of feeder voltage support devices.

Given the long-term nature of the investment at the Goulais TS, API requested an upgrade in order to accommodate long term growth forecasts as projected in the APS. Upgrading the supply now will improve capacity and potentially avoid more costly future upgrades due to increases in electricity demand. API has not considered a do-nothing given the justification and reasoning associated with the Goulais Area Voltage Conversion program.

7. Cost-to-Benefit Analysis

Not applicable.

B. Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

Efficiency:	API's planned investment supports API's voltage conversion plan for the Goulais region. Once the conversion is complete, API will experience better voltage reliability and decreased system losses.
Customer Value:	This investment supports future consideration for electrification. API will be better positioned to support organic electrification growth resulting from public policies around climate change and carbon footprint reductions.
Reliability:	This investment will support improved voltage reliability and stability.

2. Investment Drivers

The primary driver for this project is voltage reliability in consideration of future load growth.

Safety:	This investment supports the overall HOSSM refurbishment project. To the extent that there are identified needs and issues with existing 115kV HOSSM-owned assets, the replacement plan will improve overall worker safety and safe working clearances.
Cyber Security:	Not applicable.

Grid Innovation:	This investment isn't specifically considered innovative. It will however enable more connections of DERs and EV charging infrastructure.
Environmental:	The planned investment supports converting to a higher voltage. Once the distribution system is converted, it will mean that API no longer requires its 12.5/25kV autotransformer.
Statutory/Regulatory:	Not applicable.

3. Investment Justification

Evidence of Accepted Distributor Practice:	Not applicable.
Cost-to-Benefit Analysis:	Not applicable.
Historical Investments and Observed Outcomes:	Not applicable.
Substantially Exceeding Materiality Threshold:	Not applicable.

This project, along with the Goulais voltage conversion program, is based on the area plan for this region and forecasted load increase outlined in API's APS. Within API's voltage conversion plan, it has planned for upgrading a sufficient level of the Goulais distribution such that it can be converted to 25kV once the supply from the Goulais TS is upgraded to 25kV. This project will ensure that the Goulais TS can supply 25kV by 2029 so that API can complete its voltage conversion.

This project will result in cost avoidance associated with eliminating the requirement to construct a smaller station to house the existing 12.5 kV to 25kV autotransformer that supplies the Searchmont express feeder. API also expects that there will be cost avoidance associated with requiring HOSSM to purchase and install a power transformer with a reconfigurable secondary winding. The estimated cost avoidance is in the $1.5-2M range in addition to the ongoing maintenance cost of managing a smaller station.

Once the Goulais TS refurbishment is completed around 2028/2029, API can complete the voltage conversion of its Goulais distribution system. This will avoid the requirement for HOSSM to purchase and install a power transformer with a reconfigurable secondary winding (i.e., dual-voltage) and thus save the associated incremental cost that API would be required to pay. Another benefit is to eliminate the requirement to construct a smaller station to house the existing 12.5 kV to 25kV autotransformer that supplies the Searchmont 25kV circuit.

5.4.2.4.4 General Plant

The following table summarizes API's planned General Plant investments over the forecast period.

Table 4.39: Net General Plant Investment Summary for the Forecast Period ($000's)

GP Project/Program	2025	2026	2027	2028	2029	Total	Materiality
ROW Access Program	226	127	129	131	133	746	> Threshold
Tools & Equipment	92	93	95	96	97	473	< Threshold
Communications & SCADA	126	146	138	70	-	480	< Threshold
Transportation & Work Equipment	1,207	958	1,140	1,130	1,190	5,624	> Threshold
Facilities, Buildings & Yards	214	217	174	177	179	960	> Threshold
IT Hardware/Software	59	60	61	62	63	304	< Threshold
Total Items less than Materiality	116	117	119	121	123	596	< Threshold
General Plant Total	**2,039**	**1,718**	**1,855**	**1,787**	**1,785**	**9,184**	

5.4.2.4.4.1 ROW Access Program

A. General Information on the Project/Program

1. **Overview**

This program includes all costs associated with the design, engineering, legal agreements, materials, equipment, internal labour and contracts and/or easements related to the creation and enhancement of safe and reliable access to API's existing power line locations and ROWs. As discussed in section 5.2.1.2.5, API has several express feeders that are aligned along the most direct route from the transmission system delivery point to the customers and are often situated along uninhabited and undeveloped tracks of land.

5.2.1.2.5

2. **Key Project Timing**

Start Date: January 1, 2025
In-Service Date: December 31, 2029
Key factors that may affect timing: Establishing contracts and/or easements generally requires negotiating with landowners, which can lead to schedule delays.

3. **Total Expenditures**

Table 4.40: Total Planned Expenditures – ROW Access Program ($000's)

	2025	2026	2027	2028	2029
Capex (Gross)	226	127	129	131	133
CIAC	-	-	-	-	-
Capex (Net)	226	127	129	131	133

4. **Comparative Historical Expenditures**

Table 4.41: Total Historical Expenditures - ROW Access Program ($000's)

	2020	2021	2022	2023	2024
Capex (Gross)	279	(20)	-	15	288
CIAC	-	-	-	-	-
Capex (Net)	279	(20)	-	15	288

5. **Investment Priority**
Discretionary #5 - API considers this investment a medium to high priority. In locations where access is limited, there remains significant effort and cost to maintain those lines and ROWs.

6. **Alternatives Considered**
Given the potential worker safety and environmental benefits mentioned above, and the potential reduction is restoration times for outages occurring on the most inaccessible portions of API's lines, API considers the program investment levels over the next five years to be a reasonable alternative to the do-nothing approach.

7. **Cost-to-Benefit Analysis**
Not applicable

B. Evaluation Criteria and Information Requirements for Each Project/Program

1. **Efficiency, Customer Value, Reliability**

Efficiency: API's evaluation of outage response scenarios revealed where there exists insufficient or lack of access to certain line sections, this could severely hamper restoration efforts and result in prolonged restoration times.

Adequate ROW access will also result in operating and maintenance efficiencies. For example, API will avoid additional time and cost related to routine maintenance activities such as asset inspections, vegetation management, etc.

Customer Value: Establishing and enhancing access to API's express feeders and their associated ROWs ensures that API can effectively manage those powerlines. This will result in more sustainable ROWs and powerline assets, while also delivering on improved outage response.

By maintaining adequate ROW access, API is able to avoid higher costs to complete both emergency and routine work on its system, which may otherwise involve the need for complex specialized vehicles and equipment and longer travel time for crews.

Reliability:	The quality of access across land to enter onto API ROWs and the ability to traverse alongside the existing power line contributes to outage time leading to restore of service. The quality of the access can further affect the costs of on-going maintenance activities. Poor access will cause O&M costs to be higher than sections with better access.

2. Investment Drivers

The primary driver for this program is the support of system capital and maintenance investments and activities. Safe and reliable access to these powerlines and ROWs allows API to perform routine work, such as line upgrades/replacements, vegetation maintenance, line inspections, etc. This in turn ensures that our powerline and ROW assets are being managed in accordance with API AM objectives. These express feeders are generally located along a forested backline, which results in an inherent risk associated with wildfires if the powerline and the vegetation in and around the powerline is not sufficiently maintained.

Safety:	This program is expected to improve worker safety by reducing the risks associated with the current methods of accessing certain line sections (helicopter, snowmachine, walking long distances), sometimes in rugged terrain (sometimes swampy, rocky, etc.). Planned locations of access allow workers to be better prepared for hazards they may encounter by limiting the number of unknown obstacles they will meet. Ensuring that API has access to our powerline and ROWs ensures that API's AM and VM objectives are being adhered to and that the risks associated with wildfire are being reasonably mitigated.
Cyber Security:	Not applicable
Grid Innovation:	Not applicable
Environmental:	Where applicable, API will involve the MNRF and First Nations in the review of any proposed new access to ensure that the environmental impacts are minimized. In some cases, API expects that creating alternatives to existing access locations and/or access methods will reduce the future environmental impacts of capital projects, inspection and maintenance programs and outage response. Alternatively, unplanned access during emergencies may lead to unintended environmental impacts.
Statutory/Regulatory:	Not applicable

3. Investment Justification

Evidence of Accepted Distributor Practice:	It is common practice at API to have establish trails or agreements with landowner for accessing over private property, etc.
Cost-to-Benefit Analysis:	A do-nothing will result in API not being able to effectively access all its powerlines and ROWs, which would likely result in delayed maintenance activities, as well as higher costs to perform these activities. Investing in trails (new and improvement), helipads for the most remote locations, etc. will ensure API has reasonable year-round access to all its powerlines and ROWs.
Historical Investments and Observed Outcomes:	Historical investment in access has been supportive of API's operations in being able to effectively access its ROW and powerlines.
Substantially Exceeding Materiality Threshold:	Not applicable.

5.4.2.4.4.2 Transportation & Work Equipment

A. General Information on the Project/Program

1. **Overview**

   This program includes all costs for the replacement of fleet assets that are at end of life. Investment in fleet replacements is planned at a sustaining pace based on an optimized lifecycle management approach for each fleet item. This approach results in a sustainable fleet program that provides operational staff with a reliable complement of vehicles, with a consistent age profile over time. The resulting annual capital and maintenance costs are predictable and the impact on other projects or programs due to urgent unexpected replacement or repairs is minimized.

2. **Key Project Timing**

Start Date:	January 1, 2025
In-Service Date:	December 31, 2029
Key factors that may affect timing:	Delivery is subject to manufacturer scheduled and lead time. Large fleet vehicles can have procurement lead times of up to 12-24 months.

3. **Total Expenditures**

Table 4.42: Total Planned Expenditures – Transportation & Work Equipment ($000's)

	2025	2026	2027	2028	2029
Capex (Gross)	1,207	958	1,140	1,130	1,190
CIAC	-	-	-	-	-
Capex (Net)	1,207	958	1,140	1,130	1,190

4. Comparative Historical Expenditures

Table 4.43: Total Historical Expenditures - Transportation & Work Equipment ($000's)

	2020	2021	2022	2023	2024
Capex (Gross)	785	500	139	1,145	585
CIAC	-	-	-	-	-
Capex (Net)	785	500	139	1,145	585

5. Investment Priority

Discretionary Project #2 - The overall requirement to maintain an adequate fleet complement to meet API's day-to-day business requirements is among the highest priority programs within the General Plant category.

6. Alternatives Considered

Alternatives are considered for each fleet replacement and selected based on ensuring API is receiving the most cost-effective option. In general, a do-nothing option would consist of delaying replacement and extending the useful life of that asset. For older fleet assets, this approach generally result in significant increase in maintenance that is required to keep fleet vehicles in sufficient working condition. During the times when maintenance is occurring, these vehicles are unavailable, which present increased risk to API Operations in the management of its distribution system and ensuring that API is meeting customer expectations in terms of responsiveness. As a result of this, API generally considers a do-nothing approach not viable given the criticality and importance of its fleet assets.

7. Cost-to-Benefit Analysis

Not applicable

B. Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

Efficiency: Sustained replacement of fleet assets on predictable cycles with consistent year over year spending will result in the most efficient use of internal resources and the lowest program costs in the long term. API's fleet replacement program also balances the relationship between fleet capital and maintenance costs. For fleet purchases, API follows a competitive procurement that aims to ensure cost-effectiveness.

Customer Value: Maintaining an appropriate, adequate, and sustainable fleet ensures that API is positioned to perform a varying level of operational activities, such as outage response, customer connections, preventative and proactive inspection maintenance, etc.

Reliability: The investment in API's replacement of fleet mitigates the risk that vehicles are unavailable to support a prompt outage response when required.

2. Investment Drivers

The primary driver for this program is the replacement of end-of-life fleet assets at a rate that is sustainable with relatively consistent annual spending. An adequate fleet is required to support API's capital and O&M programs, as well as for outage response. The overall type, age and condition of fleet assets is the primary source of information used to justify this program.

Safety: API's overall lifecycle management of fleet assets results in the availability of safe, reliable vehicles to support operational activities.

Cyber Security: Not applicable.

Grid Innovation: Not applicable.

Environmental: Newer fleet assets are generally more fuel efficient than the units being replaced. As a result, API's fleet is expected to become more fuel efficient over time.

Statutory/Regulatory: Not applicable.

3. Investment Justification

Evidence of Accepted Distributor Practice: API has developed and maintains a Fleet plan that is based on a sustained approach to tracking current Fleet conditions and managing replacement and maintenance schedules.

Cost-to-Benefit Analysis: Alternatives are considered for each fleet replacement and selected based on ensuring API is receiving the most cost-effective option. These are typically achieved through a competitive selection process.

Historical Investments and Observed Outcomes:	API has historically budgeted for and investing in its fleet replacement plans. These investments and future investments will allow ensure that API has the required fleet to support its operations.
Substantially Exceeding Materiality Threshold:	Yes

Investment in fleet replacements is planned at a sustaining pace based on an optimized lifecycle management approach for each fleet item. This approach results in a sustainable fleet program that provides operational staff with a reliable complement of vehicles, with a consistent age profile over time. The resulting annual capital and maintenance costs are predictable and the impact on other projects or programs due to urgent unexpected replacement or repairs is minimized. API's planned expenditures for Fleet replacement accounts for the increased inflationary cost than began around the COVID-19 pandemic. From 2020-2023, there has been inflationary cost increase ranging from about 25-60% for our smaller fleet (such as ½ ton and ¾ pickups). API has also accounted for the increase associated with our heavy fleet (radial boom-derrick, material handler, etc.), which has ranged from 30-50%.

5.4.2.4.4.3 Buildings, Facilities & Yards

A. General Information on the Project/Program

1. **Overview**

   This program includes all costs associated with buildings and facility-related investments. API has one main facility and two remote work centres out of which API's manages its operations. The main facility (Sault Facility) houses the office and field staff who undertake the daily operations, including customer service, engineering, technical services, forestry, lines and material management, while API's two remote work centre locations (Wawa work centre and Desbarats work centre) house a portion of API's line department. The remote work centres are strategically located within API's service territory to ensure and enable API to more effectively respond to regional needs, such as customer connections, outage response, etc. Investments in these facilities ensure that API operations can continue to run effectively

2. **Key Project Timing**

Start Date:	January 1, 2025
In-Service Date:	December 31, 2029
Key factors that may affect timing:	If new projects of higher priority in other categories (e.g. System Access) are developed, then this may mean API will have to adjust its plan for higher priority projects.

3. **Total Expenditures**

Table 4.44: Total Planned Expenditures – Buildings, Facilities & Yards ($000's)

	2025	2026	2027	2028	2029
Capex (Gross)	214	217	174	177	179
CIAC	-	-	-	-	-
Capex (Net)	214	217	174	177	179

4. Comparative Historical Expenditures

Table 4.45: Total Historical Expenditures – Buildings, Facilities & Yards ($000's)

	2020	2021	2022	2023	2024
Capex (Gross)	135	53	166	25	154
CIAC	-	-	-	-	-
Capex (Net)	135	53	166	25	154

5. Investment Priority

Discretionary Project #9 - Investments in this program are relatively discretionary as compared to most other projects and programs, and as a result are given less priority. While justifications could be made for investments driven primarily by operability, safety, outage reliability and customer service, API is mindful of the associated rate impacts and resource requirements. Planned spending on this program is therefore relatively low in comparison to other programs and projects included in the 5-year plan.

6. Alternatives Considered

Alternatives are considered on a case-by-case basis depending on the need that's been identified.

7. Cost-to-Benefit Analysis

When specific needs are identified, API considers alternatives where applicable, and will generally select an alternative based on a least-cost option. API will consider a do-nothing option depending on the need.

B. Evaluation Criteria and Information Requirements for Each Project/Program

1. Efficiency, Customer Value, Reliability

Efficiency: Investments tied to facilities, buildings and yards indirectly result in improved efficiencies and overall productivity. Investments are generally aimed at ensuring that API staff can continue working in a safe, comfortable, and ergonomic environment. In these types of investment, API follows a competitive procurement that aims to ensure cost-effectiveness.

Customer Value:	A safe, comfortable, and ergonomic environment ensures that API staff can undertake their work effectively and provide the best levels of customer service.
Reliability:	While there is no direct impact on outage reliability, these investment supports API's field staff in responding to outages by ensuring our facilities are kept up to date and remain efficient in the everyday operations of API.

2. Investment Drivers

The primary driver for this investment program is renewing assets associated with its facility operations and not directly part of API's distribution system.

Safety:	These investments are generally aimed at ensuring that API staff can continue working in a safe, comfortable, and ergonomic environment.
Cyber Security:	There are no investments geared specifically to cyber security.
Grid Innovation:	There is nothing innovative with the proposed investment.
Environmental:	In general, these aren't environmentally driven.
Statutory/Regulatory:	This is not applicable.

3. Investment Justification

Evidence of Accepted Distributor Practice:	API has historically invested in its facilities as it relates to the ongoing upkeep of its buildings, facilities, and yards. API performs regular facility inspections.
Cost-to-Benefit Analysis:	When specific needs are identified, API considers alternatives where applicable, and will generally select an alternative based on a least-cost option. API will consider a do-nothing option depending on the need.
Historical Investments and Observed Outcomes:	Historical investments have resulted in API being capable of continuing to perform its critical services, ensured that API's facilities operate effectively and addressed health and safety defects identified through regular inspections.
Substantially Exceeding Materiality Threshold:	This is not applicable.

Algoma Power Inc.

Distribution System Plan

Appendix A

Asset Management Program

April 2024

TABLE OF CONTENTS

LIST OF APPENDICES

LIST OF ACRONYMS

AMP	Asset Management Program
API	Algoma Power Inc.
CIA	Connection Impact Assessment
CSA	Canadian Standards Association
CT	Current Transformer
CVP	Construction Verification Program
DGA	Dissolved Gas Analysis
DS	Distribution Substation
DSC	Distribution System Code
DSP	Distribution System Plan
ESA	Electrical Safety Authority
EUSA	Electrical Utility Safety Association
FIT	Feed in Tariff
HOSSM	Hydro One Sault Ste. Marie
IESO	Independent Electrical System Operator
MA	Managed Assets
MC	Measurement Canada
MOECP	Ministry of Environment, Conservation and Parks
MTO	Ministry of Transportation of Ontario
OHSA	Occupational Health and Safety Act
PEO	Professional Engineers Ontario
PT	Potential Transformer

1 INTRODUCTION

1.1 NON-DISCLOSURE

There are specific sensitive details of information, such as private customer information and confidential future business development plans that are protected by the *Ontario Freedom of Information and Protection of Privacy Act.* Therefore, certain specific details will not be described in this document.

1.2 OBJECTIVE

The fundamental objective of the Algoma Power Inc. (**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 costs, in the short and long terms.

This objective is met through the application of thorough and sound planning, prudent, justified budgeting, and ongoing oversight, documentation, and review of all efforts and expenditures while implementing the documented capital, and operating plans.

API will maintain a comprehensive AMP, which outlines the operating and capital processes, activities, and expenditures to ensure that API continues to provide the safe, reliable, and efficient distribution of electricity to its customers.

There are three key principles that are integral to the API AMP:

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

These key principles are derived from safety considerations; acts, regulations, codes and guidelines; good utility practice; and customer expectations.

1.3 SCOPE

The scope of the API AMP includes the long-term management of distribution assets owned by API.

This document is intended to provide a synopsis of the AMP at API. For reasons of brevity and confidentiality, this document does not attempt to encompass all of the information and activities that fully define the AMP, as described later. The purpose of this document is to provide an 'objective summary' with sufficient detail to supply an overall understanding of API's asset management efforts.

1.4 ACTS, REGULATIONS, CODES AND GUIDES

The following is a partial listing of the acts, regulation, codes and guidelines that direct API's operations:

1) The principal regulator guiding API's practices is the OEB. Under the guiding principles set out in the *Electricity Act, 1998* (the "Electricity Act"), the OEB has established a Distribution System Code (**DSC**) that defines how and under what conditions, a utility is to provide service and interact with its customers. It is prescriptive in nature and deals with virtually every aspect of utility operations including such things as connections and expansions, standards of business practice and conduct, quality of supply (reliability), infrastructure inspections, metering and conditions of service. The licensed distributor's conditions of service are set out by the distributor in a document that is filed with the OEB and posted on the distributor's web site.
2) A second entity is the Electrical Safety Authority (**ESA**). The ESA derives its authority from the Electricity Act. The ESA is responsible for ensuring the safety of all electrical installations in the province of Ontario for systems operating at a voltage less than 50kV under Ontario Regulation 22/04. Under the regulations, every electrical installation and associated equipment must be installed in accordance with a design or standard approved by a professional engineer. Every year there is a compliance audit conducted by an outside agency and the utility is required to sign a regulatory declaration stipulating that it has complied with the regulations.
3) The Occupational Health and Safety Act (**OHSA**) governs how work is performed and is enforced by the Ministry of Labour. The act is comprehensive and forms part of every job. At API the health and safety of employees and customers is given top priority and there is an active joint health and safety committee that oversees operational activities. There is also a Central Environmental and Safety Committee (CESC) to centrally coordinate safety and reporting activities. Extensive training programs ensure that staff is competent to perform their duties. Every effort is made to make sure that employees have the right tools and protective equipment to do their job safely.
4) The Ministry of Environment, Conservation and Parks (**MOECP**) is responsible for regulating how hazardous waste is handled. API has registered hazardous waste storage sites in its service territories and deals with a variety of substances in the course of building, operating and maintaining the electric distribution system.
5) Measurement Canada (**MC**) regulates API's revenue metering activities.
6) The Ministry of Transportation (**MTO**) is the governing body with respect to activities associated with the fleet. It also mandates the requirements for traffic control at worksites that are near or on roadways.
7) API is an engineering focused company and as such is governed in its activities by the *Professional Engineers Ontario Act* (**PEO**). The PEO regulates codes of practice and ethics within the engineering staff at the utility.
8) API owns distribution system assets in a number of municipalities located in Northern Ontario. The needs, rules and by-laws of these municipalities must be respected.
9) There are a host of other entities that mandate rules, programs and work practices. These include, but are not limited to the Electrical Utility Safety Association (**EUSA**); the Independent Electric System Operator (**IESO**); the Canadian Coast Guard; the Ministry of Natural Resources and Forestry, the Department of Fisheries and Oceans, Measurement Canada, CN and CP Rails; various Conservation Authorities; and the Canadian Standards Association (**CSA**).

All of the above impact planning, and ensure that API follows Good Utility Practice (**GUP**) in providing exceptional customer service.

1.5 Documents that Support the Asset Management Program

API has develop a sustainable AMP based on internal infrastructure studies as well as industry leading best practice guidelines. Internal studies may contain proprietary information, and are therefore not included in the AMP for general distribution. The following are examples of reports and studies supporting the AMP with a short description of each:

1.5.1 System Planning

System planning is broken into two segments; long term (15-year outlook) and medium term (5-year plan). Annually a 15-year forecast is performed identifying significant capital and maintenance programs and anticipated durations. Each program is identified with a broad scope description with cost projections. A program is intended to identify a component of the distribution network that will have a significant impact on O&M or capital investments. Regional planning with the transmitter is also intended to be included as an integral part of the long term planning process.

Medium term planning occurs subsequent to each annual long term planning review. It is at this point that the capital and maintenance programs and projects are identified and included as part of API's Distribution System Plan (**DSP**). Section 5 of this document provides more detail on the medium and long-term planning processes.

1.5.2 The API Construction Verification Program (CVP)

As required by Ontario Regulation 22/04, API performs all material procurement, project design, construction, and follow-up inspections in accordance with ESA-approved CVP, utilizing only professionally approved construction standards. This process is reviewed and updated on an ongoing basis.

1.5.3 Municipal Presentations

API meets with each municipality that is serves, through an annual presentation to their council. The presentation covers API capital and maintenance plan for the current year as well as serves as the municipality's opportunity to respond to the presented plan. It also provides municipalities an opportunity to inform API of any municipal plans (new development, streetlight projects, etc.) that may impact API's system.

API hosts an annual Roads Supervisor meeting where members of each municipal roads department meet with API staff to discuss current and future work projects. Timelines and project scopes are discussed with efforts to both streamline each project and minimize impacts to the area residents.

1.5.4 Distribution System and Substation Assessments

A comprehensive review of system and substation equipment and performance indicators is used to optimize preventative maintenance programs and to drive future capital plans. Key indicators such reliability, failure history, failure impacts, test results, safety factors and age are considered in the prioritization of capital and maintenance activities.

1.5.5 Predictive Maintenance Reports

Results from predictive maintenance techniques such as infrared scanning, oil testing, conductor testing, pole testing, and insulation testing are used to assess the condition of individual system components. The overall assessment forms the basis for the development of maintenance, refurbishment, intervention, and equipment retirement strategies.

1.5.6 Technical Studies

Various technical reports are prepared on an as-needed basis, the results of which are incorporated into the AMP as required. An example would be a Connection Impact Assessment (**CIA**) prepared for a distributed generation applicant under Ontario's Feed-In-Tariff (**FIT**) program.

1.5.7 Distribution System Information

API maintains its system asset inventory through diverse data records (and reports) such as relational databases, Computer-Aided Design (**CAD**) drawings, Geographical Information System (**GIS**) records, and electronic spreadsheets. In addition, API manages a variety of paper-based maintenance and inspection records.

API has been transitioning to the FortisOntario SAP enterprise resource planning software, as well as implementing a GIS system. It is expected that many of API's asset records, reports and assessments will be migrated to these systems in the coming years. These systems are expected to assist in providing more in-depth reporting and analysis of asset records and asset performance.

2 OVERVIEW

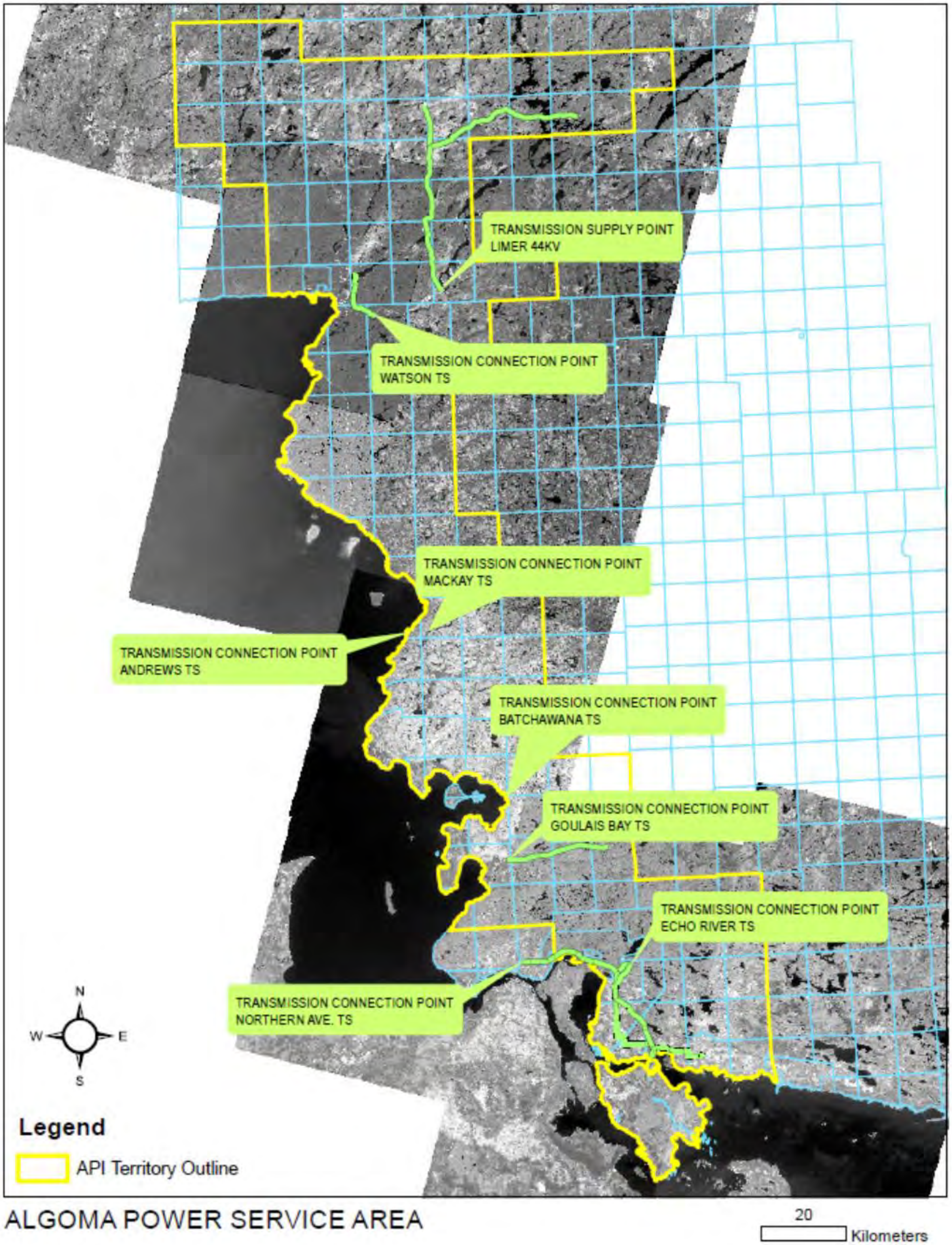
2.1 GENERAL OVERVIEW OF THE API SYSTEM

API owns and operates the electricity distribution system in portions of the district of Algoma, serving approximately 12,000 customers located in a number of townships and First Nations territories. The service territory includes an area of approximately 14,200 square kilometers, and 1861 km of distribution circuits, over 99% of which are overhead lines. The API system meets a winter peak demand of approximately 40 MW.

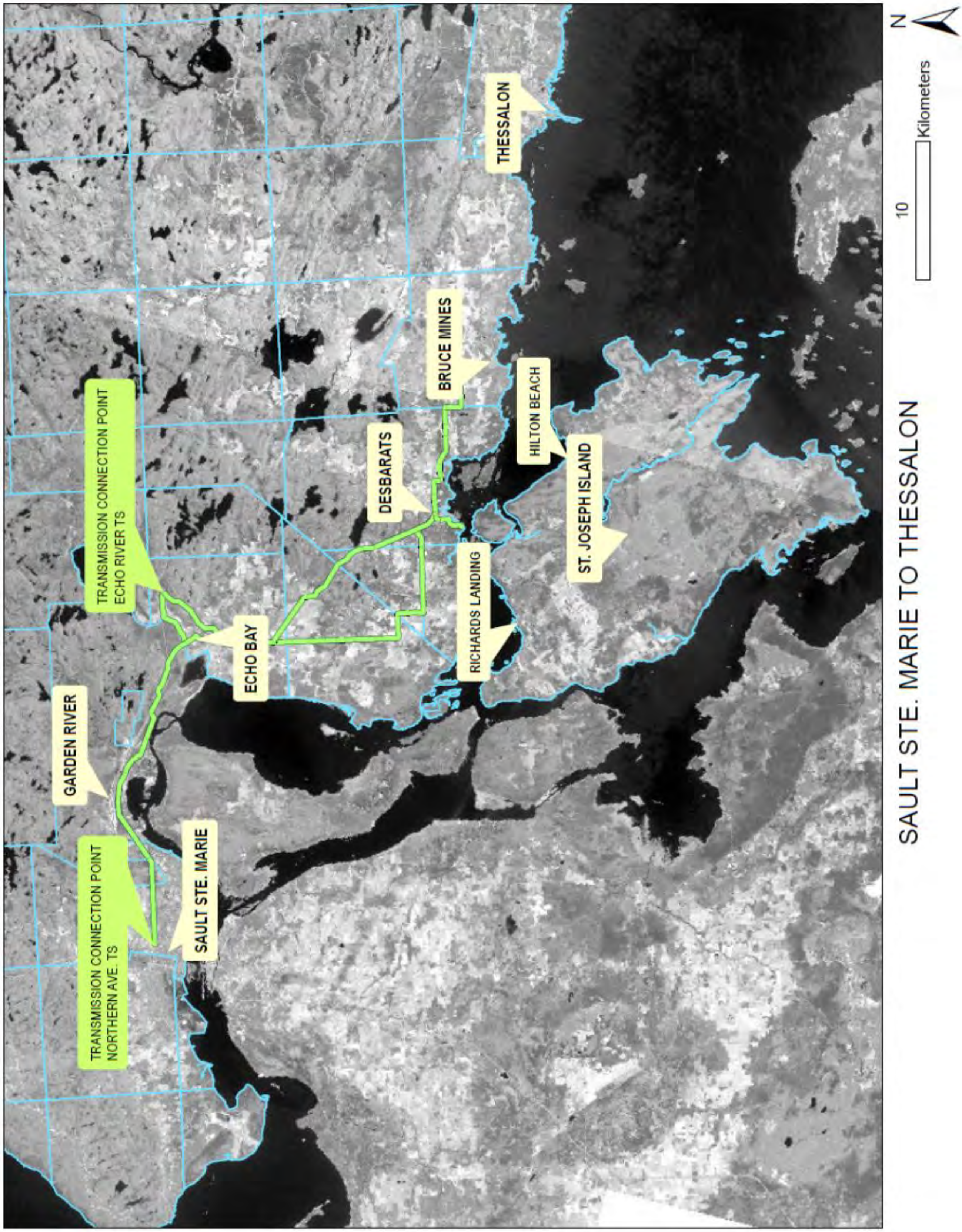
API is comprised of several distribution regions operating independent of each other in the following areas interconnected either by API's own 34.5 kV and 44 kV systems or independently supplied through various connection points by a licensed transmitter's substations. The list and service area maps below provide a summary of these operating regions:

1) Sault Ste. Marie to Thessalon (2 Transmission supply points & API 34.5 kV supply)

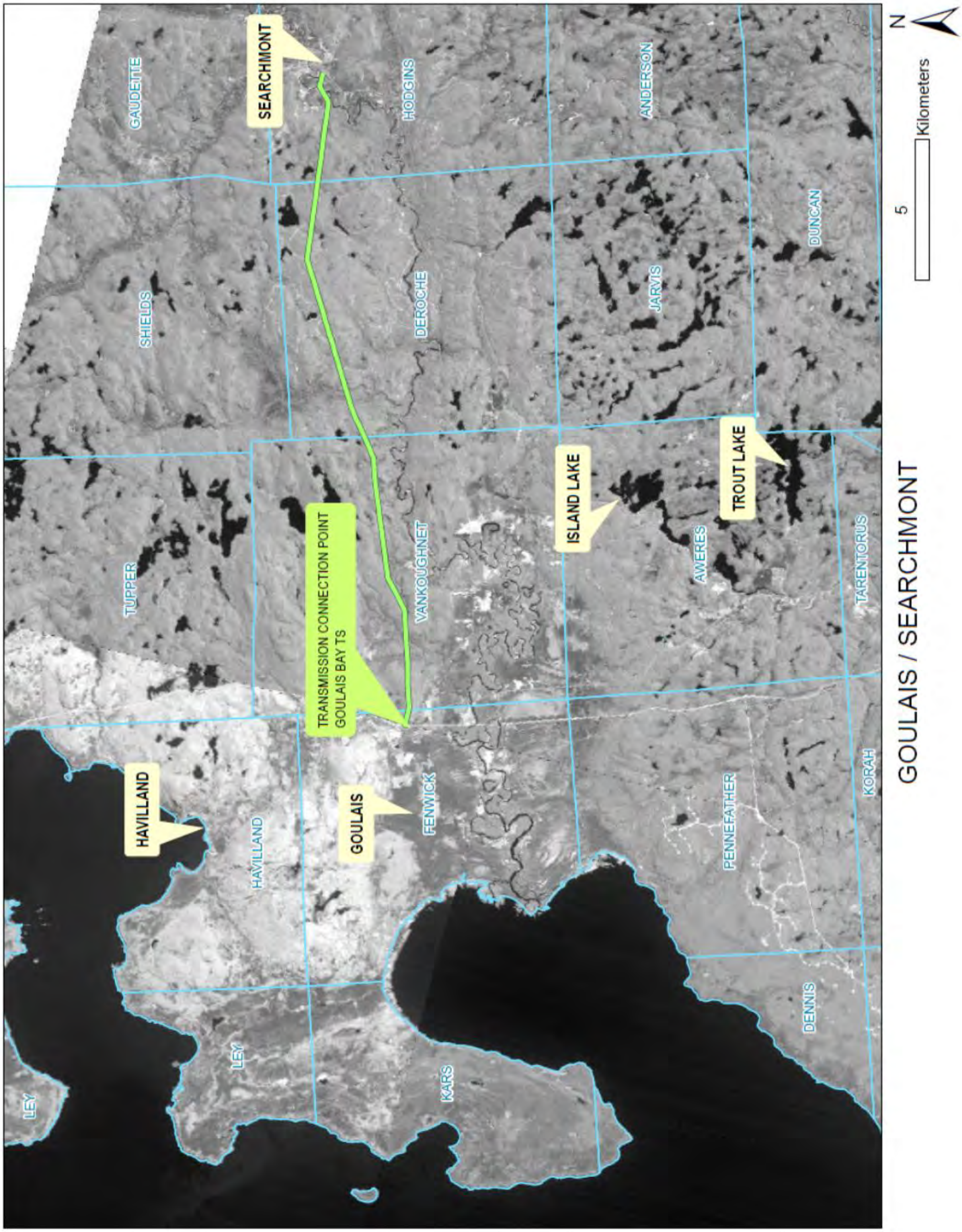
2) Goulais / Searchmont (Transmission supply point)
3) Batchawana (Transmission supply point)
4) Montreal River (Transmission supply point)
5) McKay (Transmission supply point)
6) Wawa and surrounding area (2 Transmission supply points & 34.5 kV supply)
7) Highway 101 to Whitefish Lake (3 API 44 kV supply points)
8) Hawk Junction (API 44 kV supply)
9) Goudreau (API 44 kV supply)
10) Lochalsh (API 44 kV supply)
11) Missanabie (API 44 kV supply)
12) Dubreuilville (API 44 kV supply)

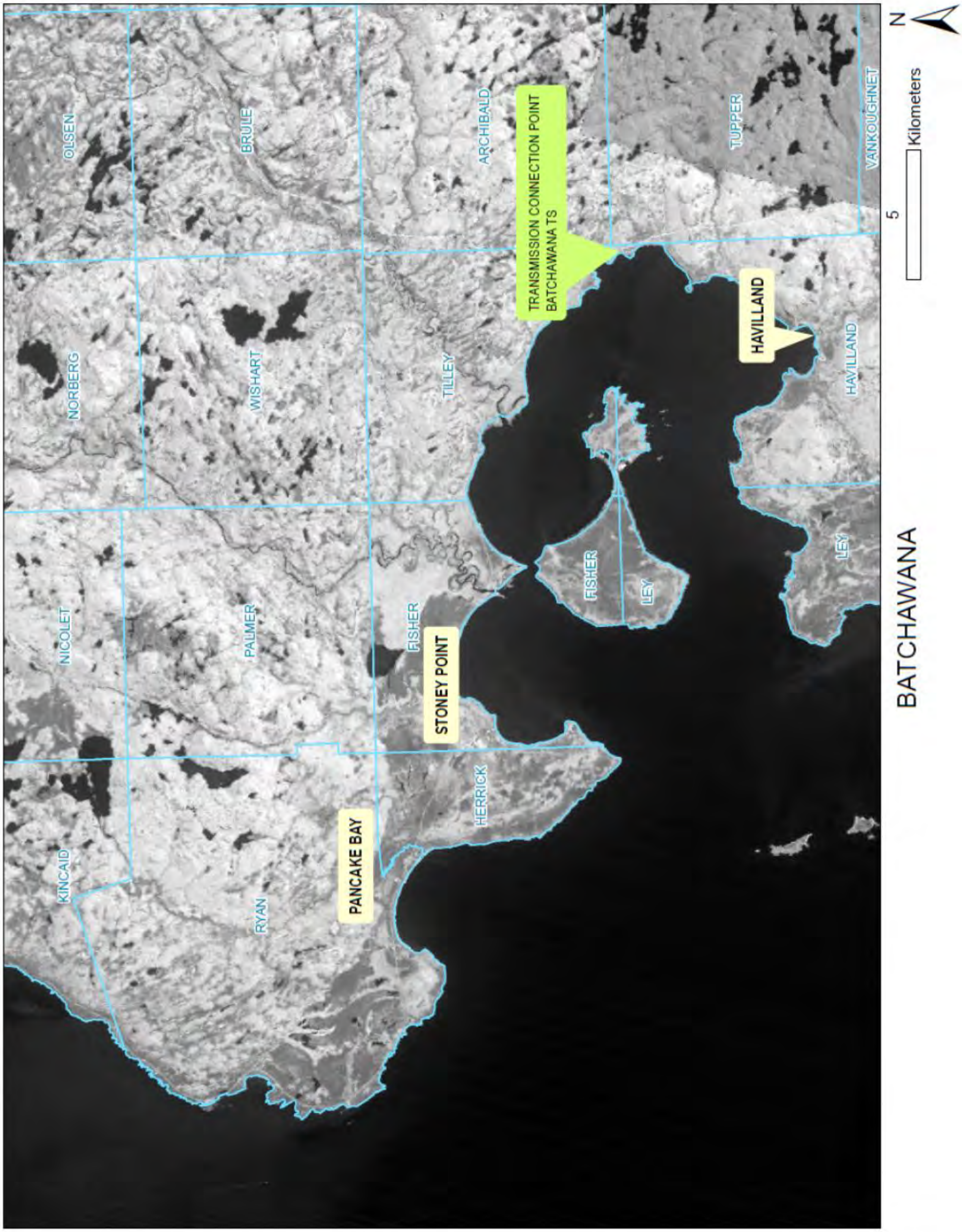


ALGOMA POWER SERVICE AREA



SAULT STE. MARIE TO THESSALON


GOULAIS / SEARCHMONT
N
5
Kilometers
SEARCHMONT
TRANSMISSION CONNECTION POINT
GOULAIS BAY TS
HAVILLAND
GOULAIS
ISLAND LAKE
TROUT LAKE
GAUDETTE
HODGINS
ANDERSON
SHIELDS
DEROCHE
JARVIS
DUNCAN
TUPPER
VANKOUGHNET
AWERES
TARENTORUS
HAVILLAND
FENWICK
PENNEFATHER
KORAH
LEY
KARS
DENNIS


BATCHAWANA
TRANSMISSION CONNECTION POINT
BATCHAWANA TS
HAVILLAND
STONEY POINT
PANCAKE BAY
OLSEN
BRULE
ARCHIBALD
TUPPER
VANKOUGHNET
NORBERG
WISHART
TILLEY
HAVILLAND
NICOLET
PALMER
FISHER
FISHER
LEY
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KINCAID
RYAN
HERRICK
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Kilometers
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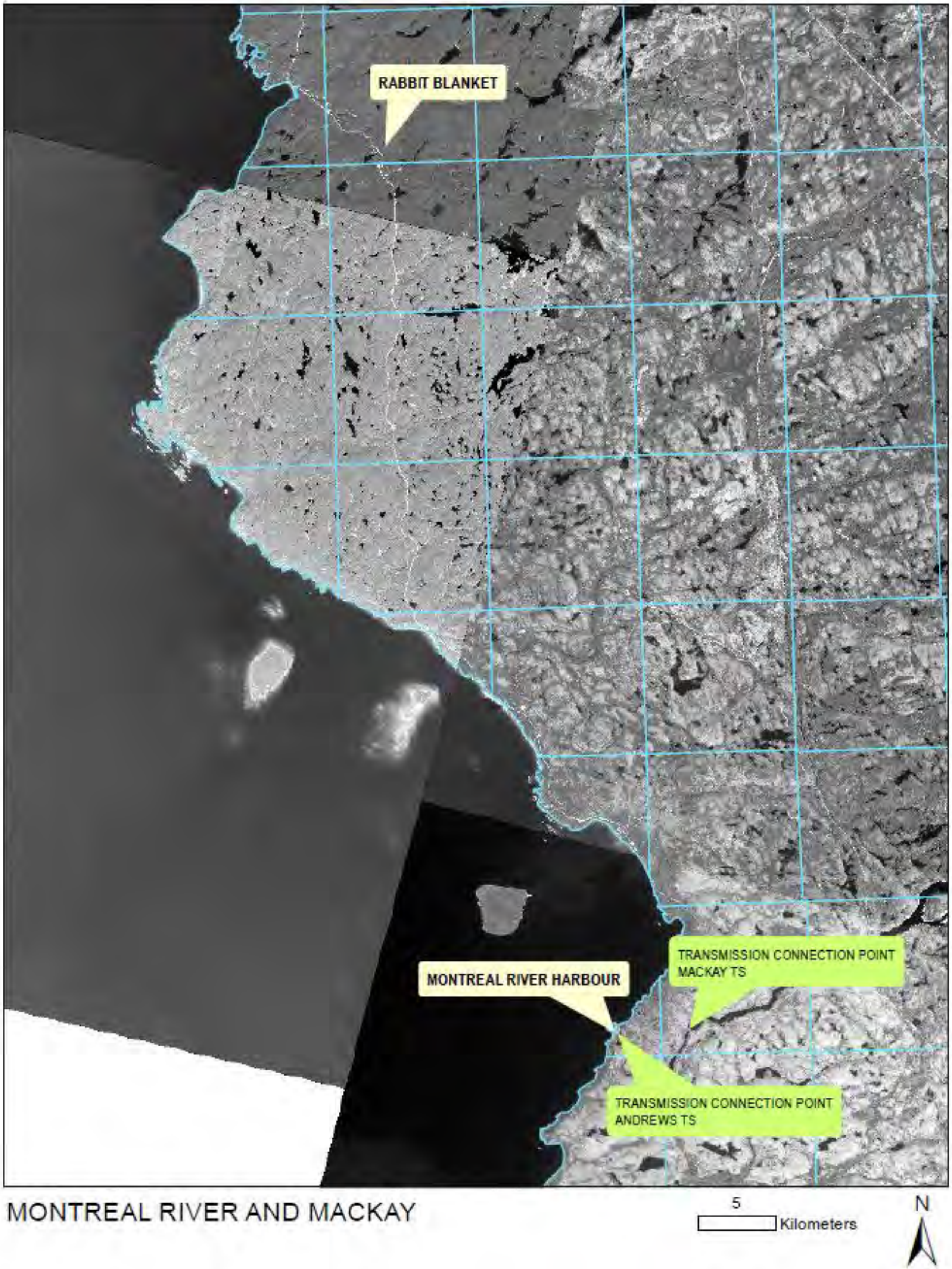
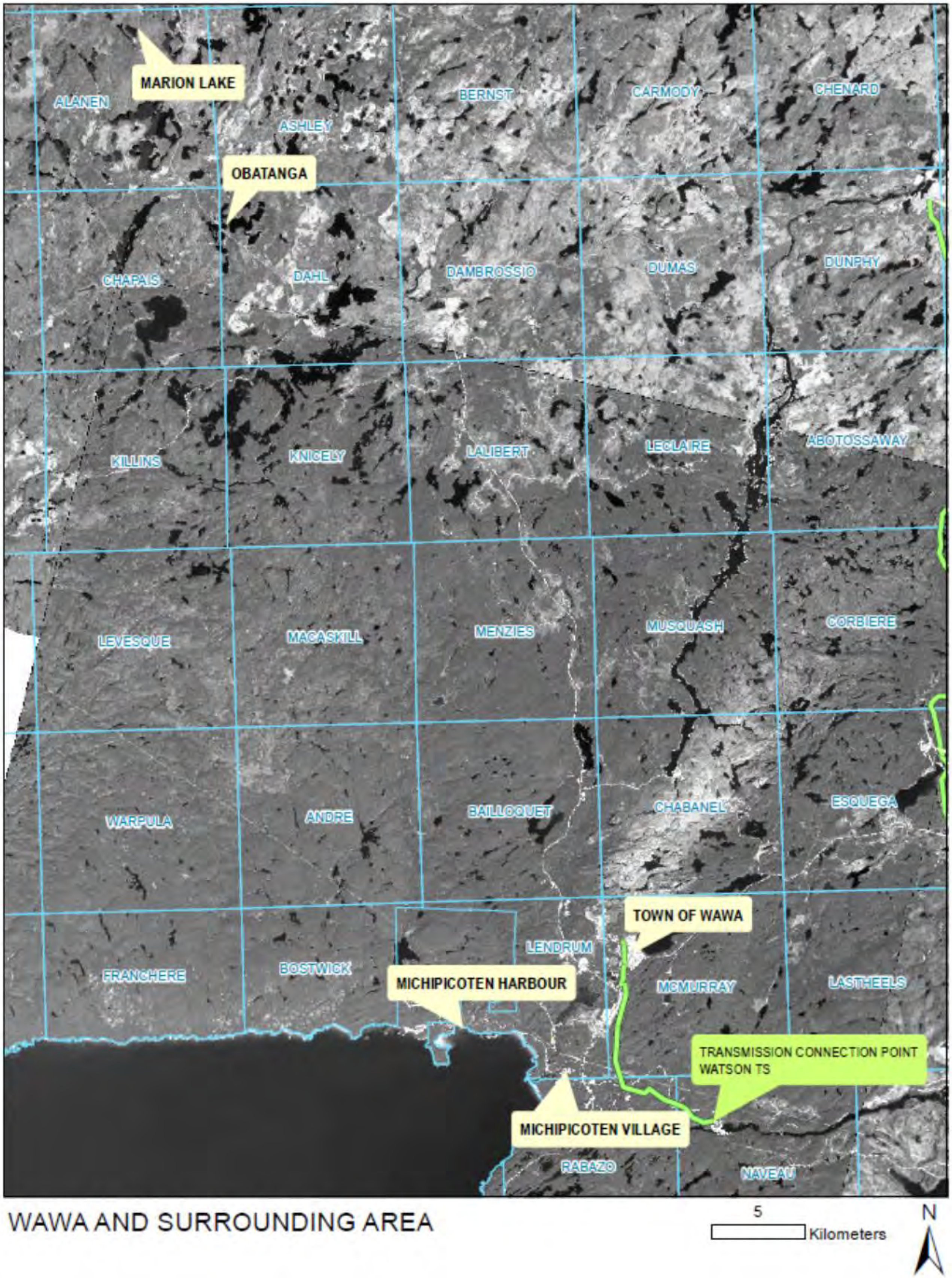

RABBIT BLANKET
MONTREAL RIVER HARBOUR
TRANSMISSION CONNECTION POINT
MACKAY TS
TRANSMISSION CONNECTION POINT
ANDREWS TS
MONTREAL RIVER AND MACKAY
5
Kilometers
N


MARION LAKE
ALANEN
ASHLEY
BERNST
CARMODY
CHENARD
OBATANGA
CHAPAIS
DAHL
DAMBROSSIO
DUMAS
DUNPHY
KILLINS
KNICELY
LALIBERT
LECLAIRE
ABOTOSSAWAY
LEVESQUE
MACASKILL
MENZIES
MUSQUASH
CORBIERE
WARPULA
ANDRE
BAILLOQUET
CHABANEL
ESQUEGA
TOWN OF WAWA
LENDRUM
FRANCHERE
BOSTWICK
MICHIPICOTEN HARBOUR
MCMURRAY
LASTHEELS
TRANSMISSION CONNECTION POINT
WATSON TS
MICHIPICOTEN VILLAGE
RABAZO
NAVEAU
WAWA AND SURROUNDING AREA
5
Kilometers
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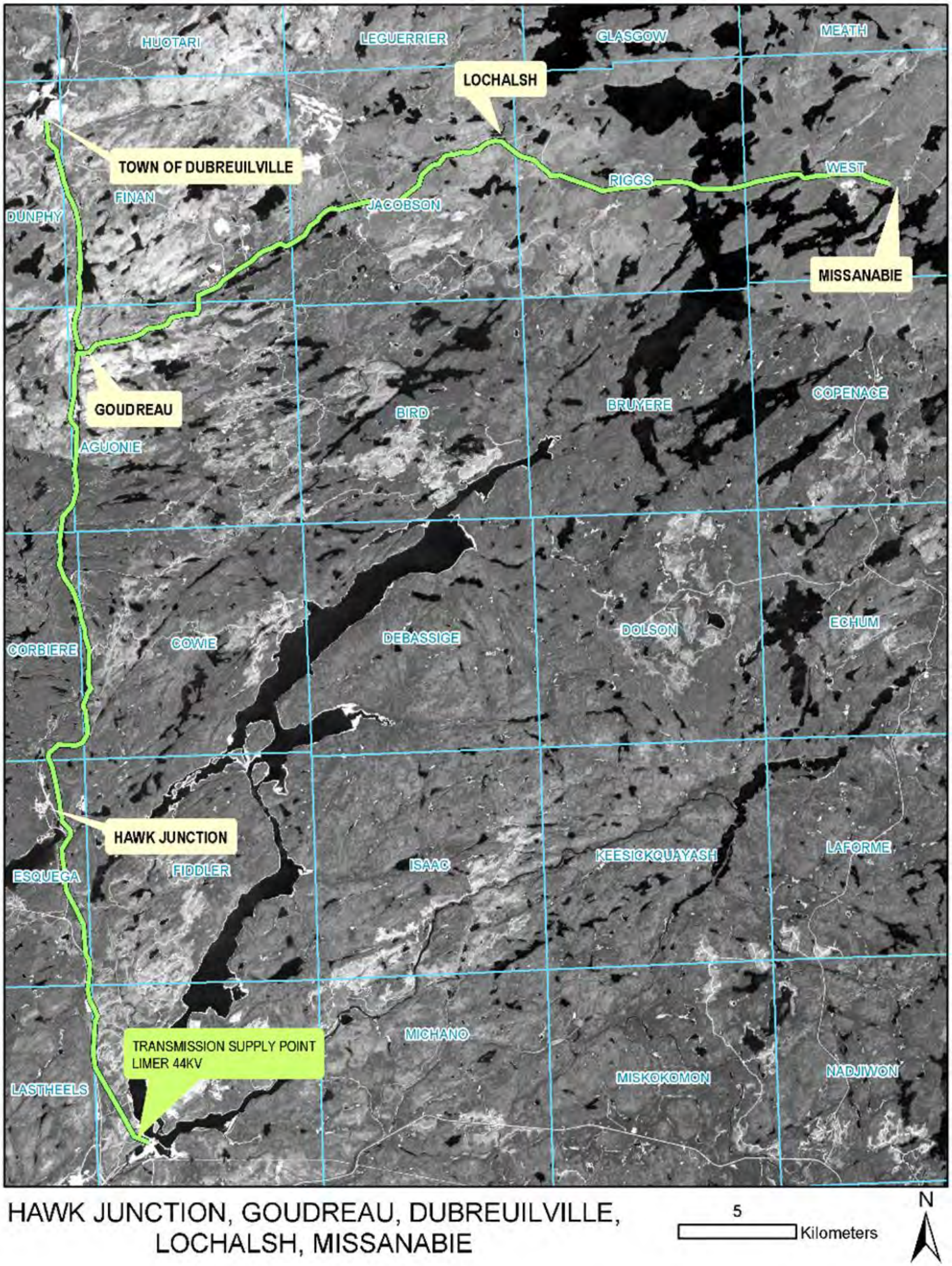


HAWK JUNCTION, GOUDREAU, DUBREUILVILLE, LOCHALSH, MISSANABIE

2.2 SUPPLY POINTS FROM THE IESO-CONTROLLED GRID

The API distribution system is supplied from the Hydro One Sault Ste. Marie (**HOSSM**)-owned transmission system through eight delivery points located at seven different transmission substations and on a HOSSM-owned 44 kV transmission circuit. Three of the HOSSM-owned transmission stations and the 44 kV transmission circuit supply 34.5 kV and 44 kV API-owned express feeders. These express feeders supply seven distribution substations (**DS**) as well as several pole-mounted step-down transformers. The other HOSSM-owned transmission substations supply distribution feeders directly at lower distribution-level voltages.

2.3 DISTRIBUTION LINES BY VOLTAGE CLASS

There are a wide variety of voltages presently in use on API's distribution system, including 44 kV, 34.5 kV, 24.9Y/14.4 kV, 12.5Y/7.2 kV, 8.3Y/4.8 kV, 4.16Y/2.4 kV, 12 kV and 4.8 kV.

- **44 kV** – A single 44 kV radial feeder is supplied as a tap from a 44 kV transmission circuit in rural areas east of Wawa. The feeder supplies three-distribution substations, six pole-mounted step-down transformers, and a number of customer-owned substations connected directly at 44 kV.

- **34.5 kV** – API operates two 34.5 kV systems in its service territory, one in the Wawa area and the other in the area east of Sault Ste. Marie. The Wawa system consists of two 34.5 kV feeders running in parallel from the D.A Watson transmission substation to the town of Wawa, where they join at the Wawa No.2 substation to supply a 34.5 kV bus in a main-alternate configuration. These feeders supply the two distribution substations in the town of Wawa as well as a single-phase step-down transformer supplying a small load in a rural area outside the town. The system east of Sault Ste. Marie consists of three 34.5 kV feeders supplied from two separate transmission substations. These feeders supply four API distribution substations, and three customer-owned substations connected directly at 34.5 kV. The feeders are normally operated radially; however, the system contains many normally open feeder interties, allowing load transfers between feeders and providing alternate supplies to many of the distribution substations. In general, many of API's larger load centres are located at long distances from its transmission supply points and use of the 34.5 kV systems allows these areas to be supplied with acceptable voltage levels and lower overall system losses than would be possible with direct supply at lower distribution-level voltages.

- **24.9Y/14.4 kV** – This voltage level is used in areas where use of API's predominant voltage of 12.5Y/7.2 kV would result in unacceptable voltage levels or excessive line losses on the distribution system. The largest system in this voltage class is located on St. Joseph Island, which serves almost 1800 customers spread over an area of 365 square kilometres. This voltage level is also used on three other feeders, either as a direct supply from a transmission station at this voltage level, or through the use of step-up transformers from a 12.5Y/7.2 kV feeder.

- **12.5Y/7.2 kV** – This voltage level serves slightly more than half of API's customer. In most areas, this voltage level can provide acceptable voltage profiles while reducing losses as compared to lower voltages previously used. As this is a common voltage level, equipment is readily available at reasonable costs and with minimal lead-time. Most of the distribution feeders east of Sault Ste. Marie (with the exception of St Joseph Island) are supplied at this voltage level via 34.5 kV to 12.5Y/7.2 kV substations. This voltage level is also supplied directly from two transmission supply points North of Sault Ste. Marie, and on a feeder from one of the distribution substations in Wawa that supplies the rural load outside of the town.

- **12 kV** – This voltage is used only on a feeder supplying customers within the city of Sault Ste. Marie. This feeder supplies the six locations within Sault Ste. Marie.

- **8.3Y/4.8 kV and 4.8 kV Delta** – Most areas using 8.3Y/4.8 kV in the area east of Sault Ste. Marie have been converted to 12.5Y/7.2 kV, or 24.9Y/14.4 kV in the case of St. Joseph Island. Some small pockets of single-phase 4.8 kV remain supplied by single-phase step-down transformers from the other voltages. These areas will continue to be converted to higher voltages in conjunction with conductor replacement, pole replacement or other capital programs in these areas in order to improve voltages and reduce losses.

  The entire 4.8 kV Delta system in the Town of Wawa was converted to 8.3Y/4.8 kV in 2009. Use of the 8.3Y/4.8 kV voltage level in this case was considered the most economical and practical choice for converting the 4.8 kV delta system. This allowed the entire conversion to take place over a period of months rather than years, with minimal service interruptions. It also allowed most of the existing distribution transformers as well as a large substation transformer to be re-used and will allow 4.8 kV transformers removed from other areas to be transferred to Wawa for future use. As there are 12.5Y/7.2 kV feeders in rural areas surrounding the town, use of the 8.3Y/4.8 kV feeders will be limited to the town site itself.

  There are also a number of lightly loaded feeders being supplied at 8.3Y/4.8 kV or at 4.8 kV single-phase in remote areas near Wawa supplied from API's 44kV subtransmission circuit. Given the extremely small load levels in these areas, and the fact that the Wawa work centre will be required to maintain an inventory of 4.8 kV class equipment for use on feeders within the town, no voltage conversion is planned for these areas in the short-term planning horizon.

- **4.16Y/2.4 kV** – This voltage class is currently in use in the Town of Bruce Mines, east of Sault Ste. Marie as well as in the Town of Dubreuilville. Bruce Mines is currently supplied from a 3-phase 12.47-4.16 step-down bank. The Bruce Mines 4.16 kV system will be gradually converted to 12.47 kV in conjunction with the planned pole replacements.

2.4 Distribution Substations

API presently operates nine distribution substations. Photos and further details of each station are illustrated in Appendix A - "Substations":

API's DS's are generally split between newer and older vintage, with four substations (Wawa#1, Garden River, Bar River, and Desbarats) having been built or upgraded in the last 10 years and the other substations being in the 30-50+ year old range.

2.4.1 List of Distribution Substations by Area

- Wawa and Surrounding Area
  - Wawa #1 DS

- Wawa #2 DS
- Hawk Junction DS (includes two-44 kV voltage regulators)
- Dubreuilville Sub 86 (previously listed as #2 DS)
- Dubreuilville Sub 87 (previously listed as #3 DS)

- Sault Ste. Marie and Surrounding area
  - Garden River DS
  - Bar River DS
- Desbarats and Surrounding Area
  - Desbarats DS
  - Bruce Mines DS

2.5 SUMMARY OF MAJOR DISTRIBUTION ASSETS

2.5.1 Distribution Line Assets

Asset	Quantity
Poles	28,931
Distribution Transformers	5,233
Capacitor Banks	4
Voltage Regulators	12
Reclosers	110
Circuit Breakers	0
Express Feeder Load-Break Switches	7
Total Overhead Line KM	2,100
Total Underground Line KM	21

2.5.2 Distribution Substation Assets

Asset	Quantity
Substations	9
Power Transformers (Banks)	14
Voltage Regulators	2
Reclosers	17
Switches	67
Power Fuses (Sets)	10

2.5.3 Metering Assets

Asset	Quantity
Tower Gateway Base (**TGB**) Stations	8
FlexNet Remote Portal (FRP)	8
FlexNet Network Portal (FNP)	15
AMI Meters	12,239
Interval Meters	69
Wholesale Meters	22

3 DISTRIBUTION ASSETS

3.1 ASSETS CATEGORIES

The distribution assets of API can be broken down into various categories and definitions:

- **Financial (Fixed) Asset**: This is the 'traditional' accounting/finance view of assets, included in various accounts and focusing on financial information such as original cost, current book value, and depreciation amounts.
- **Physical Assets (Components):** This is the 'traditional' operations view of assets, which are actual material parts such as a 45 foot class 4 wood pole, a cross-arm, or a section of 28kV underground primary cable.
- **Managed Asset (MA)**: For purposes of the API AMP, a *Managed Asset* (MA) is an assembly of one or more components tracked and managed as a single entity. For example a single 'Pole' MA might consist of the pole itself in addition to any supporting components such as guy wires and anchors. A framing MA may contain a cross-arm, three 28kV insulators, plus the sundry other approved hardware required. API's various rights of way and land corridors also are identified as managed assets.

API's AMP will focus almost entirely on *Managed Assets* as the effective meaning of 'assets' in the context of this document.

3.2 OVERHEAD AND UNDERGROUND DISTRIBUTION MANAGED ASSETS

3.2.1 Poles

Poles constructed of wood and occasionally resin composites, these form the 'backbone' of the overhead distribution system. Wooden poles are used in over 98 percent of all cases. The poles used in API's distribution systems range in height from 25' (7.6m) to 85' (25.9m). A typical height for a single-circuit three-phase pole is 45' (13.7m). Poles come in several standard 'strengths' known as classes, as defined by CSA specifications.

3.2.2 Framing Assemblies

This MA is the assorted hardware components installed on a pole or structure that provide mechanical support and clearances, and electrical isolation / insulation for the various conductors and equipment required on an overhead distribution line.

It can include cross arms, insulators, brackets, bolts, washers, nuts, and sundry other hardware.

It should be noted that the specific choice of some of these components, such as insulators, will vary depending on the required voltage of the system.

3.2.3 Transformers and Voltage Regulators

Distribution transformers are used to transform electricity from one voltage to another, for example, from 14.4 kV to 120/240 Volts. Overhead (Pole Top) transformer capacity in use at API ranges from 3 to 167 kVA. Padmount transformers range from 15 kVA to 750 kVA

Most distribution transformers change primary voltage (2400V or greater) to one of API's three standard secondary voltages:

1) 120/240V single phase
2) 120/208V three phase
3) 347/600V three phase

Some specialized units, known as step-downs or step-ups, transform one primary voltage to another. These units are generally used to supply portions of API's system that require a legacy voltage, or to supply small remote loads centres from API's 34.5 kV or 44kV express feeders.

Voltage regulators are a form of transformer that automatically maintains line voltages within a narrow specified range and allows API to maintain voltages within CSA standard guidelines on long rural feeders.

3.2.4 Overhead Switches

This type of MA allows for opening and closing, or isolating, of current-carrying components, which either prevents or allows the flow of electricity. Switches can have different characteristics:

1) Gang-operated or single-phase operated: A gang-operated switch, generally a three-phase device, allows all three phases of the switch to be opened or closed at once, often from the ground. Single-phase switches are typically operated using insulated sticks, and are operated one phase at a time.
2) Load-break or Non-load-break: A Load-break switch allows for the interruption of power flow even when a significant amount of current is flowing. Non-load-break switches cannot interrupt large current flows and are more often used in combination with nearby protective devices for providing visual confirmation of isolation.
3) Remote-controlled or locally operated.

3.2.5 Overhead Conductor

Conductors, also called wires, or cables run from pole to pole, or pole to building, and carry the current from the source to the customers. Overhead conductor has several different characteristics:

1) Metal or alloy: older conductors were mostly copper, but most modern applications use aluminum, or aluminum alloys to save weight and cost
2) Size / Gauge: the size of the wire is matched to the expected maximum current required. Larger conductors cost more, weigh more, and can take longer to install, but carry more current and can have longer useful lives
3) Insulation: some conductors have one or more layers of insulation on them, if they are bundled together or are installed in a location where they can be expected to be contacted by vegetation or the public. The bundled cable shown at right has two insulated and one bare conductor, and is used for supplying a typical 'house service'. Most primary / high voltage conductors are bare, as this saves costs and weight.

4) Single or Bundled: At lower voltages, to save space and add strength, more than one conductor may be twisted or lashed into a 'bundle'. This is most common for secondary or service wires.

3.2.6 Underground and Submarine Cable

Underground and submarine cables serve a similar function as overhead conductor. In addition to the characteristics discussed for overhead conductors above, the following characteristic are important to the selection and installation of underground or submarine cables:

1) Insulation Type and Voltage Rating: most cables in service and all new cables installed are cross-linked polyethylene (XLPE) type insulation, with ratings of 46, 35, or 28 kV.
2) Insulation Class: cables on 4-wire grounded systems (e.g. 28 kV or less) are typically specified as 100% insulation class. Cables on 3-wire systems (34.5 or 44 kV) require 133% insulation class as ground faults causing temporary over-voltages may take longer to clear.
3) Terminations: "Elbows" or terminations must be installed to transition from underground or submarine cable to equipment or overhead conductors. These terminations are frequently points of failure and must be selected and installed carefully in order to avoid becoming a weak link.
4) Mechanical Protection:
    a. Underground cables may be direct buried, installed in duct, or installed in concrete encased duct depending on location.
    b. Submarine cables typically include an outer layer with a steel armour for protection against rocks, ice, boat anchors, etc.
    c. All submarine and underground cables require additional mechanical protection, in the form of rigid ducts and/or metal guards at shorelines and riser poles for public safety.

3.2.7 Protective and System Devices

Protective and system device are aggregated into the following MA groups:

1) Reclosers (a type of aerial circuit breaker),
2) Capacitors, of two types:
    a. Fixed (always 'on')
    b. Switches (only 'on' under specific conditions)
3) Current sensors
4) Voltage sensors
5) Primary (pole-mounted) instrument transformers

3.3 Distribution Substation Managed Assets

3.3.1 Power Transformers

Power transformers in API's DS's are used to transform electricity from one of API's express feeder voltages (34.5 kV or 44 kV) to another primary voltage (8 kV to 25 kV) to supply distribution feeders.

Power transformers are typically 3-phase, with capacities ranging from 1000 to 10,000 kVA. Older installations use three single-phase transformers connected in a bank to function as a 3-phase transformer.

Power transformers are much larger than pole top transformers. These units typically weigh several thousand kilograms and contain thousands of litres of oil. As a result, they must be placed on engineered concrete foundations.

3.3.2 Protective Devices

Substation protective devices in service at API include reclosers and power fuses. Substation reclosers virtually identical to 3-phase overhead line reclosers, with modifications to the mounting arrangements. Power fuses provide protection on the primary side of most in-service power transformers.

Protective relays that monitor and control substation reclosers are currently managed as part of the recloser asset. As other SCADA assets such as data concentrators and communications equipment are installed, it is expected that relays, SCADA equipment and communications equipment will be grouped as MA's separate from the protective devices.

3.3.3 Voltage Regulators

Substation voltage regulators generally provide 3-phase voltage regulation. This regulation can be provided either on the feeders supplied by the substation, or on the express feeder serving the substation.

There is currently two substation-class regulators in service at AP. It is located at Hawk Junction DS and provides voltage regulation for loads located downstream on the No.4 Circuit 44 kV express feeder.

3.3.4 Switches

This type of MA allows for opening and closing, or isolating of current-carrying components, which either prevents or allows the flow of electricity. Switches can have different characteristics:

1) Gang-operated or single-phase operated: A gang-operated switch, generally a three-phase device, allows all three phases of the switch to be opened or closed at once, often from the ground. Single-phase switches are typically operated using insulated sticks, and are operated one phase at a time.
2) Load-break or Non-load-break: A Load-break switch allows for the interruption of power flow even when a significant amount of current is flowing. Non-load-break switches cannot interrupt large current flows and are more often used in combination with nearby protective devices for providing visual confirmation of isolation.
3) Remote-controlled or locally operated.

3.3.5 Grounding System and Lightning Protection

Substation grounding systems consist of a network of buried electrodes interconnected by buried conductors forming a "grounding grid". Conductive structures and equipment throughout the substation are connected directly to this buried grid.

Lightning masts and/or shield wires are installed to provide protection against direct lightning strikes. Also, lightning arresters are typically installed adjacent to power transformers and other critical equipment.

The main functions of the grounding and lightning protection system are:

1) To protect equipment by providing a means of carrying electric currents into the earth under normal and fault conditions.
2) To limit overvoltages at equipment terminals during lightning discharges.
3) To protect personnel in the vicinity of grounded equipment from critical shocks by limiting step and touch potentials to acceptable values.

3.3.6 Substation Civil/Structural Assets

These assets are aggregated into the following groups:

1) Steel Structures
2) Concrete Foundations
3) Fencing
4) Yard Surfacing
5) Cable Trays/Ducts

3.4 Metering Managed Assets

Metering MA include the following asset types:

1) Revenue meters that measure, store and report electricity usage
2) Instrument transformers
    a. current transformers (CTs)
    b. potential or voltage transformers (PTs)
3) All communications or data aggregation equipment owned by API used to facilitate the revenue metering process (collectors, antennae, etc.)

4 Inspection and Maintenance Programs

4.1 Inspection and Maintenance (General)

Inspection and maintenance programs are integral aspects of any AMP and good utility practice. Effectively maintaining existing line and substation equipment is necessary to keep equipment in good working condition, maximize equipment lifespan, and improve reliability by reducing the probability of failure. Maintenance programs optimize the value of capital investments. Maintaining equipment in proper working condition reduces the probability of equipment failure, enhances safety and increases reliability of supply to customers.

Maintenance activities at API are performed with a combination of internal personnel and qualified outside contractors and consultants.

1) API establishes its various maintenance cycles to achieve a number of objectives:
2) Maintenance cycles for inspections will satisfy the minimum regulatory requirements.
3) Critical assets may be inspected more frequently and may make use of more sophisticated inspection methods (e.g. thermographic scans at substations).
4) Preventive maintenance activities are scheduled on cycles that attempt to optimize the life-cycle costs of equipment considering manufacturer's recommendations, good utility practice as well as API past experience.
5) Preventive maintenance activities that are scheduled cycles greater than one year will be scheduled with a goal of levelling expenditures year-to-year, as well as levelling activities between service centres on an annual basis. This ensures adequate resource availability to complete the planned program and minimizes travel costs associated with crews traveling between service centers.

Maintenance activities can be subdivided into four basic categories:

4.1.1 Predictive Maintenance

Predictive Maintenance is the identification of equipment deficiencies that may lead to failure. Examples of predictive maintenance activities are visual inspections, equipment testing, and substation transformer dissolved gas analysis. Thorough inspections are the chief mechanism used at API for predictive maintenance, although other methodologies are used, such as pole condition testing and conductor testing.

4.1.2 Corrective Maintenance

Corrective Maintenance is the repair of equipment that resulted from deficiencies identified through visual inspections or testing.

4.1.3 Preventative Maintenance

The routine servicing or repair of equipment on a regular schedule to ensure that equipment remains in good working condition. Maintenance is undertaken at specific time intervals and is applied regardless of equipment condition. Examples of preventive maintenance activities are load-break switch maintenance, protective device maintenance, and substation equipment maintenance.

For many of API's MA's, there has been a gradual progression from preventative maintenance to predictive maintenance activities in the recent past. This trend is a result of both technological improvements and cost reductions in predictive maintenance technologies such as infrared scanning. Technological advances in new equipment has also reduced the need for regular preventive maintenance. An example would be vacuum interrupting reclosers that no longer require periodic oil and contact replacement that was essential for the proper operation of traditional oil-filled reclosers.

4.1.4 Certification Maintenance

Certain assets require periodic certification or re-certification. This generally involves testing, calibration, and documentation (such as a 'seal' or 'sticker') by a third-party accredited or industry-accepted expert group. Examples of managed assets requiring certification:

1) Revenue meters and instrument transformers (residential, commercial / industrial, and bulk)

2) Insulated booms on Bucket Trucks
3) Working grounds used by power line workers

4.2 LINE MAINTENANCE ACTIVITIES

4.2.1 Predictive Maintenance

4.2.1.1 Visual Inspections

Predictive maintenance on overhead and underground distribution systems in the API service area generally takes the form of visual inspections. Details of inspection cycles are provided in Section 4.4 below.

All overhead lines scheduled to be inspected during that year are patrolled by walking, driving, snowmobiling or flying as required and detailed inspections are carried out on most equipment. This includes poles, cross-arms, guy wires, transformers (overhead and pad-mounted), conductors and cables, insulators, arrestors, bushings, terminations, switching devices (fused cut-outs, load-break and disconnect switches, live-line openers, etc.). Civil facilities, such as transformer pads and cable chambers, are also inspected. Underground facilities are inspected only where visible (risers, terminations, etc.)

The results of these inspections and any identified deficiencies are documented for follow-up and are archived. Deficiencies are assessed on the basis of the potential for failure and consequential impact on safety or reliability. They are then prioritized for corrective action as follows:

1) Major deficiencies, where repair or replacement is required to address a pending failure or safety hazard. Examples of major deficiencies would be broken poles and cross-arms.
2) Minor deficiencies, where the deficiency is of a nature where action can be deferred for a time. An example would be a blown lightning arrestor. Repairs to less critical deficiencies are typically planned so that a group of deficiencies within a given area can be addressed by a single crew in a short timeframe.

4.2.1.2 Inspection using Specialized Equipment

In addition to the cycle inspections described above, various line components are inspected using specialized equipment, with any deficiencies recorded and prioritized for correction. Thermographic scans of critical distribution line components (e.g. load-break switches and reclosers on express feeders) are performed annually.

Beginning in 2009, API retained an external contractor to perform detailed pole testing on a small sample of its poles. This testing provides valuable details on the condition of the poles, the remaining pole strength and expected remaining life, as well as observations of any conditions that could potentially have an impact on remaining life of the poles. This information is provided in a searchable database that could be used for long-term planning of line rebuilds and pole replacements. The results of the testing have already proven valuable in that a small number of poles on a critical circuit were identified as requiring short-term replacement due to condition, while the remainder of poles had more life than expected and replacement could be delayed.

API will continue pole testing at a rate of approximately 10% of the pole population each year.

4.2.2 Corrective Maintenance

Any deficiencies identified during or outside of scheduled inspections are recorded and prioritized as described above. Repairs or replacements are carried out accordingly and completion is tracked through the corporate work management systems.

Often, corrective maintenance is performed on an ad-hoc basic, as problems are identified by employees or members of the public on an ongoing basis. Some of these problems result in an unplanned (forced) outage /service interruption.

4.2.3 Preventative Maintenance

Two major preventive maintenance activities are conducted on distribution lines and equipment:

4.2.3.1 Switch Maintenance

API will maintain load-break switches located on its express feeders on a six-year cycle, to the extent practical. This minimizes the likelihood of widespread outages due to switch failure and ensures that switches will operate reliably in the event of planned or forced outages elsewhere on the system. This maintenance activity has historically been limited due to system configuration and the outages that would be required to complete this activity. Recent system configuration changes, equipment upgrades, and changes to work practices are expected to allow maintenance of most switches starting in 2014. Switch maintenance will include the following main activities:

1) Visual inspection of switch components, such as contacts, insulators and arc horns, to identify any broken or deteriorated parts and evidence of surface tracking or corrosion.
2) Opening and closing switches to verify proper and efficient operation of blades and gang-operating mechanisms, where applicable.
3) Cleaning and lubrication of electrical connections and moving parts.
4) Replacement of worn components, or the entire switch if necessary.

4.2.3.2 Protective Device and Voltage Regulator Maintenance

API performs routine maintenance of its Reclosers and Voltage Regulators. For traditional oil-filled equipment, preventive maintenance activities are typically performed on a six-year cycle, and include the following main activities:

1) Determination of number of operations since date of last maintenance to verify that existing maintenance intervals are adequate.
2) Visual inspection of tanks, bushings, contacts, operating mechanisms, control boxes, etc. to identify any broken or deteriorated parts and evidence of surface tracking or corrosion.
3) Testing of operations, both manually and using electrical test equipment to ensure proper operation.
4) Electrical testing (ratio, resistance, etc.) to verify electrical integrity of device and all components.

The results of any tests performed are documented on equipment test forms and kept on file for trending and comparison purposes.

For newer equipment, API is transitioning to a more predictive/corrective based maintenance approach. The design of newer reclosers and voltage regulators allows for a combination of simple visual inspection, infrared scanning and analysis of operational history to determine whether or not any corrective maintenance is required. For example, the latest generation of recloser and regulator controls will estimate the percentage of remaining life on contacts or interrupters based on the history of load/fault current present during each previous operation. In many cases, this will significantly extend the time interval between overhauls or replacement.

4.3 Distribution Substation Maintenance Activities (General)

4.3.1 Predictive Maintenance

Predictive substation maintenance is integral to maintaining reliability and detecting potential equipment failure. Since substation equipment typically requires large investments for installation and since failure of substation components can affect large numbers of customers, therefore detecting potential failures before they occur is very important. There are presently three key predictive maintenance activities conducted in API substations:

4.3.1.1 Visual Inspections

Visual Inspections are essential for assessing the condition of substation components and identifying deterioration or areas where attention is required. The OEB Distribution System Code provides for different inspection intervals for substations based on various criteria and location. API's nine substations fall into the "Rural – Outdoor Open" category, and therefore performs detailed inspections at least once every six months.

Substation civil/ structural (fencing, structures, etc.) and electrical components (bus-work, switches, insulators, transformers, ground conductors, etc.) are inspected and any deficiencies recorded. In addition, data such as power transformer gauge readings are recorded. The condition of ancillary equipment such as lighting, eyewash stations, first-aid kits, and oil spill kits is also inspected.

API also performs monthly inspections of its oil containment facilities and quarterly sampling of effluent from the oil containment in accordance with Ministry of Environment, Conservation and Parks requirements. During these monthly inspections of oil containment, the remainder of the substation is visually inspected at a high level and deficiencies requiring immediate correction are identified.

Any deficiencies noted during inspections are recorded, reported, and are then prioritized for corrective action.

4.3.1.2 Transformer Dissolved Gas Analysis

Dissolved gas analysis (**DGA**) is an effective tool for assessing the condition of power transformers and identifying deterioration in transformer oil or insulation. DGA can also identify whether arcing or acid build up is occurring inside the transformer. DGA tests for the presence of dissolved gas and water in transformer insulating oil, and based on the level of gases or moisture present, assess the condition of the transformer. An important aspect of DGA is the trend analysis, which reviews the history of dissolved gas levels in the transformer.

DGA is scheduled annually on all power transformers and in API substations, whether in-service or spare. API uses a qualified contractor to perform the analysis, provide reports on transformer condition, and recommend any required actions if gassing is above normal levels or if acids are detected. Corrective action to deal with abnormalities is essential to prevent failure and extend the life of the transformer.

4.3.1.3 Thermographic Scanning

Thermographic (infra-red) scanning is scheduled annually for all distribution substations. Thermography captures the temperature of components compared to surrounding equipment and ambient temperature, and high relative temperatures can be indicative of overloaded or deteriorated components.

4.3.2 Corrective Maintenance

Corrective maintenance is a reactive activity that takes place when deficiencies in substation components are identified. Defective components are prioritized for repair or replacement on the basis of the severity of the condition, the criticality of the equipment, and the potential impact of failure on safety or service reliability.

4.3.3 Preventative Maintenance

Preventive maintenance on substation components is conducted on a regularly scheduled basis and is integral to keeping equipment in good working condition. Substation components typically undergo preventive maintenance on a six-year cycle, including inspecting, cleaning, lubricating, and testing, to the extent practical.

It is worth noting that the list of maintenance activities below are an ideal set of complete maintenance activities that would be performed if all components could be isolated and de-energized without customer outages. This historically has not been the case with API's system configuration. As a result, in many cases, API has been performing visual inspections and operation of these devices only, and performing the remaining activities on a corrective basis as issues have been identified.

Many of the substation upgrades and reconfigurations completed in the recent past are expected to allow the additional activities listed below to be performed at certain stations starting in 2014. In prioritizing and selecting reliability-based projects, one of the factors considered is the impact on future maintainability of the system. Its expected that projects in future years will have a positive benefit in terms of allowing more substation maintenance activities to occur with less customer impact.

The following major activities are included in this program:

1) Transformers (distribution and instrument) – inspection and cleaning, On-line Tap-Changer maintenance, including oil refurbishment and contact inspection and replacement as required, inspection and cleaning of gauges, access ways, bushings, and connections.
2) Breaker / Recloser / Circuit Switcher maintenance – inspection, cleaning of bushings, connections, contacts and moving parts, contact resistance and insulation testing.
3) Switch maintenance – inspection and cleaning of bushings, connections, contacts, arc horns, and operating mechanisms, insulation testing.
4) Oil renewal – replacing insulating oil in power transformers and oil-insulated circuit breakers and potential transformers as needed ensuring insulating oil is clear of contaminants.

5) Accessories – other equipment such as motor operators and heating elements are inspected, cleaned, and maintained.

4.4 Substation Equipment Maintenance Methodologies (Type-Specific)

4.4.1 Predictive Maintenance (Typically on a Six-Month Cycle)

4.4.1.1 Power Transformers

1) Inspect transformer tanks and fittings for signs of oil leaking/weeping.
2) Inspect all gauges and record readings.
3) Inspect bushings for cracks and contamination.
4) Record on-load tap changer counts and ranges, and reset sweep arms (if applicable).
5) Record any new and/or unusual noise.
6) Verify manual operation of cooling fans (if applicable).

4.4.1.2 Overhead Switches

1) Inspect the insulators for breaks, cracks, burns, or cement deterioration. If necessary clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces.
2) Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona.
3) Check for damaged fuses and replace if necessary
4) Scan the switch with an infrared scanner to check for further defects

4.4.1.3 Underground Switches and Junction Units

1) Scan the switch with an infrared scanner to check for defects

4.4.1.4 Surge Arresters

1) Check for cracked, contaminated, or broken porcelain; loose connections to line or ground terminals; and corrosion on the cap or base.
2) Check for pitted or blackened exhaust parts or other evidence of pressure relief.

4.4.1.5 Buses and Shield Wires

1) Inspect bus supports for damaged porcelain and loose bolts, clamps, or connections.
2) Observe the condition of flexible buses and shield wires.
3) Inspect suspension insulators for damaged porcelain (include line entrances).

4.4.1.6 Structures

1) Inspect all structures for loose or missing bolts and nuts.
2) Observe any damaged paint or galvanizing for signs of corrosion.

3) Inspect for deterioration, buckling, and cracking.

4.4.1.7 Grounding System

1) Check all above-grade ground connections at equipment, structures, fences, etc.
2) Observe the condition of any flexible braid type connections.

4.4.1.8 Control and Metering Equipment

1) Check current and potential transformers for damage to cases, bushings, terminals, and fuses.
2) Verify the integrity of the connections, both primary and secondary.
3) Observe the condition of control, transfer, and other switch contacts; indicating lamps; test blocks; and other devices located in or on control cabinets, panels, switchgear, etc. Look for signs of condensation in these locations.
4) Examine meters and instruments externally to check for loose connections and damage to cases and covers. Note whether the instruments are reading or registering.
5) Check the status of relay targets (where applicable).
6) Make an external examination of relays, looking for damaged cases and covers or loose connections.
7) Observe the ground detector lamps for an indication of an undesirable ground on the dc system.
8) Check the annunciator panel lights.

4.4.1.9 Cables

1) Inspect exposed sections of cable for physical damage.
2) Inspect the insulation or jacket for signs of deterioration.
3) Check for cable displacement or movement.
4) Check for loose connections.
5) Inspect shield grounding (where applicable), cable support, and termination.

4.4.1.10 Foundations

1) Inspect for signs of settlement, cracks, spalling, honeycombing, exposed reinforcing steel, and anchor bolt corrosion.

4.4.1.11 Substation Area-General

1) Verify the existence of appropriate danger and informational warning signs.
2) Check indoor and outdoor lighting systems for burned-out lamps or other component failures.
3) Verify that there is an adequate supply of spare parts and fuses.
4) Inspect oil containment systems in accordance with relevant Operational Control Procedure.
5) Check for bird nests or other foreign materials near energized equipment, buses, or fans.
6) Observe the general condition of the substation yard, noting the overall cleanliness and the existence of low spots that may have developed.
7) Observe the position of all circuit breakers in the auxiliary power system and verify the correctness of this position.

8) Inspect the area for weed growth, trash, and unauthorized equipment storage.

4.4.1.12 Substation Fence

1) Check for minimal gap under the fence or under the gate. Ensure that all gaps are less than 50mm at any point under the fence and less than 100mm at any point under the gate.
2) Ensure the fence fabric is intact and document any areas with significant rust or corrosion.
3) Ensure fence fabric, gates, tension wires, barb wire, and posts are adequately bonded and effectively ground.
4) Check that the barbed wire is taut.
5) Ensure the gate latches are operable.
6) Ensure flexible braid-type connections are intact.
7) Ensure fence is clear of obstructions such as vegetation grow-ins or imbedded objects (wind-blown trash)
8) Verify that no wire fences are tied directly to the substation fence.

4.4.2 Preventative Maintenance Methodologies (Typically on a Six-Year Cycle)

4.4.2.1 Gang-Operated Switches

1) The switch should be disconnected from all electric power sources before servicing.
2) Ground leads or their equivalent should be attached to both sides of the switch, Local and applicable OHSA regulations should be followed.
3) Inspect the insulators for breaks, cracks, burns, or cement deterioration. Clean the insulators particularly where abnormal conditions such as salt deposits, cement dust, or acid fumes exist. This is important to minimize the possibility of flashover as a result of the accumulation of foreign substances on the insulator surfaces.
4) Check the switch for alignment, contact pressure, eroded contacts, corrosion, and mechanical malfunction. Replace damaged or badly eroded components. If contact pitting is of a minor nature, smooth the surface with clean, fine sandpaper (not emery) or as the manufacturer recommends. If recommended by the manufacturer, lubricate the contacts.
5) Inspect arcing horns for signs of excessive arc damage and replace if necessary.
6) For all S&C Alduti-Rupter switches, perform the outlined continuity check and additional maintenance as out lined in the Alduti-Rupter Switch and General-Maintenance Outline.
7) Check the blade lock or latch for adjustment.
8) Inspect all live parts for scarring, gouging, or sharp points that could contribute to excessive radio noise and corona.
9) Inspect inter phase linkages, operating rods, levers, bearings, etc., to assure that adjustments are correct, all joints are tight, and pipes are not bent. Clean and lubricate the switch parts only when recommended by the manufacturer. Check for simultaneous closing of all blades and for proper seating in the closed position. Check gear boxes for moisture that could cause damage due to corrosion or ice formation. Inspect the flexible braids or slip-ring contacts used for grounding the operating handle. Replace braids showing signs of corrosion, wear, or having broken strands.
10) Power-operating mechanisms for switches are usually of the motor-driven, spring, hydraulic, or pneumatic type. The particular manufacturer's instructions for each mechanism should be followed. Check the limit switch adjustment and associated relay equipment for poor contacts, burned out coils, adequacy of supply voltage, and any other conditions that might prevent the proper functioning of the complete switch assembly.

11) Inspect overall switch and working condition of operating mechanism. Check that the bolts, nuts, washers, cotter pins, and terminal connectors are in place and in good condition. Replace items showing excessive wear or corrosion. Inspect all bus cable connections for signs of overheating or looseness.
12) Inspect and check all safety interlocks while testing for proper operation.

4.4.2.2 Power Transformers

1) Inspect the control cabinet, control relays, contactors, indicators, and the operating mechanism.
2) Look for loose, contaminated, or damaged bushings; loose terminals; and oil leaks.
3) Check oil levels in main tanks, tap changer compartment, and bushings.
4) Inspect the inert gas system (when applicable) for leakage, proper pressure, etc.
5) Read and record the operations counter indicator reading associated with the load tap changer.
6) Observe oil temperature which should not exceed the sum of the maximum winding temperature as stated on the nameplate plus the ambient temperature (not to exceed 40C) plus 10C. Generally, oil temperature does not exceed 95 and 105C for 55 and 65C winding temperature rise units, respectively; since the ambient temperature rarely exceeds 30C for periods long enough to cause an oil temperature rise above these points.
7) Perform the power factor test
8) Perform the turns ratio test
9) Perform the winding resistance test
10) Perform the excitation current test
11) Perform the insulation resistance test

4.5 Revenue Metering and Instrument Transformer Maintenance

This type of Managed Assets requires additional Certification Maintenance in addition to the typical ‘physical’ maintenance (predictive, corrective, and preventative) required by most other types of Managed Assets.

Typically, each class of revenue meter and instrument transformer (current transformers and potential / voltage transformers) must be re-certified by an accredited testing organization on a recurring basis.

The frequency and nature of these recertification are dictated by regulations enforced by Measurement Canada (Industry Canada), a Federal regulator.

5 Distribution Planning

Prudent and timely planning lies at the core of any sustainable AMP. At API, planning is a continuous and evolving process designed to meet the present and changing needs of a variety of stakeholders.

Planning is divided into three general categories, with ongoing interaction between all three:

5.1 Long-Term Planning (15-Year Planning Horizon)

5.1.1 System Capacity/Performance Planning:

Historically, the planning, design and construction of distribution feeders at API has been driven by the need to serve both existing and new load customers with acceptable voltage levels and reasonable levels of line loss. Due to the rural, low-density nature of API's service territory, this has resulted in long, mostly radial feeders that are loaded below conductor and equipment capacity ratings, even during system peak loading.

Likewise, API's distribution stations are also loaded below transformer and other equipment ratings. This is a result of four stations having been rebuilt in the last 10 years, and the fact that the remaining stations were constructed during a period of higher loading and higher annual load growth in the areas that they supply.

As a result of the current state of feeder and substation load to capacity ratios, and the minimal long-term load growth currently expected in API's service territory, long-term planning is focused on the following activities:

1) A high-level review of recent load levels to determine whether any feeder/equipment capacity ratings are being approached that would require more detailed system planning studies.
2) A review of operational data (voltage complaints, voltage data from end of feeder smart meters, outage reports, etc.) to determine if any performance issues exist at current load levels. Given the minimal future load growth expectations, review of actual operational data is considered to be more accurate and cost-effective than review of a system model in a formal system planning study.

5.1.2 End-of-Life Asset Replacement Planning:

As described in Section 5.1.1 above, there is little driver for asset replacement purely from capacity or growth perspectives. As a result, API regularly updates and reviews the following types of information (where available) on various classes of assets such as poles, transformers and protective devices:

1) Age profile
2) Information from Condition Assessments, Inspections and Testing Programs
3) Failure rates

This review is used to determine appropriate levels of sustainment capital spending (i.e. "System Renewal category) in the 5-year capital plan. The goal is to replace these assets on an end-of-life basis with annual expenditures for each asset group levelized to the extent possible.

5.2 Medium-Term Planning (5-Year Planning Horizon)

API uses results from its long-term planning efforts and other reports, such as asset condition reports, to perform 'tactical' planning which covers a five-year period. Changes to the regulatory environment must be taken into account as well.

The medium-term plan is updated annually to incorporate new information that may arise, such as new regulations, longer-term individual customer needs, or updated information arising from the activities described in the long-term planning process. Typical inputs to medium-term planning include:

1) Customer-driven needs
2) Municipal-driven needs
3) First Nation driven needs
4) Health, Safety and Environmental issues
5) Regulatory requirements
6) Reliability analysis
7) Asset replacement requirements (based on the outcome of long-term planning)
8) Expansion requirements (if any are identified through long-term planning)
9) Extraordinary initiatives, such as FIT, Smart-Grid and Smart Meters

The results of the medium-term planning process are used to select and prioritize projects for inclusion in the 5-year capital plan. Results of medium-term planning are also used to review the effectiveness of maintenance programs and to make adjustments as required.

5.3 Short-Term Planning (1-Year Planning Horizon)

Short- term planning involves developing specific plans to implement the projects defined in the current year budget as well as to operate and maintain the distribution system(s) in a safe and reliable manner.

It also addresses short-term needs, such as connection of a customer that was not identified previously during medium term planning, or reaction to external events such as a severe ice storm.

1) Current Budget Year Project Design
2) Customer-Driven Asset Development
3) Municipal and Developer-Driven Asset Development
4) Other Short-term Projects

6 Assessment of Asset condition

6.1 Distribution Substations

The relatively low quantity of each type of DS asset ensures that each item can receive regular inspection, maintenance, and qualitative assessment.

Quantitative assessments such as dissolved gas analysis, operation counts, gauge readings, and detailed electrical testing are also performed on critical assets such as power transformers and protective devices.

The results of various substation inspection and maintenance activities are used as inputs to the long-term asset replacement planning process described in Section 5.1.2.

6.2 Poles

6.2.1 Defining Asset Condition

A wooden utility pole generally remains useful until:

1) It fails (breaks or collapses) due to severe weather, vehicles, or loss of strength associated with advanced aging.
2) New requirements necessitate a pole change-out. These needs might be for a taller or stronger pole to support more equipment.
3) The pole is no longer required at its legacy location.
4) Though a gradual process of loss of wood fibre and loss of fibre strength, the strength of the pole decreases until it reaches the point where it no longer satisfies required safety factors under worst-case conditions. At this point, inspections and/or testing will identify the need.

API has approximately 30,000 poles in service. Individually, the replacement value of these assets ranges from $2,000 to over $15,000. Because of the high expected useful life and large installed base of poles, it would be extremely impractical to closely monitor and maintain each pole in the same fashion as a Substation steel structure, and the expense of such a program would far exceed its utility.

API manages its pole assets through a combination of:

1) Industry-standard purchasing specifications
2) Inspection of new distribution poles as they are installed
3) Visual circuit inspections. These inspections are performed on a six year cycle as part of API's Inspection Program.
4) Annual pole testing by a third party of in-situ poles within a defined section of the distribution network.
5) Inspections of poles whenever they are installed and/or visited during fieldwork.
6) Review of the in-service pole age profile, failure rates, as well as the results of all pole inspection and testing programs for use as inputs to the long-term asset replacement planning process described in Section 5.1.2.

6.2.2 Measuring Asset Condition

Monitoring the condition of API's individual poles has been an ongoing process for many years. Annual feeder inspections are performed by API line crews where the visual inspection of each pole identifies observed impacts such as wood pecker damage. Paper based reporting provides identification of observed damage or concern for each impacted pole. The reporting does not include poles observed to be in acceptable condition.

API has an annual pole testing program utilizing a third party to perform the testing and subsequent report on the condition of the poles tested. Testing in recent years has focused on specific areas of concern in the network. In 2013 the testing began in a regional section of the network and will continue in subsequent years to follow a regional cycle of testing and reporting.

6.3 Distribution Transformers

API has over 5,200 in-service transformers throughout its distribution network. Individually, the replacement value of these assets ranges from $2,000 to over $40,000.

Testing of pole-top transformers to quantitatively evaluate condition would require regular DGA and electrical testing, with trending for each unit. Because of a relatively low cost, and large installed base of distribution transformers, it would be extremely impractical to closely monitor and maintain each transformer in the same fashion as a substation power transformer, and the expense of such a program would far exceed its utility.

API manages its distribution transformer assets through a combination of

1) Industry-standard purchasing specifications
2) Examination of the manufacturer's technical drawings and test results for each distribution transformer order placed
3) Periodic inspection and testing of distribution transformers while they are retained in stores as spares
4) Inspections and testing of transformers whenever they are installed and/or visited during fieldwork or feeder inspections.
5) Intake inspection whenever a previously-used distribution transformer is returned to storage from the field. This is particularly important if the distribution transformer was removed from service because it is suspected to be not in good working order.
6) Review of the in-service transformer age profile, failure rates, as well as the results of inspection programs for use as inputs to the long-term asset replacement planning process described in Section 5.1.2

6.4 Reclosers, Voltage Regulators and Express Feeder Load-Break Switches

These devices are installed in relatively small numbers (less than 200 devices total). Proper operation of these devices however is critical to the safe and reliable operation of API's system and failure of any individual device can have significant impacts on reliability.

API manages this group of assets through a combination of

1) Industry-standard purchasing specifications
2) Examination of the manufacturer's technical drawings and test results (where applicable) for each order placed
3) Inspection and testing on delivery
4) Periodic inspection and testing of equipment retained in stores as spares
5) Testing of equipment whenever it is installed
6) Periodic inspection and maintenance activities as describes in Sections 4.2.1-4.2.3
7) Analysis of loading on transformers with suspected overloading
8) Intake inspection whenever previously-used equipment is returned to storage from the field
9) Review of failure rates as well as the results and costs of inspection and maintenance programs for use as inputs to the long-term asset replacement planning process described in Section 5.1.2

6.5 Other Distribution Assets

Annual capital spending for asset replacement is focused on the substation, pole, transformer and recloser/regulator/switch assets identified in the sections above. Annual spending is levelized to the extent practical in an effort to replace these assets on a sustainable long-term basis, according to their expected useful lives.

There are a large number of other relatively low-value assets in service on API's distribution lines. This includes items such as conductor, fused cutouts, insulators, arresters, single-phase switches, etc. Run-to-failure is typically the most economic approach for replacement of these assets, however they may occasionally be replaced proactively under the following circumstances:

1) Periodic visual or thermographic inspections happen to identify pending failure
2) Evaluation of outage reports identifies a specific asset type/make/model/vintage that is more prone to failure (e.g. certain runs of insulators and cutouts have been known to experience premature failure and would be replaced proactively)
3) Assets of an older vintage, an obsolete type, or observed to be in poor condition are replaced in conjunction with other asset replacements (e.g. aging conductor and insulators are replaced in conjunction with pole replacements; porcelain cutout/arrester combinations are replaced in conjunction with transformer replacements)

APPENDIX A – DISTRIBUTION SUBSTATIONS

WAWA #1 DS

Transformer Number	8600
Manufacturer	Pioneer Transformers
Number of Phases	3
Manufacturer Date	2008
Capacity MVA	6.25/7.92/9.32
Primary Voltage	34.5 kV
Secondary Voltage	8320 Y/ 4800
Taps	± 2.5 %
Total Oil (L)	4,710
Total Weight (kg)	15,520

WAWA #2 DS

Transformer Number	3296*	3297*	3298*	4039
Manufacturer	Westinghouse	Westinghouse	Westinghouse	Federal Pioneer
Number of Phases	1	1	1	3
Manufacturer Date	1974	1974	1974	1979
Capacity MVA	1.5	1.5	1.5	5.0
Primary Voltage	33 kV Δ	33 kV Δ	33 kV Δ	33 kV Δ
Secondary Voltage	7,200 Y	7,200 Y	7,200 Y	8,000 Y/ 4,619 Δ
Taps	± 5 %	± 5 %	± 5 %	± 10 %
Total Oil (L)	1,363	1,363	1,363	5,561
Total Weight (kg)	10,500	10,500	10,500	16,556

* Currently on Potential as backup to the 34.5kV Ratio Bank

HAWK JUNCTION DS

Transformer Number	4633	5236	6843	VR2
Manufacturer	Ferranti-Packard	Ferranti-Packard	Ferranti-Packard	PTI
Number of Phases	3	3	3	3
Manufacturer Date	1985	1988	1948	2015
Capacity MVA	1.0	1.0	60	30
Primary Voltage	44.0 kV Δ	44.0 kV Δ	44.0 kV Δ	44.0 kV Δ
Secondary Voltage	8,320 Y/ 4,800	8,320 Y/ 4,800	44.0 kV Δ	44.0 kV Δ
Taps	± 5%	± 5%	± 10%	± 10%
Total Oil (L)	1,905		9,201	
Total Weight (kg)	5,800		22,906	

Garden River DS

Transformer Number	6095	8224
Manufacturer	Carte	Northern
Number of Phases	3	3
Manufacturer Date	1992	2007
Capacity MVA	3.0	3.0
Primary Voltage	34.5 kV Δ	34.5 kV Δ
Secondary Voltage	12,500 Y/ 7,200	12,500 Y/ 7,200
Taps	± 5%	± 5%
Total Oil (L)	3,496	2,511
Total Weight (kg)	11,045	9,254

BAR RIVER DS

Transformer Number	7549
Manufacturer	Northern
Number of Phases	3
Manufacturer Date	2001
Capacity MVA	6.0/8.0/10.0
Primary Voltage	34.5 kV Δ
Secondary Voltage	12,500 Y/ 7,200
Taps	± 5%
Total Oil (L)	4,359
Total Weight (kg)	16,239

DESBARATS DS

Transformer Number	8971	9318
Manufacturer	Virginia	Northern
Number of Phases	3	3
Manufacturer Date	2010	2013
Capacity MVA	5.0/6.67/8.33	6.0/8.0/10.0
Primary Voltage	34.5 kV Δ	34.5 kV Δ
Secondary Voltage	24,940 Y/ 14,400	12,500 Y/ 7,200
Taps	± 5%	± 5%
Total Oil (L)	4,163	4,450
Total Weight (kg)	15,291	16,961

*CO#9318 was previously located at the Bruce Mines DS, but was relocated to the Desbarats DS following a failure at transformer T1 (previously CO#7402)

Bruce Mines DS

Transformer Number	5108
Manufacturer	Carte
Number of Phases	3
Manufacturer Date	1987
Capacity MVA	5.0
Primary Voltage	34.5 kV Δ
Secondary Voltage	12,500 Y/ 7,200
Taps	± 5%
Total Oil (L)	3,832
Total Weight (kg)	11,454

*CO#9318 was previously located at the Bruce Mines DS, but was relocated to the Desbarats DS following a failure at transformer T1 (previously CO#7402)

DUBREUILVILLE SUB 86

Transformer Number	C-4710-1	C-4710-2
Manufacturer	CES	CES
Number of Phases	3	3
Manufacturer Date	2021	2021
Capacity MVA	3000	3000
Primary Voltage	44.0 kV Δ	44.0 kV Δ
Secondary Voltage	2.4/4.16Y	2.4/4.16Y
Taps	+2.5%/-7.5%	+2.5%/-7.5%
Total Oil (L)	3000	3000
Total Weight (kg)	9500	9500

DUBREUILVILLE SUB 87

Transformer Number	W0656-001
Manufacturer	Markham Electric Ltd.
Number of Phases	3
Manufacturer Date	1991
Capacity MVA	1.0/1.3
Primary Voltage	44.0 kV Δ
Secondary Voltage	2.4/4.16Y
Taps	± 5%
Total Oil (L)	1,673
Total Weight (kg)	4,591

Algoma Power Inc.

Distribution System Plan

Appendix B

API VEGETATION MANAGEMENT PLAN

Vegetation can interfere with the safe and reliable operation of API's electrical system. Trees and brush growing in the vicinity of electrical wires increase the risk of injury to the public and API's employees and vegetation contacting or arcing with power lines has the potential of starting forest fires and/or grass fires (wildfires).

Vegetation can cause electrical service interruptions when branches contact or come close to power lines. Some examples of contact are as vegetation grows naturally towards the conductor, as well as, during windstorms or with ice or snow build-up which causes movement or failure (breakage) of the vegetation and power lines to sag and/or swing. Trees or branches falling on power lines are also a major cause of power interruption whether through natural tree health decline and/or loading forces on trees, such as wind, snow, and ice (see Figure 1). Vegetation can also impede the efforts of staff to locate, inspect, maintain, and repair disruptions to electrical service.

The Vegetation Management Plan (VMP) has an overall objective to manage vegetation in proximity to electrical equipment on a regular schedule to:

- Avoid vegetation caused outages through system hardening to achieve sustainable reliability performance
- Decrease risk of wildfire ignition and spread by reducing the likelihood of tree contact with powerlines and eliminating volumes of fuel source wood
- Enhance public safety near electrical equipment
- Allow worker accessibility to the system
- Secure infrastructure resiliency by reducing impact caused by extreme weather events
- Manage and plan vegetation work activities in a least cost sustainable manner.

Figure 1: Express Feeder ROW - Trees under snow load

API manages Right-of-Ways (**ROWs** or **ROW**) to support its 2,100 kilometers of distribution line. Approximately 85% of API's power lines have treed edges (see Figure 2 & 3) averaging 490 trees per km with an average height 20.7m (68ft). Greater than 23% of API system has forested edges on both sides of the ROW (i.e. cross-country and double-sided ROW - see Figure 1 & 2). The remainder of API's ROWs are mainly comprised of front yard trees (residential) and farmland and other natural areas containing brush and shrubs.

Figure 2 (Left): Harbour Circuit - Double-Sided ROW
Figure 3 (Right): Goulais River along HWY 17 - Forested Edge

The service territory is divided into three geographical zones: Wawa, Sault and Desbarats, which are shown on the map in Figure 4. The current VM plan is administered using these three zones, as well as system criticalities (outage trends, level of control, assessments/patrols), and ROW characteristics (i.e. on-road, off-road, double sided) to manage smaller parts and different work activities within the entire system.

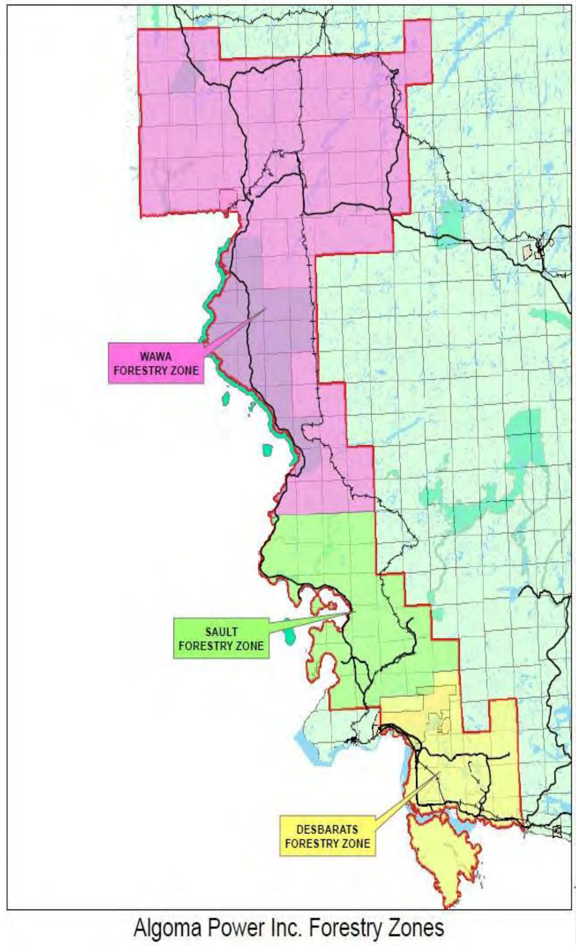


Figure 4: Map of API's Service Territory and Forestry Geographical Zones

Removing the annual volume workload (AVW) of vegetation provides simultaneously the least cost program and the lowest incidence of tree-related outages for the established clearance standards, work practices and maintenance cycle frequency. A successful VMP can only be delivered if funding is adequate to remove and manage the AVW and the incident of hazard trees.

In 2011, API completed its ROW expansion program and decreased the number of trees that could contact a conductor and other electrical equipment. API's ROW clearance widths (see Table 1: API ROW Clearance Standard) are specifically designed to meet the needs and requirements of its service territory and are typical of industry standards for a rural and remote system.

Wildfire Risks and Mitigation

Wildfire risk is a natural phenomenon that is increasing with climate change and adverse weather events. Over the past 10 years, API's service territory has experienced a change in weather trending more mild winters (longer growing season), high wind events and unpredictable weather patterns (extreme highs and lows). With the growing impact of climate change, unpredictable weather, changes in forest health and increased human populations in wildfire areas have made preventing wildfires and protecting electrical facilities a significant priority for utilities.

API's clearance standards, cycle frequency and specifications for ROW conditions include measures to ensure the amount of fuel source material (vegetation/woody debris) is managed to reduce the risk of ignition and spread. API ROW cleanup standards include the chipping, spreading and/or removal of vegetation and woody debris associated with cutting activities. If debris should be left due to limited access in remote areas, API specifications for mulching cut material on site follow the Ministry of Natural Resources and Forestry (MNRF) guidelines for fire breaks and windrowing practices.

Wildfire mitigation efforts at API include Industrial Operations Fire Prevention and Preparedness Plan to support field staff for job planning and work practices. One of the most prevalent wildfire mitigation strategies utilities employ is to develop, implement and maintain an enterprise-wide Wildfire Mitigation Plan (WMP) and include vegetation management (see recommendation provided by ECI, *Appendix A: Assessment of the Algoma Power Inc., Distribution Vegetation Management Program, Page 33 & 36).*

In 2014, based on the established conditions of a larger ROW area to be maintained, API completed a third-party performance management review and risk assessment to:

a) identify ROW hardening priorities,
b) quantify the volume of vegetation to be maintained based on growth rates and tree mortality,
c) understand changes to cycle frequency founded on acceptable vegetation thresholds and level of control, and
d) ensure resources were directed to the most efficient and cost effective VM practices.

From the review, recommendations brought forward the requirement to utilize best management practices and continue working towards a preventative maintenance program. This was completed by removing a backlog of hazard trees to stabilize (harden) newly created ROW edges and to find cost and operational efficiencies through working towards increasing the use of mechanical equipment and herbicide work applications to manage brush densities (regrowth) within the area of the ROW.

In 2018, API conducted a progress audit following the 2014 report to evaluate current VMP status/efforts, update pertinent data related to managing volume of VM work and make relevant changes as necessary in accordance with the VMP's objectives to achieve a least cost sustainable program. Audit findings identified that API had completed majority of the ROW hardening program and through the implementation of annual condition assessments and in conjunction with the preventative maintenance program, the prioritization of hazard tree removals resulted in a decrease in hazard trees that would require future management and an increase in reliability performance.

API has made substantial advances in improving safe reliable service under the coordination and completion of the ROW widening and hardening programs.

In addition to system hardening improvements along the ROW edge, findings weighed heavily on efforts towards continuing to increase the use of mechanical and herbicide work activities to achieve higher volume removal efficiency. The amount of treed edge and prominent species along API ROW's is subject to being populated by incompatible (tall growing) tree species and requires active ongoing management.

In 2023, to continually monitor VMP objectives API hired Environmental Consultants Inc. (ECI) to conduct a review. For the comprehensive report see *Appendix A: Assessment of the Algoma Power Inc., Distribution Vegetation Management Program.* ECI conducted a benchmarking comparison using similar sized utilities (number of customers) for non-storm tree-caused outages. Although the data was not adjusted for tree exposure (amount of treed edge, density), API ranked favourably to the industry average for tree-caused outage occurrence and impact to customers, particularly in frequency and duration of outage. API is demonstrating resiliency in reliability performance for outage prevention and restoration. *Appendix A: Assessment of the Algoma Power Inc., Distribution Vegetation Management Program: Vegetation Outage Analysis Page 7 – Page* 13. The amount of treed edge and incompatible species adjacent to API ROW is a main contributor to the level of active ongoing maintenance required. It can be expected that brush will develop where there are adjacent trees supplying seed or through vegetative reproduction (suckering). While vegetation growth is not static, annual growth is comprised of biomass additions (annual volume workload). While it is relevant to understand the quantity and type of incompatible species, it is equally important to understand the type of work activity needed to achieve the best level of management to control costs and maintain operational efficiencies. As recommended in the 2014 and 2023 report, API has incorporated some mechanical brushing into its VMP. The amount of area that can be mowed is limited by rock outcroppings, ditches, and fences (see Figure 5). Remote areas with limited access require specialized equipment or can restrict the use of mechanical equipment entirely as an option. In some cases, a combination of mechanical and manual cutting is used depending on terrain and accessibility. As a recommended industry best practice with cost saving potential, API continues to gain experience and determine suitable locations to optimize the use of mechanical methods and equipment where possible.

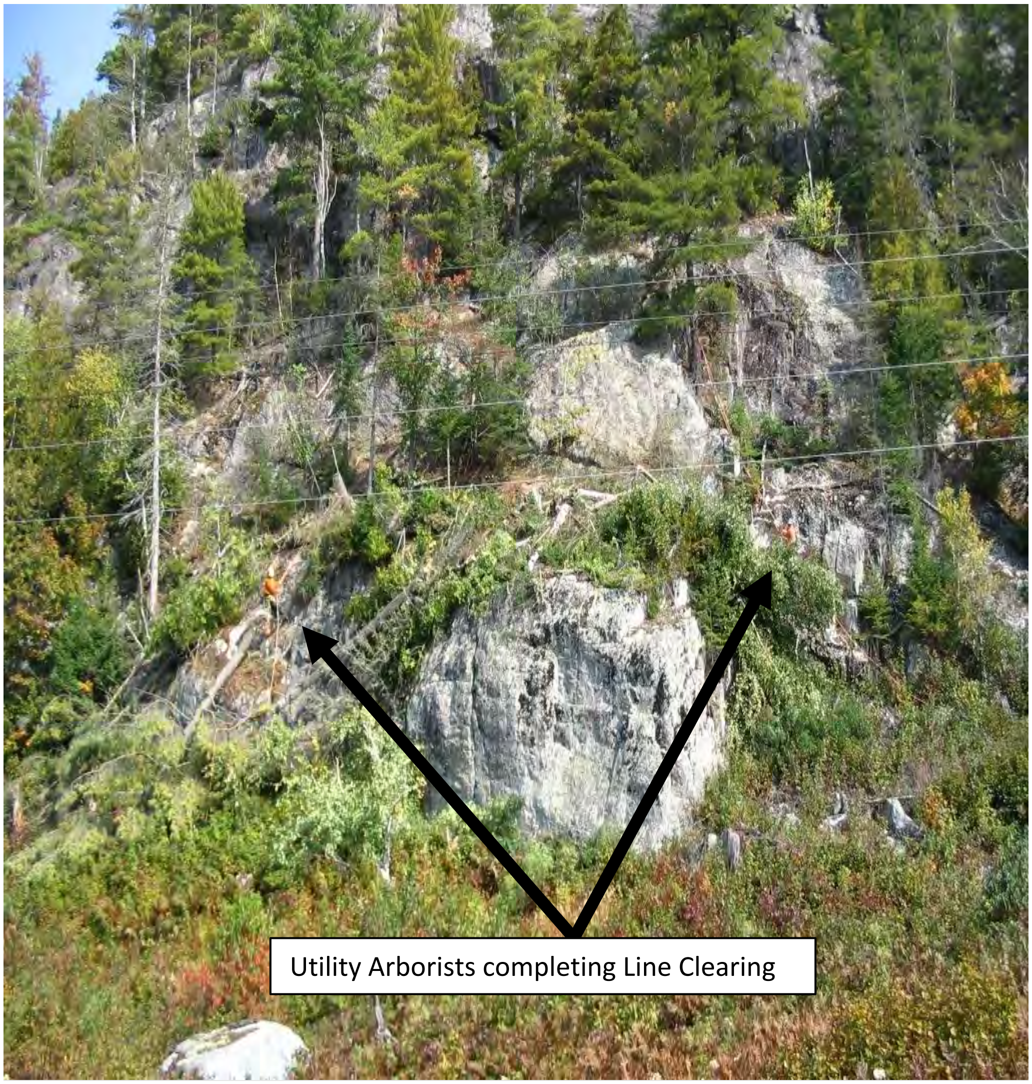


Figure 5: Rock Outcropping with Utility Arborist completing work

Also recommended in 2014 and 2023 reports, API is applying herbicide where permitted to reduce the amount of existing incompatible vegetation, to prevent growth and regrowth from the suckering of cut stems (see Figure 6). Recognized as an industry best practice, herbicides are most effective on woody vegetation species to reduce future workload and costs. *Appendix A: Algoma Program Assessment Report, Page 36-37*. Generally, utilities strive to convert the ROW from incompatible vegetation (see Figure 7) to powerline compatible low growing vegetation (see Figure 8 & 9) that will resist the re-establishment of incompatible vegetation. By decreasing or eliminating tall vegetative growth (incompatible), herbicides extend the cycle frequency or maintenance free period.

Figure 6: Multiple stem growth from a single cut stem (suckering)


Figure 7 (Left): Brush growth without herbicide (cut only)

Figure 8 (Right): Post herbicide treatment – Low Growing Compatible Vegetation

Currently, API is trending towards a 25% decrease in the use of herbicide since 2017 mainly due to a reduction in landowner consent. The reduction of herbicide has had an impact on previous and future management requirements (annual volume workload) and cost and operational efficiencies.The deceased level of control has increased the annual volume workload AVW (higher number of stems and height) creating more biomass (volume of vegetation) to be managed. The denser the brush stems and taller the brush height, the higher the cost to control. As seen in Figure 9 and as mentioned in *Appendix A: Algoma Program Assessment Report, Page 37, Brush Control, u*sing herbicides to treat stumps on deciduous trees where allowed, prevents re-sprouting which leads to a decrease in biomass.

Figure 9: Herbicide Treatment – show a decrease in biomass (tall vegetation) converting ROW to compatible vegetation

Vegetation Management Plan (VMP): Programs and Work Activities

Line Clearing Program

To manage tree growth and hazard trees thereby controlling vegetation encroaching and/or falling into the lines. Work activities would typically include manual and mechanical tree removal, tree trimming and clean-up of cut material.

Brush Control Program

To maintain the active ROW widths and manage "grow-ins" by removing tall growing vegetation and promoting low growing "compatible" vegetation. Defining compatible/incompatible vegetation depends on many factors, such as type of vegetation, location of vegetation within the ROW, height of the power line (when at maximum sag point), voltage, and power line design. Work activities would typically include brush cutting both manual and mechanical, clean-up of cut material and herbicide treatments where acceptable.

Demand Work

To address imminent threats (vegetation concerns that cannot remain until schedule maintenance work occurs) identified by customer concerns, hazardous reports, and other unplanned maintenance.

Condition Assessments

To evaluate the effectiveness of the work program, document vegetation clearances and tree conditions, through inspections and reporting any immediate hazards.

Project Planning and Reporting

To analyze, prioritize, coordinate, and evaluate both API's long-term cycle program and short-term annual work programs while meeting the objectives of API's VM plan. Work activities include working with government agencies, First Nations and municipalities ensuring regulatory requirements are met; setting targets, scope of work, budgets and forecasting for successful work completion and monitoring, recording data and reporting on annual work programs that ultimately drive the success of API's long- term VM plan.

Customer/landowner notifications

To inform landowners and/or customers of API's annual VM work activities including permissions for herbicide use. Work activities include confirming land ownership and completing VM work notifications, creating work packages entailing scope of VM activities for field crews and managing public relations including community information sessions.

Quantification of APIs VM Workload - Annual Volume Workload (AVW)

The Annual Volume Workload (AVW) is the annual work required to achieve the overall VMP objectives and is based on the average volume (the amount and/or density) of the vegetation and complexity of the work which includes worker qualifications (specialized/Utility Arborist see Figure 5), accessibility to and along the ROW, type of terrain and equipment required to complete the work. AVW is measured across a density level classification related to tree growth (biomass additions/amount of growth), mortality (rate of tree decline) and complexity of work. It is classified as low, medium, or heavy. A ROW that is rated as "low" level of density, has a low volume of vegetation to be managed and is accessible along a roadside. Comparatively, a "heavy" level of density has a high volume of vegetation to be managed in combination with remote and hard to access ROWs (rough terrain).

The total amount of work is determined for each work category or program (tree trimming, hazard tree removal, brush cutting/mowing and herbicide application). The maintenance cycles for each work category, except hazard trees, are derived from growth rates. The brush control area is defined by the width and the length of ROWs that are located adjacent to natural tree stands.

Hazard trees are defined as trees that both could contact electric facilities on failure (breakage or tipping over) and have a visually assessable fault or indicator of failure (dead, diseased, damaged, etc.). The AVW for hazard trees is based on the tree inventory, conditional assessment, and priority risk rating for failure based on the following:

- imminent,
- within the year or
- tracked and to be managed/assessed during next line clearing cycle.

VM Programs and Work Activities: Maintenance Cycle Frequency

With the work completed to identify API's annual workload, the foundation for a least cost sustainable VMP has been provided. The associated maintenance cycles, based on API's annual volume of work are described below.

Brush Removal is brush needing to be cut, whether by manual or mechanical means, and has a maintenance cycle of 6 years. By revisiting each area every 6 years, minimal brush is encroaching on conductors and impeding public safety, access to the powerline and reliability and increase the risk vegetation contacting or arcing with power lines which may have the potential of starting forest fires. While recent recommendations, with benefit of a cost efficiency, (see *Appendix A: Algoma Program Assessment Report, Page 29, Cycle Lengths),* it is noted that a level of control (related to brush height and density) must first be achieved, which API has not yet reached.

Herbicide Application is brush that will be treated with herbicide and is on a maintenance cycle of 6-years. Brush suitable for herbicide applications represents the lowest level of public and reliability risk and the least cost treatment for a utility. The current 6-year cycle is based on encroachment (growth of vegetation) into the powerline versus height of growth for a low volume foliar application. It is recommended in the report provided by ECI (*Appendix A: Algoma Program Assessment Report, Page 39, Recommendations Brush Control, Page 39),* that API implement a 3-year cycle frequency to gain cost and operational efficiencies by reducing brush density to be managed. Unfortunately, due to the declining landowner permission issue outlined below, API is unable to implement this approach at this time on a system-wide basis, but API will continue to attempt to implement this where opportunities for larger-scale applications exist (ie: where permissions are obtained for larger sections of line).

Tree trimming is trees requiring clearance through trimming work and has a 6-year maintenance cycle. This cycle will serve to reduce and minimize the number of encroachments and grow-in related outages.

Hazard Tree Removal is trees needing to be removed and has a 6-year maintenance cycle. The annual volume of work includes funding for the removal of newly emergent hazard trees. A 6-year established maintenance cycle will prevent the major build up in hazard trees between maintenance events.

API's ROW clearance widths are typical of industry standards. Clearance standards are based on average growth rates for the predominant vegetation species on API's electrical system based on a 6-year maintenance cycle.

Table 1: API ROW Clearance Standard

Line Type	*Width (m)
Express Feeder (44kV)	16.5
Express Feeder (12.5-34.5kv)	10.5
New Primary (2.4-25 kV)	6
Existing Primary (2.4-25 kV)	4.5
Secondary (<750V) – System	1.5
Secondary (<750V) - Taps	1
Underground – Various Voltage Classes	3

*Widths are measured from either side of the outside conductor.

VM Future Considerations and Recommendations

VM budget is based on actual field conditions including the system's tree exposure, tree and brush growth and mortality rates specific to API's service territory. The following summary of key recommendations provided by ECI (*see Appendix A: Algoma Program Assessment Report, Summary of Key Recommendations, Page 1*) recommends improvements and efficiencies that are to assist API in achieving program goals and objectives:

Improvement and efficiencies achieved through this VM Plan are:

1. Work collaboratively with vendors to better understand and remove risk barriers that are driving up costs.
2. Consider working several high price bid circuits (pilot) under T&M to measure and quantify the

potential savings over firm-price.

3. Pending a successful outcome of the pilot, consider converting the current firm price contract strategy to T&M, eventually building in incentives to encourage the contractor to take responsibility for production goals and targets. T&M contracts will allow for an easy transition to longer-term contracts and lead to the development of a steady local workforce.
4. Require the Arborist/Forester to update work specification documents, process documents and internal control reports to bring API up to best-in-class and meet current industry best management practices.
5. Continue to require the contractor to demonstrate that he/she is setting daily and weekly targets for work completion for his/her crews to control costs.
6. Expand the use of herbicides where allowed to treat stumps on removed deciduous trees (trees removed by contract tree crews) to prevent re-sprouting which leads to increased biomass when one stem becomes many stems.
7. Expand the current herbicide program on distribution line segments, particularly in rural areas. Consider a more robust Integrated Vegetation Management (IVM) program by continuing to implement foliar herbicide applications to control brush on the ROW floors. Refer to the provided IVM Plan for additional program enhancements. While initial costs may be significant, the potential for future cost savings is high.
8. Consider a work acceptance (QC) process for planned maintenance work utilizing the ANSI/ASQ Z1.4 audit process to reduce the amount of time required to perform completed work audits. Incorporate the audit process into existing contracts and specifications.
9. Continue to maintain a maximum six-year maintenance cycle for pruning work. However, consider increasing brush cycle on manual cut rights-of-way (ROW) to recommended nine-year cycle if conditions allow, in order to save O&M planned maintenance expenditures.
10. Begin post-outage investigations on all multi-phase and outages affecting 89 customers or more or where the outage duration is in excess of 221 minutes. This will be beneficial to help identify problem areas requiring maintenance, aid in the development of reliability-based annual and long-range maintenance plans, ensure program dollars are being effectively utilized to reduce outage events, and verify that the correct outage cause-code was used.
11. Adopt the principles of RCM (reliability centered maintenance) to ensure crews are cutting only the trees that should be maintained

Adequate Funding and Associated Risks of Underfunding VM Work

To mitigate risks and ensure safe and reliable operation of the electrical system, adequate funding is necessary to manage the annual volume workload (AVW). Taking an approach that annually addresses the AVW will provide the least cost sustainable program while simultaneously minimizing tree-related service interruptions.

The performance and quantification review completed in 2014, identified the AVW based on tree exposure, growth, and rate of decline, setting a foundation for the annual workload to be removed each year. The investment to remove the AVW avoids inefficiencies that are inherently more costly when trees become a problem and typically require more reactive management (higher cost, less productive). When AVW is systematically approached, cost and operational efficiencies are presented through preventative and adaptive management by reducing the risk of exposure and occurrence of tree-caused outages and hazards. Additionally, managing the AVW extends and/or introduces the use of best management practices such as more mechanized equipment and herbicide applications thereby extending the maintenance free period. In reference to the 2014 study, the Program Assessment completed in 2023 by ECI, recommends API continue to extend the use of mechanical and herbicide treatments to manage AVW and to increase operational efficiencies and control or lower costs. Reducing the AVW and extending the cycle frequency is a key component to:

- increasing system performance and resiliency,
- meeting long term sustainability goals and,
- lowering overall costs associated with vegetation management over time.

Algoma Power Inc.

Distribution System Plan

Appendix C

Filed Separately due to File Size

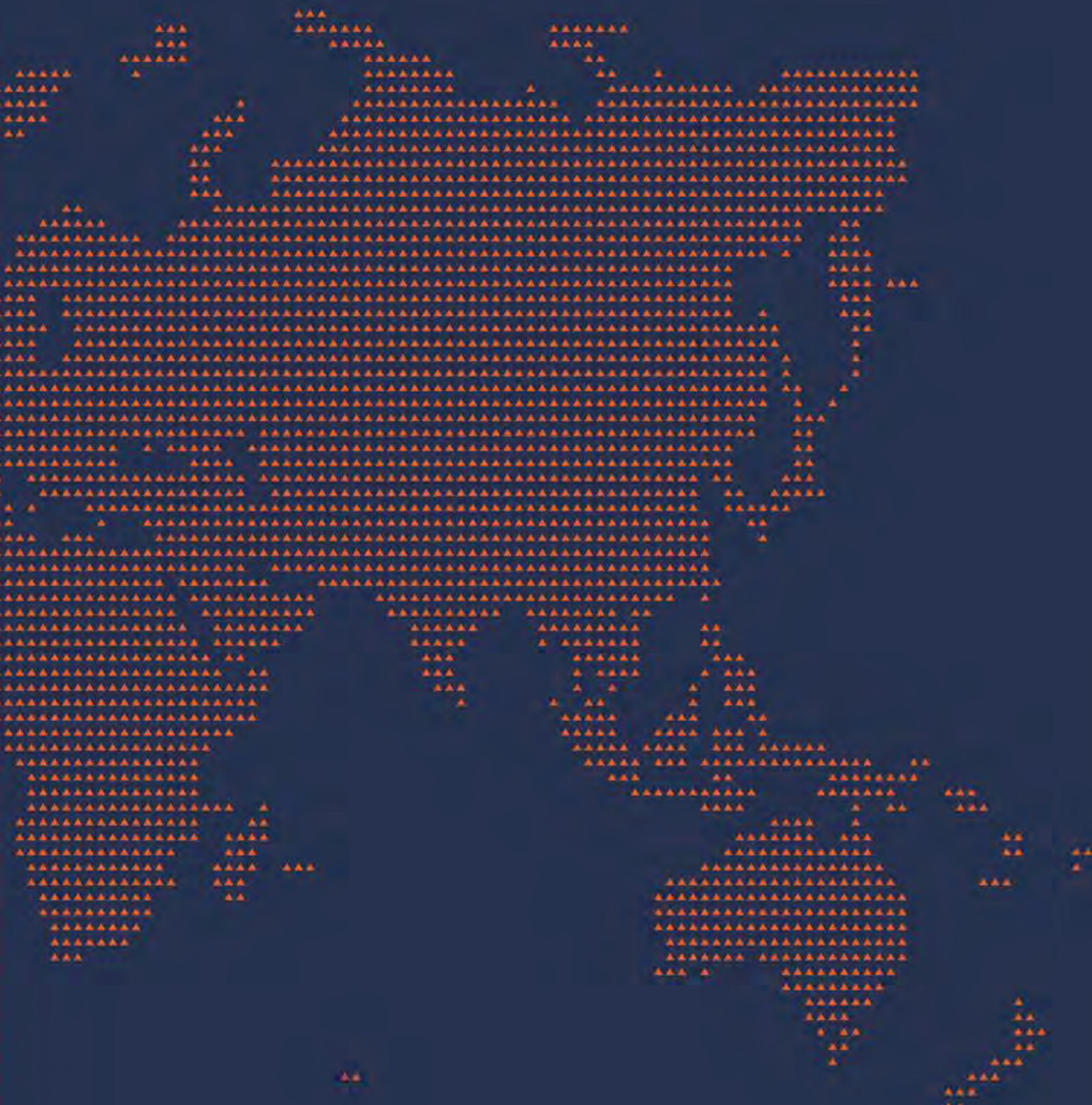
Algoma Power Inc.

Distribution System Plan

Appendix D

METSCO

MAKING IT POSSIBLE



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ASSET CONDITION ASSESSMENT REPORT 2023

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Prepared by

Project #23-214 – Final Draft

Dec 2023

Title:	Asset Condition Report 2023
Project ID:	P-23-144

Revision	Date	Authors	Description
R0	Oct 2023	A. Rana G. Watmough K. Martin-Sturmey	Issued for review
R1	Nov 2023	A. Rana G. Watmough K. Martin-Sturmey	Revised draft based on updated information and client feedback.
R2	Dec 2023	A. Rana G. Watmough K. Martin-Sturmey	Second revision and final draft.
R3	Jan 2024	A. Rana G. Watmough K. Martin-Sturmey	Transcription errors corrected.

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Executive Summary

This Asset Condition Assessment (ACA) report is prepared for API's distribution and station assets. The report provides estimates of the condition of API's assets based on data provided by API in the summer of 2023 and serves as a follow up to the previous report issued in 2018. In addition to re-evaluating API's assets, this report assesses the implementation of recommendations made in 2018 and suggests additional recommendations that API can take to further the maturity of their asset management programs and preserve the health of their equipment.

A brief outline of implementing a risk-based asset management is documented in Section 2, articulating the purpose and general methodology that informs this process. The general asset management methodology is presented in Section 3. The comprehensive methodology that has been developed and implemented for API's specific assets in scope is documented in Section 4. Section 5 provides recommendations based upon the results of the analysis and section 6 serves as a conclusion to the report.

Context of the Study

In the summer of 2023, API retained METSCO Energy Solutions Inc. ("METSCO") to conduct an ACA study for the utility in line with the previous report issued in 2018. To assist API and those unfamiliar with the previous report, this document includes a discussion on the role that ACA results play in the modern evidence-based AM frameworks and provides a series of recommendations aimed at the establishment of a comprehensive and sustainable AM practice over time.

Scope of the Study

The study covers fourteen electrical asset classes, which collectively represent the bulk of material assets owned by the utility and cover the majority of the essential equipment directly involved in the delivery of electricity distribution service.

The assets in scope include:

- **Station Assets:**
    - Station Power Transformers and Voltage Regulators
    - Station Reclosers
    - Station Switches
    - Station Yards
- **Distribution Assets:**
    - Wood Poles
    - Overhead Conductors
    - Underground Cables

- Distribution Transformers
- Ratio-bank Transformers
- Reclosers
- Capacitor Banks
- Voltage Regulators

Methodology and Findings

For all asset classes that underwent assessment, METSCO used a consistent scale of asset health, containing five categories – from Very Good to Very Poor. The Health Index ("HI") formulations for individual asset classes represent weighted averages of numerical scores for individual HI subcomponents, known as condition parameters, scored on a scale from 0 to 100. The numerical score ranges, condition categories, and typical characteristics of an asset are described in Table 0-1.

Table 0-1: Definition of HI Scores

HI Score (%)	Condition	Description	Implications
85-100	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
70-85	Good	Significant Deterioration of some components	Normal Maintenance
50-70	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
30-50	Poor	Widespread serious deterioration	Start planning process to replace or rehabilitate, considering risk and consequences of failure
0-30	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on the assessment

Condition parameters are weighted relative to their importance to the health of the asset and are aggregated to produce the HI. This methodology was used to calculate HIs for all of API's asset classes that had sufficient data. METSCO's findings for each asset class developed using this methodology are provided in Figure 0-1 , Table 0-2, and Table 0-3. These results are described in more detail in Section 4.

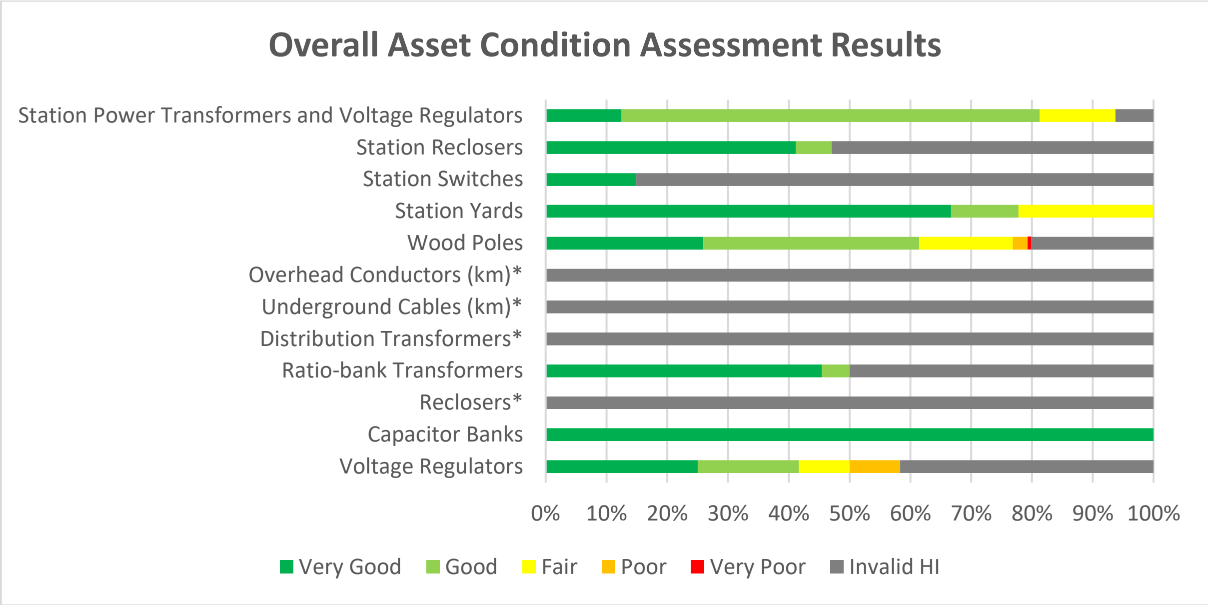

Figure 0-1: Overall Asset Condition Assessment Results

**No HI formulation created*

Table 0-2 Overall Asset Condition Assessment Results

Asset Category	Asset Population (#)	HI Distribution						DAI
		Very Good	Good	Fair	Poor	Very Poor	Invalid HI	
Station Assets								
Station Power Transformers and Voltage Regulators	16	2	11	2	0	0	1	83%
Station Reclosers	17	7	1	0	0	0	9	61%
Station Switches	67	10	0	0	0	0	57	63%
Station Yards	9	5	2	2	0	0	0	100%
Distribution Assets								
Wood Poles	28,931	7,512	10,272	4,440	718	157	5,832	76%
*Overhead Conductors (km)**	2,926	-	-	-	-	-	-	4%
*Underground Cables (km)**	34	-	-	-	-	-	-	33%
*Distribution Transformers**	5,233	-	-	-	-	-	-	99%
Ratio-bank Transformers	44	20	2	0	0	0	22	95%
*Reclosers**	110	-	-	-	-	-	-	-
Capacitor Banks	4	4	0	0	0	0	0	95%
Voltage Regulators	12	3	2	1	1	0	5	79%

**No HI Formulation Available*

Table 0-3 Age Demographics Summary

Asset Category	Asset Population (#)	Age Distribution					
		0-10 Years	11-20 Years	21-30 Years	31-40 Years	40+ Years	Unknown
Station Assets							
Station Power Transformers and Voltage Regulators	16	4	3	2	4	2	1
Station Reclosers	17	2	5	1	1	0	8
Station Switches	67	6	8	4	0	0	49
Station Yards	9	-	-	-	-	-	-
Distribution Assets							
Wood Poles	28,931	1,626	5,904	2,668	5,056	7,845	5,832
Overhead Conductors (km)	2,926	13	53	25	1	27	2,808
Underground Cables (km)	34	7	3	2	0	0	23
Distribution Transformers	5,233	704	1,254	1,130	1,123	959	63
Ratio-bank Transformers	44	15	18	4	6	0	1
*Reclosers***	110	-	-	-	-	-	-
*Capacitor Banks***	4	-	-	-	-	-	-

*Voltage Regulators***	12	-	-	-	-	-	-

***No age information available*

As the above figure and tables indicate, the majority of API's assets for which a valid HI could be calculated are in Good condition or better. There is a relatively minor portion of the system with assets in Poor or Very Poor condition which indicates that there is no extensive deterioration across the system and there are no major concerns with the manner in which assets have been managed. API's assets that have been assessed to be in Fair condition should be more closely monitored, as they may require more frequent maintenance or replacement, depending on the risk they pose to API's operations in the event of a failure.

To contextualize the lack of data availability in asset classes as a whole, the asset classes most affected by data availability issues are those where condition data is logistically complex or uneconomic to collect (e.g., overhead conductors where condition tests typically involve the use of expensive equipment and are typically reserved for transmission equipment only);

Section 4 of this report provides an extensive discussion of the HI calculations for each asset class, outlines the assumptions underlying our interpretation of the data provided by API, and provides recommendations for future enhancements.

API's Current Health Index Maturity and Continuous Improvement

Overall, we found API to have a material amount of data that enabled us to conduct analysis that should yield meaningful managerial insights to the utility's planners. With respect to the core distribution utility assets like wood poles and station power transformers, we were able to construct relatively advanced multi-factor health indices. While comparatively less information is available for some other asset classes, the lack of availability or data diversity should not necessarily be identified as a gap or an oversight on the part of the utility. The scope of a utility's data collection is just one of a multitude of factors that influence a utility's decision-making, where strategic trade-offs need to be made in an environment of multiple priorities and constrained operating costs.

METSCO understands API is committed to improving the maturity of its asset management program and will continuously improve its asset management practices . We expect that API will continue to make these determinations based on the recommendations contained in this report, balancing the continuous improvement considerations with the opportunity cost of other activities.

Table of Contents

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List of Tables

List of Acronyms and Abbreviations

The following acronyms are used within the Asset Condition Assessment report:

Acronym	Definition
ACA	Asset Condition Assessment
AM	Asset Management
API	Algoma Power Inc.
DAI	Data Availability Index
DSP	Distribution System Plan
HI	Health Index
ISO	International Organization for Standardization
METSCO	METSCO Energy Solutions Inc.
O&M	Operations and Maintenance
TUL	Typical Useful Life

1 Introduction

METSCO Energy Solutions Inc. ("METSCO") previously developed an asset health index ("HI") framework for API's fixed electrical distribution and substation assets in 2018. Since then, API's asset data quality has improved, and there are more inspection/test results available. This allows for continuous improvement of API's asset health demographics in a manner consistent with international Asset Management ("AM") standards. API engaged METSCO to update the Asset Condition Assessment ("ACA") of API's fixed electrical distribution and substation assets to improve the accuracy of system health demographics based on the latest maintenance and inspection data available in 2023. To assist API with further asset condition data integration efforts, Section 5 of this report contains a set of recommendations for the utility's management to consider going forward.

In preparation of this report, METSCO relied on the following data sources:

- Asset inspection and testing data collected by API staff or external contractors;
- Trouble reports for certain types of equipment completed by API staff;
- The previous iteration of the report from 2018.

METSCO employed an objective threshold-based approach related to the percentage of assets for which data was available to determine whether a given parameter would be included in the health index calculation. As such and by way of foreshadowing our recommendations to management, METSCO recommends that API's integrated AM function concentrate its efforts on ensuring that the data already being collected for some assets is captured for all the assets in the system rather than investing in new types of asset information.

To assist API in its ongoing work to define the scope and nature of its future AM strategy, this report contains several recommendations identifying specific types of data to be collected for the asset classes examined.

In recognition of API's current efforts to define its future AM strategy, this report also provides a set of recommendations for advanced AM metrics that the utility can choose to deploy to derive additional managerial insights from the data collected in the field. We provide our recommendations solely for the purposes of helping the utility consider the range of approaches to advancing its AM capabilities and expect that API will exercise its discretion as to their suitability based on careful consideration of their value proposition relative to the opportunity cost of other strategic initiatives.

2 Context of the ACA Within AM Planning

The ACA is a key step in developing an asset replacement strategy. By evaluating the current set of available data related to the condition of in-service assets comprising an organization's asset portfolio, condition scores for each asset are determined. The ACA involves the collection, consolidation, and utilization of the results within an organizational AM framework for the purposes of objectively quantifying and managing the risks of its asset portfolio. The level of degradation of an asset, its configuration within the system, and its corresponding likelihood of failure feed directly into the risk evaluation process, which identifies asset candidates for intervention (i.e., replacement or refurbishment). Assets are then grouped into program and project scopes that are evaluated and prioritized.

The ACA is designed to provide insights into the current state of an organization's asset base, the risks associated with identified degradation, approaches to managing this degradation within the current AM framework, and how to best make use of these results to extract the optimal value from the asset portfolio going forward.

2.1 International Standards for AM

The following paragraphs serve as a brief introduction to the International Organization for Standardization ("ISO") standards and provide a brief overview of the applicability of AM standards within an entity.

The industry standard for AM planning is outlined in the ISO 5500X series of standards, which encompass ISO 55000, ISO 55001, and ISO 55002. Each business entity finds itself at one of the three main stages along the AM journey:

1. Exploratory stage - entities looking to establish and set up an AM system;
2. Advancement stage - entities looking to realize more value from an asset base; and
3. Continuous improvement stage - those looking to assess and progressively enhance an AM system already in place for avenues of improvement.

Given that AM is a continuous journey, ISO 5500X remains continuously relevant within an organization; providing an objective, evidence-based framework against which the organizations can assess the managerial decisions relating to their purpose, operating context, and financial constraints over the different stages of their existence.[1]

An asset is any item or entity that has value to the organization. This can be actual or potential value, in a monetary or otherwise intangible sense (e.g., public safety). The hierarchy of an AM framework begins with the asset portfolio, containing all known information regarding the assets, and sits as the

[1] ISO 55000 – Asset management – Overview, principles and terminology

fundamental core of an organization. The ACA is the procedure to turn the known condition information into actionable insights based on the level of deterioration.

Around the asset portfolio, the AM system operates and represents a set of interacting elements that establish the policy, objectives, and processes to achieve those objectives. The AM system is encompassed by the AM practices – coordinated activities of the organization to realize maximum value from its assets. Finally, the organizational management organizes and executes the underlying hierarchy.[1]

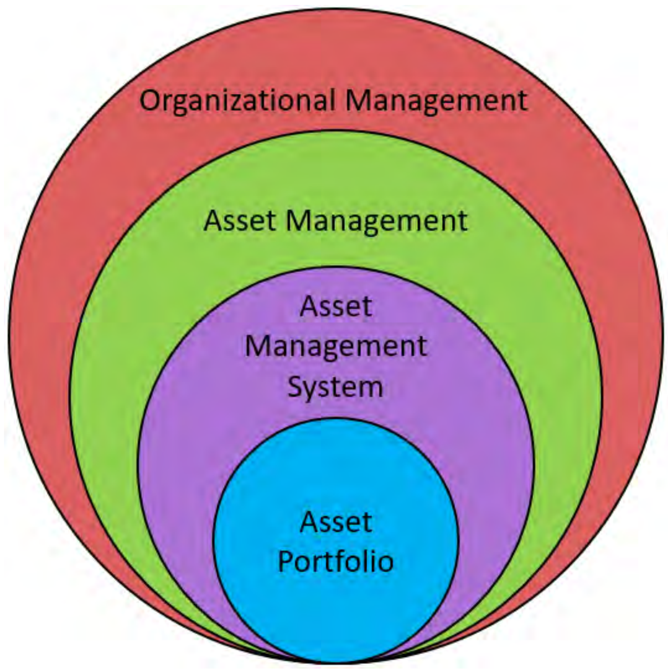


Figure 2-1: Relationship Between Key AM Terms[1]

2.2 ACA Within the AM Process

A well-executed AM strategy hinges on the ability of an organization to classify its assets via comprehensive and extensive data and data collection procedures. This includes but is not limited to:

- Collection and storage of technical specifications;
- Historical asset performance;
- Projected asset behaviour and degradation;
- Configuration of an asset or asset-group within the system; and
- Operational relationship of one asset to another.

In this way, AM systems should be focused on the techniques and procedures in which data can be most efficiently extracted and stored from its asset base to allow for further analysis and insights to be made.

With more asset data on hand, better and more informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio managed by an organization.[2]

AM is fundamentally grounded in a risk-based evaluation of continued value. The overarching goal of an AM process is to quantify all assets risk by their probability and impact (where possible) and then look to minimize these risks through AM operations and procedures. The ACA quantifies the condition of each asset under study and is an appropriate indicator of its failure probability. Making asset replacement decisions directly based on the ACA results constitutes a condition-based intervention strategy.

AM practices can help quantify and drive strategic decisions. A better understanding of the asset portfolio and how it is performing within an organization will allow for optimal decision-making. This is largely due to best AM practices being a fundamentally risk-based approach, which lends it to be a structured framework for creating financial plans driven by data. AM practices should also have goals in mind when framing asset investments, changes in asset configuration, or acquisition of new assets. This can include better technical compliance, increased safety, increased reliability, or increased financial performance of the asset base. ISO 55002 states explicitly that all asset portfolio improvements should be assessed via a risk-based approach prior to being implemented. The criticality of the asset determines its failure impact. A risk-based asset intervention strategy should consider both the probability and impact in the decision-making process.

2.3 Continuous Improvement in the AM Process

The application of rigorous AM processes can produce multiple types of benefits for an organization including, but not limited to: realized financial profits, better classified and managed risk among assets, better-informed investment decisions, demonstrated compliance among the asset base, increased public and worker safety, and corporate sustainability.[1]

AM processes are ideally integrated throughout the entire organization. This requires a well-documented AM framework that is shared between all relevant agents. In this way, the organization stands to benefit the most from its internal resources, whether it be via technical experts, those operating and maintaining the assets or those with an understanding of the financial operations and constraints on the organization. As a future-state goal, utilities and other organizations alike should strive to document their AM guiding principles within a Strategic Asset Management Plan (“SAMP”). The SAMP should be used as a guide for the organization to apply its AM principles and practices for its specific use case. Distribution of the SAMP should be well-publicized within an organization and updated on a regular basis, to best quantify the most current and comprehensive AM practices being implemented. Just as the asset base performance is subject to an in-depth review, the AM process and system should be reviewed with the same rigor.[1]

AM should be regarded as a fluid process. Adopting a framework and an idealized set of practices does not bind the organization or restrict its agency. With time, the goal of any AM system is to continually

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

improve and realize benefits within the organization through better management of its asset portfolio. Continually improved asset data and data collection procedures, updated SAMPs, and further integration into all aspects of an organization's activities as it grows and changes over time should be the goal of any AM framework.

3 Asset Condition Assessment Methodology

METSCO's scope of work for API's ACA study was divided into several parts:

1. Reviewing previous iteration of API's ACA to identify improvements in HI formulation for their assets.
2. Performing a condition assessment on assets based on API's current data from various sources (demographics, visual, testing, etc.).
3. Summarizing results of the ACA.
4. Making recommendations for future data collection improvements.

3.1 Data Sources

To assess the demographics and establish the unit population of API's assets, the utility provided METSCO with various data sources, such as demographic information, visual inspection records, and test results. When synthesizing these datapoints, METSCO used an additive approach to formulate the HI. In an additive model, asset degradation factors and scores are used to independently calculate a score for each individual asset, with the HI representing a weighted average of all individual scores from 0 to 100. This methodology is in alignment with other utilities in Ontario.

3.2 Overview of Selected Methodology

To calculate the HI for an asset, formulations are developed based on condition parameters that can be expected to contribute to the degradation and eventual failure of that asset. A weight is assigned to each condition parameter to indicate the amount of influence the condition has on the overall health of the asset. Figure 3-1 exemplifies an HI formulation table.

Condition parameters of the assets are characteristic properties that are used to derive the overall HI. Condition parameters are specific and uniquely graded to each asset.

Degradation Factor:
The asset aging mechanisms, tests, or failure modes.

Condition Indicator Numerical Score:
The converted numerical score associated with the degradation factor, which corresponds directly with the indicator letter score.

Condition Max Score:
The highest obtainable Score for each degradation factor. (4 x Weight)

#	Degradation Factor	Weight	Condition Indicator Letter Score	Condition Indicator Numerical Score	Condition Max Score
1	Degradation Factor 1	4	A-E	4-0	16
2	Degradation Factor 2	6	A,C,E	4,2,0	24
3	Degradation Factor 3	6	A-E	4-0	24
				Asset Max Score	64

Condition Weight:
The impact of the condition with respect to asset failure and/or the safe operation of the asset. Higher impact results in higher weight

Condition Indicator Letter Score:
The letter grade associated with the degradation factor – this is typically captured from the raw inspection data.

Asset Max Score:
The highest numerical grade that can be assigned to the asset / asset class, given the associated degradation factors and weights.

Figure 3-1: HI Formulation Components

The scale used to determine an asset's score for a condition parameter is called the "condition indicator". Each condition parameter is ranked from A to E and each rank corresponds to a numerical score. In the above example, a condition score of 4 represents the best grade, whereas a condition score of 0 represents the worst grade.

A – 4	Best Condition
B – 3	Normal Wear
C – 2	Requires Remediation
D – 1	Rapidly Deteriorating
E – 0	Beyond Repair

3.2.1 Final Health Index Formulation

The final HI, which is a function of the condition scores and weightings, is calculated using the following formula:

$$HI = \left(\frac{\sum_{i=1} Weight_i * Numerical\ Grade_i}{Total\ Score}\right) x\ 100\%$$

Where *i* corresponds to the condition parameter number, and the HI is a percentage representing the remaining life of the asset.

3.2.2 Health Index Results

METSCO's assessment of API's assets uses a consistent five-point scale along the expected degradation path for every asset, ranging from Very Good to Very Poor. To assign each asset into one of the categories, METSCO constructs an HI formulation, which captures information on individual degradation factors contributing to that asset's declining condition over time. Condition scores assigned to each degradation factor are also expressed as numerical or letter grades along with pre-defined scales. The final HI – expressed as a value between 0% and 100% - is a weighted sum of scores of individual degradation factors, with each of the five condition categories (Very Good, Good, Fair, Poor, Very Poor) corresponding to a numerical band. For example, the condition score of Very Good indicates assets with HI values between 100% and 85%, whereas those found to be in a Very Poor condition score are those with calculated HI values less than 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 3-1 presents the HI ranges with the corresponding asset condition, its description as well as implications for maintaining, refurbishing or replacing the asset prior to failure.

Table 3-1: HI ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

3.3 Data Availability Index

To put the calculation of HI values into the context of available data, METSCO supplemented its HI findings with the calculation of the DAI: a measure of the availability of the condition parameter data weighted by each condition parameter to the HI score. The DAI is calculated by dividing the sum of the weights of the condition parameters available to the total weight of the condition parameters used in the HI formulation for the asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} Weight_i * \alpha_i}{\sum_{i=1} Weight_i} \right) x\ 100\%$$

Where *i* corresponds to the condition parameter number and α is the availability of coefficient (=1 when data available =0 when data unavailable).

4 Asset Condition Assessment Results

This section presents the current HI formulation for each asset class, the calculated HI scores, and the data available to perform the study.

In this iteration, we see an improvement in the DAI of most asset classes, with a few exceptions. Even as API is refining its data collection procedure, there are assets that do not qualify for a full HI. It is still useful to highlight those assets where data improvements are expected to show progress in future reports.

For most of the assets, an HI was already developed based on industry best practices and then modified based on a reasonable expectation of data availability. In the case of some asset classes, only demographic information is given because condition data is not available. In other cases, the only data available is demographic (age) data taken from the asset registry along with the results of visual field inspections.

Regardless of the number of available data points, for the sake of consistency in reviewing the study's results, all of METSCO's findings are presented in the same visual distribution format – separating assets into five condition bands between "Very Poor" and "Very Good" with the sixth category of "Invalid HI" to identify the number of assets where data availability was insufficient to meet the threshold.

Where missing data are assumed to be infrequent and random, the HI may be extrapolated across the asset category. Ideally, for extrapolation to be carried out for an asset class, a minimum of 40 known values per age band is usually required which is based on a 95% data confidence interval.

The tables and figures below present the results of the ACA study.

Table 4-1 HI Summary Results

Asset Category	Asset Population (#)	HI Distribution						DAI
		Very Good	Good	Fair	Poor	Very Poor	Invalid HI	
Station Assets								
Station Power Transformers and Voltage Regulators	16	2	11	2	0	0	1	83%
Station Reclosers	17	7	1	0	0	0	9	61%
Station Switches	67	10	0	0	0	0	57	63%
Station Yards	9	5	2	2	0	0	0	100%
Distribution Assets								
Wood Poles	28,931	7,512	10,272	4,440	718	157	5,832	76%
*Overhead Conductors (km)**	2,926	-	-	-	-	-	-	4%
*Underground Cables (km)**	34	-	-	-	-	-	-	33%
*Distribution Transformers**	5,233	-	-	-	-	-	-	99%
Ratio-bank Transformers	44	20	2	0	0	0	22	95%
*Reclosers**	110	-	-	-	-	-	-	-
Capacitor Banks	4	4	0	0	0	0	0	95%
Voltage Regulators	12	3	2	1	1	0	5	79%

**No HI Formulation Available*

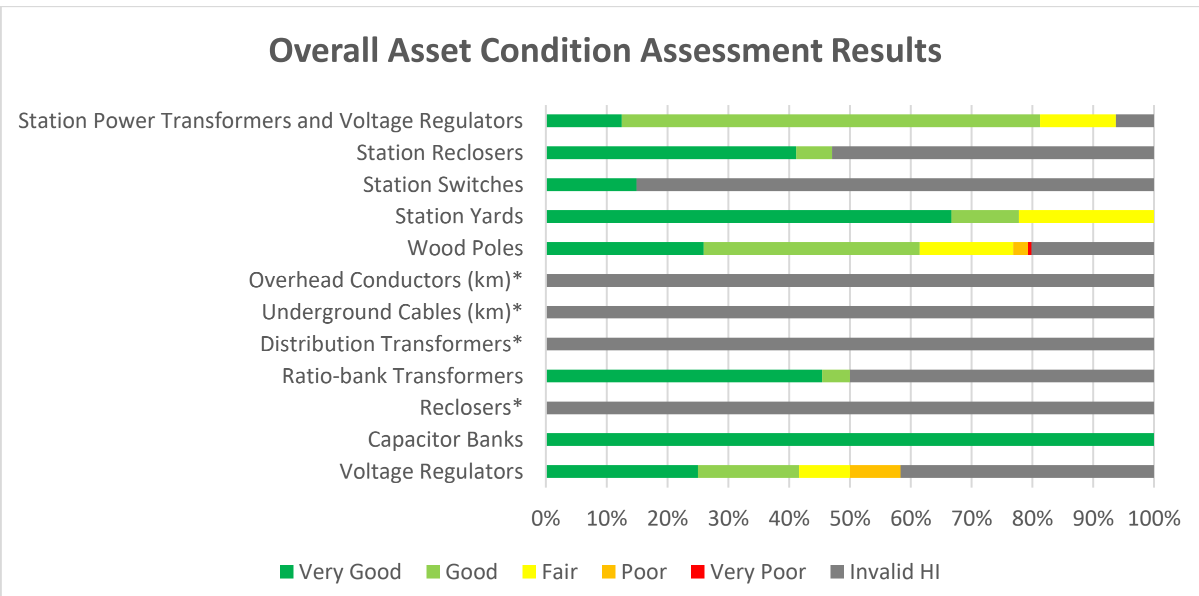


Figure 4-1 Overall Asset Condition Assessment Results

Table 4-2 Age Demographics Summary

Asset Category	Asset Population (#)	Age Distribution					
		0-10 Years	11-20 Years	21-30 Years	31-40 Years	40+ Years	Unknown
Station Assets							
Station Power Transformers and Voltage Regulators	16	4	3	2	4	2	1
Station Reclosers	17	2	5	1	1	0	8
Station Switches	67	6	8	4	0	0	49
Station Yards	9	-	-	-	-	-	-
Distribution Assets							
Wood Poles	28,931	1,626	5,904	2,668	5,056	7,845	5,832
Overhead Conductors (km)	2,926	13	53	25	1	27	2,808
Underground Cables (km)	34	7	3	2	0	0	23
Distribution Transformers	5,233	704	1,254	1,130	1,123	959	63
Ratio-bank Transformers	44	15	18	4	6	0	1
*Reclosers***	110	-	-	-	-	-	-
*Capacitor Banks***	4	-	-	-	-	-	-
*Voltage Regulators***	12	-	-	-	-	-	-

***No age information available*

It should be noted that minor differences are to be expected between ACA population counts and other data sources due to the data scrubbing and validation process, and totals may not add up to 100% due to rounding.

As the above results indicate, the majority of API's assets are in Good condition or better, with relatively minor portions of assets receiving Fair grades and fewer still receiving Poor or Very Poor grades. As such, the results are indicative of a relatively healthy system – with no signs of material deterioration consistent with poor AM practices. While the portions of assets with No Valid HIs are significant for some asset classes, data availability has generally improved across asset classes since the 2018 ACA. This is sentiment is present in both the inclusion of new asset classes that were not analyzed in the 2018 ACA, as well as the availability of more granular data points for previously analyzed asset classes that enables the improvement of their HI methodology. This is most notable for API's wood poles.

In some cases, such as for overhead conductors, the collection of empirical condition data involves expensive laboratory or field-testing techniques, which are commonly seen as uneconomical for distribution assets (relative to their high-voltage transmission counterparts). Accordingly, while material data gaps exist across a number of asset classes, in many cases these gaps signal a deliberate strategic choice where collecting condition information was deemed to be impractical or uneconomical.

API is continuously evolving its long-term AM strategy and we expect it to revisit the scope and nature of data collection practices across its asset classes using the recommendations contained in the remainder of this report.

4.1 Stations Assets

This section describes those assets which represent the main station assets of the distribution system. Other assets are located at some stations which may be too minor to track.

4.1.1 Station Power Transformers and Voltage Regulators

Condition Assessment Methodology

Station transformers are the single most critical asset class owned by an LDC. Each transformer can be valued in the range of hundreds of thousands to millions of dollars and can affect tens of thousands of customers.

Degradation mechanisms include loss of insulation or oil quality due to overload or low-level internal faults causing heating, arcing, and/or physical deterioration such as corrosion or failed cooling systems. Station transformers are the most tested and tracked utility assets and reliable indicators of the impending need for maintenance or replacement include dissolved gas analysis (“DGA”), oil quality (“OQ”), and power factor (“PF”) testing. Some tests can be conducted in-service, and others required taking the asset out of service. Many features such as cooling fans are external to the tank and can be maintained in place.

Table 4-3 provides the HI algorithm for station transformers. The HI algorithm was constructed around several types of condition data: demographic information, operational data, test records, and visual inspection data. Demographic information refers to data related to the characteristics of individual assets, operational data encompasses information on the conditions in which it is expected to provide service, and test records document results from specific assessments or evaluations. Examples of visual inspection datapoints include the condition of the main tank, bushings, cooling equipment, gaskets, and paint.

The HI formulation has changed in some ways from the last iteration of the ACA as new data was provided while some parameters were no longer tracked and available from API. Additional details about these condition parameters and how they are graded can be found in Appendix A.

Table 4-3 Station Transformer and Voltage Regulator HI Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	6	A,B,C,D,E	4,3,2,1,0	24
2	Visual Inspection	12	A,B,C,D,E	4,3,2,1,0	48
3	Dissolved Gas Analysis	10	A,B,C,D,E	4,3,2,1,0	40
4	Insulation Power Factor / Polarization Index	10	A,B,C,D,E	4,3,2,1,0	40
5	Oil Quality	8	A,B,C,D,E	4,3,2,1,0	32
6	Peak Load	1	A,B,C,D,E	4,3,2,1,0	4
7	IR Scan	3	A,B,C,D,E	4,3,2,1,0	12
MAX SCORE					**200**

Data Collection and Assumptions

There are thirteen in-service station power transformers across ten stations within API's service territory, as well as one that serves as an on potential spare at the Hawk Junction Distribution Station. In addition to these station transformers, there are two voltage regulator transformers, one of which serves as an on potential spare also at Hawk Junction.

The DAI for this asset class is 83%. The availability of data for station power transformers and voltage regulators is presented below in Table 4-4.

Table 4-4 Station Power Transformer and Voltage Regulator Data Availability

Condition Parameter	Data Availability
Service Age	94%
Visual Inspection	75%
Dissolved Gas Analysis	94%
Insulation Power Factor / Polarization Index	69%
Oil Quality	88%
Peak Load	88%
IR Scan	81%

Demographics

Figure 4-2 shows the age distribution of API's station transformers and voltage regulators.

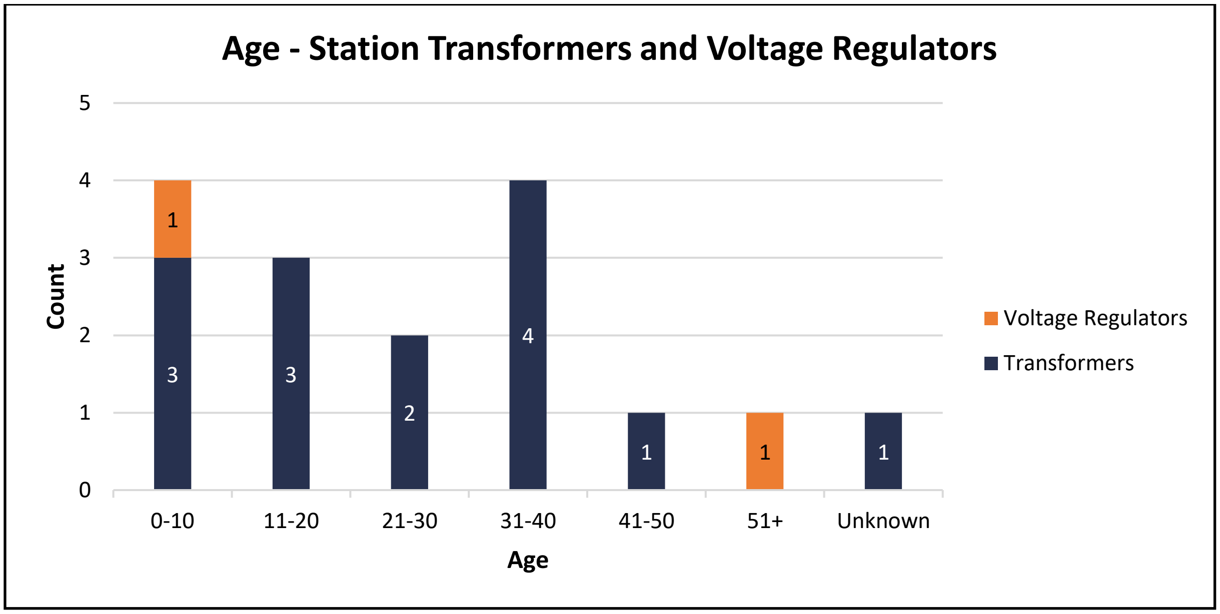


Figure 4-2: Station Transformer and Voltage Regulator Age Demographics

Hawk Junction's spare transformer has an unknown age, while its spare voltage regulator is 52 years old.

HI Results

Of API's sixteen total assets, fifteen had sufficient data to form a health index, two of which were in Fair or worse condition, as shown in Figure 4-3.

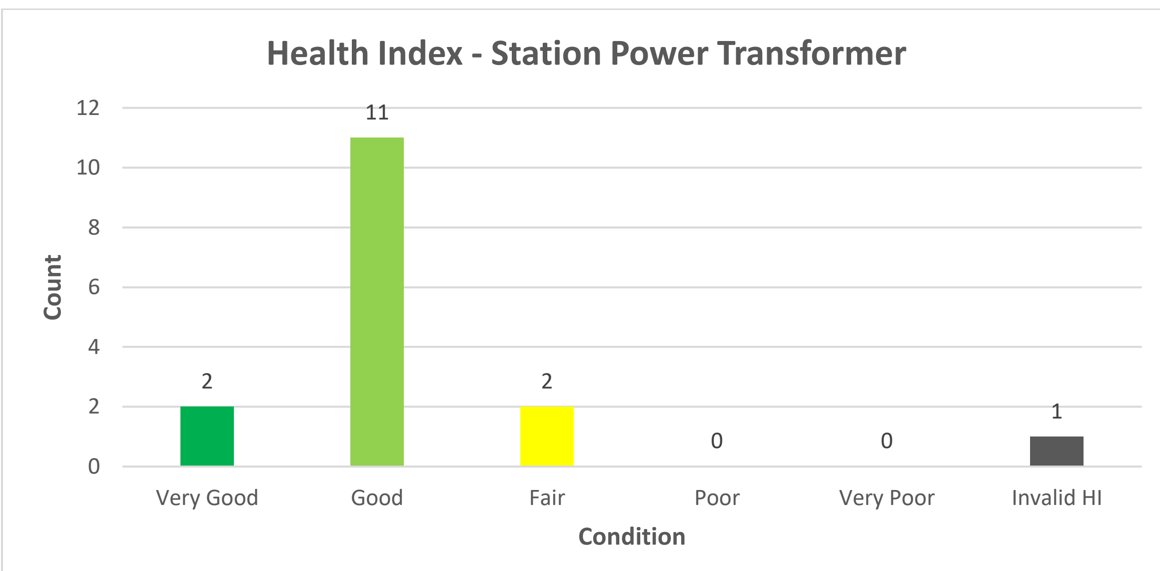


Figure 4-3: Station Transformer and Voltage Regulator HI Results

The breakdown of station transformer and voltage regulator assets, their DAI, and their calculated HI is presented in Table 4-5.

Table 4-5 Station Transformer and Voltage Regulator HI Breakdown

Station	Designation	DAI(%)	HI Score (%)	Condition
Bar River DS	T1	100%	92%	Very Good
Wawa #1 DS	T1	100%	90%	Very Good
Desbarats DS	T2	100%	85%	Good
Hawk Junction DS	T2	88%	83%	Good
Garden River DS	T2	100%	82%	Good
Desbarats DS	T1	80%	81%	Good
Bruce Mines DS	T1	80%	78%	Good
Hawk Junction DS	T1	78%	77%	Good
Dubreuilville Sub 87	T1	76%	76%	Good
Goulais TS	T1	94%	76%	Good
Dubreuilville Sub 86	T1	70%	71%	Good
Dubreuilville Sub 86	T2	70%	71%	Good
Hawk Junction DS	VR1	98%	71%	Good
Garden River DS	T1	80%	64%	Fair
Wawa #2 DS	T1	100%	56%	Fair
Hawk Junction DS	VR2	20%	--	--

The transformer in Fair condition, at Garden River DS, has reached a more advanced age (31 years in service) and scored poorly on the dissolved gas analysis and very poorly on the oil quality analysis. The transformer in Poor condition, at Wawa #2, is of a significantly advanced age (44 years in service) and has serious deficiencies in its physical condition. There is evidence of an oil leak on the conservator tank, damage to relays and paint, and significant corrosion of its control wiring.

As with all units assessed to be in Fair or worse condition, METSCO recommends closely monitoring these units as they may need more frequent maintenance or eventual replacement, posing a potential risk to API's operations.

4.1.2 Station Reclosers

<u>Condition Assessment Methodology</u>

Station reclosers are essential components in station electrical systems, functioning as protective devices that automatically interrupt and restore electrical power in the event of temporary faults or disturbances. These reclosers are typically larger and more robust than distribution reclosers, making them suitable for higher voltage levels and heavier loads. API's station reclosers feature significantly more robust data than their counterparts at the distribution level. The parameters that informs the HI is shown in Table 4-6 and additional information is available in Appendix A.

Table 4-6 Station Recloser HI Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	3	A,B,C,D,E	4,3,2,1,0	12
2	IR Scan	4	A,B,C,D,E	4,3,2,1,0	16
MAX SCORE					**28**

Data Collection and Assumptions

All data was provided by API and no assumptions were made.

The DAI for station reclosers is 61%. The availability of data for station reclosers is presented below in Table 4-7.

Table 4-7 Station Recloser Data Availability

Condition Parameter	Data Availability
Service Age	53%
IR Scan	71%

Demographics

Nine of API's seventeen station reclosers have age data. The breakdown is presented in Figure 4-4

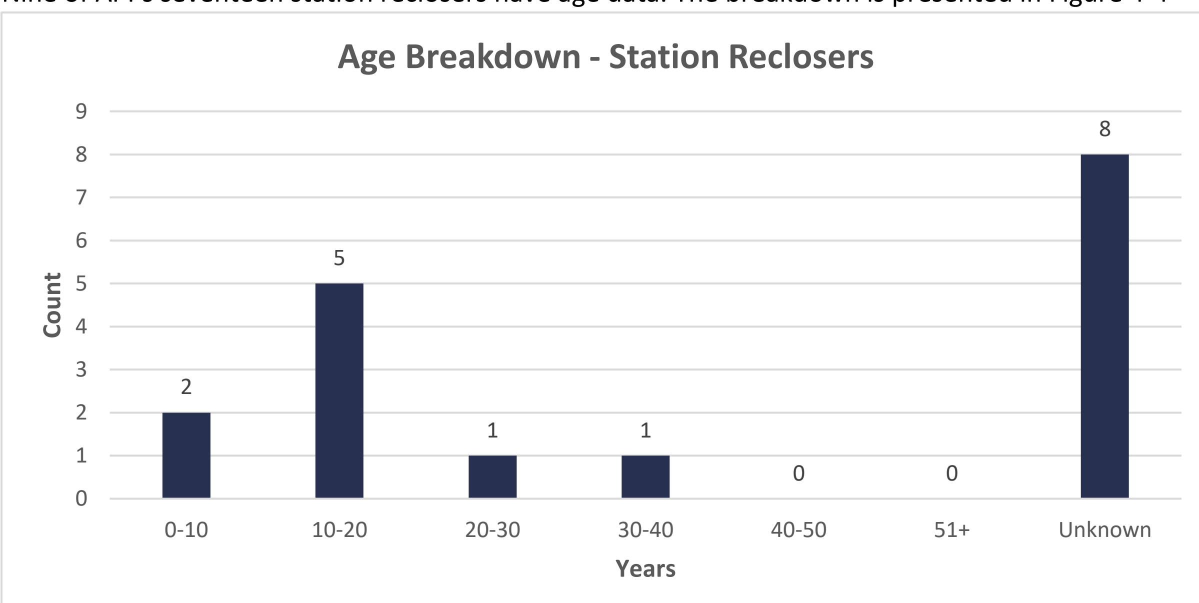


Figure 4-4 below. The reclosers that contain age data do not constitute a large enough sample size to be extrapolated to the remaining station reclosers without valid age data.

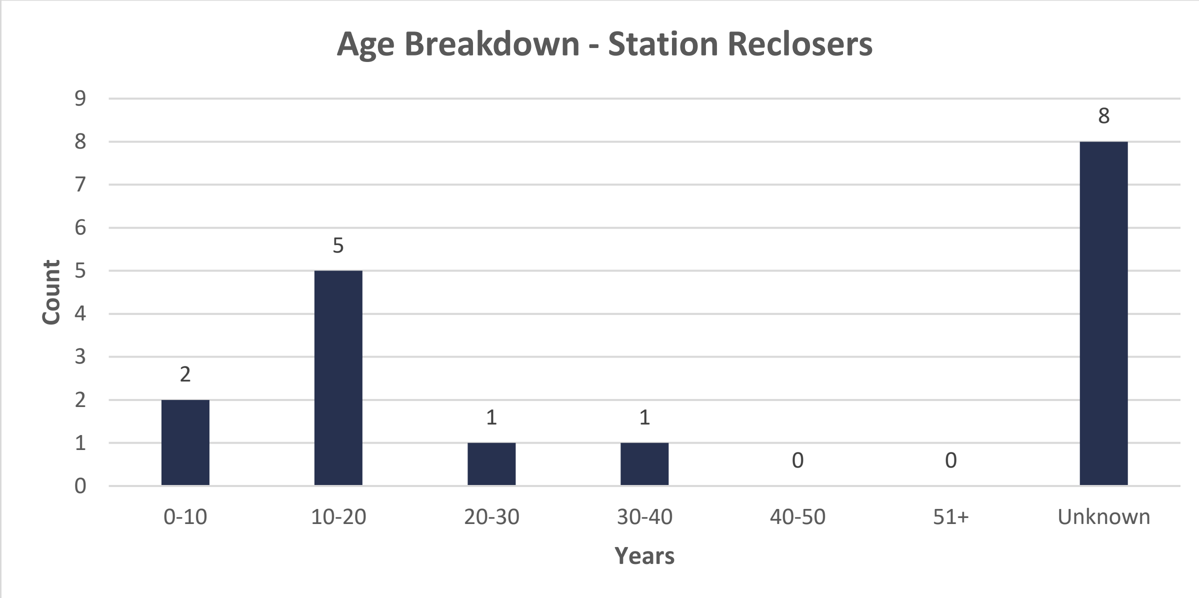


Figure 4-4 Age Breakdown – Station Reclosers

HI Results

Of the seventeen station reclosers, eight had enough data to form a valid health index, seven of which were assessed as being in Very Good condition and one identified as Good condition. The results are presented below in Figure 4-5.

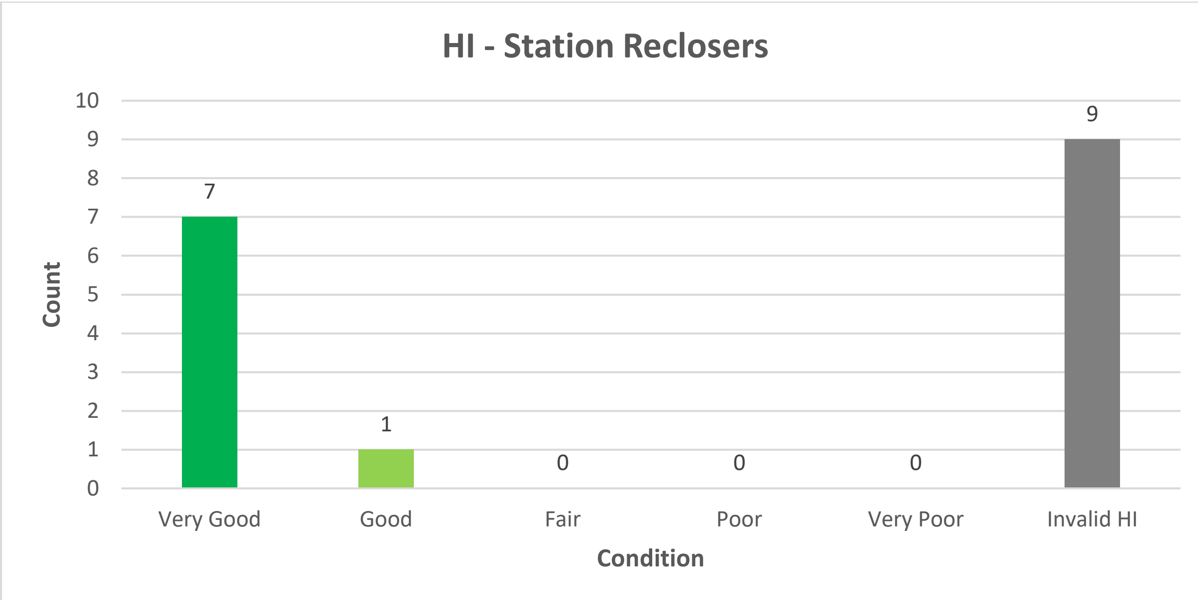


Figure 4-5 Health Index - Station Reclosers

4.1.3 Station Switches

Condition Assessment Methodology

Station switches serve as key control points that enable the manual or automated isolation and reconfiguration of electrical circuits within the substation. Station switches come in various types, such as disconnect switches, circuit breakers, and load-break switches, each designed for specific functions. They are crucial for safety, maintenance, and operational flexibility. Station switches allow for the de-energization of equipment for maintenance or repair, the isolation of faulty sections of the grid, and the reconfiguration of circuits to manage power flow and optimize grid reliability.

The parameters informing the HI are presented in Table 4-8. and further elaborated on in Appendix A.

Table 4-8 Station Switch HI Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Service Age	1	A,B,C,D,E	4,3,2,1,0	4
2	IR Scan	2	A,B,C,D,E	4,3,2,1,0	8
MAX SCORE					**12**

Data Collection and Assumptions

API operates 67 non-recloser switches at the station level. All data was provided by API and no assumptions were made.

The DAI for station switches is 63%. The data availability for station switches is presented below in Table 4-9

Table 4-9 Station Switches Data Availability

Condition Parameter	Data Availability
Service Age	27%
IR Scan	81%

Demographics

Eighteen of API's station switches possessed age data. The distribution of asset age is shown in Figure 4-6.

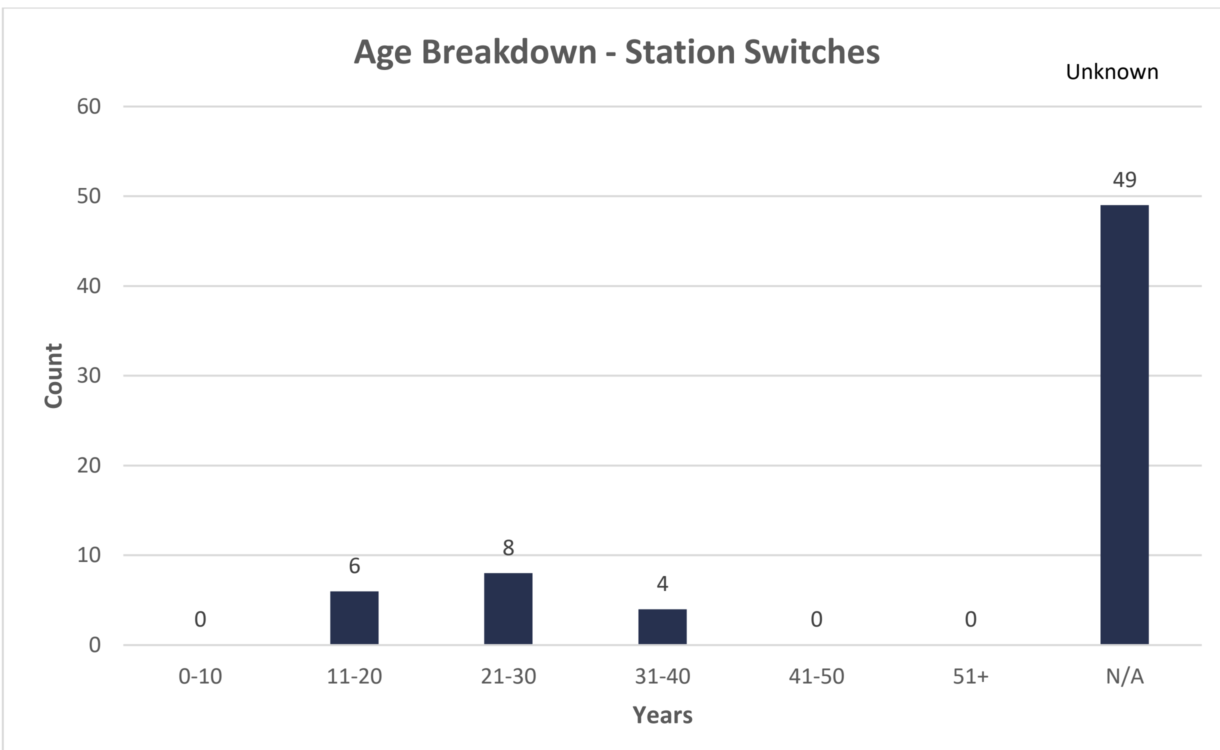


Figure 4-6 Age Breakdown - Station Switches

HI Results

Of the 67 station switches, only 10 have a sufficient amount of data to form an asset health index. The results are presented below in Figure 4-7.

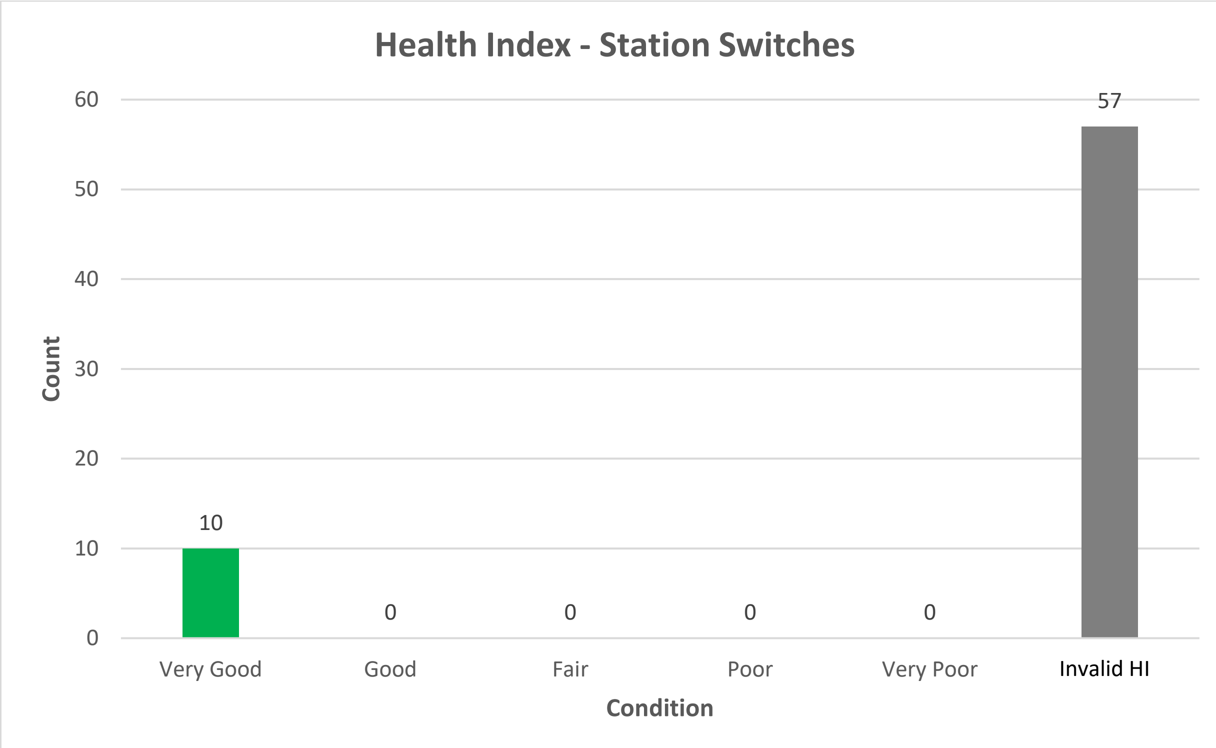


Figure 4-7 Health Index - Station Switches

4.1.4 Station Yards

<u>Condition Assessment Methodology</u>

Station yards, such as the grounds and fences of the installation, are major infrastructure components of a utility substation. The HI algorithm for API's station yards can be seen in Table 4-10, which is comprised only of visual inspection elements. Additional details about these condition parameters below can be found in Appendix A.

Table 4-10: Station Fence HI Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Fence Condition	6	A,B,C,D,E	4,3,2,1,0	24
2	Fence Coverage	3	A,B,C,D,E	4,3,2,1,0	12
3	Fence Signage	2	A,B,C,D,E	4,3,2,1,0	8
4	Gate Condition	3	A,B,C,D,E	4,3,2,1,0	12
5	Yard Condition	3	A,B,C,D,E	4,3,2,1,0	12
MAX SCORE					**68**

Data Collection and Assumptions

All data was provided by API and no assumptions were made. Of the nine stations that API currently owns, all had inspection records for their yards. An additional station, Goulais, is managed but not owned by API and was not assessed.

The DAI for station yards is 100%. The availability of station yard data is presented below in Table 4-11 Station Yard Data Availability

Table 4-11 Station Yard Data Availability

#	Condition Criteria	Data Availability
1	Fence Condition	100%
2	Fence Coverage	100%
3	Fence Signage	100%
4	Gate Condition	100%
5	Yard Condition	100%

Demographics

API owns nine station yards. Demographic information for stations and fences was not part of the dataset provided and is not deemed critical in assessing the health of these assets.

HI Results

Of the nine station yards evaluated, two were found to be in Fair condition. The breakdown of HI results is presented below in Figure 4-8.

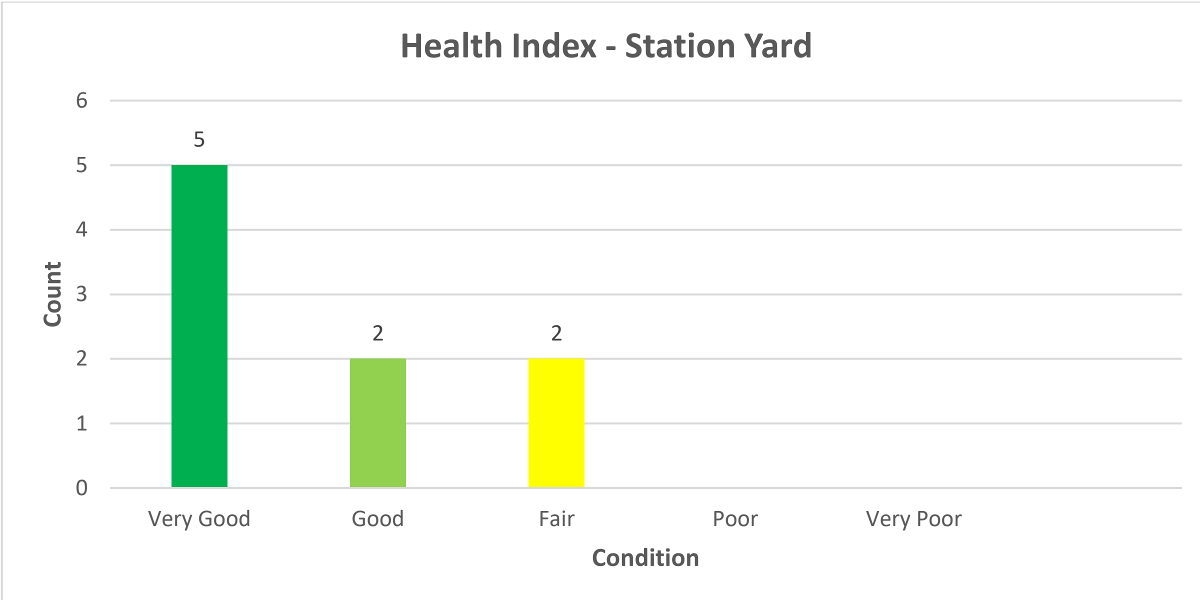


Figure 4-8: Station Yard HI Results

A breakdown of the health index for station yards is presented below in Table 4-12.

Table 4-12 Health Index Breakdown - Station Yards

#	Condition	HI Score	Condition Rating
1	#86 Dubreuilville	100%	Very Good
2	Hawk Junction	100%	Very Good
3	Bar River	96%	Very Good
4	#87 Dubreuilville	88%	Very Good
5	#1 Wawa	88%	Very Good
6	Garden River	82%	Good
7	Desbarats	75%	Good
8	Bruce Mines	59%	Fair
9	#2 Wawa	57%	Fair

The two yards in Fair condition, Bruce Mines and #2 Wawa are possible candidates for remedial work or replacement, depending upon their criticality. Bruce Mines has deficiencies in its fence condition, fence signage, and yard condition. #2 Wawa has deficiencies in its fence condition, gate condition, and yard condition.

4.2 Distribution Assets

4.2.1 Wood Poles

Condition Assessment Methodology

Wood poles are the most common asset owned by an electrical utility and are an integral part of the distribution system. Poles are the support structure for overhead distribution lines as well as assets such as overhead transformers, switches, and reclosers.

Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation processes for wood poles involve biological and environmental mechanisms such as wildlife damage and the effects of weather which can impact the mechanical strength of the pole. Loss in the strength of the pole can present additional safety and environmental risks to the public and the utility.

The HI for wood poles is calculated based on end-of-life criteria summarized in Table 4-13. Appendix A provides grading tables for each condition parameter.

Table 4-13 Wood Pole HI Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Remaining Strength	42	A,B,C,D,E	4,3,2,1,0	168
2	Service Age	20	A,B,C,D,E	4,3,2,1,0	80
3	Pole Treatment	5	A,C,E	4,2,0	20
4	Mechanical Damage	6	A,C,D,E	4,2,1,0	24
5	Wood Rot	4	A,C,D,E	4,2,1,0	16
6	Pole Top Feathering	4	A,C,D,E	4,2,1,0	16
7	Crossarm Damage	2	A,C,D,E	4,2,1,0	8
8	Fire Damage	1	A,C,D,E	4,2,1,0	4
9	Woodpecker Damage	1	A,C,D,E	4,2,1,0	4
10	Insect Damage	1	A,C,D,E	4,2,1,0	4
11	Cracks	1	A,C,D,E	4,2,1,0	4
MAX SCORE					**348**

Data Collection and Assumptions

All data was provided by API. Data for wood poles is accumulated over time through inspection cycles that look at a select number of poles - approximately 10% of poles listed in API's asset registry - from year to year. This process represents a good accumulation of wood pole data over time and creates a relatively recent sample of data that is very reflective of API's population of wood poles as a whole.

Two assumptions were made when interpreting API's data. The first was the use of API's test records from 2015-2022 as the frame of reference for the ACA over API's central database for poles, as there were several difficulties linking the available test records back to this central registry. For a more in-depth discussion of this assumption, see section 5.

The second assumption was the use of a linear degradation method to approximate the loss of pole strength since a pole's last inspection, based on the current pattern of degradation observed in the asset.

Average DAI for wood pole assets is 76%. The availability of data for wood poles is presented below in Table 4-14.

Table 4-14 Wood Pole Data Availability

#	Condition Criteria	Data Availability
1	Remaining Strength	75%
2	Service Age	75%
3	Pole Treatment	75%
4	Mechanical Damage	59%
5	Wood Rot	65%
6	Pole Top Feathering	72%
7	Crossarm Damage	65%
8	Fire Damage	65%
9	Woodpecker Damage	65%
10	Insect Damage	65%
11	Cracks	65%

Demographics

API manages 28,931 poles. API collected 23,227 inspection records between 2015-2022, representing 80.3% of their total poles. Figure 4-9 presents the age distribution for wood poles in-service. Age is unknown for all uninspected wood poles and a small proportion of API's inspected wood poles, for a total of 5,832 assets with an unknown age.

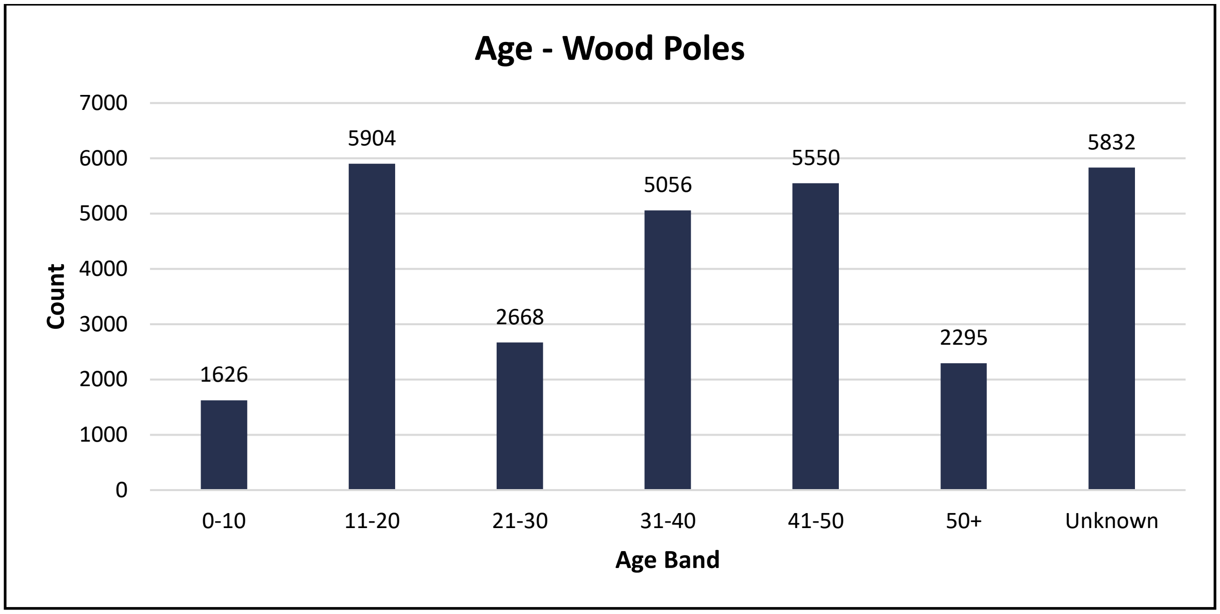


Figure 4-9: Wood Pole Age Distribution

HI Results

Data from 2015-2022 provides 23,227 inspection records, constituting approximately 80% of the poles in API's registry of 28,931. 128 poles from this collection of inspection records lacked sufficient data to form an HI, in addition to the 5,704 uninspected poles, for a total of 5,832. The results are shown below in Figure 4-10.

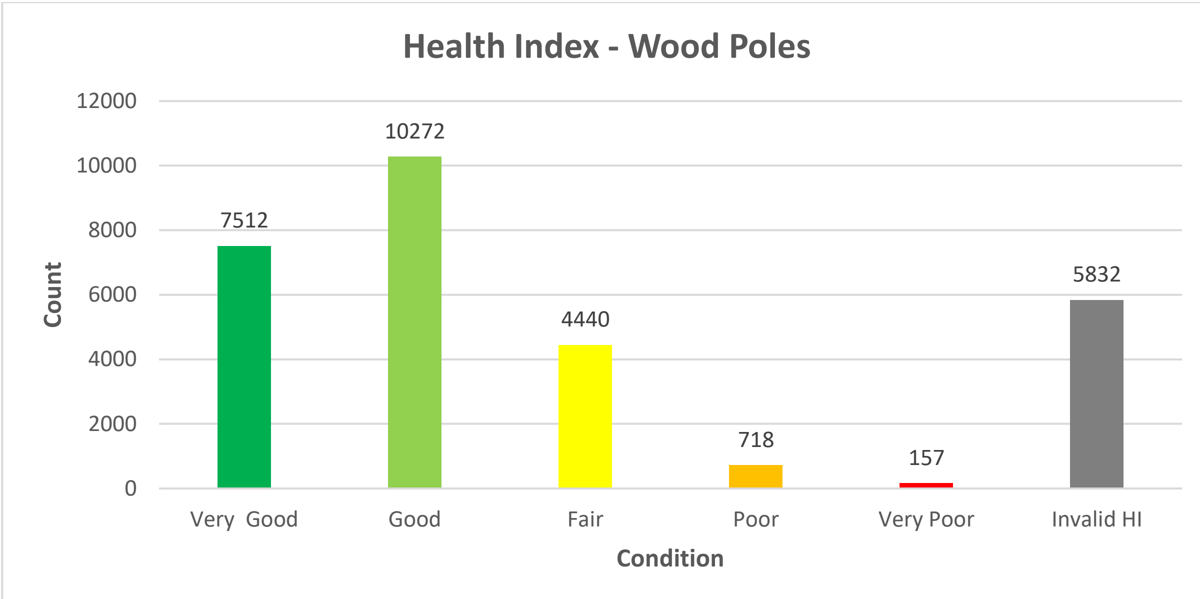


Figure 4-10: Health Index – Wood Poles

There is a differential of 5,702 poles between API's central wood pole registry and its test records. These poles are assumed to have unavailable test records. In conjunction with the 128 inspected poles that could not formulate an HI even after inspection, a total of 5,832 of API's poles could not formulate a valid HI.

An HI for the 5,832 poles that could not form an HI was extrapolated based on the HI distribution of the asset population with a valid HI score. As illustrated in Figure 4-11, 23% of API's wood poles are in Fair or worse condition.

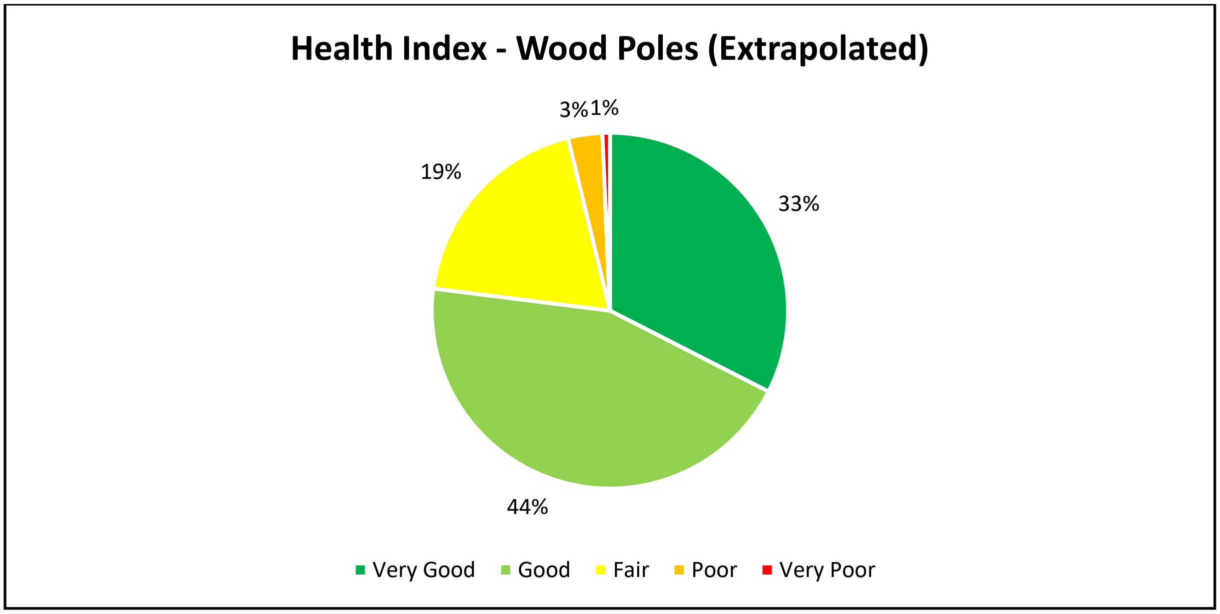


Figure 4-11: Extrapolated Wood Pole HI Results

4.2.2 Overhead Conductors

<u>Assessment Methodology</u>

Overhead ("OH") conductors are an important component of an overhead system. Conductor assets tend to be renewed when poles are replaced, when voltages are upgraded, or when lines are restrung for technical reasons. It is very rare that the conductor condition would drive a distinct replacement investment program. There is one recognized conductor risk, namely the tendency for small copper conductors to age at an accelerated rate and become brittle.

Although laboratory tests are available to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. The service age provides a reasonably good measure of the remaining strength of overhead conductor with the lack of visual inspection for conductor defects. However, conductors on distribution lines typically outlive the poles and are not usually on the critical path to determine end of life for a line section.

The only exception to the above rule might be where small gauge, solid strand copper conductors susceptible to frequent breakdowns are in use or where line conductors are too small for line loads resulting in sub-optimal system operation due to high line losses. However, API does not employ these types of conductors. As such, only a demographic analysis of age data was used.

<u>Data Collection and Assumptions</u>

All data was provided by API. No assumptions were made when processing the data.

The DAI for overhead conductor assets is 4%. The data is presented below in Table 4-15.

Table 4-15 Overhead Conductor Data Availability

#	Condition Criteria	Data Availability
1	Service Age	4%

Age data available for overhead conductor assets is very limited. Of the approximately 2,926km of overhead conductors, there is age data for approximately 118km of its length, representing just 4% of total conductor.

Demographics

The types of cable used by API is shown in Figure 4-12, with a breakdown of the phasing and voltage characteristics shown in Figure 4-13. A breakdown of the cable length by age is shown in Figure 4-14 below.

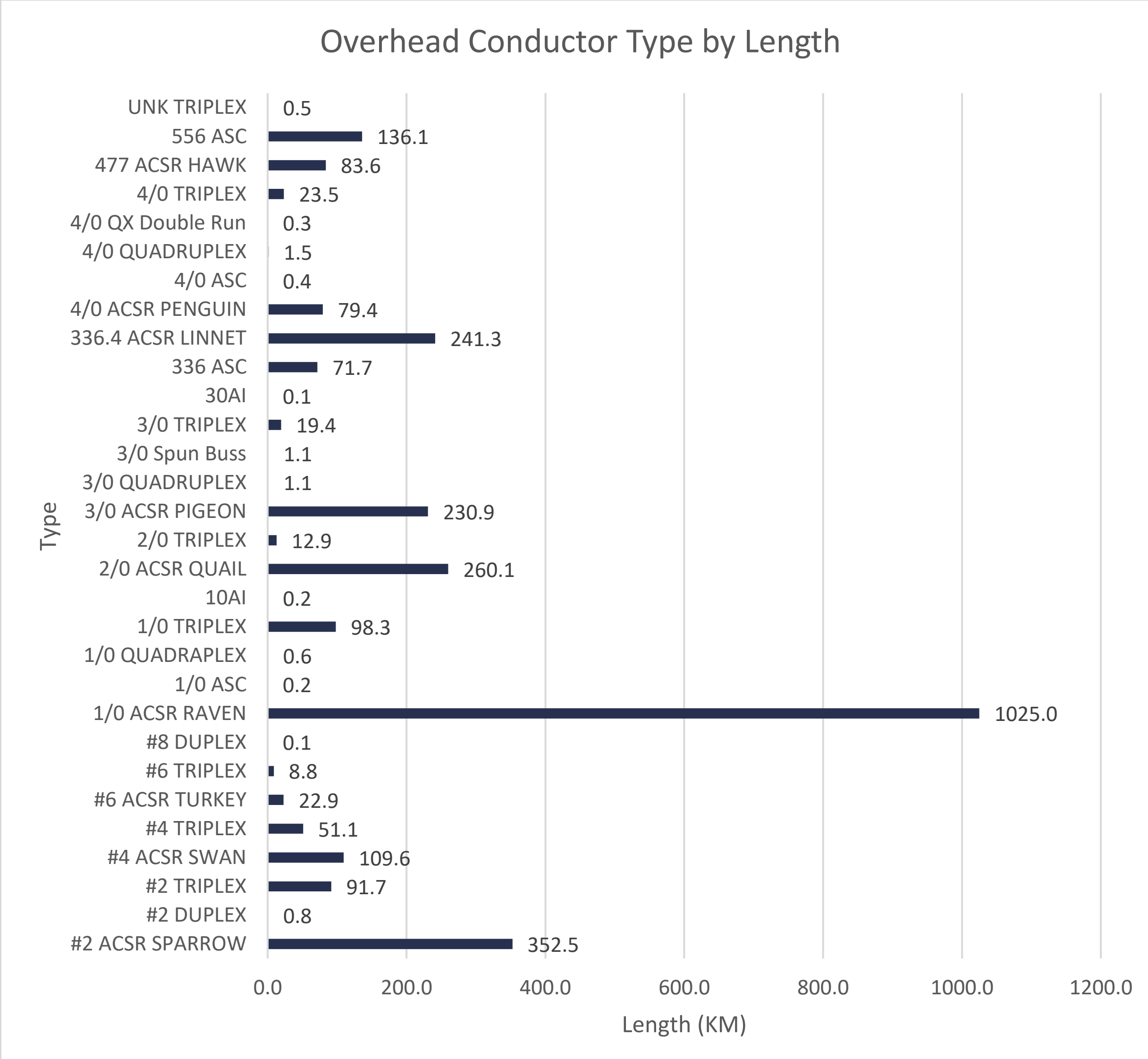


Figure 4-12 Demographics of Overhead Conductors

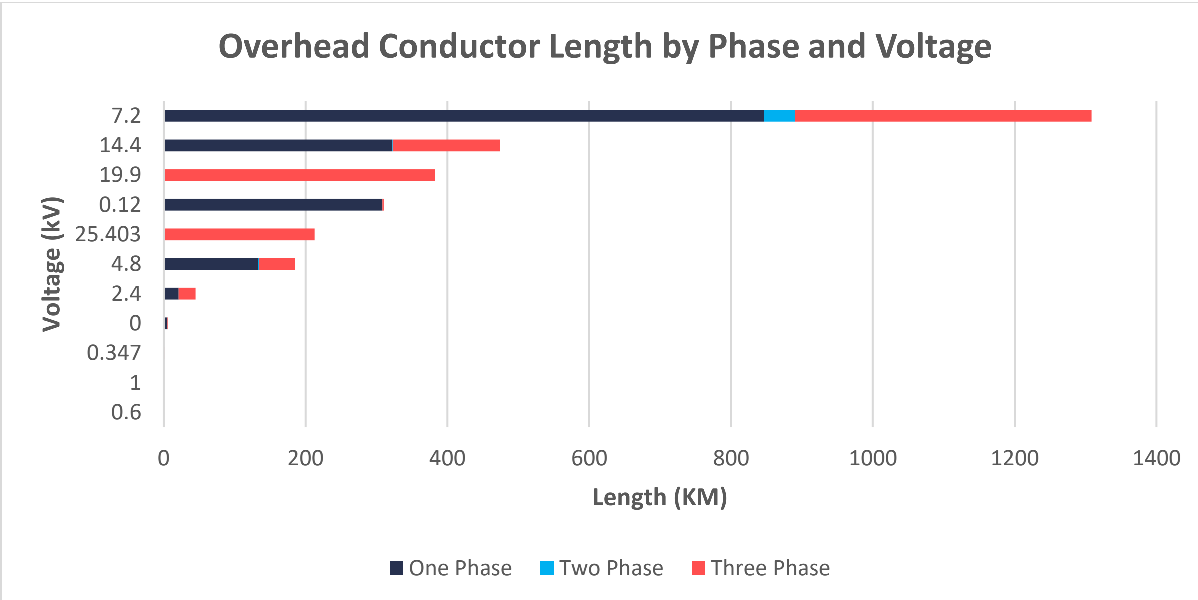


Figure 4-13 Overhead Conductor Length by Phasing and Voltage

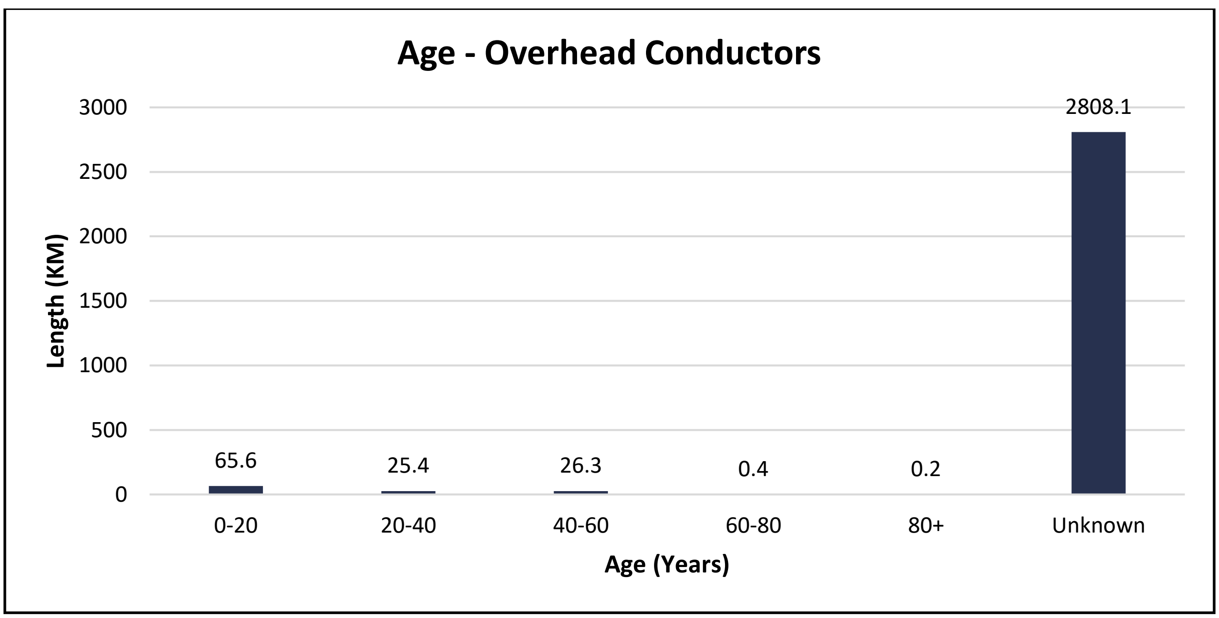


Figure 4-14: Overhead Conductors Age Distribution

HI Results

As only age and other demographic data was provided for the overhead conductor class, no HI was formed.

4.2.3 Underground Cables

Assessment Methodology

Distribution underground cables are one of the more challenging assets in electricity systems from a condition assessment and AM viewpoint. Although a number of test techniques such as partial discharge testing have become available over recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The standard approach to managing underground cable systems has been monitoring cable failure rates and the impacts of in-service failures on reliability and operating costs. In recognition of these difficulties, underground cables are replaced when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs, become higher than the annualized cost of underground cable replacement.

Data Collection and Assumptions

No inspection data was collected, and no assumptions were made about the information provided.

The DAI for underground cable assets is 33%. The data is presented below in Table 4-16.

Table 4-16 Underground Cable Data Availability

#	Condition Criteria	Data Availability
1	Service Age	33%

Demographics

API owns approximately 33.9 km of underground cable within its service territory. Figure 4-15 presents the demographics of underground cable types, while Figure 4-16 shows the demographics of its phasing and voltage. Approximately, 20% of type 2/0 Al 28 kV Full Neutral, followed by approximately 18% of type 1/0 Al 15 kV Full Neutral, with the remainder being mostly single phase rated for 7.2 kV.

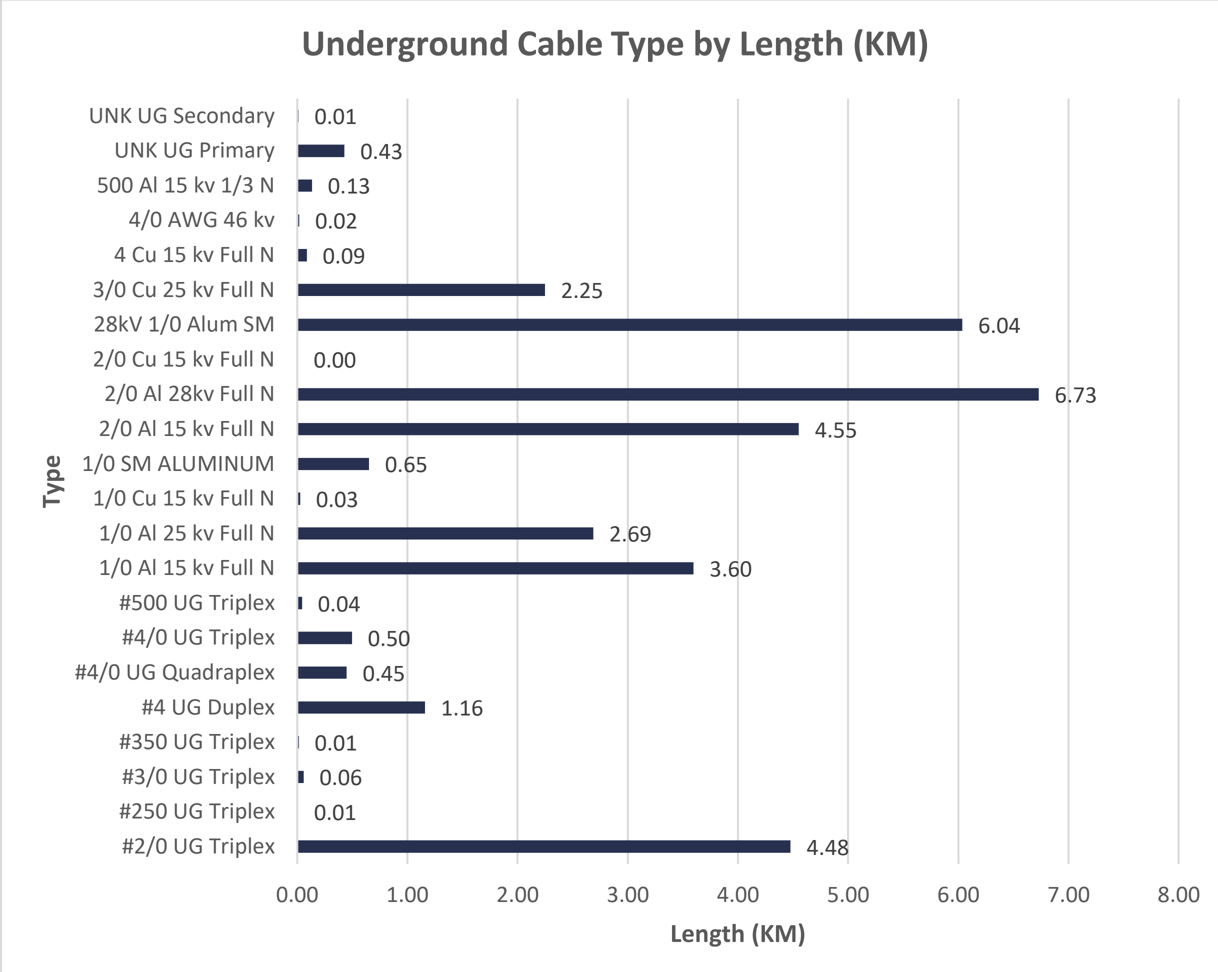


Figure 4-15: Underground Conductor Type Demographics

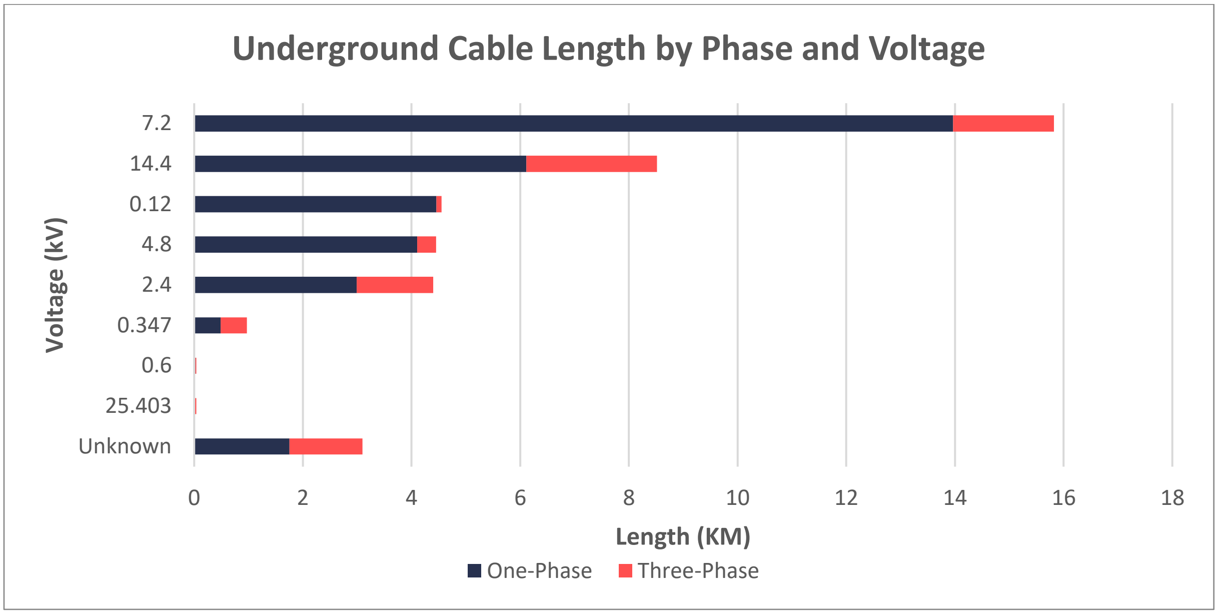


Figure 4-16 Underground Cable Length by Phase and Voltage

Unknown

Figure 4-17 displays the age demographics of API's underground cable assets.

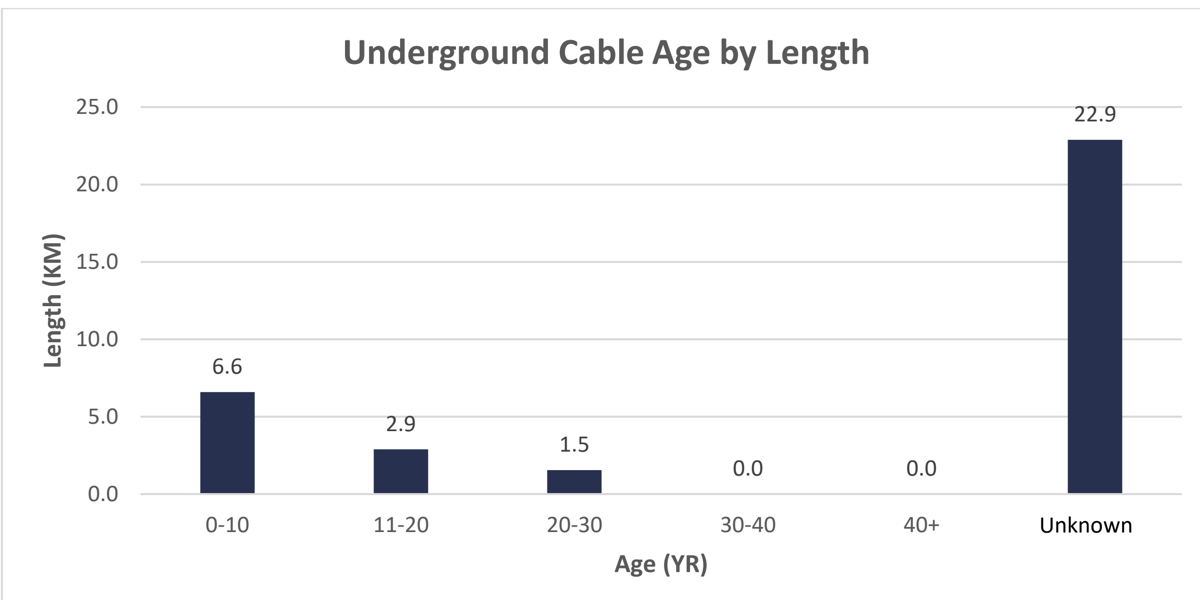


Figure 4-17 Underground Cable Age by Length

HI Results

As only age data was available for API's underground cable assets, no HI was formulated.

4.2.4 Distribution Transformers

Assessment Methodology

Pole-mount and pad-mount transformers are essential components in distribution systems. These devices play a pivotal role in stepping down high-voltage electricity to lower, safer levels for efficient distribution to homes and businesses. Pole-mount transformers are elevated on utility poles while pad-mount transformers are typically installed in ground-level enclosures.

Data Collection and Assumptions

API has records of 5,723 distribution transformers in its database – 5,507 pole-mounted transformers (POL) and 222 pad-mounted transformers (PAD). Of this total number of transformers, 5,233 are currently installed (5,066 POL and 167 PAD), 352 are available in a spare capacity (320 POL and 32 PAD), and 138 are designated for other purposes. Only assets in service were assessed.

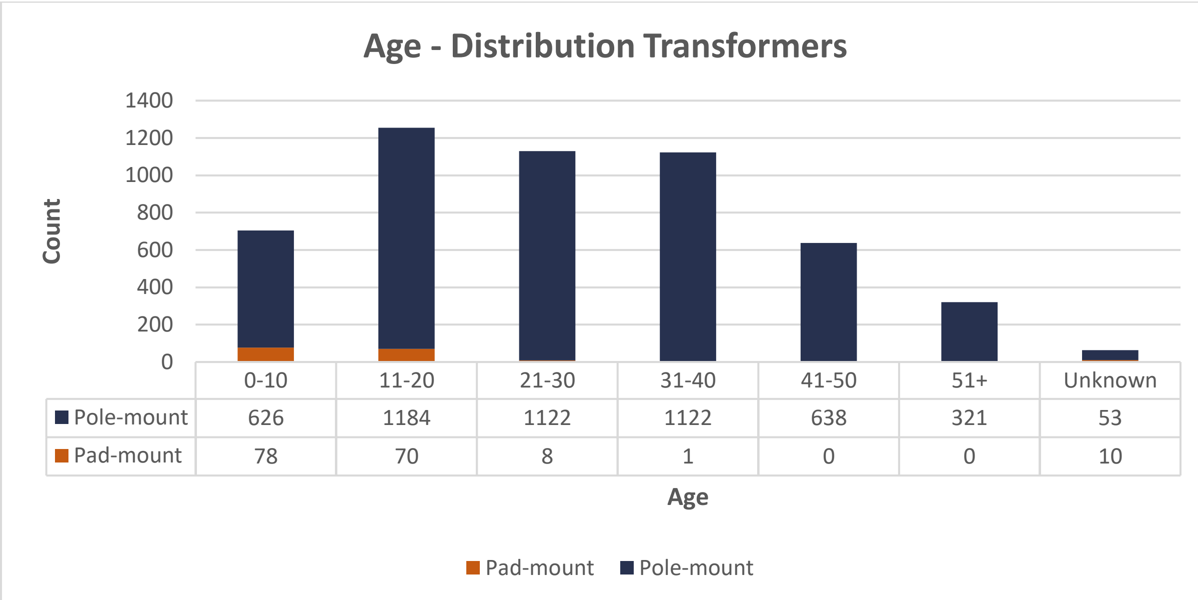
Of the 5,233 in-service transformers assessed, 5,170 had available age information. The DAI is 99%, presented below in Table 4-17.

Table 4-17 Distribution Transformer Data Availability

#	Condition Criteria	Data Availability
1	Service Age	99%

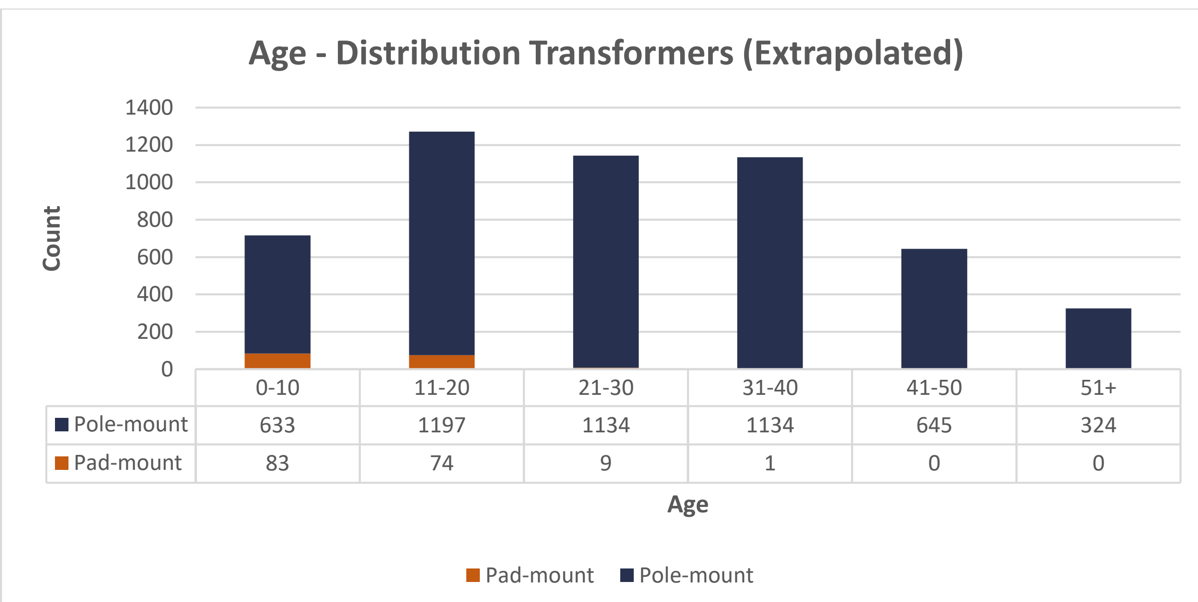
Demographics

As the age breakdown of distribution transformers is shown in Figure 4-18 and the extrapolated numbers are presented in Figure 4-19.



	0-10	11-20	21-30	31-40	41-50	51+	Unknown
Pole-mount	626	1184	1122	1122	638	321	53
Pad-mount	78	70	8	1	0	0	10

Figure 4-18 Age - Distribution Transformers



	0-10	11-20	21-30	31-40	41-50	51+
Pole-mount	633	1197	1134	1134	645	324
Pad-mount	83	74	9	1	0	0

Figure 4-19: Age - Distribution Transformers (Extrapolated)

HI Results

As only age data was available for distribution transformers, no HI was formulated for these assets.

4.2.5 Ratio-Bank Transformers

Condition Assessment Methodology

Ratio bank transformers are specialized transformers that play a vital role in ensuring the efficient and reliable operation of electrical systems by providing the flexibility to fine-tune voltage levels as needed, thus optimizing the distribution of electrical power. Table 4-18 shows the parameters that make up the HI algorithm for this asset class, and more information on how these parameters are interpreted is provided in Appendix A.

Table 4-18 Ratio-Bank HI Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Visual Inspection	4	A,B,C,D,E	4,3,2,1,0	16
2	Service Age	3	A,B,C,D,E	4,3,2,1,0	12
3	Loading History	3	A,B,C,D,E	4,3,2,1,0	12
MAX SCORE					**40**

Data Collection and Assumptions

All data was provided by API. Demographics, testing, and visual inspection data were provided for ratio-bank transformers. No assumptions were necessary when tabulating results.

The DAI of installed ratio-bank transformers is 95%. Table 4-19 shows the availability of ratio-bank transformer data.

Table 4-19 Ratio-Bank Transformers Data Availability

Condition Parameter	Data Availability
Visual Inspection	92%
Service Age	96%
Loading History	96%

Demographics

All but one of API's ratio-bank transformers possess age data. The breakdown of age is presented in Figure 4-20.

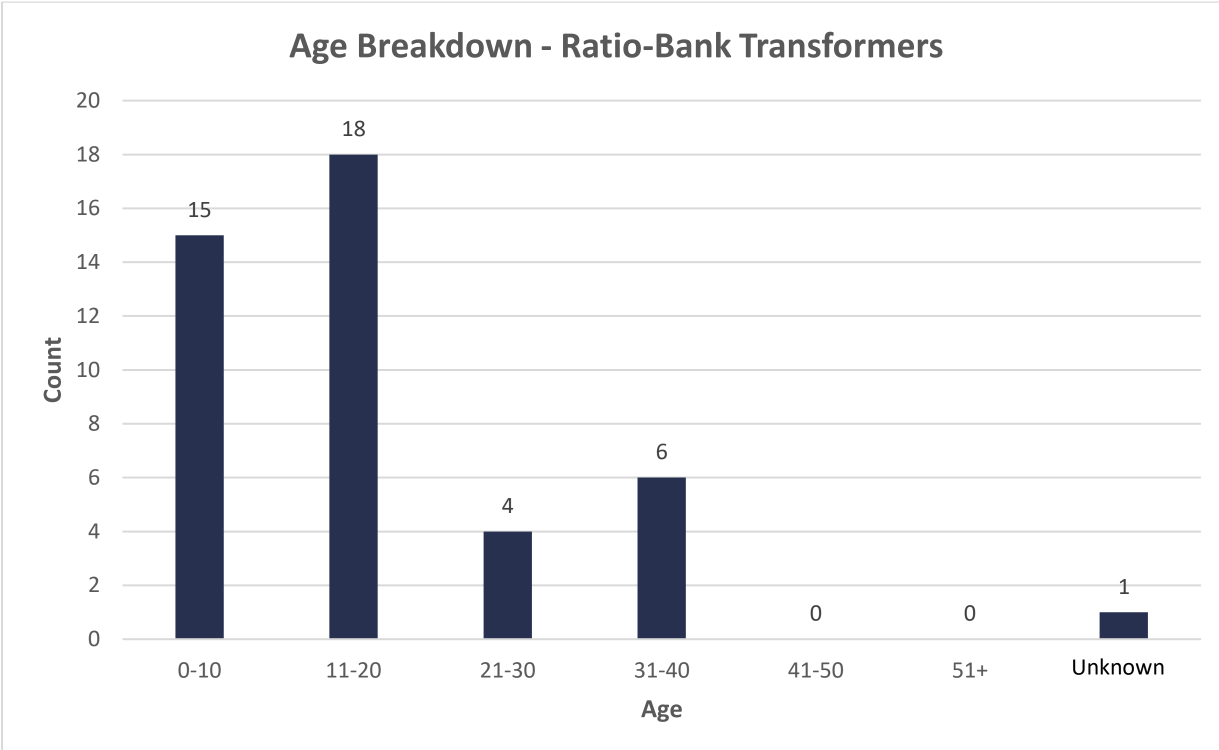


Figure 4-20: Ratio-Bank Transformer Age Demographics

HI Results

22 of API's ratio-bank transformers have enough data to construct a valid health index, 20 of which of which are currently installed. The average health index of installed units is 95%. Figure 4-21 shows the HI results for this asset class.

Unknown

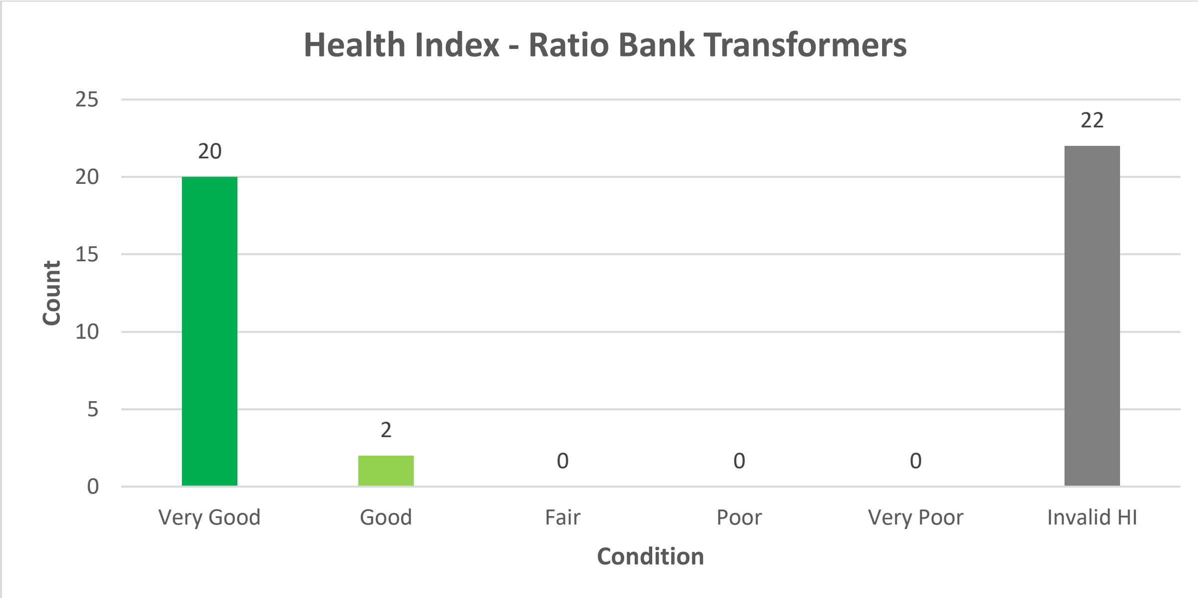


Figure 4-21: Ratio-Bank Transformer HI Results

Table 4-20 articulates the installation status of API's ratio-bank transformers. None of the "not installed" units were able to formulate an HI.

Table 4-20 Installation Status of Ratio-Bank Transformers

Type	Installed		Not Installed	
PLATFORM	• AP000111 • AP000841 • AP000842 • AP001100 • AP001117 • AP001690 • AP001817 • AP001882	• AP002128 • AP004146 • AP004703 • AP004812 • AP004843 • AP004844 • AP005097 • AP005128	• APT05498 • APT07236 • APT08664 • APT08665 • APT08969 • APT09310 • APT09311	• APT09513 • APT09513 • APT09782 • APT09783 • APT09784 • APT09314
POLEMOUNT	• AP004436 • AP004588 • AP004635 • AP004636	• AP004686 • AP004687 • AP004688 • AP004804	• APT09142 • APT09142 • APT09223 • APT09223	• APT09949 • APT10078 • APT10079

4.2.6 Reclosers

Assessment Methodology

Distribution reclosers are essential devices in electrical distribution systems, designed to automatically interrupt and restore power during temporary faults or disruptions. These devices quickly detect faults, such as short circuits or momentary issues, and temporarily interrupt the circuit. Unlike traditional circuit breakers, they make multiple attempts to restore power at predetermined intervals. Reclosers incorporate protective features to assess fault persistence, ensuring power is restored only if the fault is temporary. They often include remote monitoring capabilities for efficient network management, ultimately enhancing reliability by minimizing power outages and facilitating quick responses to issues.

Data Collection and Assumptions

Data was provided by API and no assumptions were made.

Demographics

API owns 110 reclosers that operate at the distribution level. Their breakdown is presented in Figure 4-22.

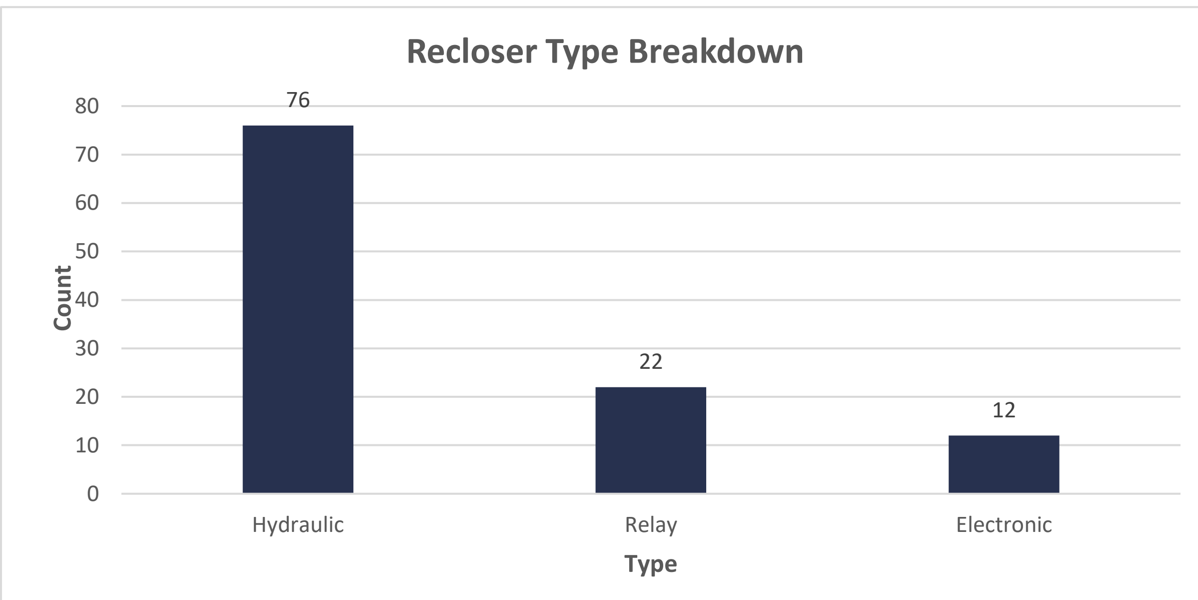


Figure 4-22: Recloser Type Demographics

HI Results

As only recloser type information was provided, no HI was formed.

4.2.7 Capacitor Banks

Condition Assessment Methodology

Capacitor banks are comprised of multiple capacitors connected in parallel and are strategically placed within the distribution network. Their primary function is to improve power factor by offsetting the reactive power generated by devices like motors and transformers. This helps to maximize the efficient use of electricity and reduce energy losses.

API owns four capacitor banks, each having a shunt connection type. The HI formulation for capacitor banks is shown below in Table 4-21. Additional details about these condition parameters and how they are graded can be found in Appendix A.

Table 4-21 Capacitor Bank HI Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Condition of Capacitor Units	5	A,B,C,D,E	4,3,2,1,0	20
2	Condition of Bank	4	A,B,C,D,E	4,3,2,1,0	16
3	Contamination	4	A,B,C,D,E	4,3,2,1,0	16
4	IR Scan	3	A,B,C,D,E	4,3,2,1,0	12
MAX SCORE					**64**

Data Collection and Assumptions

Asset information and inspection information was provided by API and no assumptions were made.

The DAI of capacitor banks is 95%. The availability of capacitor bank data is presented below in Table 4-22.

Table 4-22 Capacitor Bank Data Availability

Condition Parameter	Data Availability
Condition of Capacitor Units	100%
Condition of Bank	100%
Contamination	100%
IR Scan	75%

Demographics

API operates four shunt-type capacitor banks. No age data was provided.

HI Results

All four of API's capacitor banks are in Very Good condition, as shown in Figure 4-23.

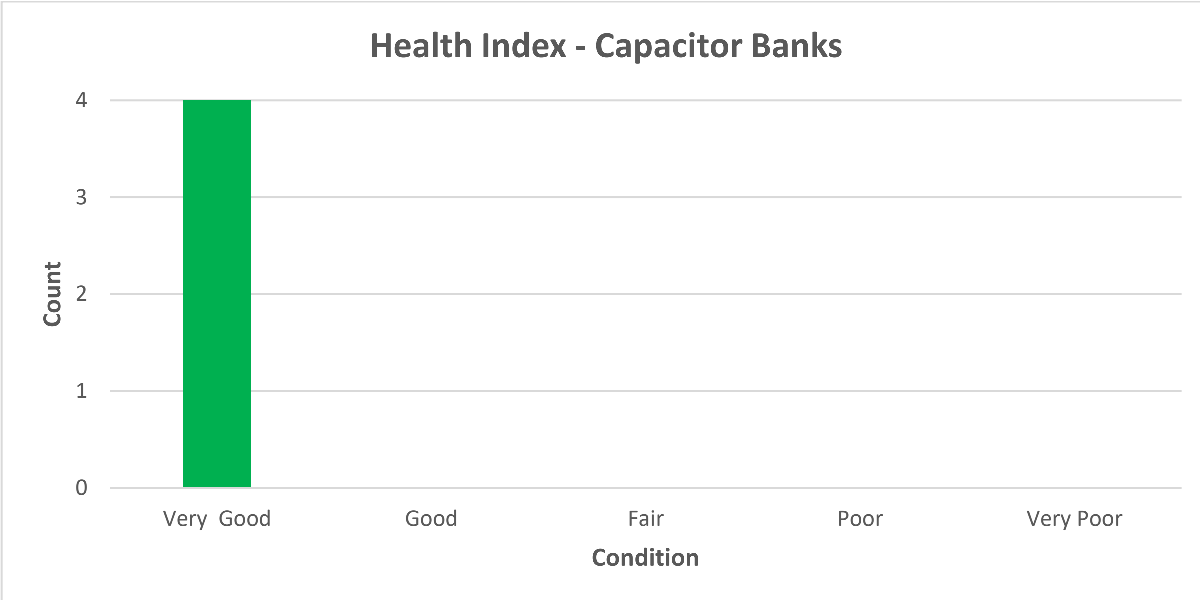


Figure 4-23 Health Index – Capacitor Banks

4.2.8 Voltage Regulators

Condition Assessment Methodology

Voltage regulators play a pivotal role in ensuring the reliability and stability of electrical systems by maintaining a consistent output voltage despite fluctuations in input power or varying load conditions. In the context of electrical infrastructure and equipment inspection, voltage regulators are subject to thorough assessments to guarantee their optimal performance and safety. The meticulous inspection of voltage regulators is essential in preserving the integrity of voltage regulators, ultimately contributing to the reliability and longevity of the electrical systems on which they depend.

The HI of voltage regulators was informed by three conditions: visual inspections, infrared scans, and counter readings. The algorithm is shown in Table 4-23. Additional details about these condition parameters and how they are graded can be found in Appendix A.

Table 4-23 Voltage Regulator HI Algorithm

#	Condition Criteria	Weight	Condition Score	Factors	Maximum Score
1	Visual Inspection	3	A,B,C,D,E	4,3,2,1,0	12
2	IR Scan	3	A,B,C,D,E	4,3,2,1,0	12
3	Counter Reading	2	A,B,C,D,E	4,3,2,1,0	8
MAX SCORE					**32**

Data Collection and Assumptions

All information was provided by API and no assumptions were made. Of the seventeen voltage regulators API manages, twelve are currently installed. Only installed units were assessed.

The DAI for installed voltage regulators is 79%. The availability of voltage regulator data is presented below in Table 4-24.

Table 4-24 Voltage Regulator Data Availability

Condition Parameter	Data Availability
Visual Inspection	92%
IR Scan	58%
Counter Reading	92%

Demographics

Age information was not provided for voltage regulators.

HI Results

The health index for voltage regulators is shown in Figure 4-24. As the number of assets is relatively small, an HI for these units cannot be extrapolated.

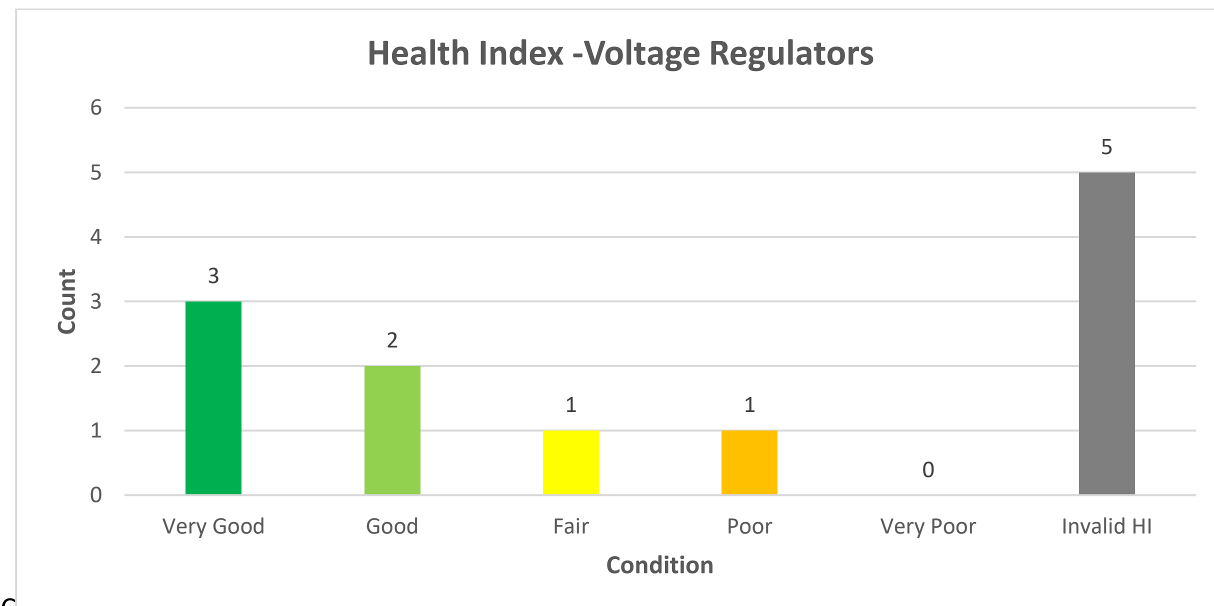


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Figure 4-24 Health Index - Voltage Regulators

The voltage regulator in Fair condition, VR-26, has deficiencies in its visual inspection and a high counter reading. The voltage regulator in Poor condition, VR-32, has a moderate counter reading but severe visual inspection deficiencies. These units should be considered for intervention or replacement, depending on their criticality.

5 Recommendations

This section breaks down METSCO's recommendations into the following categories for each asset class:

1. Asset intervention strategies;
2. HI Formulation Improvements; and
3. Data Availability Improvements.

5.1 Asset Intervention Strategies

The recommended intervention strategies are given for assets in each condition in Table 5-1. This framework prioritizes Very Poor assets for replacement, while proactive plans are developed to replace assets in Poor condition. Replacing both Very Poor and Poor condition assets reduces the potential number of reactive replacements required which are expensive for the utility as they can result in safety hazards, unplanned outages, and expedited work.

Table 5-1 Recommended Asset Intervention Strategy by HI Category

Condition	Recommended Action
Very Good	Normal Maintenance
Good	Normal Maintenance
Fair	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
Poor	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
Very Poor	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

The majority of API's assets are in Very Good or Good condition. While all assets in Fair or worse condition should be monitored and considered for intervention, several of API' asset classes have elevated numbers of assets in these conditions that API could consider for prioritization.

Table 5-2 below summarizes the percentage of assets in fair or worse condition.

Table 5-2 Assets in Fair or Worse Condition

Asset Class	Fair or Worse Condition (%)
Station Power Transformers and Voltage Regulators	13%
Station Reclosers	0%
Station Switches	0%
Station Yards	22%
Wood Poles	18%
Ratio-bank Transformers	0%
Capacitor Banks	0%
Voltage Regulators	17%

Additionally, for assets that did not have enough condition parameters to form a valid HI, Table 5-3 below shows the percentage of assets that have exceeded their TUL.

Table 5-3 Assets Exceeding TUL

Asset Class	TUL (Years)	% over TUL
Overhead Conductors	60	0.02%*
Underground Cables	30	0%
Distribution Transformers	40	18%

Based on available age data

Recloser assets lacked sufficient data to formulate an asset intervention strategy.

5.2 HI Formulation Improvements

In order to improve the asset health index formulations, METSCO recommends API collect information on the condition parameters mentioned in this section for each asset class. It is important to note that while these condition parameters can add depth to API's HI formulations, the ultimate value of collecting this information must be balanced against API's internal considerations for how to best use their resources.

5.2.1 Station Power Transformers

METSCO recommends API collect data on the following condition parameters to improve the formulation of its station transformer health index.

Table 5-4 Station Power Transformer HI Improvement Recommendations

#	Condition Type	Condition Parameter
1	Visual	Condition of Main Tank Corrosion
2	Visual	Condition of Conservator
3	Visual	Condition of Transformer Foundation
4	Visual	Condition of Transformer Grounding
5	Visual	Condition of Gaskets and Seals
6	Visual	Condition of Transformer Connectors
7	Visual	Condition of Load-Tap-Changer
8	Test	Turns Ratio Test
9	Test	Winding Temperature
10	Test	Transformer Dissipation Factor
11	Test	Dissolved Gas Analysis (Load-Tap-Changer)
12	Test	Oil Quality (Load-Tap-Changer)
13	Test	Bushing Power Factor
14	Test	Insulation Moisture Content
15	Test	Winding Resistance

While some of this information was collected for the transformers at Wawa #1 and Wawa #2, it was unavailable for the majority of API's units and could not be incorporated into the health index formulation. Additionally, while API collects information on the "overall condition" of its station transformer assets, the additional granularity provided by visual parameters listed above can add depth to the formulation of the HI.

5.2.2 Station Reclosers

METSCO recommends API collect data on the following condition parameters to improve the formulation of its station switches health index.

Table 5-5 Station Recloser HI Improvement Recommendations

#	Condition Type	Condition Parameter
1	Demographics	Service Age
2	Visual	Contacts Condition
3	Visual	Condition of Tank/Enclosure
4	Visual	Condition of Terminations
5	Test	Insulation Resistance
6	Test	Contact Resistance

5.2.3 Station Switches

METSCO recommends API collect data on the following condition parameters to improve the formulation of its station switches health index.

Table 5-6 Station Switches HI Improvement Recommendations

#	Condition Type	Condition Parameter
1	Visual	Switch or Disconnect Operator Controls
2	Visual	Condition of Switch/Disconnect Blades & Contacts
3	Visual	Power Train Drive Assembly
4	Visual	Connectors and Conductors
5	Visual	Contacts Condition
6	Visual	Insulators/Porcelains
7	Visual	Foundation/Support Steel/Grounding
8	Test	Insulation Resistance
9	Test	Contact Resistance Test

5.2.4 Station Yards

METSCO has no recommendations for API to improve the HI formulation of its station yards at this time.

5.2.5 Wood Poles

METSCO has no recommendations for API to improve the HI formulation of its wood poles at this time. However, please see section 5.3 for additional discussion on data availability improvements.

5.2.6 Overhead Conductors

METSCO has no recommendations for API to improve the HI formulation of its overhead conductor assets at this time.

5.2.7 Underground Cables

METSCO recommends API collect data on the following condition parameters to improve the formulation of its underground cable health index.

Table 5-7 Underground Cable HI Improvement Recommendations

#	Condition Type	Condition Parameter
1	Visual	Condition of Concentric Neutral
2	Visual	Visual Inspection of Splices
3	Operating	Failure Rates
4	Test	Cable Test

5.2.8 Distribution Transformers

METSCO recommends API collect data on the following condition parameters to improve the formulation of distribution transformer health index.

Table 5-8 Distribution Transformer HI Improvement Recommendations

#	Type	Condition Type	Condition Parameter
1	Pole-mount	Visual	Visual Inspection Data
2	Pad-mount	Visual	Pad Condition
3	Pad-mount	Visual	Tank Condition
4	Pad-mount	Visual	Enclosure Condition
5	Pad-mount	Visual	Oil Leaks

5.2.9 Ratio-Bank Transformers

METSCO has no recommendations for API to improve the formulation of its ratio-bank transformers at this time.

5.2.10 Reclosers

METSCO recommends API collect data on the following condition parameters to improve the formulation of its reclosers' health index.

Table 5-9 Distribution Recloser HI Improvement Recommendations

#	Condition Type	Condition Parameter
1	Visual	Condition of Tank
2	Visual	Condition of Terminations
3	Visual	Condition of Operating Mechanisms
4	Visual	Presence of Oil/Air Leaks

5.2.11 Capacitor Banks

METSCO has no recommendations for API to improve the HI formulation of its capacitor bank assets at this time.

5.2.12 Voltage Regulators

METSCO has no recommendations for API to improve the HI formulation of its voltage regulator assets at this time.

5.3 Data Availability Improvements

5.3.1 Discussion

The quality and availability of API's data was generally low. METSCO identified the following key issues with API's data:

- Inconsistencies in how assets are identified in central databases against how they are identified during inspections.
- Lack of consistency in how assets are inspected:
  - Assets of the same class could be evaluated by different criteria within the same year.
  - Inspection procedures changing year over year.
- Inspection records are not logged in a central database and must be accessed individually.
- Low availability of visual inspection records for several asset classes.

These issues make it difficult and inefficient for API to access its data, draw meaningful conclusions regarding the condition of an asset, track the condition of an asset over time, and compare assets against each other.

Data quality issues are exemplified by the data provided for the wood pole asset class. API manages a central database containing its wood pole information, but errors in data collection make it difficult to link this registry to a second database containing API's pole inspection records. Issues include:

- Identification of poles uses inconsistent nomenclature to identify them.
  - How pole information is recorded in the field.
  - How pole information is recorded in central databases.
  - Errors transferring information between inspection data and central database.
- Poles may have been removed from the asset registry since their last inspection or added to the registry since the last inspection cycle in 2022.
- Duplicate Records.

Of the 23,227 inspection records accumulated between 2016 and 2022, roughly 50% of these records could not be directly linked to a pole in API's asset registry.

While the inspection information was robust and the assessment criteria was consistent across all years, data from some years articulated the results of all criteria by which a pole was assessed and indicated their condition, while other years only indicated when an asset showed a deficiency in a certain area.

5.3.2 Recommendations

Based on the issues noted above, METSCO has several recommendations for API to improve the quality and availability of its data:

Data Availability

METSCO recommends that API continues to conduct visual inspections and tests on all its asset classes, in line with the HI formulation recommendations in section 5.2, to accumulate a greater sample of data that can be applied to future asset condition assessments.

Data Quality

Good data management practices are crucial to ensuring that data is accurate, reliable, and suitable for its intended purpose. The implementation of principles can enable API to make more powerful, evidence-based decisions regarding the management of its assets.

Guidelines for improved data management include:

- **Data Governance**:
  - Establish clear data governance policies and procedures.
  - Define roles and responsibilities for data stewardship and ownership.
- **Data Quality Strategy**:
  - Develop a data quality strategy aligned with overall business goals and objectives.
- **Data Profiling**:
  - Regularly profile your data to identify issues like missing values, duplicates, and outliers.
- **Data Cleaning**:
  - Implement data cleaning processes to correct or remove errors, inconsistencies, and inaccuracies.
  - Use validation rules and automated data cleansing tools.
- **Data Validation**:
  - Implement data validation checks to ensure data meets defined criteria and business rules (e.g., Asset Nomenclature)
  - Perform checks for data type, format, and range.
- **Data Standardization**:
  - Standardize data formats, units of measurement, and naming conventions to ensure consistency.
  - Use reference data and code sets where applicable.
- **Data Entry and Capture**:
  - Ensure data is accurately captured at the source with validation and verification mechanisms.
  - Upload newly captured data immediately to central databases.
- **Data Documentation**:
  - Maintain metadata and data dictionaries to describe data elements and their meanings.
  - Document data sources, transformations, and lineage.
- **Data Ownership**:
  - Assign data ownership to individuals or teams responsible for data quality.
- **Continuous Improvement**:
  - Establish a culture of continuous improvement in data quality management.
  - Regularly review and enhance data quality processes.

6 Conclusion

On top of a condition assessment of API's major asset classes, this report provided API with a broad range of recommendations with respect to specific types of information that it may choose to collect and the metrics it may deploy to enhance its asset management analytics.

As noted elsewhere in this report, the amount of asset condition information that API made available for METSCO in the context of this study in some ways exceeded the sum of data that was included in earlier iterations. This fact alone represents the evidence of continuous improvement efforts over the recent years that we fully expect to continue as API refines its strategic priorities within the AM function and beyond. METSCO commends API for their significant improvements in data collection and digitization of asset records. However, there is still a noteworthy issue with a regression in data availability with some asset classes, as well as data management issues that impede analysis and the ability to synthesize various sources of data. METSCO remains confident that these issues will be addressed in future iterations and looks forward to future work with API.

This concludes METSCO's Asset Condition Assessment report for API's assets. We thank API's staff and management for the opportunity to participate in this complex study and for their ongoing support throughout its development.

A. Appendix – Condition Parameters

A.1 Station Transformers

The following tables articulate the criteria for the dissolved gas analysis.

Table A-1 Gas Concentration Limits (ppm)

Gas	O2/N2 Ratio <= 0.2				O2/N2 Ratio >0.2			
	Transformer Age in Years				Transformer Age in Years			
	Unknown	1-9	10-30	>30	Unknown	1-9	10-30	>30
H_2	80	75		100	40	40		
CH_4	90	45	90	110	20	20		
C_2H_6	90	30	90	150	15	15		
C_2H_4	50	20	50	90	50	25	60	
C_2H_2	1	1			2	2		
CO	900	900			500	500		
CO_2	9000	5000	10000		5000	3500	5500	

Table A-2 Gas Rate of Change Limits (ppm)

Gas	Maximum (ppm) variation between consecutive DGA samples	
	O2/N2 Ratio <= 0.2	O2/N2 Ratio >0.2
H_2	40	25
CH_4	30	10
C_2H_6	25	7
C_2H_4	20	
C_2H_2	Any Increase	
CO	250	175
CO_2	2500	1750

Table A-3 Criteria for DGA results

Condition Rating	Corresponding Condition
A	All parameters within acceptable limits
B	1 parameter does not meet acceptability limits.
C	2 parameters do not meet acceptability limits.
D	3 parameters do not meet acceptability limits.
E	4 or more parameters do not meet acceptability limits.

Table A-4 Criteria for Peak Loading

Condition Rating	Corresponding Condition
A	Average peak load less than 50% of its rating
B	Average peak load of 50% to 75% of its rating
C	Average peak load of 75% to 100% of its rating
D	Average peak load of 100% to 125% of its rating
E	Average peak load of greater than 125% of its rating

Table A-5 Criteria for Insulation Power Factor / Polarization Index

Condition Rating	Corresponding Condition
A	MAXIMUM POWER FACTOR < 0.5
B	0.5 ≤ MAXIMUM POWER FACTOR < 1
C	1 ≤ MAXIMUM POWER FACTOR < 1.5
D	1.5 ≤ MAXIMUM POWER FACTOR < 2
E	MAXIMUM POWER FACTOR ≥ 2 or POLARIZATION INDEX < 2

Table A-6 Criteria for IR Scan

Condition Rating	Corresponding Condition
A	No hot spots are noticeable; no temperature excess over reference point of transformer at normal temperature.
B	Small hotspots are identified but do not require further investigation; excess of 0-9 degrees Celsius over reference point.
C	Significant hot spots are identified, and further investigation is required; excess of 10-20 degrees Celsius over reference point.
D	Serious hot spots are identified that need further investigation/attention as soon as possible; excess of 21-49 degrees Celsius over reference point
E	Critical hotspots are identified that need immediate attention; excess of more than 50 degrees Celsius over reference point.

The grade assigned to the “Oil Quality” condition parameter is derived from the worst result of several tests. Table A-7 below articulates these tests and their criteria.

Table A-7 Criteria for Oil Quality Tests

Test	Station Transformer Voltage Class	Grade
	U ≤ 69 kV	
Acid Number	≤0.05	A
	0.05-0.20	C
	≥0.20	E
IFT [mN/m]	≥30	A
	25-30	C
	≤25	E
Dielectric Strength [kV]	>23 (1mm gap) >40 (2 mm gap)	A
	≤40	E
Water Content [ppm]	<35	A
	≥35	E

Table A-8 Criteria for Service Age

Condition Rating	Corresponding Condition
A	Less than 20 years
B	20 to 40 years
C	40 to 60 years
D	60-80 years
E	More than 80 years

The following tables encompasses station transformer visual inspection criteria. This includes overall condition, bushing condition, oil level, radiators/fan condition, oil leaks, and other miscellaneous criteria.

Table A-9 Criteria for Visual Inspection

Condition Rating	Corresponding Condition
A	Very Good
B	Good
C	Fair
D	Poor
E	Very Poor

A.2 Station Reclosers

Table A-10 Criteria for Service Age

Condition Rating	Corresponding Condition
A	Less than 10 years.
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table A-11 Criteria for Visual Inspection

Condition Rating	Corresponding Condition
A	All components are in good condition and free of cracks, rust, corrosion, etc.
B	There is minor damage that does not impede operation of the asset.
C	There is evidence of damage, such as rust, corrosion, or chips, requiring corrective maintenance in the next several months.
D	There is significant damage that requires immediate corrective action.
E	There is extreme damage that indicates the unit is beyond repair

Table A-12 Criteria for IR Scan

Condition Rating	Corresponding Condition
A	No hot spots are noticeable; no temperature excess over reference point of switch at normal temperature.
B	Small hotspots are identified but do not require further investigation; excess of 0-9 degrees over reference point.
C	Significant hot spots are identified, and further investigation is required; excess of 10-20 degrees over reference point.
D	Serious hot spots are identified that need further investigation/attention as soon as possible; excess of 21-49 degrees over reference point
E	Critical hotspots are identified that need immediate attention; excess of more than 50 degrees over reference point.

A.3 Station Switches

Table A-13 Criteria for Service Age

Condition Rating	Corresponding Condition
A	Less than 10 years.
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table A-14 Criteria for Visual Inspection

Condition Rating	Corresponding Condition
A	All components are in good condition and free of cracks, rust, corrosion, etc.
B	There is minor damage that does not impede operation of the asset.
C	There is evidence of damage, such as rust, corrosion, or chips, requiring corrective maintenance in the next several months.
D	There is significant damage that requires immediate corrective action.
E	There is extreme damage that indicates the unit is beyond repair

Table A-15 Criteria for IR Scan

Condition Rating	Corresponding Condition
A	No hot spots are noticeable; no temperature excess over reference point of switch at normal temperature.
B	Small hotspots are identified but do not require further investigation; excess of 0-9 degrees over reference point.
C	Significant hot spots are identified, and further investigation is required; excess of 10-20 degrees over reference point.
D	Serious hot spots are identified that need further investigation/attention as soon as possible; excess of 21-49 degrees over reference point
E	Critical hotspots are identified that need immediate attention; excess of more than 50 degrees over reference point.

A.4 Station Yard

The following visual inspection criteria encompasses the station yard parameters: fence condition, fence coverage, fence signage, gate condition, and yard condition.

Table A-16 Criteria for Visual Inspection

Condition Rating	Corresponding Condition
A	No deficiencies.
B	Only minor deficiencies.
C	Moderate deficiencies requiring planned corrective action.
D	Extensive deficiencies.
E	Major deficiencies requiring immediate attention.

A.5 Wood Poles

Table A-17 Criteria for Remaining Strength

Condition Rating	Corresponding Condition
A	91% to 100%
B	81% to 90%
C	71% to 80%
D	61% to 70%
E	Less than 60%

Table A-18 Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 55 years
E	Over 55 years

Table A-19 Criteria for Treatment Type

Condition Rating	Corresponding Condition
A	Full
C	Butt
E	None

The following table articulates the visual damage criteria of wooden poles. This includes mechanical damage, wood rot, pole top feathering, crossarm damage, fire damage, woodpecker damage, insect damage, and cracks.

Table A-20 Criteria for Visual Inspection

Condition Rating	Corresponding Condition
A	There is no evidence of damage.
C	There is slight damage that does not require corrective action. Minimal deterioration.
D	There is moderate damage, requiring planned corrective action. Significant deterioration.
E	There is extensive damage requiring intervention. Major deterioration.

A.6 Overhead Conductors

No condition parameters were used to assess this asset class.

A.7 Underground Cables

No condition parameters were used to assess this asset class.

A.8 Distribution Transformers

No condition parameters were used to assess this asset class.

A.9 Ratio-Bank Transformers

Table A-21 Criteria for Visual Inspection

Condition Rating	Corresponding Condition
A	No rust on tank/enclosure, no damage to components, no sign of oil leaks
B	Only one of the following defects: Minor rust, or minor damage to components or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/radiator badly rusted or major damage to components or major oil leak
E	Two or more of the above indicated defects

Table A-22 Criteria for IR Scan

Condition Rating	Corresponding Condition
A	No hot spots are noticeable; no temperature excess over reference point of switch at normal temperature.
B	Small hotspots are identified but do not require further investigation; excess of 0-9 degrees over reference point.
C	Significant hot spots are identified, and further investigation is required; excess of 10-20 degrees over reference point.
D	Serious hot spots are identified that need further investigation/attention as soon as possible; excess of 21-49 degrees over reference point
E	Critical hotspots are identified that need immediate attention; excess of more than 50 degrees over reference point.

Table A-23 Criteria for Service Age

Condition Rating	Corresponding Condition
A	Less than 20 years
B	20 to 40 years
C	40 to 60 years
D	More than 60 years

Table A-24 Criteria for Peak Loading

Condition Rating	Corresponding Condition
A	Typical peak load less than 50% of its rating
B	Typical peak load of 50% to 75% of its rating
C	Typical peak load of 75% to 100% of its rating
D	Typical peak load of 100% to 125% of its rating
E	Typical peak load of greater than 125% of its rating

A.10 Reclosers

No condition parameters were used to assess this asset class.

A.11 Capacitor Banks

Table A-25 Criteria for Condition of Capacitor Units

Condition Rating	Corresponding Condition
A	No indication of any capacitor failures though bulging of cans or oil leaks. No external sign of deterioration of gaskets/ weld seams on cans. No external corrosion or rust on cans
B	Less than 1% of capacitor cans indicate failure through bulged tanks or oil leaks. Minor external sign of deterioration of gaskets/ weld seams and minor rust on remaining healthy capacitor cans.
C	Fewer than 3% of capacitor cans indicate failure through bulged tanks or leaking oil. Significant external signs of deterioration of gaskets/ weld seams and/or rusting of remaining healthy capacitor cans. Minor signs of oil leaks or oil stains on capacitor cans. Requires corrective maintenance within the next several months.
D	Fewer than 5% of capacitor cans indicate failure through bulging of tanks or oil leaks. Major external sign of deterioration of gaskets/ weld seams on cans. Signs of significant oil leaks or oil stains on healthy cans. Extensive external corrosion or rust on cans. Requires corrective action within the next few weeks.
E	More 5% of capacitor cans indicate failure through bulged tanks and oil leaks. Capacitor bank unable to provide intended function and has degraded beyond repairs.

Table A-26 Criteria for Condition of Bank

Condition Rating	Corresponding Condition
A	Capacitor Bank is externally clean, corrosion free. All primary and secondary connections are in good condition. No external evidence of overheating or any other abnormality. Appears to have been well maintained.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable.
D	More than two of the above characteristics are unacceptable.
E	Capacitor is defective, damaged or degraded beyond repairs.

Table A-27 Criteria for Contamination

Condition Rating	Corresponding Condition
A	Capacitor Bank indicates no evidence of contamination.
B	Slight evidence of contamination.
C	Moderate evidence of contamination.
D	Extensive evidence of contamination.
E	Extreme evidence of contamination.

Table A-28 Criteria for IR Scan

Condition Rating	Corresponding Condition
A	No hot spots are noticeable; no temperature excess over reference point at normal temperature.
B	Small hotspots are identified but do not require further investigation; excess of 0-9 degrees over reference point.
C	Significant hot spots are identified, and further investigation is required; excess of 10-20 degrees over reference point.
D	Serious hot spots are identified that need further investigation/attention as soon as possible; excess of 21-49 degrees over reference point
E	Critical hotspots are identified that need immediate attention; excess of more than 50 degrees over reference point.

A.12 Voltage Regulators

Table A-29 Criteria for Visual Inspection

Condition Rating	Corresponding Condition
A	There are no oil leaks, and the condition of the platform, equipment grounds, control box, and bushings are excellent.
B	There is minor damage to one of the elements above.
C	There is significant damage to one or more of the elements above.
D	There is extensive damage to one or more of the elements above.
E	There is extreme damage to one or more of the elements above.

Table A-30 Criteria for IR Scan

Condition Rating	Corresponding Condition
A	No hot spots are noticeable; no temperature excess over reference point at normal temperature.
B	Small hotspots are identified but do not require further investigation; excess of 0-9 degrees over reference point.
C	Significant hot spots are identified, and further investigation is required; excess of 10-20 degrees over reference point.
D	Serious hot spots are identified that need further investigation/attention as soon as possible; excess of 21-49 degrees over reference point
E	Critical hotspots are identified that need immediate attention; excess of more than 50 degrees over reference point.

Table A-31 Criteria for Counter Reading

Condition Rating	Corresponding Condition
A	The voltage regulator’s counter reading is in the 20th percentile for the population.
B	The voltage regulator’s counter reading is in the 40th percentile for the population.
C	The voltage regulator’s counter reading is in the 60th percentile for the population.
D	The voltage regulator’s counter reading is in the 80th percentile for the population.
E	The voltage regulator’s counter reading exceeds the 80th percentile for the population.

Algoma Power Inc.

Distribution System Plan

Appendix E

Algoma Power Inc.

Reliability Study

Revision Number	Date	Details	Prepared By
R0	2023-10-01	Initial Draft	M. Degilio
R1	2024-01-23	Final Draft	M. Degilio

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Algoma Power Inc.
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1. Introduction

As part of Algoma Power's ("API") area planning study effort, a reliability study has been undertaken to evaluate the historical reliability performance, identify outage cause trends, and recommend actions to reduce customer-hour outages.

API operates a rural and remote distribution system, with power lines that are geographically dispersed within a large service territory and located along a predominantly forested backline.

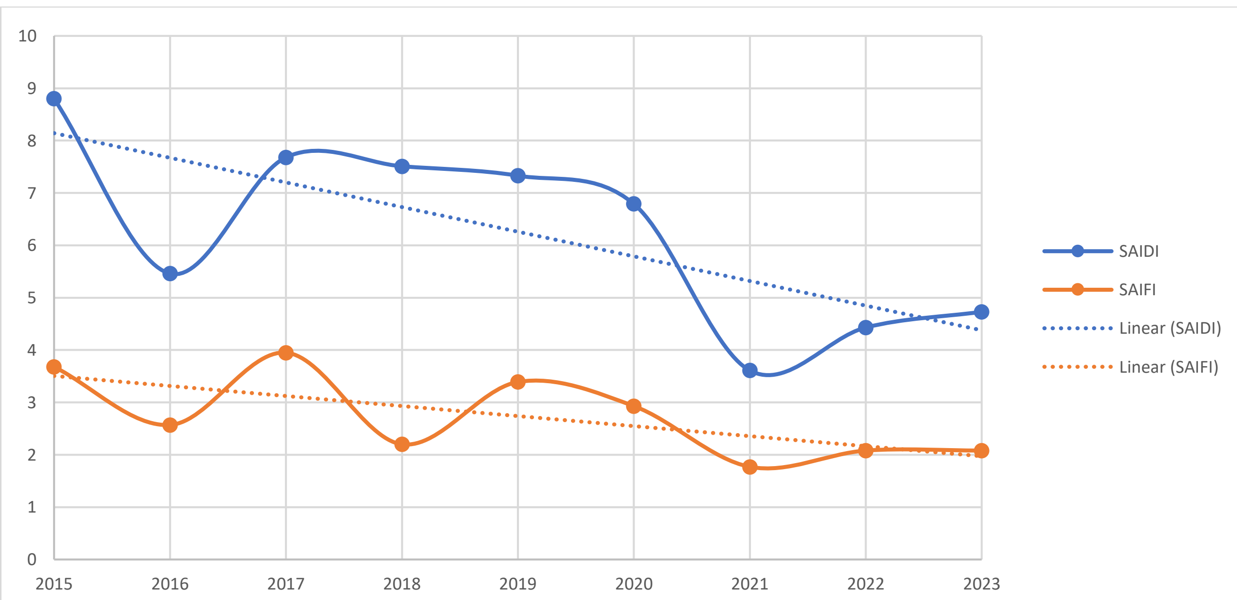
API Scorecard system reliability result:

Table 1: API Scorecard Reliability Metrics

Measure	2015	2016	2017	2018	2019	2020	2021	2022	2023
SAIDI	8.80	5.46	7.68	7.51	7.33	6.79	3.61	4.43	4.73
SAIFI	3.68	2.57	3.95	2.20	3.39	2.93	1.77	2.08	2.08

Excluding Major Events and Loss of Supply

Figure 1: 2015-2023 SAIDI, SAIFI



2. Analysis Approach

The evaluation of API's reliability is performed by reviewing and assessing the historical outage data derived from API's Outage Management System ("OMS"). The outage information is assembled based on cause and location, and then further refined based on average interruption frequency and duration.

The outage cause analysis will consider all cause-type to provide an overall view of outage cause trending. A refined analysis will exclude supply loss outages to provide a clearer picture of how and where API should focus its reliability improvement efforts.

API is required by the *Electricity Reporting and Record Keeping Requirements* to report on two reliability indices – SAIDI and SAIFI, relating to the frequency and duration of outages. These indices are defined in the Electricity Distribution Rate Handbook (2006) as follows:

- **System Average Interruption Duration Index ("SAIDI")**
  An indicator of system reliability that expresses the length of outage customers experience in the year on average. All planned and unplanned interruptions of one minute or more should be used to calculate this index. It is defined as the total hours of power interruptions normalized per customer served, and is expressed as follows:

  SAIDI = Total Customer Hours of Interruption / Total Number of Customers Served

- **System Average Interruption Frequency Index ("SAIFI")**
  An indicator of the average number of interruptions each customer experiences. All planned and unplanned interruptions of one minute or more should be used to calculate this index. It is defined as the number of the interruptions normalized per customer served, and it is expressed as follow:

  SAIFI = Total Customer Interruptions / Total Number of Customers Served

- **Customer Average Interruption Duration Index ("CAIDI")**
  Is an indication of the speed at which power is restored. All planned and unplanned interruptions of one minute or more should be used to calculate this index. It is defined as the average duration of interruptions in the year, and it is expressed as follows:

  CAIDI = SAIDI (Total Customer Hours of Interruption) / SAIFI (Total Customer Interruptions)

Up until July 2023, API classified its outage data in accordance with the IEEE standard 1782-2014 (IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events). In July 2023 and going forward, API implemented changes to its reliability reporting processes in response to new requirements announced by the OEB in its letter of November 21, 2022 (related to EB-2021-0307). Table 2 describes each category of outage causes (as defined in the Amendments to the Electricity Reporting and Record-keeping Requirements, dated November 21, 2022).

Table 2: Classification of Outage Causes

Category	Description
Unknown	Interruption with no apparent cause. If the interruption was caused by equipment failure and the distributor cannot determine the root cause of the failure, the interruption should be reported under code 5 (code 5.1).
Scheduled	Interruption due to the disconnection at a selected time for the purpose of construction or preventive maintenance. Scheduled interruption initiated by transmitter or host distributor should be reported under code 2. Secondary interruption that must be initiated in order to repair and/or restore a previous interruption or interruption initiated to allow for staged restorations should be reported under the root cause of the previous interruption. For example, if the distributor needs to interrupt load to switch a section of overhead line back into service following a car accident, this interruption should be attributed to code 9 (or code 9.2).
Loss of Supply	Interruption due to problems associated with the distribution system owned and/or operated by another distributor, and/or in the transmission system. This cause code includes interruptions caused by transmitter or host distributor scheduled interruption.
Tree Contacts	Interruption caused by faults resulting from tree contact with energized circuits under normal environment and weather conditions.
Lightning	The lightning category includes all interruptions caused by lightning. This may be by a direct strike contacting the wires or another piece of equipment, or by a lightning-induced flashover of the wires or to another piece of equipment.
Equipment Failure	Interruption resulting from the failure of distributor-owned equipment due to deterioration, insufficient maintenance or defective equipment/material. Customer interruptions caused by DER equipment failure shall be reported under this category if the DER is owned by the distributor. Scheduled interruption to repair/replace deteriorated equipment should be reported under Scheduled interruption.
Adverse Weather	Interruption resulting from sever rain, ice storms, heavy snow, sever windstorm (90 kilometers an hour), extreme temperatures, freezing rain, frost, hail or other extreme weather conditions. Adverse weather includes but is not limited to the following conditions: • Severe windstorm greater than 90 kilometres an hour. • Rain at zero degrees Celsius, resulting in freezing rain accumulating on conductors. • Ice or snow buildup on distribution equipment/lines.
Adverse Environment	Interruption due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.
Human Element	Interruption due to the interface of distributor staff with the distribution system. Only interruptions caused by distributor staff should be reported under this cause code, including improper protection settings, improper system operation and improper construction & installation.
Foreign Interference	Interruption caused by external factors, such as those cause by customer equipment, DERs not owned by distributors, animals, vehicles, dig-ins, vandalism, sabotage, foreign objects and cybersecurity event.

Historically, API has through its OMS and outage recording process identified specific cause codes in accordance with the outage cause definitions defined in Table 2. Starting in July 2023, API began using the subcodes as required and indicated in the Amendments to the Electricity Reporting and Record-keeping Requirements, dated November 21, 2022. The cause codes are defined in Table 3 and 4 below:

Table 3: API Cause Code Classification

Main Code	Sub Code	Cause Title	Sub Code	Cause Title
	API Historical		New Sub Code	
0	000	Unknown	011	Non-Equipment Unknown Outage
1	101	Customer Requested	111	Non-Distributor – Customer Requested
			117	Non-Distributor – Building High/Load Move
			118	Non-Distributor – Arc Flash Mitigation
	102	Construction	122	Distributor – Construction
	103	Maintenance	123	Distributor – Maintenance
	104	Vegetation Management	124	Distributor – Vegetation Management
	105	Forced Switching	125	Distributor – Forced Switching
	106	Sectionalizing	126	Distributor - Sectionalizing
			129	Distributor – Arc Flash Mitigation
2	201	Transmission Planned	211	Transmission Planned
	202	Transmission Inadvertent	212	Transmission Inadvertent
			213	Transmission Inadvertent FON
3	301	Falling Trees	311	Falling Tree – On ROW
	302	Broken Branch	322	Broken Branch
	303	Tree Growth/Untrimmed Tree	323	Tree Growth/Untrimmed Tree
	304	Off-ROW Tree	334	Falling Tree – Off ROW
	305	Other Vegetation		
4	401	Lightning	411	Lightning
5	501	Electric Failure	511	Equipment Failure – Electrical Failure
	502	Mechanical Failure	512	Equipment Failure – Mechanical Failure
	503	Defective Equipment/Material		
	504	Corrosion	514	Equipment Failure – Corrosion
	505	Moisture Ingress	515	Equipment Failure – Moisture Ingress
	506	Other Equipment Failure	516	Equipment Failure - Other
			520	Equipment Failure – Distributor Owned DER
			531	Defective Equipment – Electrical Failure
			532	Defective Equipment – Mechanical Failure
			533	Defective Equipment – Other
6			610	Tree Contact
			620	Equipment Breakage
	601	Extreme Wind > 90km/hr		
	602	Freezing Rain		
	603	Wet Snow		
	604	Ice/Icing		
	605	Other Adverse Weather	630	Other Adverse Weather
7	701	Contamination (Salt)	711	Contamination (Salt)
	702	Contamination (Dirt, pollution, other particles)	712	Contamination (Dirt, pollution, other particles)
	703	Fire	713	Fire
	704	Flood	714	Flood
	705	Unstable Earth	715	Unstable Earth
	706	Other Adverse Environment	716	Other Adverse Environment

Table 4: API Cause Code Classification continued

Main Code	Sub Code	Cause Title	Sub Code	Cause Title
	API Historical		New Sub Code	
8			810	Distributor Owned DER
	801	Switching Error	821	Switching Error
	802	Protection Setting	822	Protection Setting
	803	Improper Design	823	Improper Design
	804	Improper Construction/Installation	824	Improper Construction/Installation
	805	Improper Equipment/Tool/Maintenance	825	Improper Equipment/Tool/Maintenance
	806	Commissioning Error	826	Commissioning Error
	807	Incorrect Records/Label	827	Incorrect Records/Label
	808	Other Human Element	828	Other Human Element
9	901	Wildlife (Bird/Animal)	912	Wildlife
	902	Vehicle	922	Vehicle
	903	Crane	943	Customer Equipment – Crane
	904	Agricultural Equipment	944	Customer Equipment – Agricultural Equipment
	905	Dig-in	933	Dig-in
	906	Customer Equipment	946	Customer Equipment – Other
	907	Foreign Objects	967	Human – Foreign Objects
	908	Customer-cut Trees	968	Human – Customer Cut-Trees
	909	Vandalism/Sabotage	969	Human – Vandalism/Sabotage
	910	Other Utilities	966	Human – Other Utilities
	911	Other Foreign		
			945	Customer Equipment – Tree on Customer Line
			950	Non-Distributor Owned DER

2.1 Overview of Algoma Power

API operates eight (8) distinct distribution systems throughout its service territory, each geographically separated and mostly isolated from one another. Within these eight distribution systems, API serves approximately 12,000 customers through approximately 1,800 kilometers of distribution lines in an area that covers over 14,000 square kilometers. The following table provides a summary of these systems.

Table 5: Summary of API distinct distribution systems

Distribution Systems	Transmission Supply Connection(s)	# Distribution Stations	# of Customers Served	Approximate Circuit KM
East of Sault	Echo River TS	4	6193	977.5
Sault Industrial	Northern Ave TS	0	8	20.6
Goulais[1]	Goulais TS	1	3142	289.1
Batchawana	Batchawana TS	0	840	87.4
Montreal River	Andrews TS	0	60	83.9
Mackay	Mackay TS	0	9	1.4
Wawa	Watson TS	2	1677	179.9
No. 4 Circuit	Circuit Limer	3	652	172.3

(1) API owns and operates equipment inside the Goulais TS. This TS is planned for refurbishment starting in 2024 and at the time of writing this study report will include API constructing a DS adjacent to the TS that will contain its distribution equipment.

API operates sub-transmission and distribution feeders based on the transmission supply voltage connection, distribution station connection and ratio bank connection. The transmission supply connection and the type of feeder connected are described in Table 6 below.

Table 6: Summary of Transmission Supply Connections

Transmission Supply Connection	Feeder Connection Type	Feeder Designation
Echo River TS	Sub-transmission	ER1, ER2
Northern Ave TS	Sub-transmission & Distribution	NA1, 4110
Goulais TS	Distribution	5110, 5120, 5130
Batchawana TS	Distribution	5200
Andrews TS	Distribution	7210
Mackay TS	Distribution	7610
Watson TS	Sub-transmission	Wawa No.1 Circuit , Wawa No.2 Circuit
Circuit Limer	Sub-transmission	Wawa No.4 Circuit

API operates nine (9) distribution substations, each connected to API's sub-transmission circuits. The connection of these stations to the sub-transmission circuits are described in Table 7 below.

Table 7: Summary of API Station and Sub-transmission Connections

Distribution Station Connection	Sub-transmission Connection	Feeder Designation
Garden River DS	NA1, ER2	3110, 3120
Bar River DS	ER2	3210, 3220
Desbarats DS	ER1, ER2	3400, 3510, 3600
Bruce Mines DS	ER1	3810, 3820
Wawa #2 DS	Wawa No.1 Circuit, Wawa No.2 Circuit	9210, 9220
Wawa #1 DS	Wawa No.2	9110, 9120
Hawk Junction DS	Wawa No. 4 Circuit	8100
Dubreuilville Sub 86	Wawa No. 4 Circuit	8610, 8620, 8630
Dubreuilville Sub 87	Wawa No. 4 Circuit	8700

API operates ten (10) ratio bank connections that are connected to API's sub-transmission circuits. These connections are described in Table 8 below.

Table 8: Summary of API Sub-transmission connected Ratio Banks

Ratio Bank Connection	Sub-transmission Connection	Feeder Designation
Whitefish Stepdown	Wawa No. 4 Circuit	9711D
Limer Stepdown	Wawa No. 4 Circuit	9711C
Highway 101 Stepdown	Wawa No. 4 Circuit	9711
Goudreau Stepdown	Wawa No. 4 Circuit	8210
Lochalsh Stepdown	Wawa No. 4 Circuit	8310
Missanabie Stepdown	Wawa No. 4 Circuit	8400, 8410, 8420
Wawa Ratio Stepdown	Wawa No. 1 Circuit, Wawa No. 2 Circuit	9410
Wawa High Falls Stepdown	Wawa No. 1 Circuit	9512

3. Summary of Reliability Statistics

All reliability statistics below exclude customer requested outages.

3.1 Overall Reliability Statistics

The following tables and figures present a summary of outage statistics that reflects the overall annual trend in the number of outages, the frequency (number of incidents) and duration of outages. MEDs and LOS Outages are removed as noted below in the respective table columns.

Table 9: Annual Number of Interruptions

Year	All Outages	All Outage, excluding MEDs	All Outages, excluding MEDs & LOS
2015	679	598	571
2016	698	698	685
2017	733	674	657
2018	592	476	471
2019	612	521	513
2020	575	575	559
2021	623	529	513
2022	680	680	670
2023	511	511	495

Figure 2: Annual Number of Interruptions

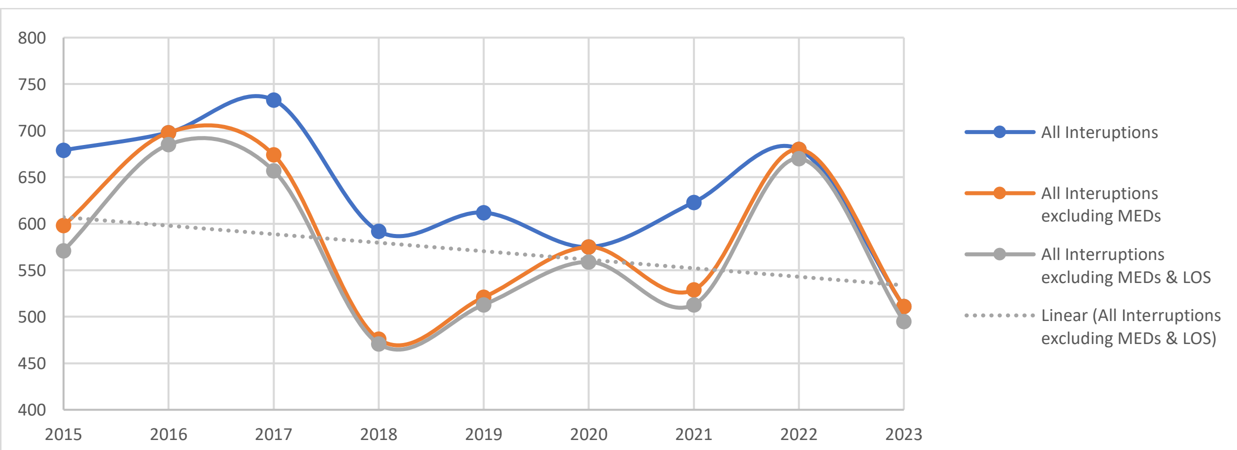


Table 10: Annual Sum of Total Customer Interruptions

Year	All Outages	All Outage, excluding MEDs	All Outages, excluding MEDs & LOS
2015	83,024	74,569	42,890
2016	45,043	45,043	30,075
2017	70,002	66,385	46,313
2018	49,921	38,848	25,778
2019	57,770	47,552	39,844
2020	68,120	68,120	35,497
2021	42,822	31,247	21,589
2022	45,607	45,607	25,556
2023	56,079	56,079	28,166

Figure 3: Annual Sum of Total Customer Interruptions

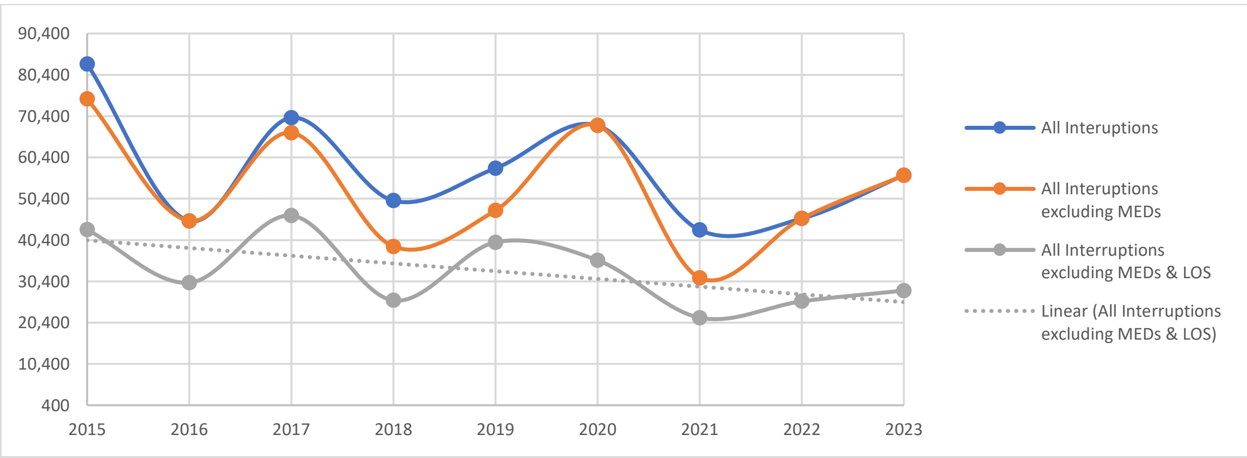
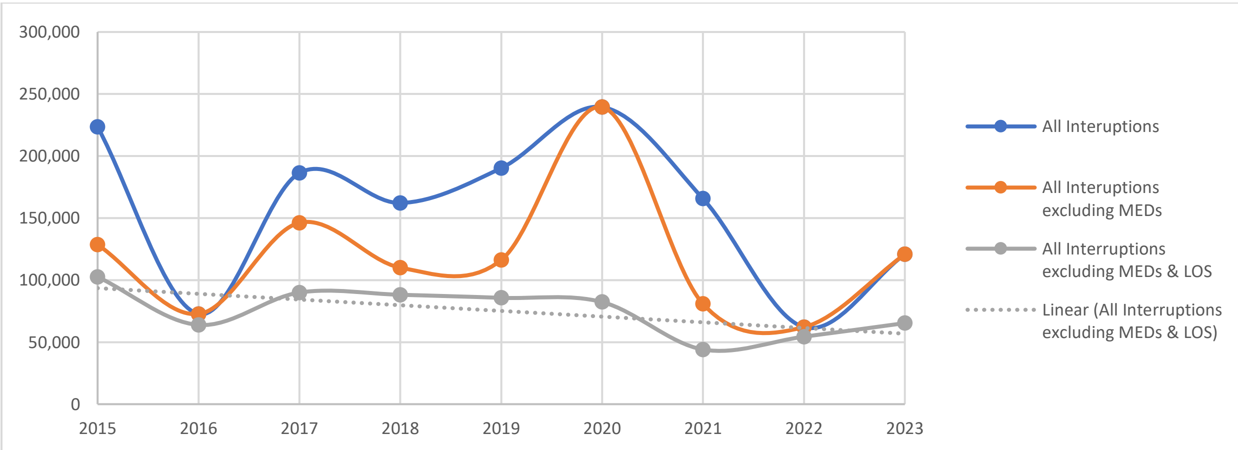


Table 11: Sum of Customer-Hour Interruption Duration

Year	All Outages	All Outage, excluding MEDs	All Outages, excluding MEDs & LOS
2015	223,555	128,637	102,644
2016	72,720	72,720	63,893
2017	186,320	146,235	89,969
2018	162,207	110,062	88,156
2019	190,302	116,225	85,703
2020	239,460	239,460	82,295
2021	165,623	80,772	44,057
2022	62,115	62,115	54,404
2023	120,859	120,859	65,336

Figure 4: Annual Sum of Customer-Hour Interruption Duration



3.2 Major Event Day Outages

A major event, as defined in the electricity reporting and record keeping requirements is an outage event that is beyond the control of the distributors and is:

a. Unforeseeable;
b. Unpredictable;
c. Unpreventable; or
d. Unavoidable.

Such events disrupt normal business operations and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, they take significantly longer than usual to repair, and they affect a substantial number of customers.

"Beyond the control of the distributor" means events that include, but are not limited to, force majeure events and Loss of Supply events

Between 2015 and 2023, API experienced nine (9) major event day outages. Table 12 below provides a summary overview of each event and how they contributed to the number of interruptions, number of customers interrupted and customer hours of interruptions:

Table 12: Major Event Day Outages

YEAR	2015	2017	2018		2019		2021		
DAY	Dec 24	Jun 11	Sep 21	Oct 04	Nov 27	Dec 29	Aug 11	Nov 21	Dec 16
Number of Interruptions	**81**	**60**	**57**	**59**	**43**	**48**	**37**	**10**	**48**
0-Unknown									1
1- Scheduled Outage					1				
2-Loss of Supply		1							1
3-Tree Contacts	78	55	56	58		29	36	10	42
4-Lightning		1							
5-Defective Equipment			1	1		1	1		1
6-Adverse Weather					42	17			3
7-Adverse Environment									
8-Human Element									
9-Foreign Interference	3	3				1			
Number of Customer Interruptions	**8,455**	**9,634**	**6,807**	**4,266**	**5,440**	**4,778**	**2,345**	**4,886**	**4,975**
0-Unknown									344
1- Scheduled Outage					2,279				
2-Loss of Supply		6,017							631
3-Tree Contacts	8,452	3,612	6,806	4,264		2,412	2,339	4,886	3,594
4-Lightning		2							
5-Defective Equipment			1	2		3	6		1
6-Adverse Weather					3,161	2,362			405
7-Adverse Environment									
8-Human Element									
9-Foreign Interference	3	3				1			
Number of Customer Hours of Interruptions	**94,918**	**43,394**	**25,813**	**26,332**	**14,505**	**59,572**	**32,597**	**39,419**	**12,994**
0-Unknown									625
1- Scheduled Outage					1,557				
2-Loss of Supply		3,309							158
3-Tree Contacts	94,869	40,013	25,791	26,299		50,926	32,366	39,419	11,922
4-Lightning		22							
5-Defective Equipment			22	33		21	260		6
6-Adverse Weather					12,948	8,616			284
7-Adverse Environment									
8-Human Element									
9-Foreign Interference	49	50				9			

3.2 Interruption Frequency and Duration Statistics

The annual statistics presented below provide the overall reliability performance throughout each year with MEDs and customer scheduled outages excluded. The overall statistics are presented based on cause category and feeders.

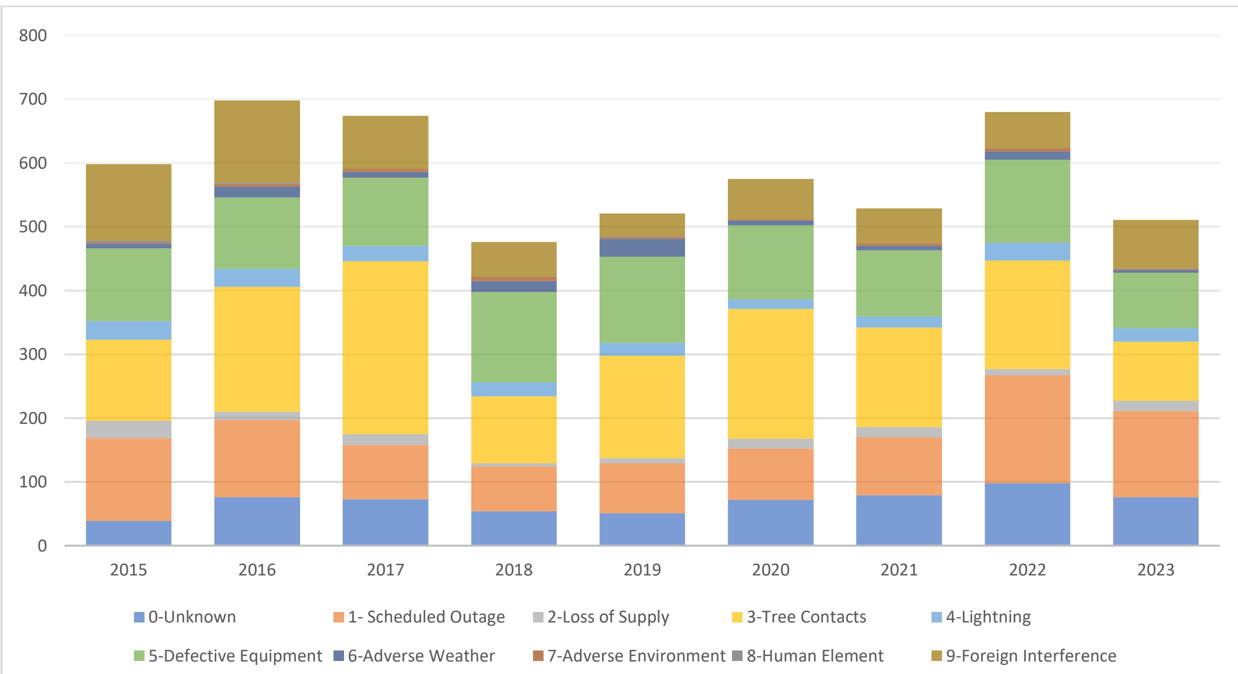
3.2.1 Number of Interruptions

The following table summarizes the total quantity of interruption per year grouped by cause category.

Table 13: Number of Interruptions per Year by Cause Category

Main Cause Code	2015	2016	2017	2018	2019	2020	2021	2022	2023
0	39	76	73	54	51	72	79	98	76
1	130	121	85	70	78	80	91	169	135
2	27	13	17	5	8	16	16	10	16
3	127	196	271	105	161	203	156	170	93
4	29	28	24	22	20	15	17	28	21
5	114	112	107	142	135	116	104	130	87
6	7	17	9	17	28	8	7	13	4
7	2	4	5	7	3	2	4	5	2
8	3	2	0	0	1	0	0	0	1
9	120	129	83	54	36	63	55	57	76

Figure 5: Number of Interruptions by Year by Cause Category



The following table outlines the annual number of interruptions grouped by API main feeders (distribution and subtransmission) as well as Transmission supply station outages. The feeders with the highest number of interruptions are highlighted in orange.

Table 14: Number of Interruptions by Feeder

Feeder	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
3110	12	11	8	13	14	19	13	12	15	117
3120	3	4	5	5	1	3	3	5	0	29
3210	28	38	21	19	12	25	24	24	21	212
3220	35	27	40	31	41	39	45	34	34	326
3400	16	27	26	30	23	25	34	38	34	253
3510	10	20	25	25	20	10	14	18	13	155
3600	101	169	125	73	72	102	105	107	95	949
3810	5	4	4	3	5	8	7	5	7	48
3820	78	31	29	25	22	17	36	24	27	289
3830	0	51	42	34	48	39	35	27	34	310
4110	4	1	1	1	5	2	0	3	0	17
5110	27	22	29	17	20	18	30	75	12	250
5120	97	114	116	70	89	73	57	80	62	758
5130	7	8	32	10	14	17	3	8	2	101
5200	37	33	35	29	28	39	33	65	38	337
7210	14	29	24	12	26	28	22	32	6	193
7610	1	1	2	1	0	0	0	0	0	5
8100	5	2	4	2	3	1	3	8	3	31
8210	0	0	2	0	0	0	0	1	0	3
8310	0	0	0	1	0	3	0	1	1	6
8400	1	2	4	3	0	0	0	0	0	10
8410	1	0	2	0	0	1	1	4	0	9
8420	1	4	8	2	0	2	2	2	3	24
8610	0	0	0	0	0	3	0	2	0	5
8620	0	0	0	0	0	7	0	2	0	9
8630	0	0	0	0	0	1	4	3	0	8
9110	8	8	4	5	5	2	1	6	8	47
9120	1	2	2	1	1	1	0	1		9
9210	12	5	3	4	3	2	2	13	1	45
9220	2	2	1	1	0	1	0	0	0	7
9400	37	50	35	26	38	38	21	42	45	332
9512	0	0	0	0	0	0	0	1	0	1
9710	8	9	13	4	1	11	4	10	12	72
9711	2	0	0	0	1	1	3	1	1	9
9712	0	0	0	0	0	0	0	0	1	1
9711D	4	4	4	5	3	5	0	5	0	30
CircuitLimer	5	4	6	0	0	3	2	1	0	21
DB1	2	2	6	3	2	3	3	3	0	24
ER1	0	0	0	1	2	0	1	1	3	8
ER2	2	2	1	2	7	3	0	1	1	19
GR1	0	0	0	0	0	0	0	1	0	1
NA1	3	3	3	2	3	1	1	0	4	20
No.4 Cct	3	4	4	10	3	9	8	5	19	65
TS Andrews	7	0	0	0	0	0	3	0	2	12
TS Batchawana	3	2	1	0	1	2	1	2	0	12
TS Echo River	3	1	2	2	1	1	0	2	3	15
TS Goulais	4	2	4	0	0	7	2	2	1	22
TS Mackay	1	0	0	0	4	0	3	1	0	9
TS Northern Ave	3	0	0	0	2	0	3	1	0	9
TS Watson	0	0	1	3	1	3	0	1	2	11
Wawa No.1	4	0	0	0	0	0	0	0	0	4
Wawa No.2	1	0	0	1	0	0	0	0	1	3

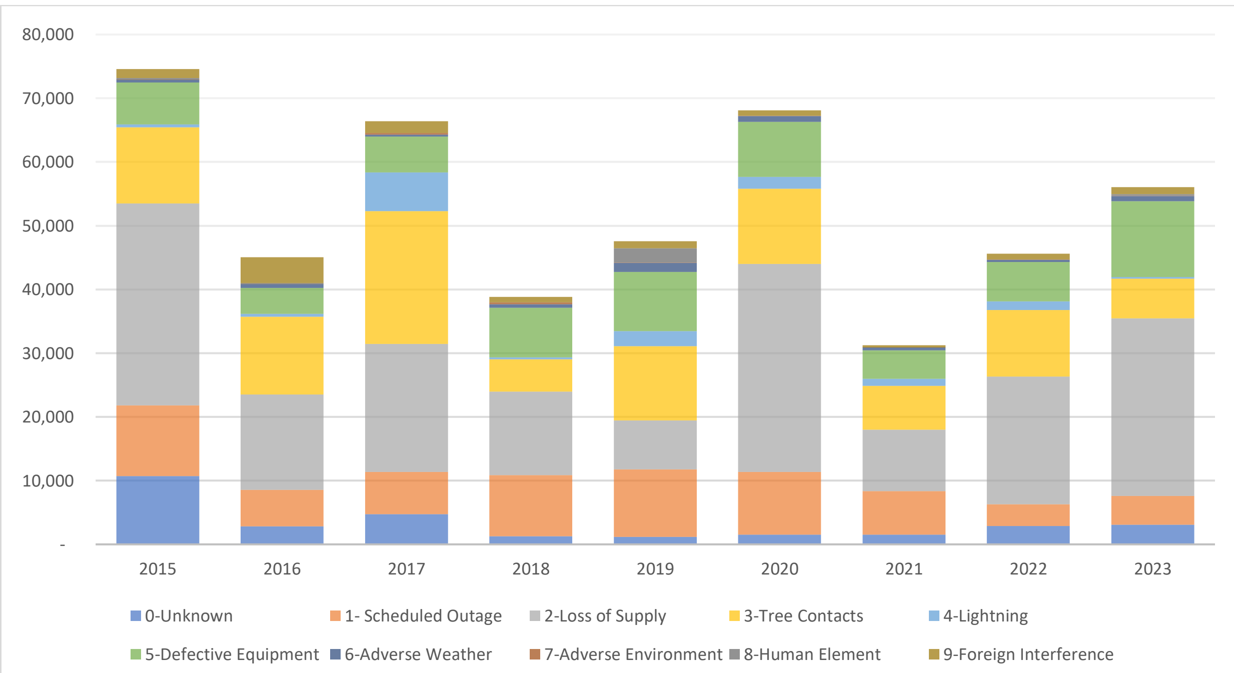
3.2.2 Total Customer Interruptions

The following table summarizes the total customer interruptions (frequency) per year by cause category.

Table 15: Sum of Customer Interruptions per Year by Cause Category

Main Cause Code	2015	2016	2017	2018	2019	2020	2021	2022	2023
0	10,715	2,839	4,746	1,285	1,198	1,521	1,528	2,900	3,064
1	11,100	5,715	6,621	9,591	10,557	9,838	6,814	3,388	4,515
2	31,679	14,968	20,072	13,070	7,708	32,623	9,658	20,051	27,913
3	11,973	12,186	20,868	5,108	11,643	11,820	6,876	10,436	6,200
4	435	477	6,072	272	2,349	1,865	1,121	1,349	270
5	6,565	4,057	5,602	7,793	9,277	8,615	4,456	6,195	11,888
6	400	580	290	577	1,416	927	441	330	823
7	4	12	247	279	55	34	9	34	6
8	286	171	0	0	2,279	0	0	0	258
9	1,412	4,038	1,867	873	1,070	877	344	924	1,142

Figure 6: Sum of Customer Interruptions per Year by Cause Category



The following table outlines the total customer interruptions grouped by API main feeders (distribution and subtransmission) as well as Transmission supply station outages. The feeders with the highest number of interruptions are highlighted in orange.

Table 16: Sum of Customer Interruptions by Feeder

Feeder	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
3110	38	335	132	457	840	348	191	289	579	3,209
3120	8	55	144	149	4	6	84	15	0	465
3210	498	166	327	245	97	742	1,057	360	601	4,093
3220	1,211	148	1,006	1,684	2,437	2,034	3,589	1,726	1,266	15,101
3400	752	650	331	262	492	97	1,604	1,485	586	6,259
3510	365	365	153	159	166	355	47	292	63	1,965
3600	5,365	6,114	5,536	1,256	2,454	2,914	2,452	2,212	2,690	30,993
3810	54	116	38	159	43	404	126	169	118	1,227
3820	826	1,245	1,071	139	481	78	1,359	117	1,903	7,219
3830	0	961	511	700	743	270	243	483	238	4,149
4110	4	1	4	4	34	3	0	9	0	59
5110	245	1,609	4,412	877	1,594	2,158	1,965	1,697	35	14,592
5120	12,021	7,897	14,811	5,207	12,009	8,803	3,050	4,571	3,868	72,237
5130	237	379	507	131	910	698	35	40	220	3,157
5200	4,286	1,395	1,458	975	2,946	1,557	2,959	3,846	1,431	20,853
7210	219	410	358	86	576	576	339	416	103	3,083
7610	1	1	14	1	0	0	0	0	0	17
8100	302	107	4	17	25	1	83	154	7	700
8210	0	0	3	0	0	0	0	2	0	5
8310	0	0	0	1	0	10	0	7	1	19
8400	4	92	180	135	0	0	0	0	0	411
8410	1	0	3	0	0	3	3	8	0	18
8420	1	5	32	3	0	2	14	2	9	68
8610	0	0	0	0	0	235	0	9	0	244
8620	0	0	0	0	0	105	0	24	0	129
8630	0	0	0	0	0	11	37	3	0	51
9110	98	495	9	92	74	21	2	151	92	1,034
9120	1	7	105	11	78	99	0	78	0	379
9210	302	46	29	78	58	85	12	402	26	1,038
9220	65	2	10	1	0	41	0	0	0	119
9400	817	1,015	1,731	680	1,099	1,336	249	1,000	665	8,592
9512	0	0	0	0	0	0	0	1	0	1
9710	46	75	77	14	9	73	32	75	96	497
9711	92	0	0	0	29	46	58	28	1	254
9712	0	0	0	0	0	0	0	0	14	14
9711D	68	136	105	94	108	200	0	138	0	849
CircuitLimer	1,483	1,185	1,782	0	0	1,898	1,262	633	0	8,243
DB1	2,365	2,356	3,521	2,280	2,331	2,321	4	1,173	0	16,351
ER1	0	0	0	2,283	4,559	0	1,121	2,300	5,439	15,702
ER2	6,870	2,636	3,719	4,704	4,179	3,775	0	534	5,617	32,034
GR1	0	0	0	0	0	0	0	534	0	534
NA1	1,490	1,016	6	4	6	2	2	0	1,078	3,604
No.4 Cct	638	452	180	1,247	641	3,151	2,170	1,206	6,082	15,767
TS Andrews	415	0	0	0	0	0	183	0	118	716
TS Batchawana	2,460	1,636	818	0	824	1,650	825	1,662	0	9,875
TS Echo River	17,474	6,009	9,756	9,778	6,033	6,048	0	9,932	16,864	81,894
TS Goulais	11,767	5,926	11,863	0	0	21,043	6,057	6,160	2,640	65,456
TS Mackay	7	0	0	0	28	0	21	7	0	63
TS Northern Ave	18	0	0	0	10	0	12	4	0	44
TS Watson	0	0	1,639	3,292	1,637	4,921	0	1,653	3,315	16,457
Wawa No.1	8	0	0	0	0	0	0	0	0	8
Wawa No.2	1,647	0	0	1,643	0	0	0	0	314	3,604

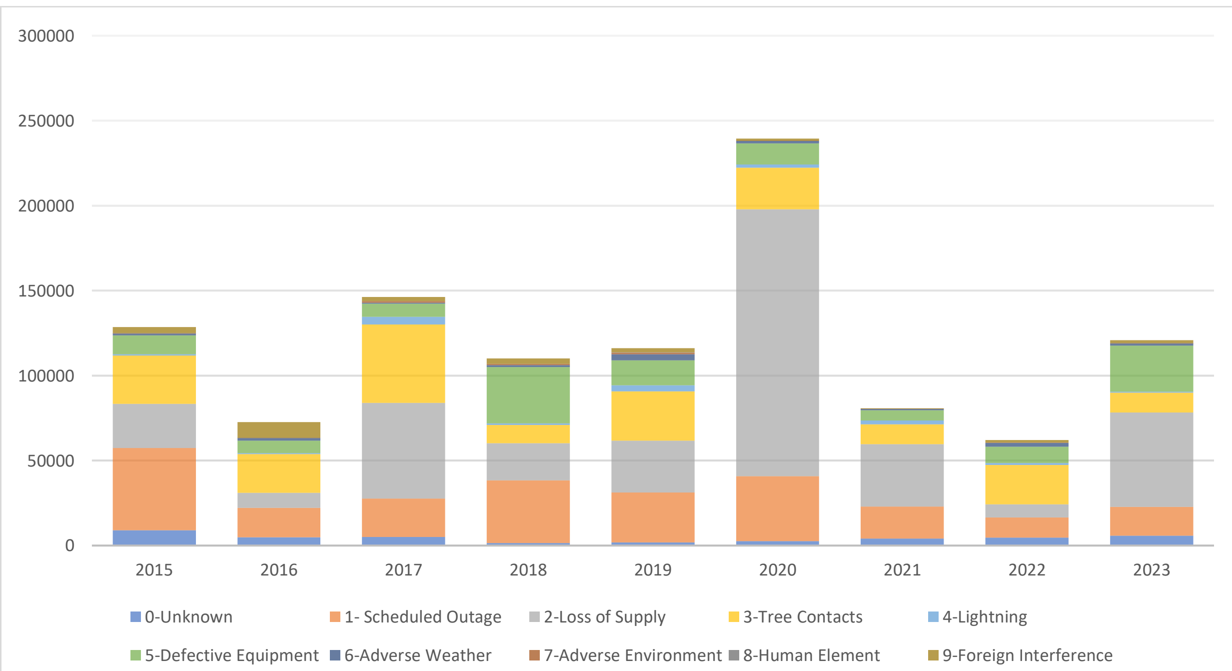
3.2.3 Customer-Hour Interruption Duration

The following table summarizes the total sum of customer hour interruption duration per year by cause category.

Table 17: Sum of Customer Hour Interruption Duration per Year by Cause Category

Main Cause Code	2015	2016	2017	2018	2019	2020	2021	2022	2023
0	9,077	4,911	5,074	1,492	1,858	2,536	4,094	4,658	5,766
1	48,248	17,252	22,667	36,856	29,283	38,204	18,891	11,806	17,020
2	25,994	8,827	56,266	21,906	30,522	157,165	36,715	7,711	55,523
3	28,577	22,817	46,168	10,745	29,091	24,419	11,645	23,296	11,741
4	691	564	4,405	825	3,484	1,994	2,172	1,128	456
5	11,028	7,317	7,774	33,184	14,803	12,291	6,171	9,594	27,118
6	1,046	1,538	473	1,122	3,460	1,612	726	2,262	1,231
7	3	10	1,050	830	918	10	12	83	10
8	382	160	0	0	190	0	0	0	357
9	3,593	9,324	2,357	3,102	2,615	1,230	347	1,577	1,638

Figure 7: Sum of Customer-Hour Interruption Duration by Year by Cause Category



The following table outlines the sum of customer interruption duration grouped by API main feeders (distribution and subtransmission) as well as Transmission supply station outages. The feeders with the highest total sum of customer-hour interruption duration are highlighted in orange.

Table 18: Sum of Customer-hour Interruption Duration by Feeder

	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
3110	35	332	191	694	2,239	896	612	619	617	6,235
3120	9	64	287	121	6	8	473	21	0	989
3210	460	270	1,177	385	413	928	1,531	140	882	6,185
3220	3,320	497	2,973	3,329	5,470	3,462	9,117	2,911	4,863	35,943
3400	99	1,381	536	631	1,702	202	3,965	1,944	916	11,376
3510	541	467	637	152	602	303	81	368	176	3,328
3600	18,286	11,337	12,583	2,284	9,830	5,442	5,629	4,016	7,479	76,885
3810	52	174	94	289	362	1,296	431	244	267	3,210
3820	1,798	3,278	1,251	128	1,695	70	2,025	411	4,288	14,945
3830	0	2,717	2,285	1,782	3,843	901	491	980	447	13,445
4110	6	2	23	14	38	9	0	31	0	124
5110	446	553	9,152	441	5,197	5,584	5,177	4,802	82	31,433
5120	25,191	18,241	31,847	11,496	29,005	25,598	4,179	9,849	5,692	161,097
5130	508	260	2,248	227	2,693	1,034	224	76	48	7,316
5200	14,918	3,951	3,991	2,472	4,525	2,194	6,157	9,716	3,339	51,265
7210	916	1,947	1,889	609	2,652	2,465	771	1,918	161	13,328
7610	3	9	47	2	0	0	0	0	0	61
8100	950	82	7	30	19	1	135	226	13	1,466
8210	0	0	7	0	0	0	0	3	0	9
8310	0	0	0	19	0	82	0	3	3	107
8400	25	426	795	877	0	0	0	0	0	2,123
8410	0	0	10	0	0	2	2	8	0	22
8420	119	11	106	8	0	6	25	6	33	314
8610	0	0	0	0	0	1,330	0	14	0	1,343
8620	0	0	0	0	0	391	0	41	0	432
8630	0	0	0	0	0	47	67	13	0	127
9110	153	1,265	17	463	108	18	5	563	120	2,712
9120	1	3	379	3	100	41	0	27	0	555
9210	274	61	37	53	40	79	8	611	9	1,172
9220	139	2	28	4	0	155	0	0	0	327
9400	1,397	2,899	4,065	3,186	2,937	2,372	475	2,969	1,452	21,751
9512	0	0	0	0	0	0	0	1	0	1
9710	75	364	232	16	11	159	41	172	405	1,476
9711	123	0	0	0	203	58	122	96	0	603
9712	0	0	0	0	0	0	0	0	6	6
9711D	94	206	152	193	184	431	0	160	0	1,419
CircuitLimer	1,946	3,975	680	0	0	337	326	116	0	7,380
DB1	5,893	4,422	5,005	6,248	6,786	4,090	3	2,968	0	35,414
ER1	0	0	0	27,958	380	0	2,622	2,338	9,044	42,343
ER2	5,369	6,239	3,935	21,314	2,749	3,839	0	401	18,255	62,100
GR1	0	0	0	0	0	0	0	1,719	0	1,719
NA1	1,658	2,540	8	5	9	5	0	0	1,358	5,583
No.4 Cct	2,675	1,276	749	1,876	1,115	8,210	4,197	4,020	20,933	45,051
TS Andrews	3,129	0	0	0	0	0	217	0	383	3,728
TS Batchawana	2,064	1,009	5,412	0	787	5,638	4,638	471	0	20,018
TS Echo River	8,696	340	10,680	9,235	29,937	2,419	0	4,409	5,997	71,713
TS Goulais	26,599	2,123	39,932	0	0	154,766	26,892	2,465	15,752	268,531
TS Mackay	22	0	0	0	152	0	83	46	0	304
TS Northern Ave	306	0	0	0	51	0	52	10	0	419
TS Watson	0	0	2,786	12,671	382	4,592	0	193	17,671	38,296
Wawa No.1	39	0	0	0	0	0	0	0	0	39
Wawa No.2	302	0	0	849	0	0	0	0	167	1,318

3.3 Feeder Performance

Table 19 below outlines causes for the top ten most interrupted feeders (expressed as a percentage of the total frequency of interruptions between 2015 and 2023). Top cause is highlighted in orange.

Table 19: Cause Category breakdown of API's worst performing feeders by Interruption Frequency

Feeder	0	1	2	3	4	5	6	7	8	9
3210	18.9%	10.4%	0.0%	17.0%	6.1%	22.2%	0.0%	2.4%	0.5%	22.6%
3220	15.0%	11.7%	0.0%	21.8%	3.1%	23.3%	4.0%	0.6%	0.3%	20.2%
3400	10.3%	10.3%	0.0%	24.1%	3.6%	37.9%	0.8%	0.0%	0.0%	13.0%
3600	8.9%	16.2%	0.0%	41.4%	3.0%	15.9%	3.2%	0.0%	0.0%	11.5%
3820	7.6%	9.3%	0.0%	36.3%	3.8%	21.8%	0.7%	1.7%	0.3%	18.3%
3830	11.3%	10.6%	0.0%	40.3%	3.9%	21.3%	2.6%	0.3%	0.0%	9.7%
5110	18.8%	26.4%	0.0%	20.8%	0.8%	16.4%	1.6%	1.2%	0.0%	14.0%
5120	15.6%	13.3%	0.0%	25.5%	4.4%	21.5%	1.8%	1.1%	0.1%	16.8%
5200	15.1%	18.1%	1.2%	30.3%	2.7%	13.4%	1.2%	1.5%	0.3%	16.3%
9400	9.0%	37.0%	0.6%	19.6%	5.1%	18.7%	1.5%	0.3%	0.0%	8.1%

Table 20 below outlines the interruption causes for the top ten worst performing feeders based on customers interrupted (expressed as a percentage of the total frequency of interruptions between 2015 and 2023). Top cause is highlighted in orange.

Table 20: Cause Category breakdown of API's worst performing feeders by Customers Interrupted

Feeder	0	1	2	3	4	5	6	7	8	9
3600	3.3%	15.6%	0.0%	58.8%	1.6%	14.8%	3.4%	0.0%	0.0%	2.6%
5120	2.3%	26.2%	0.0%	47.8%	0.7%	14.9%	1.3%	0.7%	0.4%	5.7%
5200	11.4%	12.3%	11.0%	40.5%	4.8%	14.3%	3.8%	0.1%	0.0%	2.0%
DB1	0.0%	14.0%	0.0%	43.0%	0.0%	28.6%	0.0%	0.0%	0.0%	14.4%
ER1	12.4%	14.5%	0.0%	7.5%	0.0%	51.0%	0.0%	0.0%	14.5%	0.0%
ER2	38.8%	17.2%	0.0%	0.0%	4.2%	39.8%	0.0%	0.0%	0.0%	0.0%
No.4 Cct	12.3%	25.8%	28.2%	1.0%	2.5%	21.6%	1.9%	0.0%	0.0%	6.7%
TS Echo River	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
TS Goulais	0.0%	9.1%	81.9%	0.0%	9.1%	0.0%	0.0%	0.0%	0.0%	0.0%
TS Watson	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Table 21 below outlines the interruption causes for the top ten worst performing feeders based on customer-hour interruption duration (expressed as a percentage of the total frequency of interruptions between 2015 and 2023). Top cause is highlighted in orange.

Table 21: Cause Category breakdown of API's worst performing feeders by customer hour interruption duration

Feeder	0	1	2	3	4	5	6	7	8	9
3220	3.4%	50.4%	0.0%	30.7%	2.6%	6.5%	4.0%	0.0%	1.0%	1.4%
3600	1.5%	22.9%	0.0%	58.7%	1.0%	9.3%	2.8%	0.0%	0.0%	3.8%
5120	1.3%	41.1%	0.0%	36.9%	0.9%	10.6%	1.0%	1.7%	0.2%	6.1%
5200	11.3%	18.4%	22.0%	32.8%	2.6%	8.5%	3.3%	0.0%	0.0%	1.1%
ER1	10.7%	0.4%	0.0%	2.9%	0.0%	85.6%	0.0%	0.0%	0.4%	0.0%
ER2	18.4%	41.0%	0.0%	0.0%	2.4%	38.2%	0.0%	0.0%	0.0%	0.0%
No.4 Cct	6.8%	28.7%	32.9%	1.9%	2.7%	23.1%	0.6%	0.0%	0.0%	3.2%
TS Echo River	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
TS Goulais	0.0%	12.7%	85.8%	0.0%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%
TS Watson	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

3.3.1 Worst performing feeders grouped by area 2015-2023

All feeder performance statistics below are based on the operating device(s) that isolated the abnormal system conditions.

When considering the worst performing feeders, the customer hour interruption duration is the metric used. From the list of top ten (10) worst performing feeders based on customer hour interruption duration, Tables 17 to 26 below identify the common operating device(s) used to isolate the abnormal system condition. Only outage causes with an aggregate interruption duration greater than **2,000** customer hours is included in these lists.

Table 22: Outage Statistics Feeder 3220

TroubledElement	Sub Cause Code	Number of Interruptions	Number of Customers Affected	Sum of Customer Hour Interruption Duration
SW3200-88	1	4	3,596	9,9524
SW3222-72	3	14	1,110	2,744
SW3220-62	1	2	672	2,228

Table 23: Outage Statistics Feeder 3600

TroubledElement	Sub Cause Code	Number of Interruptions	Number of Customers Affected	Sum of Customer Hour Interruption Duration
SW3610C-23	3	4	1,090	3,522
SW3610D-92	3	8	4,494	10,271
SW3611-10	3	7	1,078	2,120
SW3611C-158	1	2	546	3,089
SW3612C-21	3	4	956	2,061
SW3630-162	3	4	2,106	6,263
	9	1	536	2,649
SW3630-63	1	1	516	2,012

Table 24: Outage Statistics Feeder 5120

TroubledElement	Sub Cause Code	Number of Interruptions	Number of Customers Affected	Sum of Customer Hour Interruption Duration
OHG2I5120A-18	1	2	962	4,930
OHG2I5120A-55	1	2	868	4,629
SW5120-200	1	4	6,244	24,832
	3	3	6,440	8,551
	5	1	2,126	3,601
SW5120A-106	1	8	4,312	14,935
	3	7	4,079	6,755
	5	1	647	3,009
SW5120A-14	3	6	1,550	2,903
SW5120B-108	3	1	1,008	3,226
SW5120B-174	1	7	413	2,558
	3	5	3,788	6,100
SW5120B-177	3	1	688	2,030
SW5121-132	1	1	393	2,351
SW5121-71	3	7	5,197	9,120
	5	3	3,363	3,575
SW5121B-61	9	2	1,114	3,643
SW5121B-64	3	6	3,139	4,232
	9	2	1,013	2,781
SW5121D-75	3	5	1,731	2,452
SW5123A-28	3	9	667	2,329

Table 25: Outage Statistics Feeder 5220

TroubledElement	Sub Cause Code	Number of Interruptions	Number of Customers Affected	Sum of Customer Hour Interruption Duration
OHJ4H5221-102	1	2	534	2,358
SW5200-1	0	3	1,834	3,934
	3	7	4,052	5,336
SW5221-30	3	6	2,344	6,673

Table 26: Outage Statistics Feeder DB1

TroubledElement	Sub Cause Code	Number of Interruptions	Number of Customers Affected	Sum of Customer Hour Interruption Duration
REC052	3	6	7,025	18,123
	5	1	1,170	4,290
	9	2	2,356	4,422
SW046	1	1	1,111	2,685
SW061	5	2	2,341	3,779

Table 27: Outage Statistics Feeder ER1

TroubledElement	Sub Cause Code	Number of Interruptions	Number of Customers Affected	Sum of Customer Hour Interruption Duration
DesbaratsT1	5	1	1,121	2,622
GLPT-SW562	5	2	4,583	30,297
SW2020	1	1	1,949	4,515
SW023	5	1	2,307	3,307

Table 28: Outage Statistics Feeder ER2

TroubledElement	Sub Cause Code	Number of Interruptions	Number of Customers Affected	Sum of Customer Hour Interruption Duration
GLPT-SW020	0	3	10,589	9,304
	5	1	5,617	18,255
SW022	1	1	1,318	4,679
SW2020	0	3	10,589	9,304
	1	1	4,183	20,776
	5	2	6,093	4,120

Table 29: Outage Statistics Feeder TS Echo River

TroubledElement	Sub Cause Code	Number of Interruptions	Number of Customers Affected	Sum of Customer Hour Interruption Duration
GLPT-SW020	2	3	11,296	19,492
TS Echo River	2	12	70,598	52,220

Table 30: Outage Statistics Feeder TS Goulais

TroubledElement	Sub Cause Code	Number of Interruptions	Number of Customers Affected	Sum of Customer Hour Interruption Duration
TS Goulais	1	2	5,950	34,182
	2	18	53,578	230,282
	4	2	5,928	4,067

Table 31: Outage Statistics Feeder TS Goulais

TroubledElement	Sub Cause Code	Number of Interruptions	Number of Customers Affected	Sum of Customer Hour Interruption Duration
TS Watson	2	10	16,455	38,291

4. Major Cause Trend Analysis & Recommendations

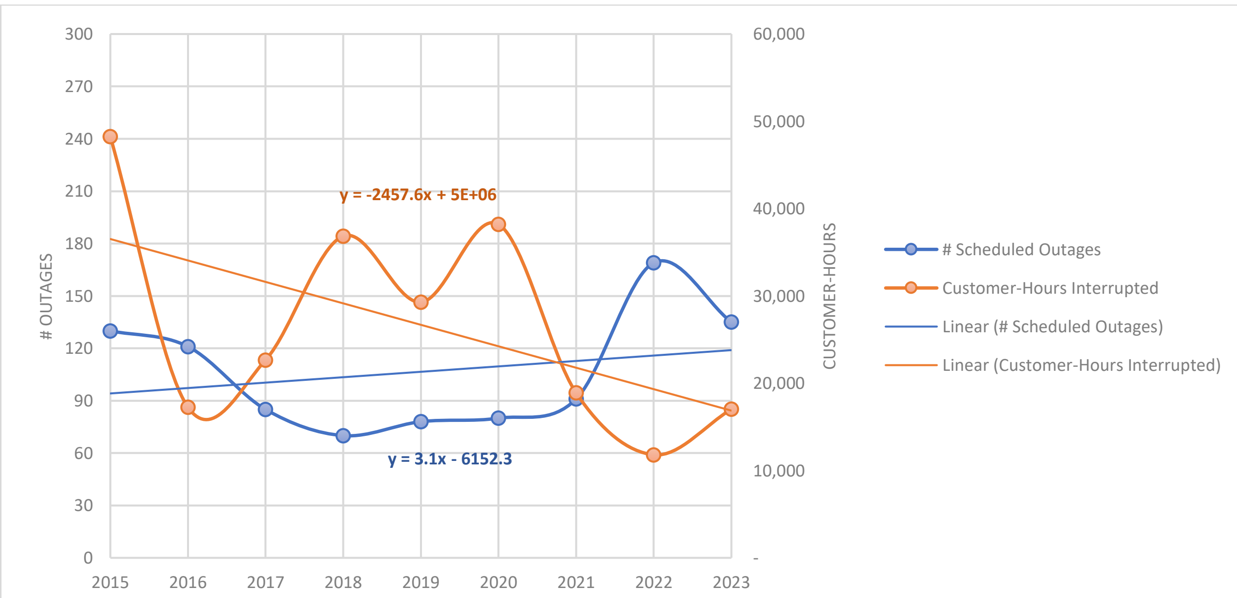
The results, presented in section 3, indicate that the major causes of outages are scheduled outages, loss of supply, vegetation, and equipment failure.

4.1 Scheduled Outages

As part of API day-to-day operations, scheduled outages are required to complete certain work activities. API operates a radial and rural distribution system, which results in limited capability in transferring loads to minimize/mitigate planned outages. As is shown in the figure below, there has been a slight increasing trend in the frequency of outages, but an overall slight decrease in the customer-hour interruption duration.

Figure 8 below shows the overall trend in scheduled outages between 2015 and 2023.

Figure 8: Trend in Scheduled Outages 2015 to 2023



From 2015 to 2023, API had eleven (11) scheduled outages that resulted in a customer-hour impact greater than 3,000 customer-hours. These eleven outages represent approximately **<u>41%</u>** of the total customer-hour interruption impact of scheduled outages.

Table 32: Top Scheduled Outages by Customer-Hour Interrupted

Date	Feeder	Isolation Device	Total Customers	Duration (hours)	Customer Hours
Feb 21, 2015	5120	SW5120-200	1,978	3.92	7,747.2
Sep 13, 2015	TS Goulais	TSGoulais	2,941	8.00	23,528.0
Sep 25, 2016	ER2	SW022	1,318	3.55	4,678.9
Aug 23, 2017	5120	SW5120A-106	503	6.08	3,059.9
Oct 19, 2018	ER2	SW2020	4,183	4.97	20,775.6
May 28, 2019	5120	SW5120-200	2,008	2.00	4,016.0
Nov 02, 2020	TS Goulais	TSGoulais	3,009	4.07	10,653.9
Nov 25, 2020	5120	SW5120-200	2,032	6.42	13,038.7
Aug 23, 2022	5110	SW5112-165	671	5.97	3,279.8
Jun 04, 2023	3220	SW3200-88	830	4.25	3,527.5
Jun 22, 2023	No.4 Circuit	SW2056	415	9.42	3,907.9

Recommendation(s):

As part of the job planning process, consider opportunities to minimize or reduce outages, such as using live-line technique or increasing crew size.

The feeder configuration in the Goulais area has resulted in larger outages, both planned and unplanned. Of note, feeders connected to 5120 and 5110 are amongst the work performing in terms of outage frequency and impact. Upgrading the feeder between the Goulais TS and the Batchawana TS will allow for increase load-transfer capability between both systems. Establish a loop feed in and around the Goulais TS will allow for greater flexibility in load management, outage planning and improve reliability.

Automation of the East of Sault sub transmission feeders will allow for improved reliability through automated fault isolation and system restoration.

4.2 Loss of Supply Outages

Loss of supply outages are interruptions caused by a failure in the transmission system, including the transmission portion of a substation. Scheduled outages from the transmission system are grouped in the loss of supply category. These types of outages are generally beyond API's control, but it is however worth noting the reason for the outage and whether there is any opportunity for API and the Transmitter to mitigate future unplanned outages and to coordinate on scheduled outages.

Figure 9 below shows the overall trend in loss of supply outages between 2015 and 2023.

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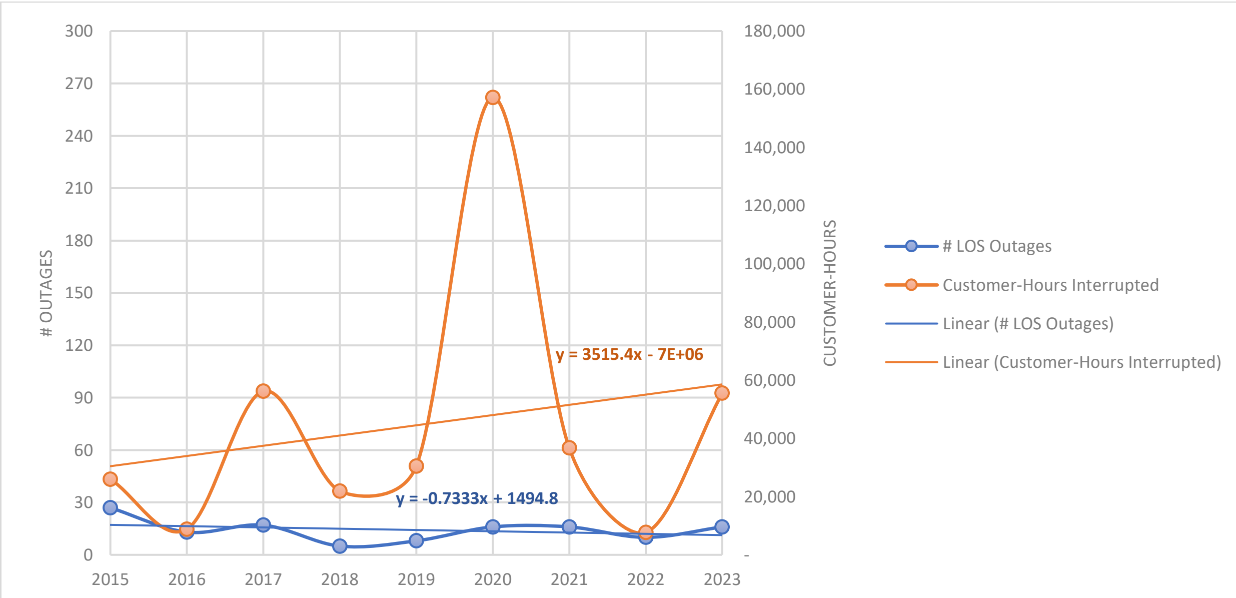
Figure 9: Loss of Supply Outages 2015 to 2023



From 2015 to 2023, API had eight loss of supply outages that resulted in a customer-hour impact greater than 10,000 customer-hours. These ten (10) outages represent approximately **62%** of the total customer-hour outage impact of loss of supply outages.

Table 33: Top Supply Outages by Customer-Hour Interrupted

Date	Feeder	Isolation Device	Total Customers	Duration (hours)	Customer Hours	Reason for Outage
Apr 09, 2017	TS Goulais	TSGoulais	2,964	4.83	14,326.0	Lightning Causing Supply Outage
Sep 16, 2017	TS Goulais	TSGoulais	2,971	7.25	21,539.8	Planned Supply Outage
Jun 23, 2019	TS Echo River	TSEcho River	6,033	6.53	29,936.6	Breaker issue at Echo River TS
Jan 06, 2020*	TS Goulais	TSGoulais	3,003	58.85	67,292.2	Drop lead connection failure leading to 115kV Transformer damage
Jan 08, 2020	TS Goulais	TSGoulais	3,003	11.77	19,991.1	Planned Supply Outage
Nov 02, 2020	TS Goulais	TSGoulais	3,009	4.00	12,036.0	Planned Supply Outage
Nov 09, 2020	TS Goulais	TSGoulais	3,009	5.35	15,812.0	Planned Supply Outage
Nov 15, 2020	TS Goulais	TSGoulais	3,009	9.70	28,481.1	High Winds Causing Supply Outage
May 29, 2021	TS Goulais	TSGoulais	3,028	11.50	24,720.8	Planned Supply Outage
Oct 28, 2023	TS Goulais	TSGoulais	2,640	5.67	15,752.0	Planned Supply Outage

As expected, the impact of supply outages, specifically unplanned outages has had the largest overall customer-hour interruption impact.

Recommendation(s):

The existing supply configuration at the Goulais TS has been the major supply issue since 2017 (one of the worst performing supply feeds). With the limited transfer capability from Batchawana, these outages, planned and unplanned have had significant outage impact to API's customers. Through the regional planning process, API has been working with the Transmitter on a refurbishment plan for this station. It is recommended to ensure that the configuration of the refurbished station allow for better supply redundancy to optimize work planning and improved outage response during unplanned outages.

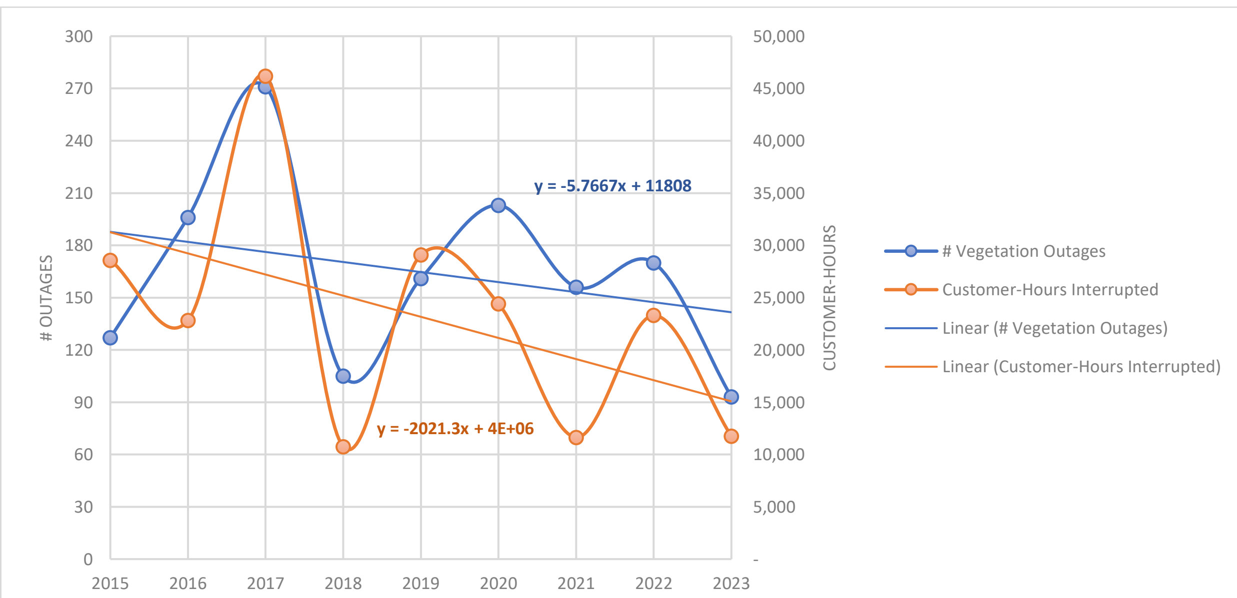
Continue to coordinate outages where possible and practicable to reduce the quantity of outages experienced by API customers. Consideration should also be given to the timing of the outages (day of the week and time of day), to coordinate with community events, industrial customer planned shutdowns, etc.

4.3 Vegetation Outages

API operates a rural and radial distribution system in Northern Ontario, which means that much of its system is surrounded by a treed backline. Vegetation caused outages occur when vegetation contacts the distribution system, causing a phase-to-phase or phase-to-ground fault. These types of outages can be particularly challenging depending on the type of vegetation and whether any damage occurs to the distribution system (e.g., broken conductor).

Figure 10 below shows the overall trend in vegetation caused outages between 2015 and 2023.

Figure 10: Vegetation caused Outages 2015 to 2023



While there is variability year-over-year in the quantity of outages and the overall customer-hour interrupted, the trend is a decreasing.

In order to better understand the root cause of vegetation caused outages, it is best to look at area specific data to understand where problems might exist and the need for increased vegetation management. API's vegetation management program splits the distribution system into Forestry parts and each part is managed on a specific cycled frequency. Each outage can be tied back to a Forestry part and totaled each year from 2015 to 2023. The Forestry parts are grouped in the following way:

Table 34: Forestry Parts

Area	Forestry Parts
Andrews	Andrews Part 1, Andrews Part 2
Bar River	Bar River Part 1, Bar River Part 2, Bar River Part 3
Batchawana	Batchawana Part 1, Batchawana Part 2
Bruce Mines	Bruce Mines Part 1, Bruce Mines Part 2, Bruce Mines Part 3, Bruce Mines Part 4
Desbarats	Desbarats Part 1, Desbarats Part 2
No.4 Circuit Dist.	Dubreuilville Part 1, Goudreau Part 1, Hawk Junction Part 1, Lochalsh Part 1, Missanabie Part 1
HWY101	HWY 101 Part 1
Garden River	Garden River Part 1, Garden River Part 2
Goulais	Goulais Part 1, Goulais Part 2, Goulais Part 3, Goulais Part 4, Goulais Part 5, Goulais Part 6
Michipicoten	Michipicoten Part 1
Sault	Sault Part 1
St. Joseph Island	St. Joseph Island Part 1, St. Joseph Island Part 2, St. Joseph Island Part 3, St. Joseph Island Part 4
Wawa	Wawa Part 1, Wawa Part 2, Wawa Part 3

Table 35 below provides a summary of vegetation related outages between 2015 and 2023 and their associated customer-hour interruption impact.

Table 35: Summary of Vegetation-related Outage Statistics by area from 20215-2023

Forestry Part	# Outages	Customers Interrupted	Customer-hours Interrupted
Andrews	64	961.0	3,978.3
Bar River	106	5,332.6	12,848.0
Batchawana	103	8,442.0	16,812.2
Bruce Mines	248	6,805.5	18,624.3
Desbarats	113	9,747.8	22,532.9
No.4 Circuit Dist.	24	416	1,138.5
HWY101	67	1,048.0	2,128.3
Garden River	32	753.0	1,446.7
Goulais	262	42,982.8	79,078.5
Michipicoten	3	11.0	123.0
Sault	2	5.0	9.2
St. Joseph Island	393	18,237.3	45,146.9
Wawa	65	2,368.0	4,630.8

The figures 11 to 39 below depicts the overall annual in the number of vegetation-related interruptions and customer-hours interrupted, grouped by Forestry Part. Outage statistics in Dubreuilville Part 1, Goudreau Part 1, Hawk Junction Part 1, Lochalsh Part 1, Missanabie Part 1, Michipicoten Part 1, and Sault Part 1 were intentionally omitted as the quantity of outages were too low to derive any meaningful trend and analysis.

Figure 11: 2015-2023 Vegetation-related Outage Statistics, Andrews Part 1

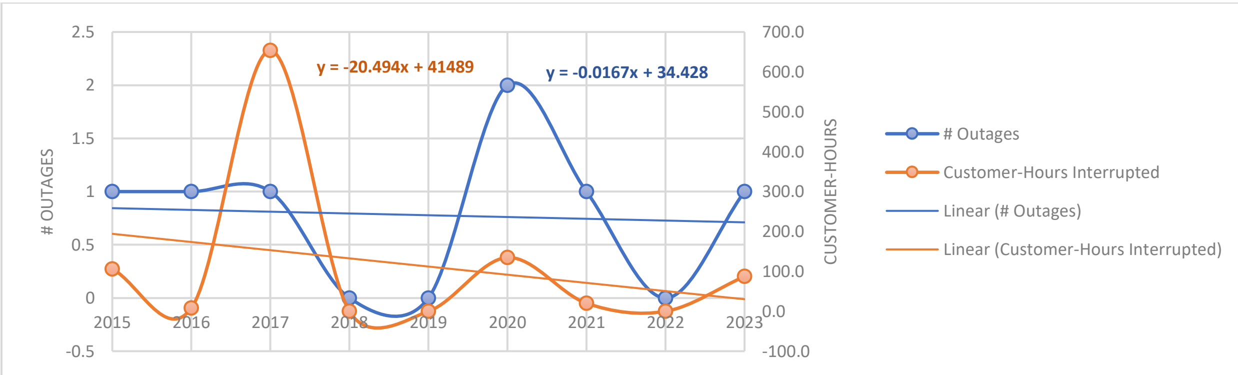


Figure 12: 2015-2023 Vegetation-related Outage Statistics, Andrews Part 2

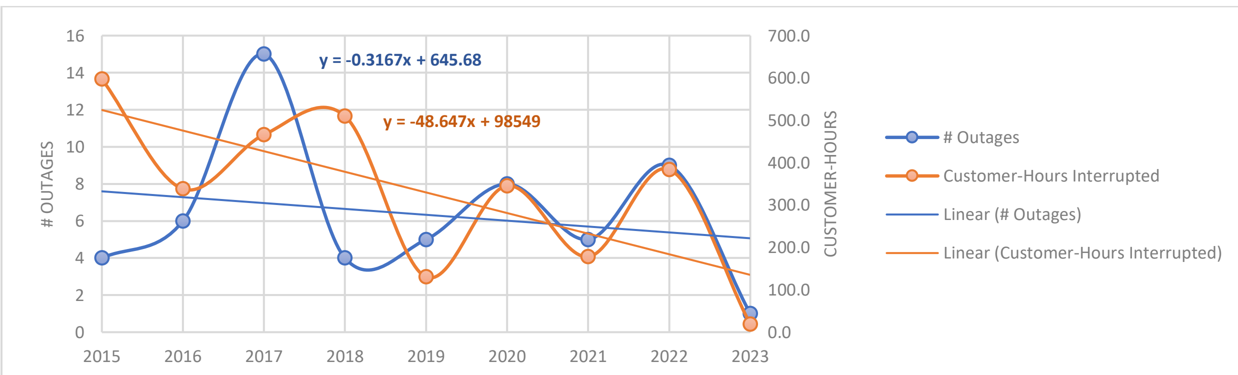


Figure 13: 2015-2023 Vegetation-related Outage Statistics, Bar River Part 1

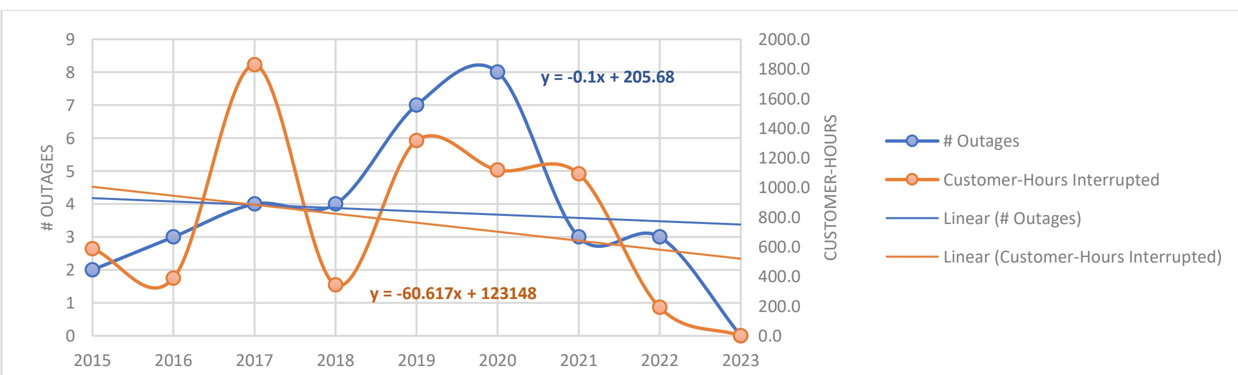


Figure 14: 2015-2023 Vegetation-related Outage Statistics, Bar River Part 2

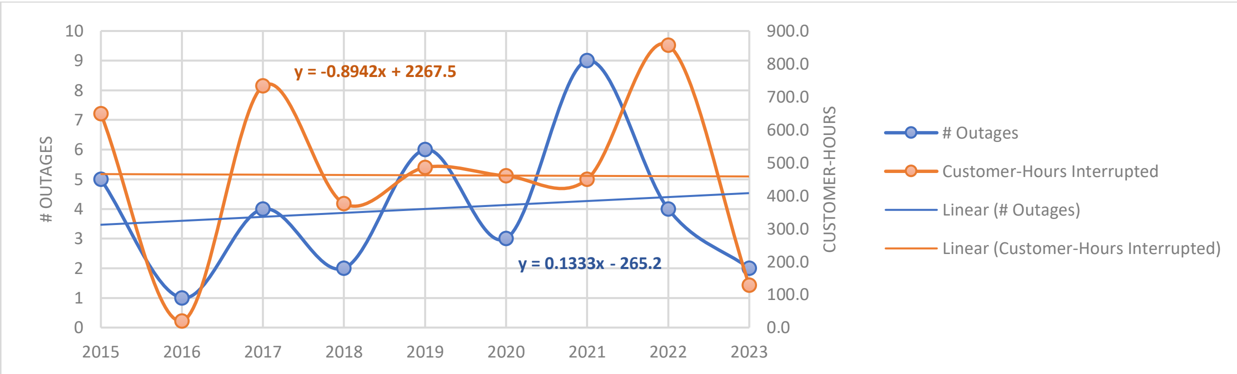


Figure 15: 2015-2023 Vegetation-related Outage Statistics, Bar River Part 3

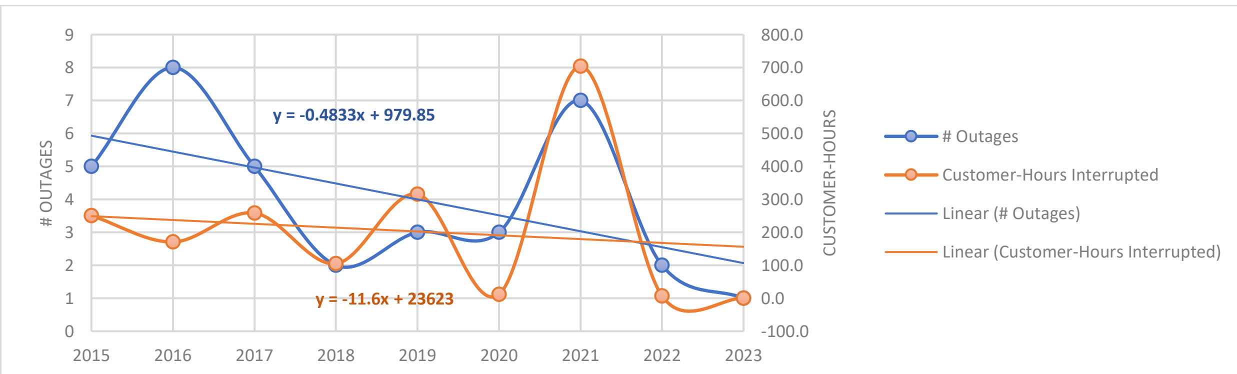


Figure 16: 2015-2023 Vegetation-related Outage Statistics, Batchawana Part 1

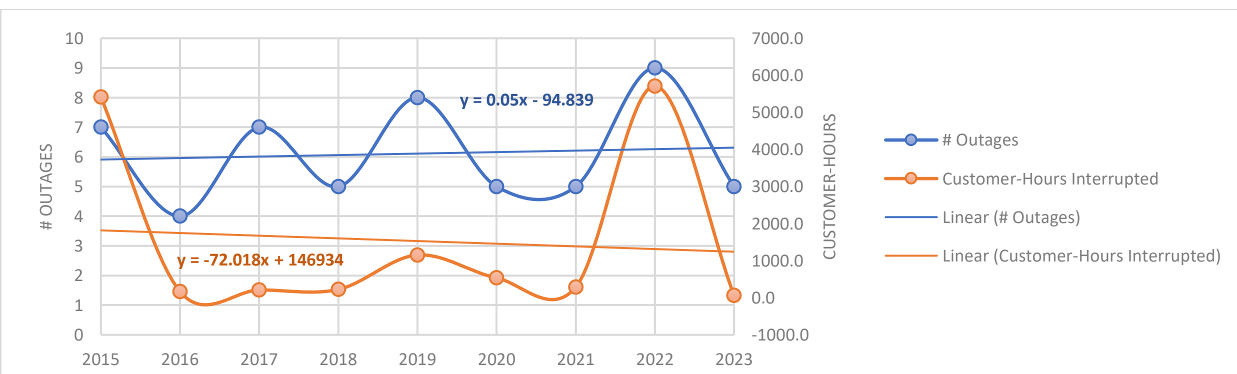


Figure 17: 2015-2023 Vegetation-related Outage Statistics, Batchawana Part 2

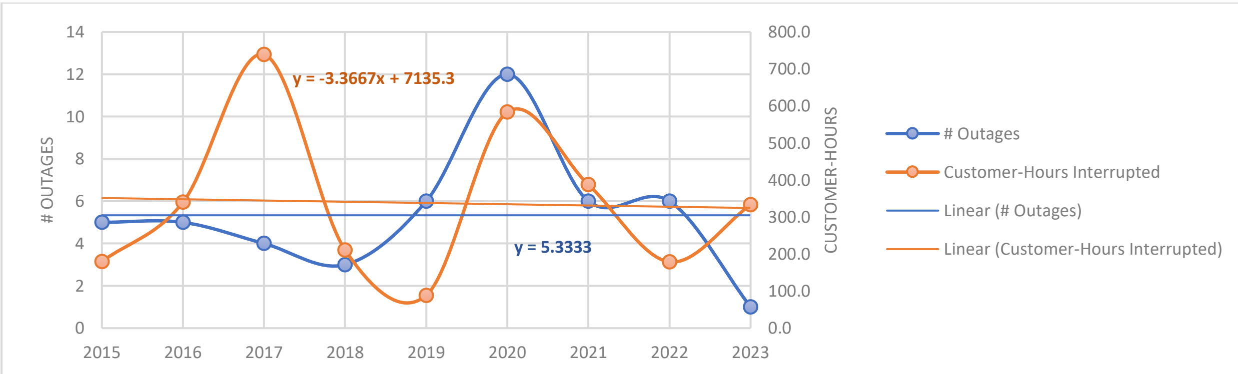


Figure 18: 2015-2023 Vegetation-related Outage Statistics, Bruce Mines Part 1

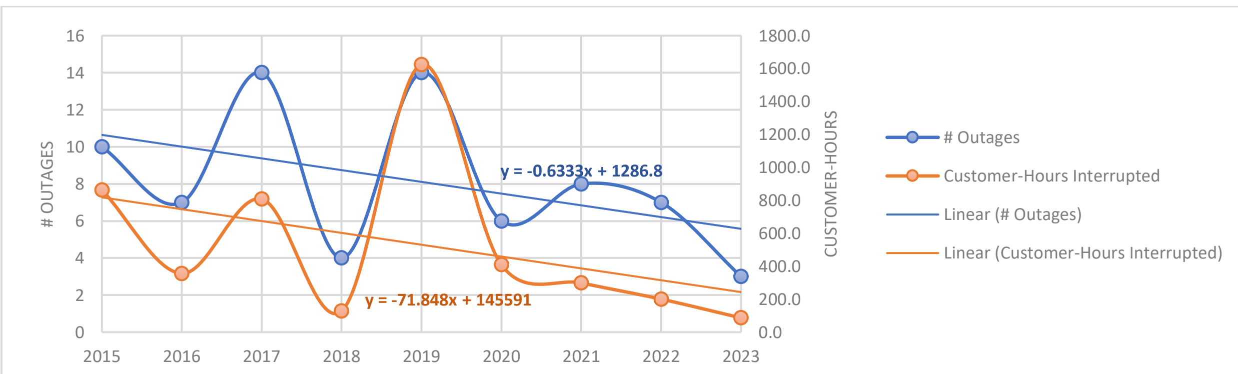


Figure 19: 2015-2023 Vegetation-related Outage Statistics, Bruce Mines Part 2

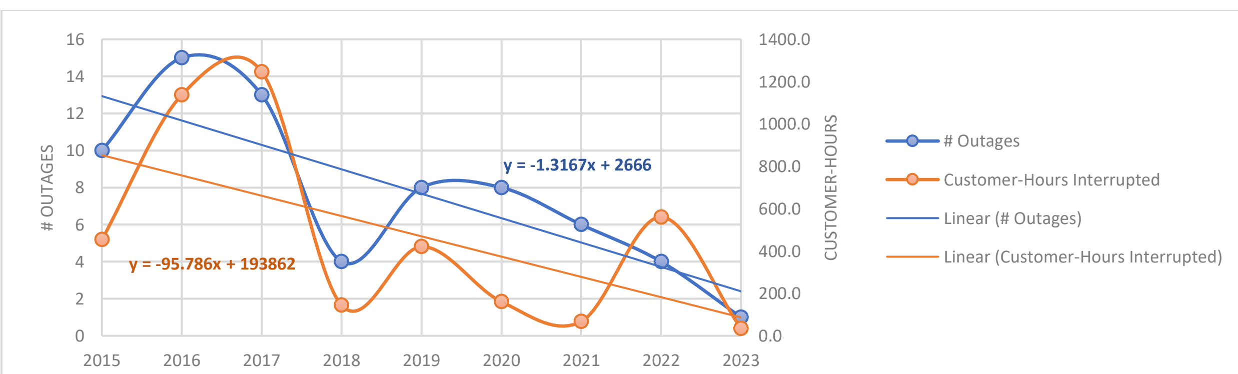


Figure 20: 2015-2023 Vegetation-related Outage Statistics, Bruce Mines Part 3

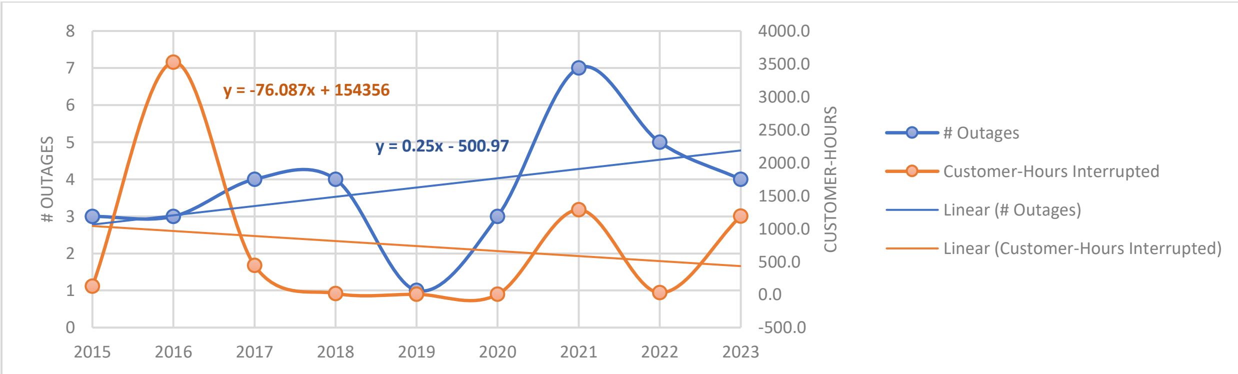


Figure 21: 2015-2023 Vegetation-related Outage Statistics, Bruce Mines Part 4

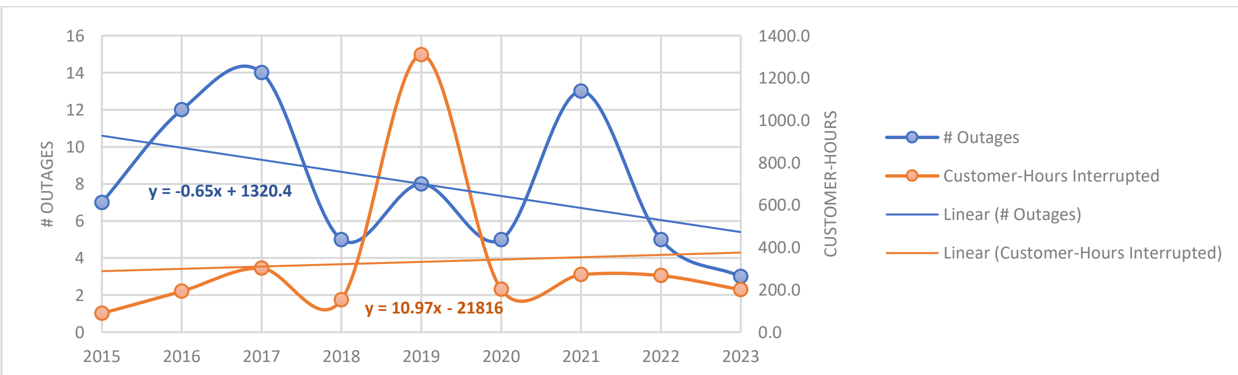


Figure 22: 2015-2023 Vegetation-related Outage Statistics, Desbarats Part 1

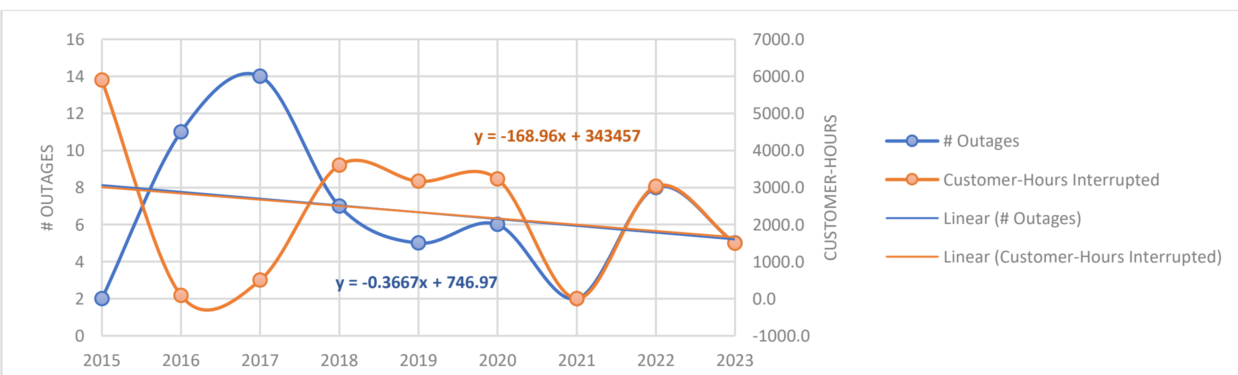


Figure 23: 2015-2023 Vegetation-related Outage Statistics, Desbarats Part 2

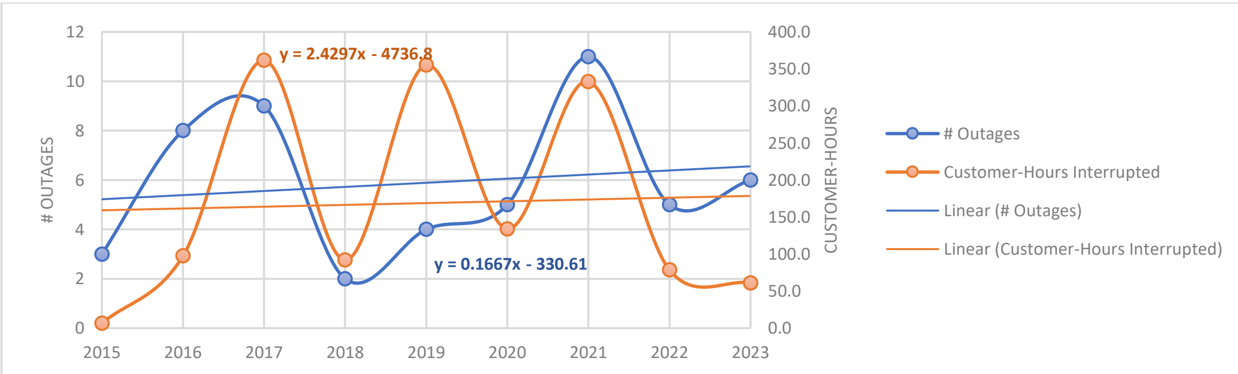


Figure 24: 2015-2023 Vegetation-related Outage Statistics, Garden River Part 1

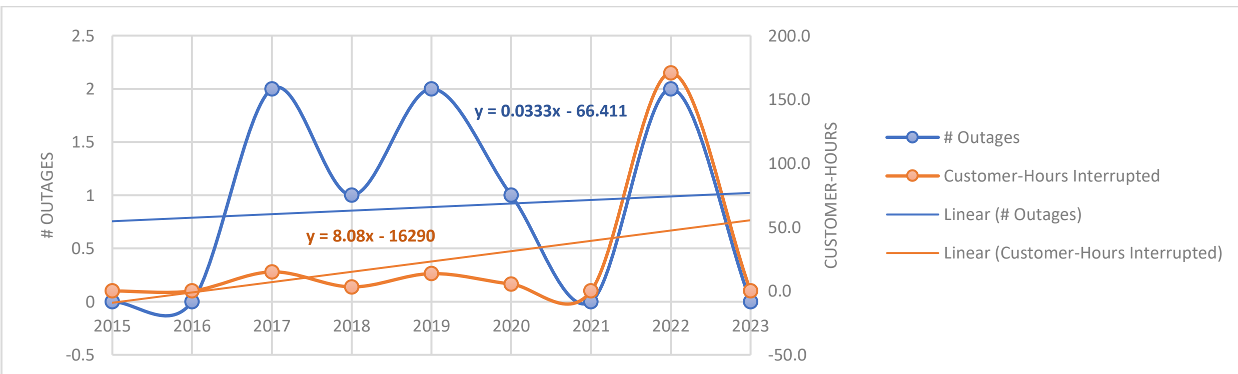


Figure 25: 2015-2023 Vegetation-related Outage Statistics, Garden River Part 2

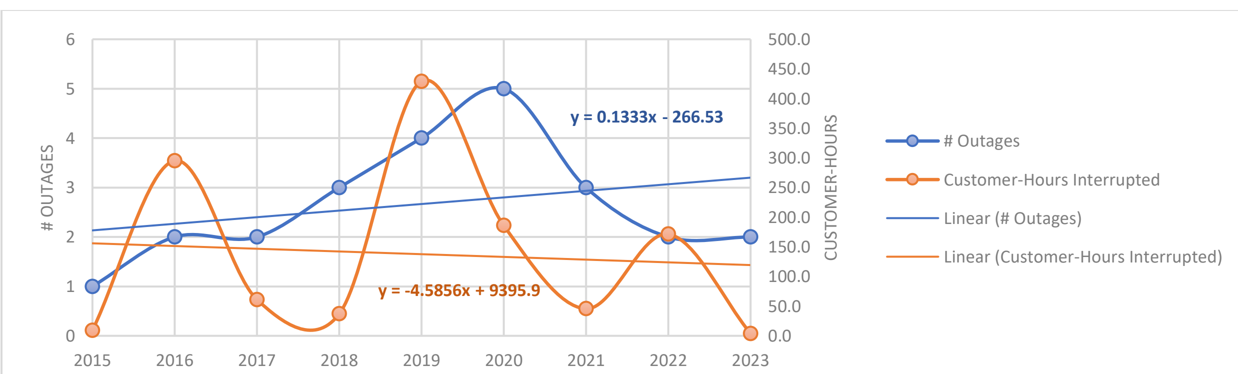


Figure 26: 2015-2023 Vegetation-related Outage Statistics, Goulais Part 1

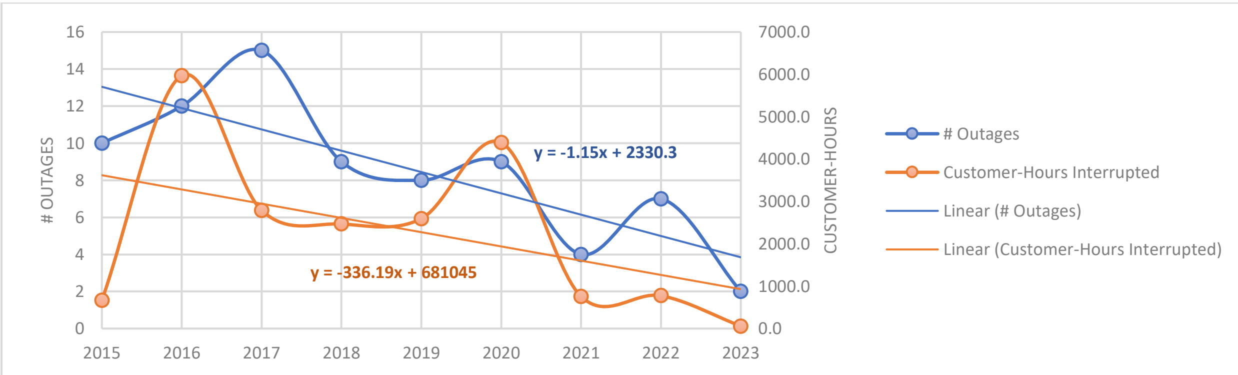


Figure 27: 2015-2023 Vegetation-related Outage Statistics, Goulais Part 2

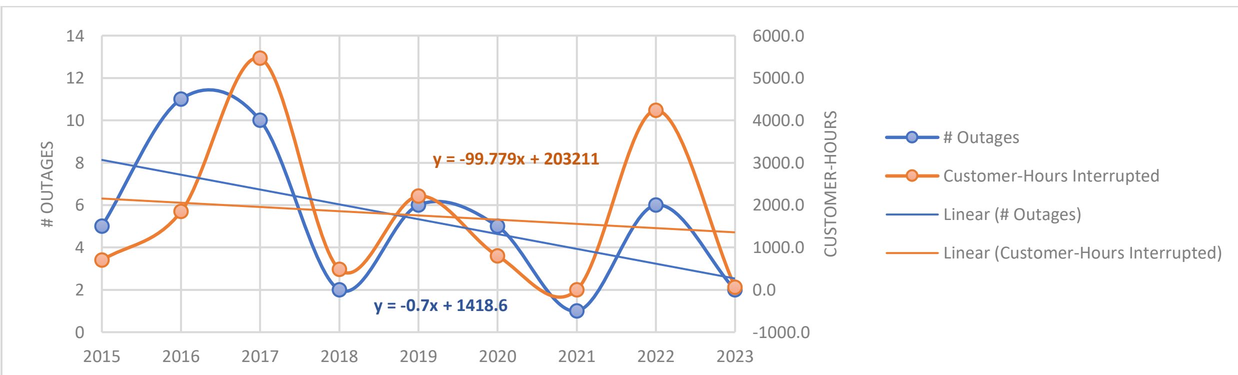


Figure 28: 2015-2023 Vegetation-related Outage Statistics, Goulais Part 3

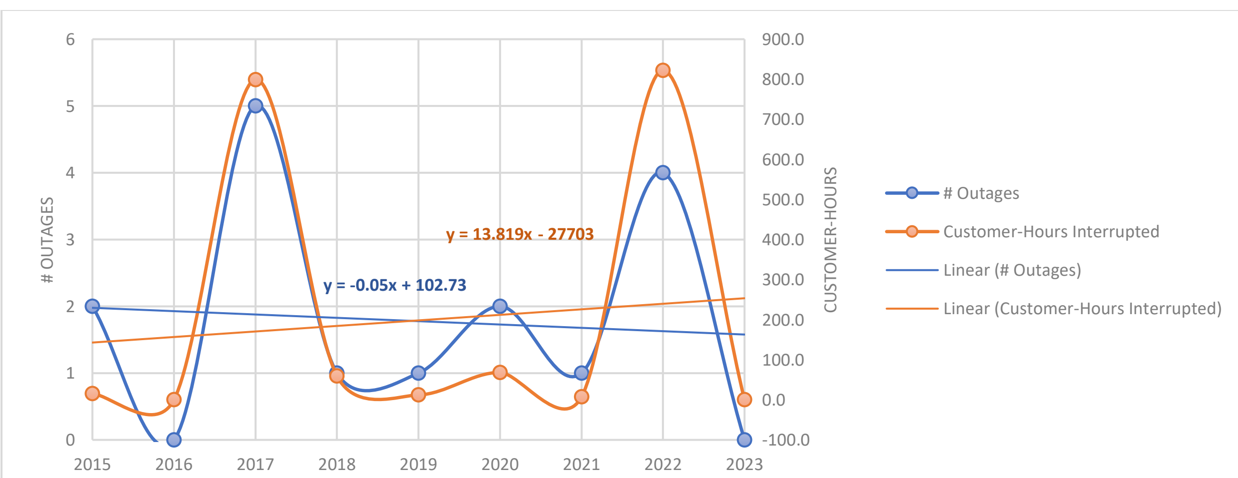


Figure 29: 2015-2023 Vegetation-related Outage Statistics, Goulais Part 4

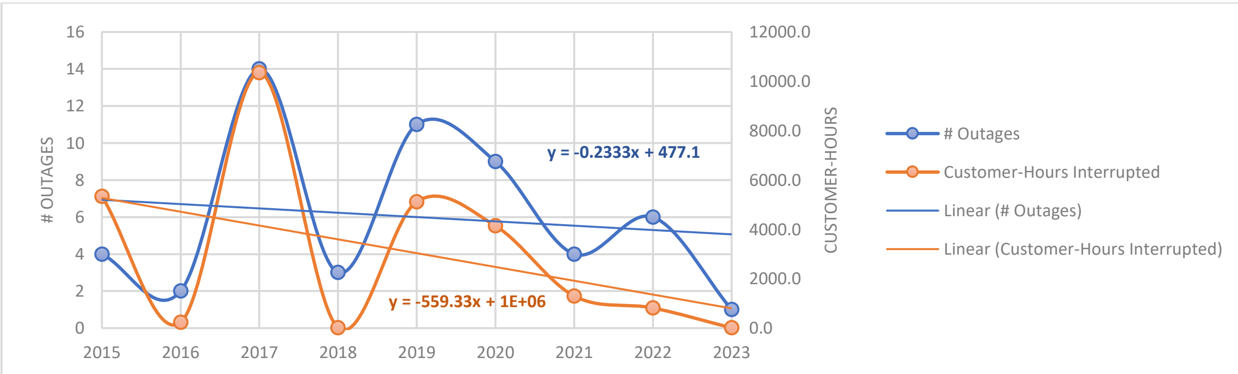


Figure 30: 2015-2023 Vegetation-related Outage Statistics, Goulais Part 5

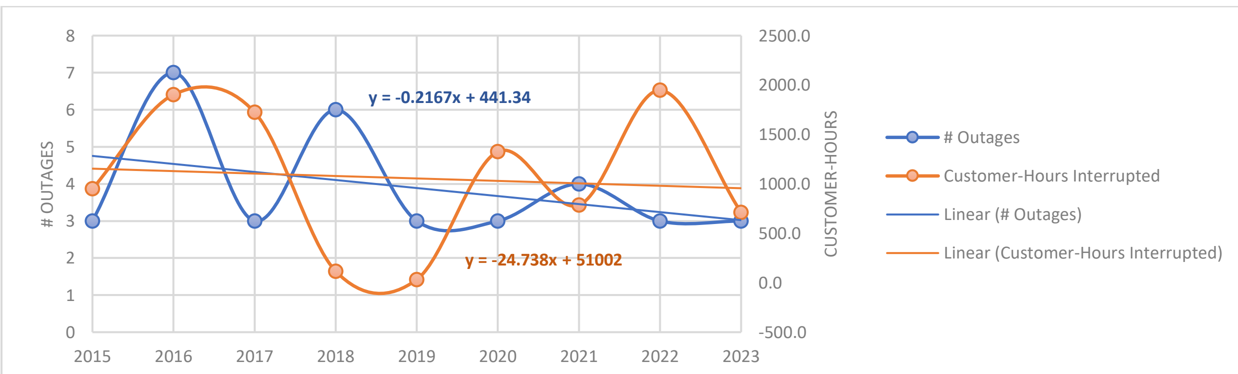


Figure 31: 2015-2023 Vegetation-related Outage Statistics, Goulais Part 6

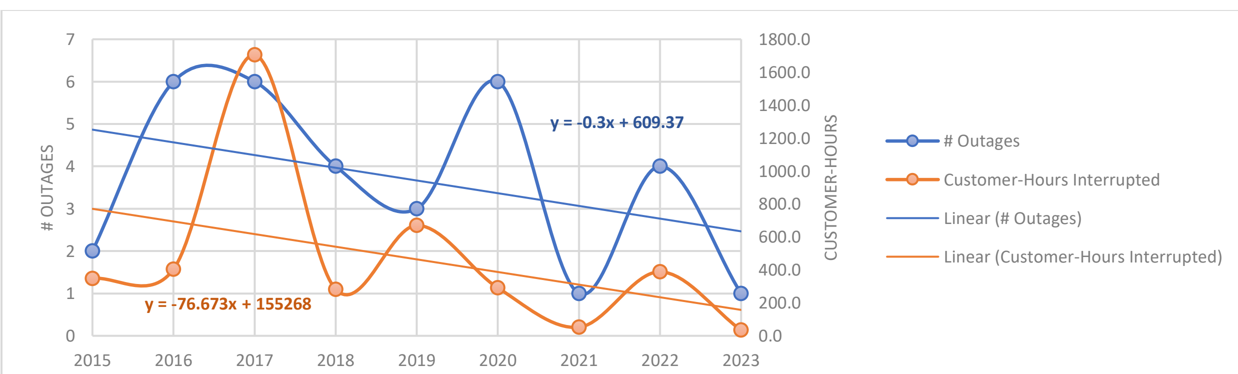


Figure 32: 2015-2023 Vegetation-related Outage Statistics, HWY 101 Part 1

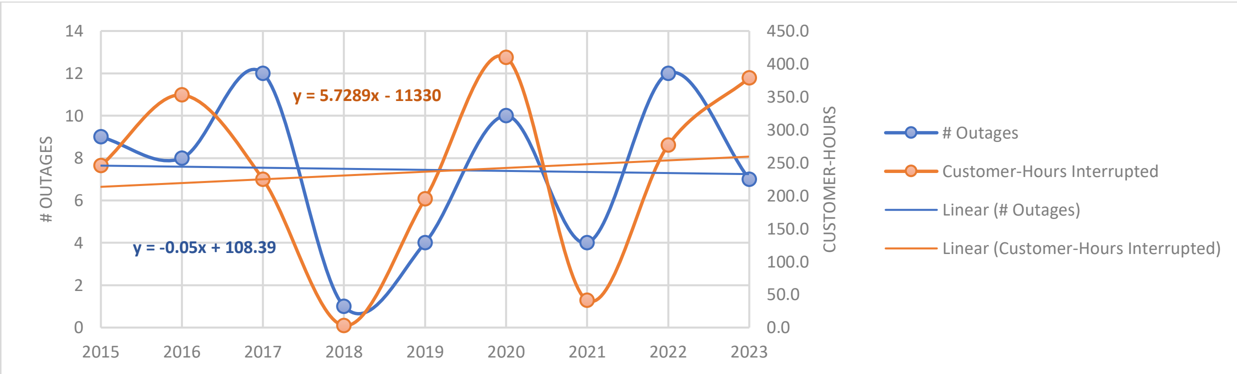


Figure 33: 2015-2023 Vegetation-related Outage Statistics, St. Joseph Island Part 1

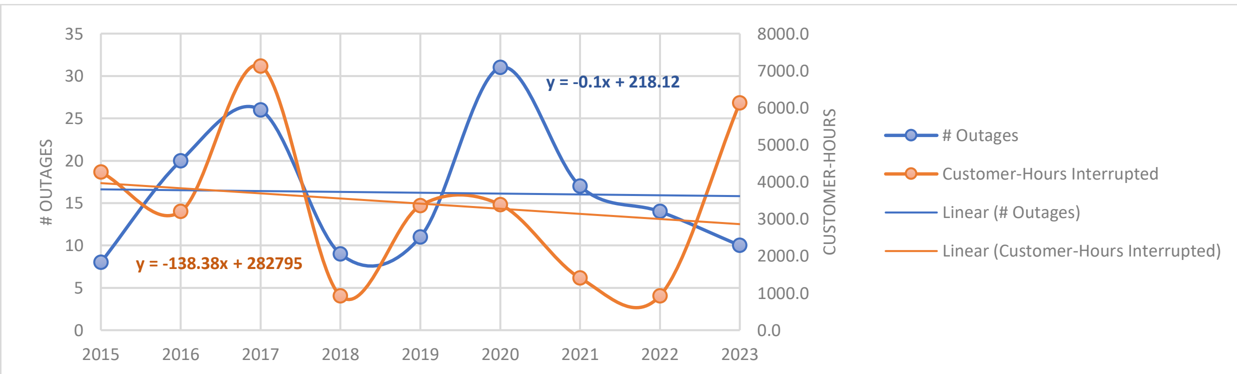


Figure 34: 2015-2023 Vegetation-related Outage Statistics, St. Joseph Island Part 2

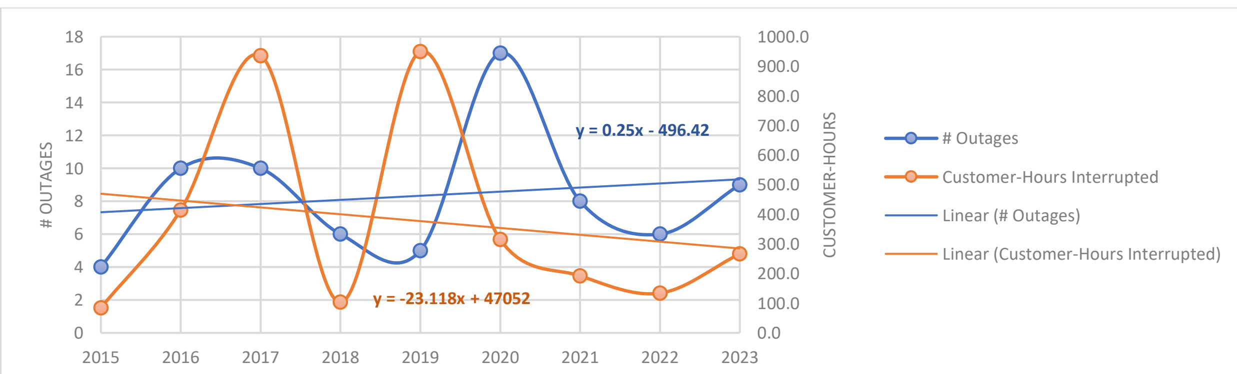


Figure 35: 2015-2023 Vegetation-related Outage Statistics, St. Joseph Island Part 3

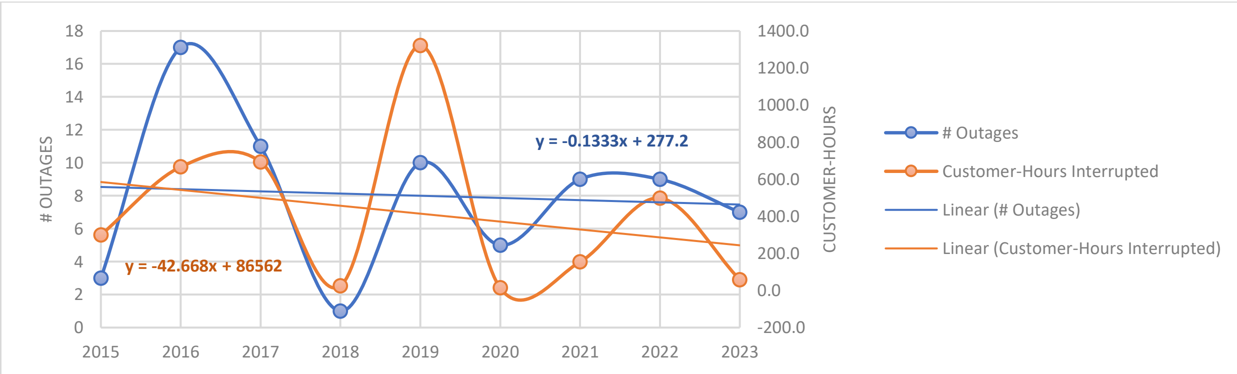


Figure 36: 2015-2023 Vegetation-related Outage Statistics, St. Joseph Island Part 4

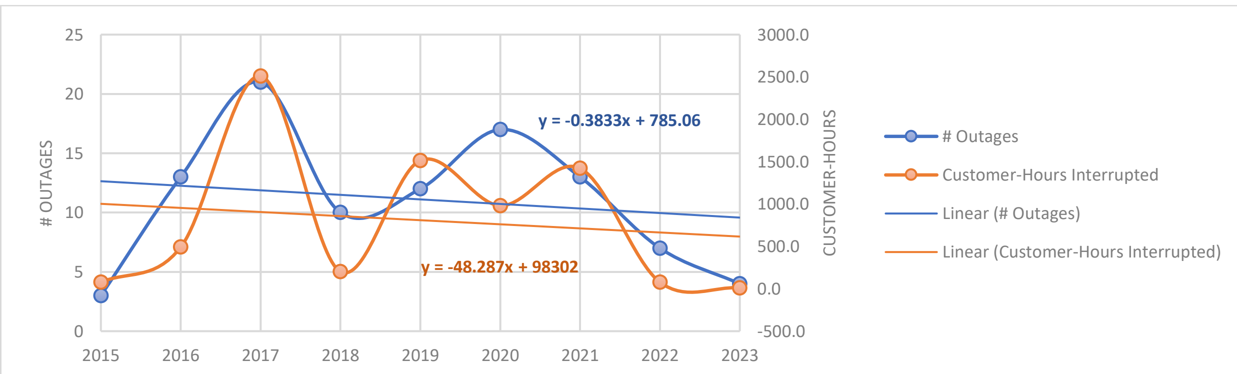


Figure 37: 2015-2023 Vegetation-related Outage Statistics, Wawa Part 1

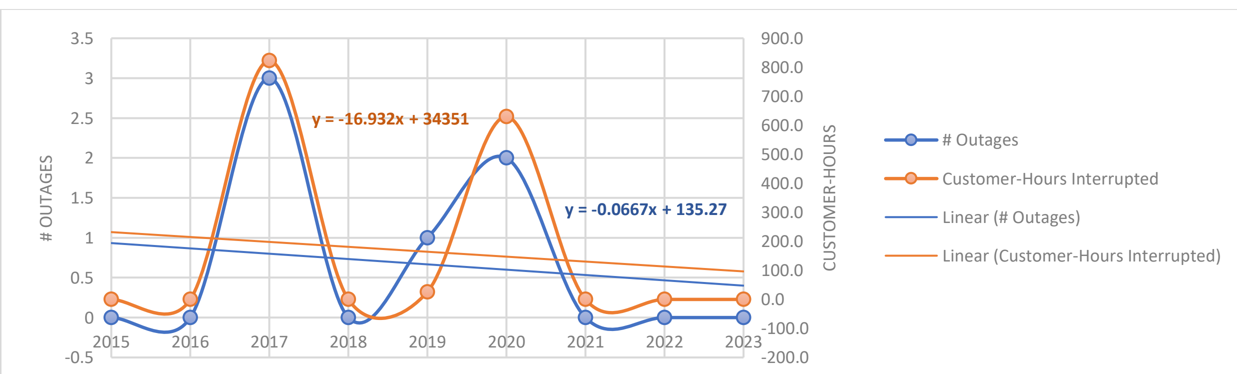


Figure 38: 2015-2023 Vegetation-related Outage Statistics, Wawa Part 2

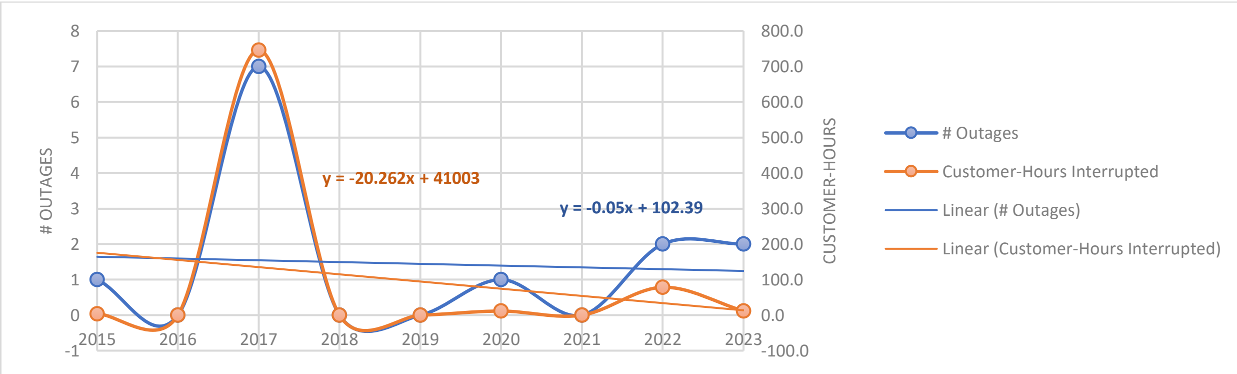
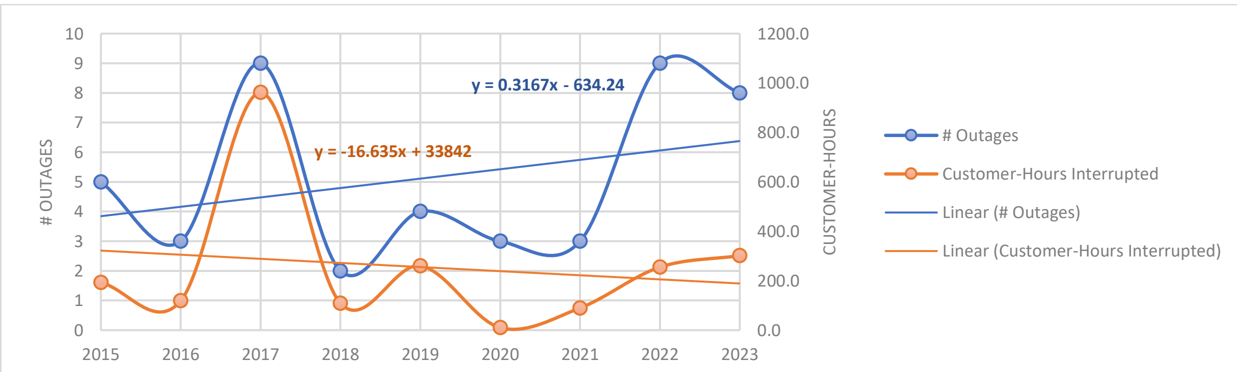


Figure 39: 2015-2023 Vegetation-related Outage Statistics, Wawa Part 3

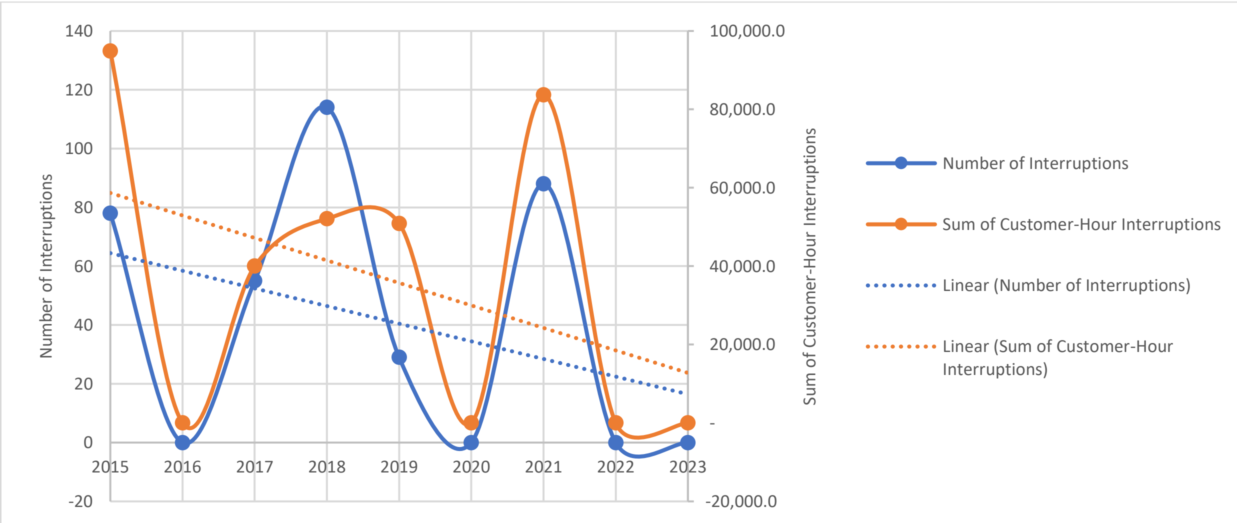


Overall, vegetation-related outages have had a decreasing trend over that last nine (9) years. However, in some of the Forestry parts the trend has been increasing, which warrants a deeper review of the vegetation management program and where the status of these parts within the program.

As is shown in Table 9, the bulk of the impact to Major Event days is associated with tree contact. This tree contact is generally caused by high winds, ice accumulation or both (adverse weather). The trend in major event days though has been decreasing as is shown in figure 44. The decreasing trend can be attributed mostly to several years where no major events occurred. For this same reason, it is challenging to draw a conclusion on the performance without overlaying some level of weather event data. The resiliency of the distribution system and right-of-ways would be clearer when weather event data is considered.

Starting in 2023, tree contract during wind/ice will be recorded under the adverse weather cause code (as opposed to tree contact).

Figure 40: Tree Contacts associated with MEDs



Recommendation(s):

Overall, API's seen improvement in the impact of vegetation caused outages. The quantity of interruptions has in general remained unchanged, but the impact has been reduced and response times improved. Continuing to examine the vegetation management strategy and plan is recommended to ensure the cycle frequency is appropriate based on brush and danger tree exposure.

Monitor Forestry parts to identify any underlying trend in tree-related outages. Consider an area-specific strategic approach vs a blanket vegetation strategy for the whole system.

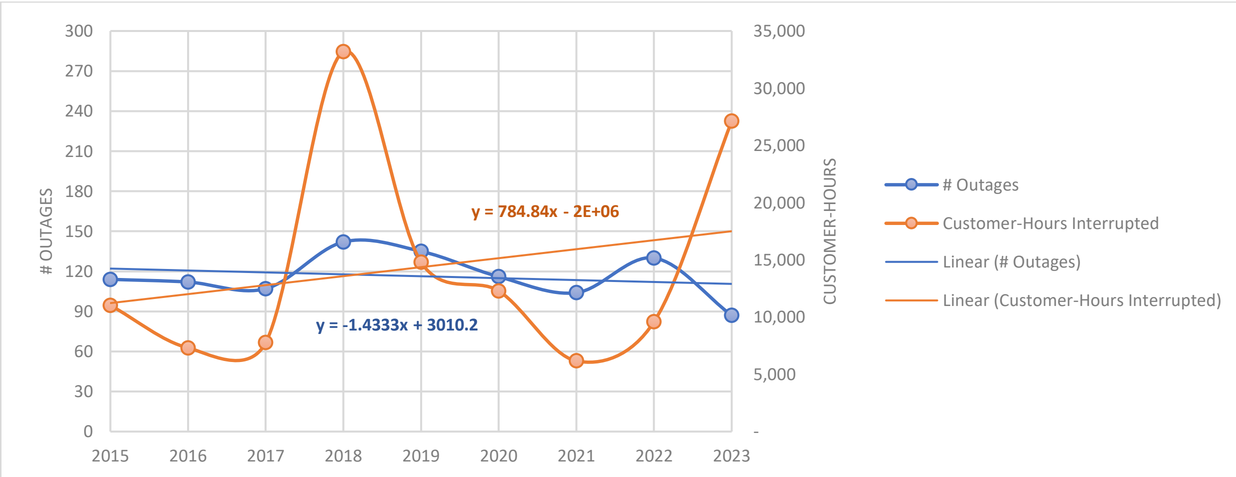
Track and report on adverse weather even when no major events occur so that system performance and resiliency can be tracked even further.

For any line upgrade project, consider design alternatives to traditional overhead systems where practicable and cost effective. Where overhead construction is the optimal design, consider alternative framing that will increase backline clearances.

4.4 Equipment-based Outages

From time to time, API experiences equipment failure, which can have large consequences depending on the asset that failed, the mode of failure and what contingency plan is currently in place. Figure 45 depicts the trend in equipment-related outage from 2015 to 2023.

Figure 41: Equipment Failure Outages 2015 to 2023



Over the last nine (9) years API experienced on average 116 equipment failure outages annually. Many of these outages are of minimal impact. Approximately **40%** of these outages impact just a single customer, while about **81%** impact 20 or less customers.

In terms of outage impact, the top ten (10) outages by customer-hours interrupted represent approximately **55%** of the total customer-hour outage impact of equipment-based outages. These ten outages are listed in the table below:

Table 36: Top 10 Equipment-Based Outages by Customer-Hour Interrupted

Date	Feeder	Isolation Device	Total Customers	Duration (hours)	Customer Hours	Reason for Outage
Aug 09, 2015	5120	SW5120-200	2,126	3.10	3,601.2	Failed insulator on 3-phase pole
Dec 01, 2016	5120	SW5120A-106	647	4.65	3,008.6	Failed switch on 3-phase pole with Transformer and primary tap
Nov 11, 2017	DB1	SW061	1,170	2.37	2,530.1	Temporary fault, but caused mis-coordination of devices
Oct 20, 2018	ER1	GLPT-SW562	2,283	21.83	27,958.2	T1 at Desbarats DS failed, caused by mechanical damage that occurred during previous maintenance
Mar 05, 2019	DB1	REC052	1,170	3.67	4,290.0	Broken pole on the 34.5kv East of Desbarats
May 17, 2019	ER2	SW2020	4,173	0.65	2,712.5	Device mis-operation while performing switching operation
Jul 24, 2020	No.4 Cct	SW2055	557	8.75	2,824.5	Failed insulator on 3-phase pole
Feb 09, 2021	ER1	Desbarats T1	1,121	4.02	2,622.1	Temporary transformer bank overload failure
Jun 08, 2023	ER2	GLPT-SW020	5,617	3.25	18,255.3	Recloser (REC052) failure on the 34.5kV system (ER1 supply was isolated so the entire East of Sault supply was tripped)
Jun 09, 2023	ER1	SW2023-B	2,307	1.43	3,306.7	Follow-up outage to complete repair following the Recloser failure on June 08, 2023

<u>Recommendation(s):</u>

Place increased focus on critical asset contingency planning, ensuring that in the event of a major equipment failure that would result in a significant quantity of customers impacted and/or a longer than average restoration timeline a suitable plan is in place to minimize these impacts.

Continue the proactive replacement of aged infrastructure, with increased emphasizes on critical supply feeds. In particular, identify at risk infrastructure (e.g., aged and worn insulator) during annual inspection programs and other routine work. Identify any gaps in and ensure that preventative maintenance on major assets is completed.

Monitor the smaller impact but more frequent equipment outages to identify the underlying cause(s). Where the cause is systematic and can be proactively address, draft an appropriate mitigation plan and strategy.

Algoma Power Inc.

Distribution System Plan

Appendix F

INNOVATIVE RESEARCH GROUP

2025 Customer Engagement
Online Workbook Report

Algoma Power Inc.
A FORTIS ONTARIO Company

February 2024

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:

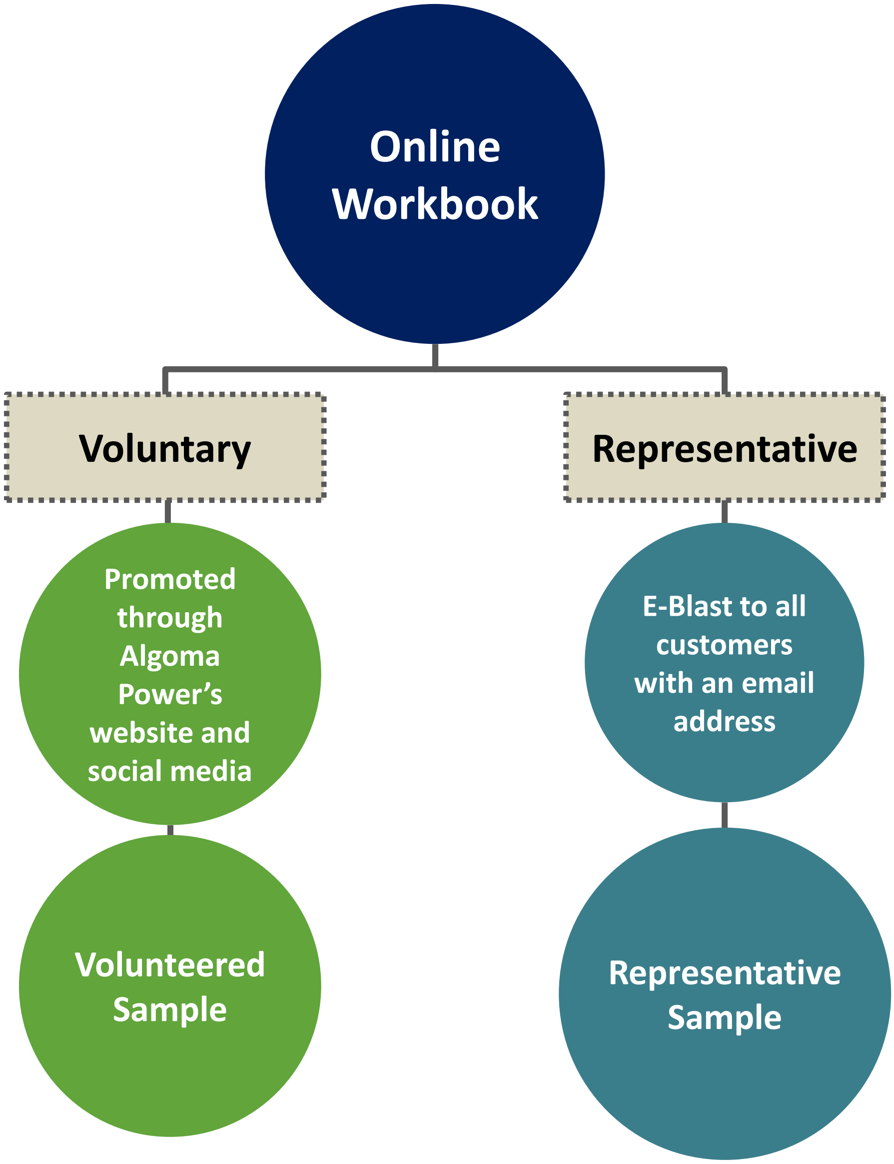
1. **Region:** Using customer data provided by Algoma Power, we split customers into three regions for analysis based on the first three characters of their postal code; North/West, East, and Central.
    - **Central**: Areas immediately surrounding Sault Ste. Marie
    - **North/West**: All Northern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

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)

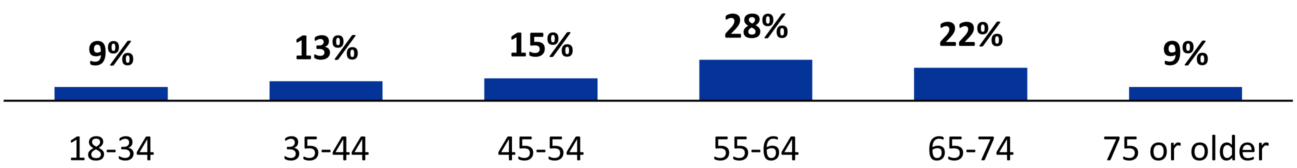
Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Online Workbook

Demographic breakdown

Residential

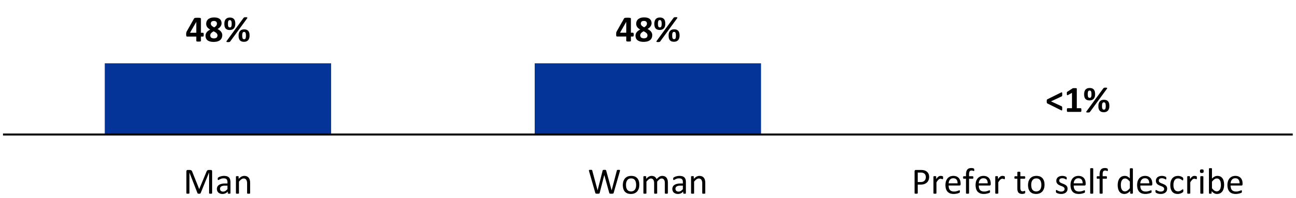
Q Age



“Prefer not to say”(2%) not shown.

n=1,000

Q Gender



“Prefer not to say”(3%) not shown.

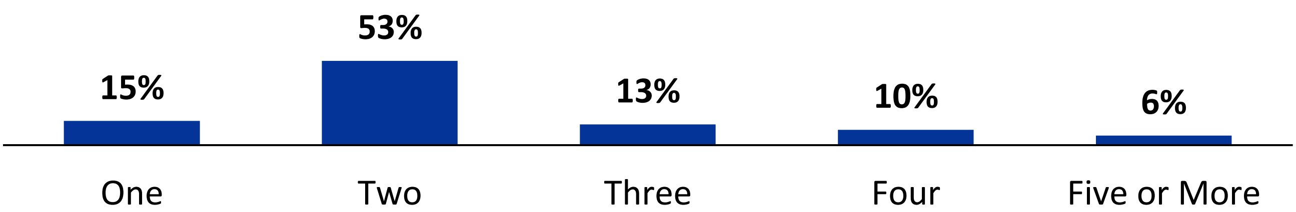
n=1,000

Online Workbook

Demographic breakdown

Residential

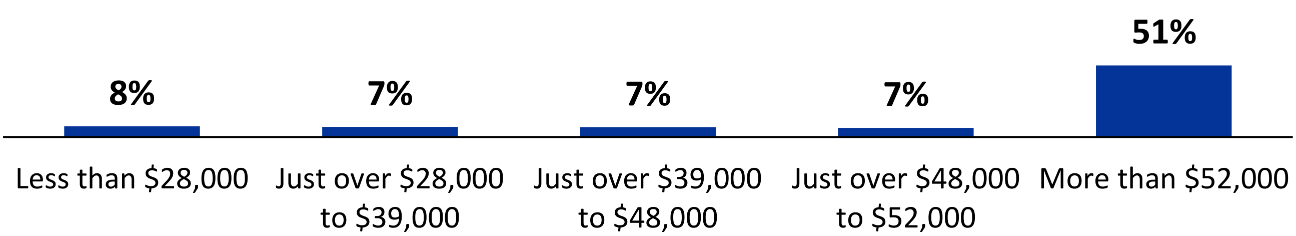
Q Household Size



“Prefer not to say” (2%) not shown.

n=1,000

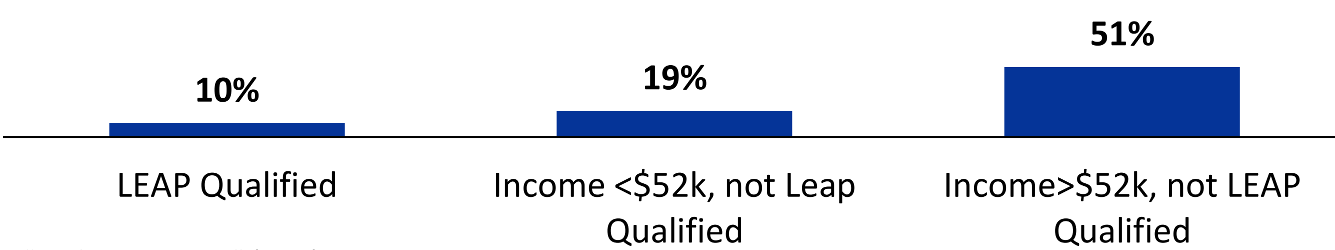
Q After Tax Household Income



“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

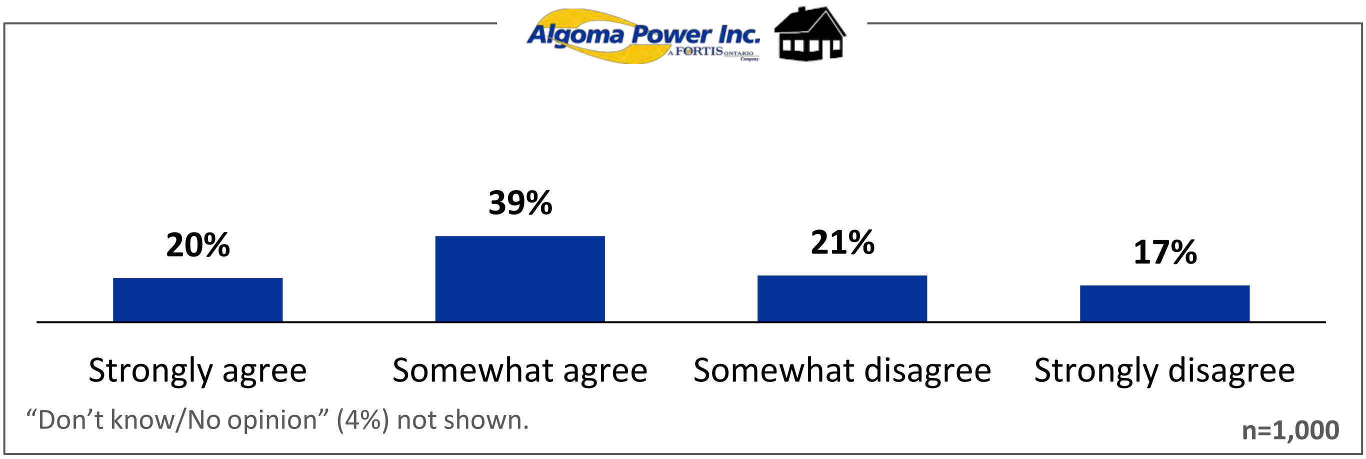
Online Workbook

Environmental Controls

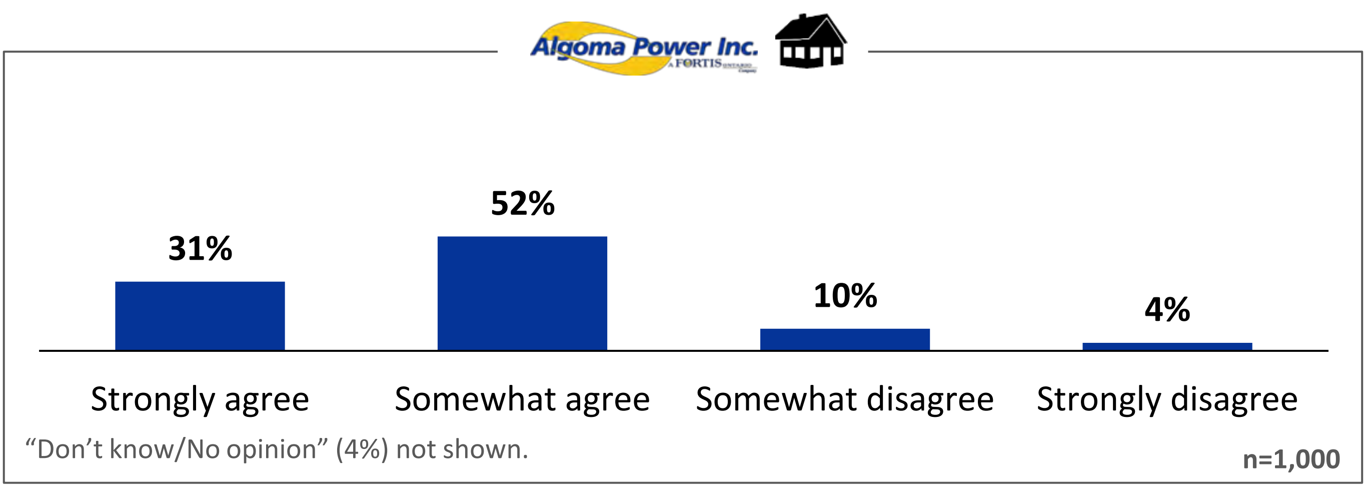
Residential

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.



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



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.

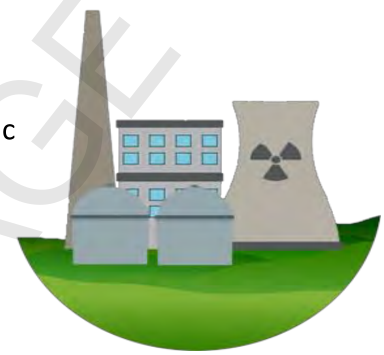
Electricity 101

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

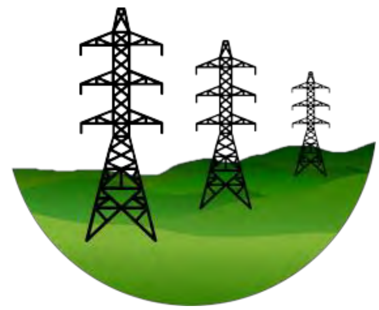


Ontario gets its electricity from a mix of energy sources. More than half comes from nuclear power. The remainder comes from a mix of hydroelectric and natural gas, and to a lesser extent, wind and solar.

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.

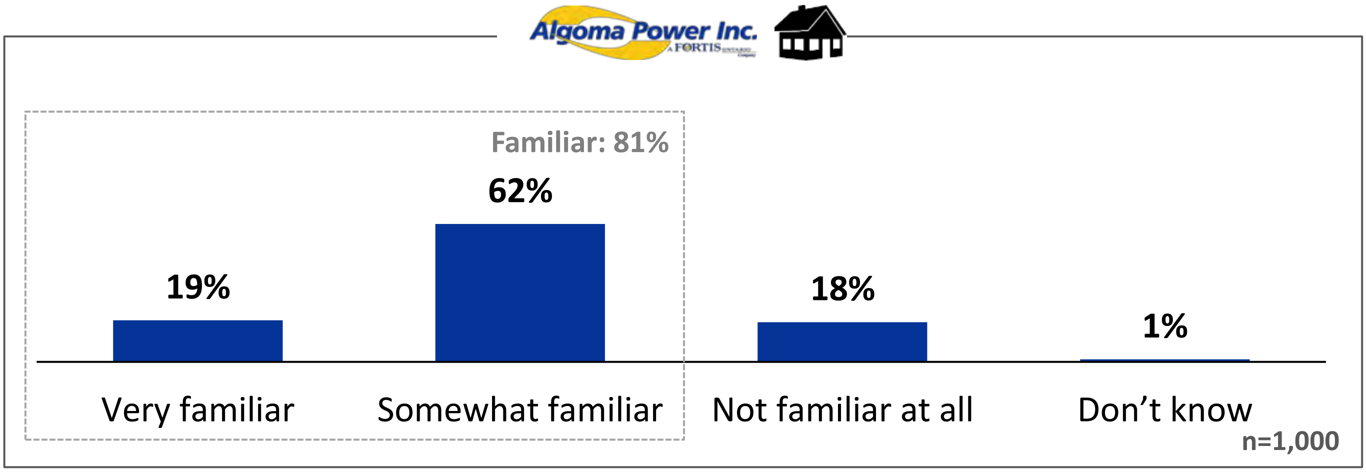
- Algoma Power manages all aspects of the electricity distribution business throughout the Algoma District of northern Ontario.
- In your community, amongst other functions, Algoma Power is responsible for:
    - Building and maintaining the local electricity distribution system
    - Responding to outage 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?



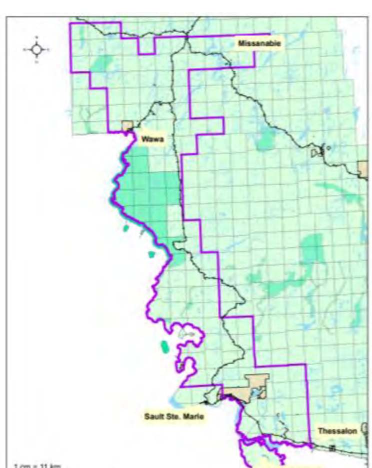
	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Very familiar	17%	23%	16%	19%	19%	20%	17%	22%	15%	19%
Somewhat familiar	63%	61%	61%	65%	63%	59%	61%	58%	67%	61%
Not familiar at all	18%	16%	22%	15%	16%	21%	20%	18%	17%	19%
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%**

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.



Algoma Power Territory

Online Workbook

Planning for the Future: 2025-2029 Rate Application

Residential

Electricity 101

How much of my electricity bill goes to Algoma Power?

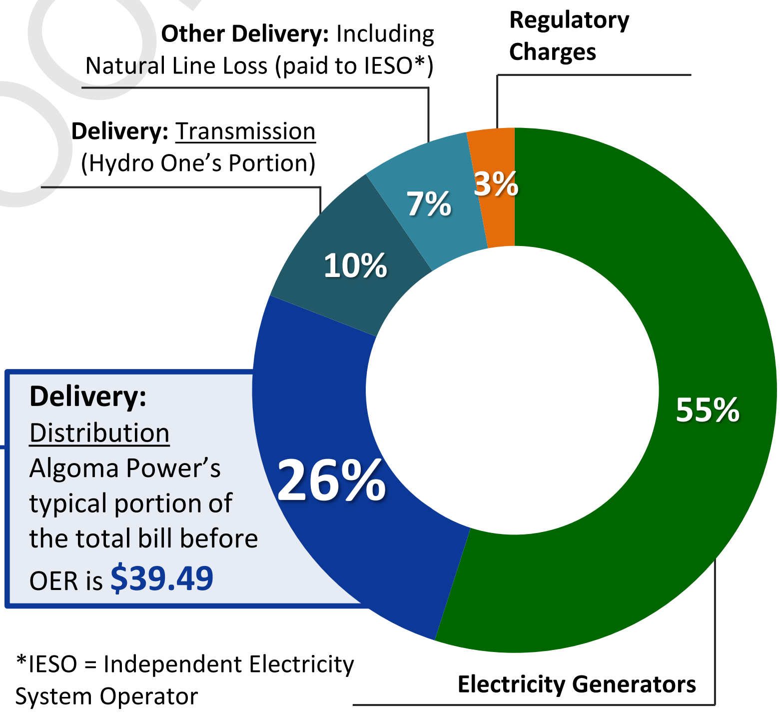
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While Algoma Power is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery 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.

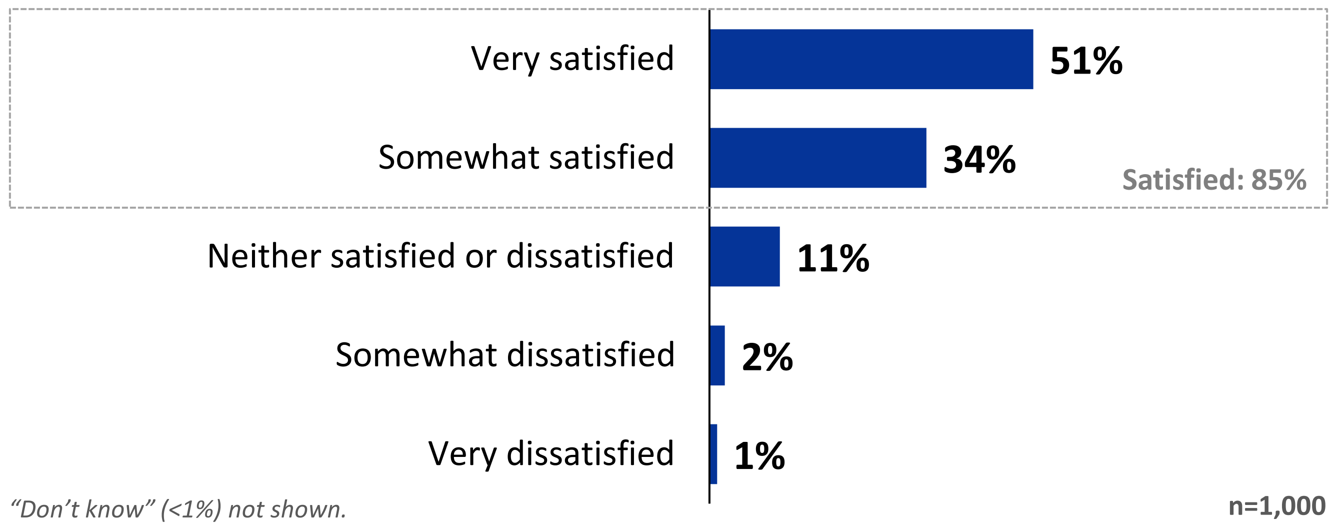
The sample bill above uses an average consumption level of 750kWh per month, however your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

Online Workbook

Familiarity with Algoma Power

Residential

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?



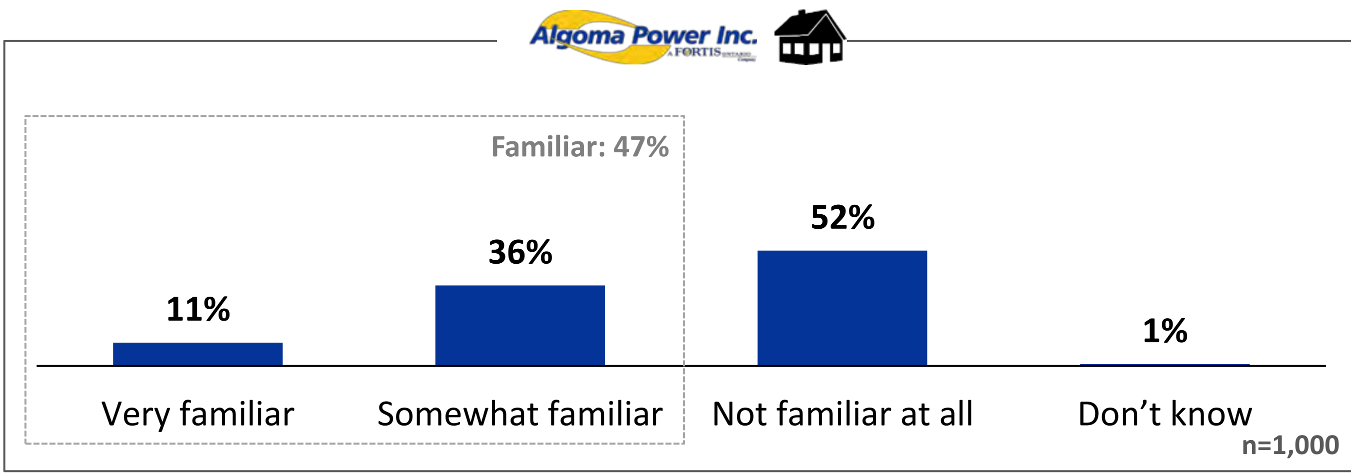
	Region			Consumption Quartiles				LEAP Qualification		
	North/ West	East	Central	First	Second	Third	Fourth	Yes	No <$52K	No >$52K
Very satisfied	52%	51%	44%	56%	55%	46%	48%	56%	51%	52%
Somewhat satisfied	33%	32%	46%	31%	33%	36%	36%	32%	33%	33%
Neither satisfied nor dissatisfied	11%	12%	7%	10%	10%	12%	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%**

Online Workbook

Residential

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

How Algoma Power can Improve Services to Customers

Residential

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

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.

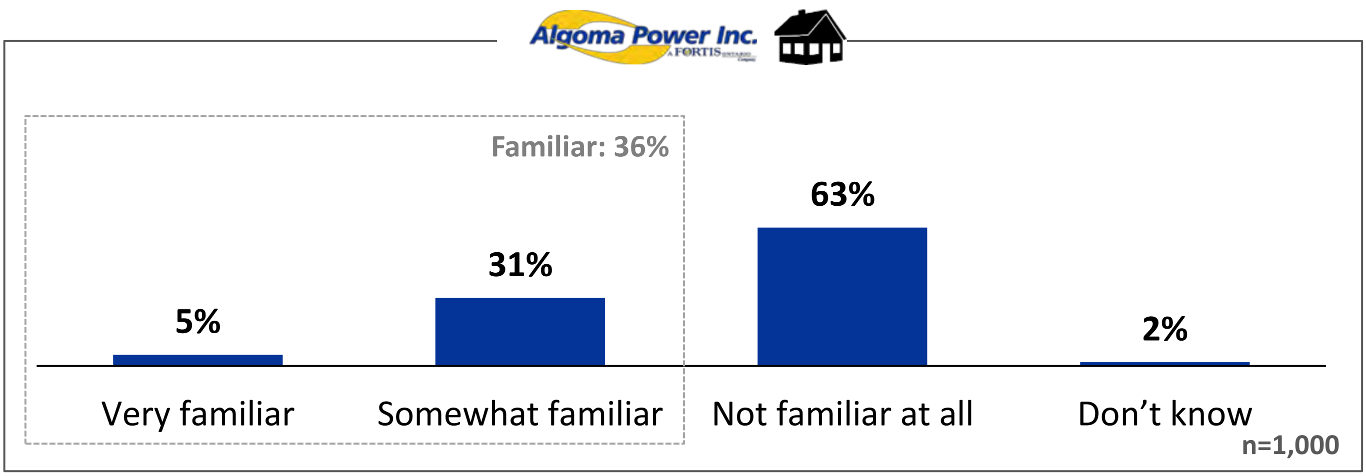
- As of this year, the maximum monthly base distribution charge has been set at **$39.49**.
- That means, as long as these protections remain in place, customers like yourself won't pay more than the maximum amount set by the program.

Online Workbook

Familiarity with Government Programs

Residential

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%**

Online Workbook

Setting Priorities within Algoma Power's Plans

Residential

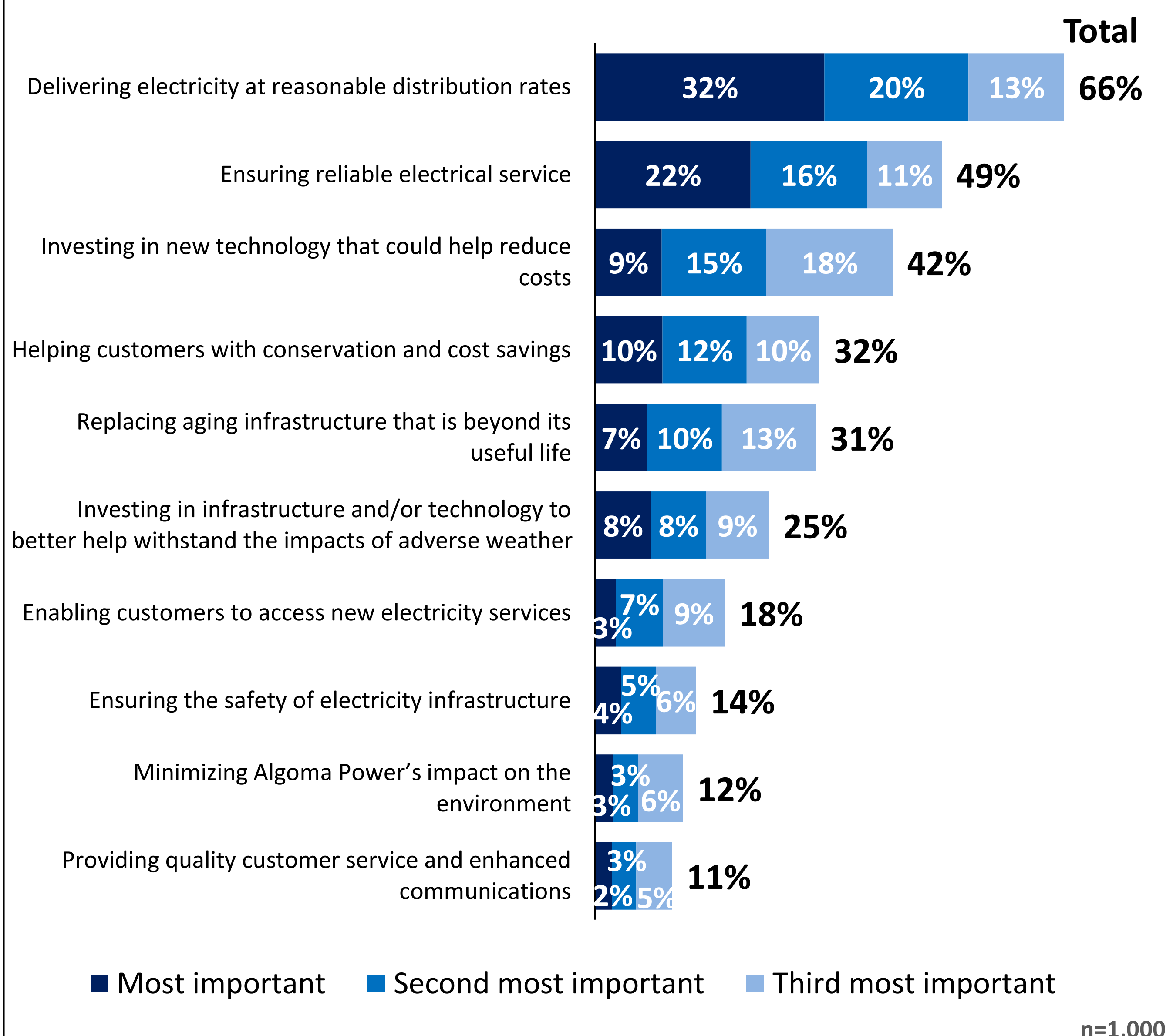
Q

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.



Online Workbook

Setting Priorities within Algoma Power's Plans

Residential

% 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

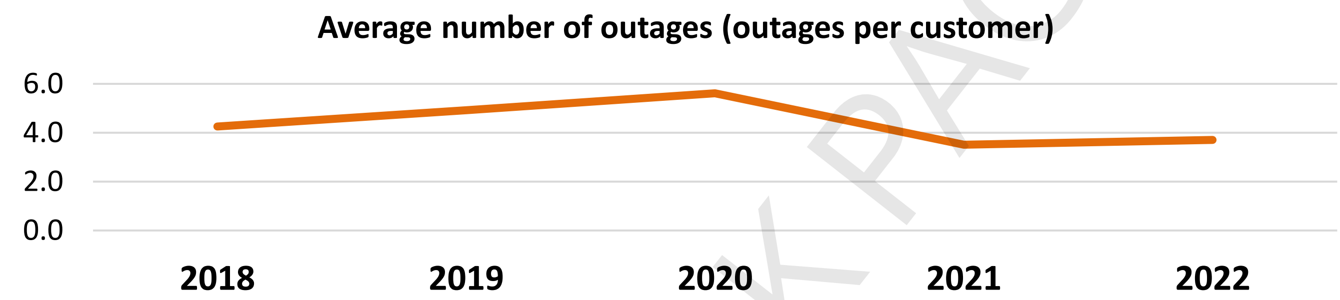
Background Context

Focus on Reliability

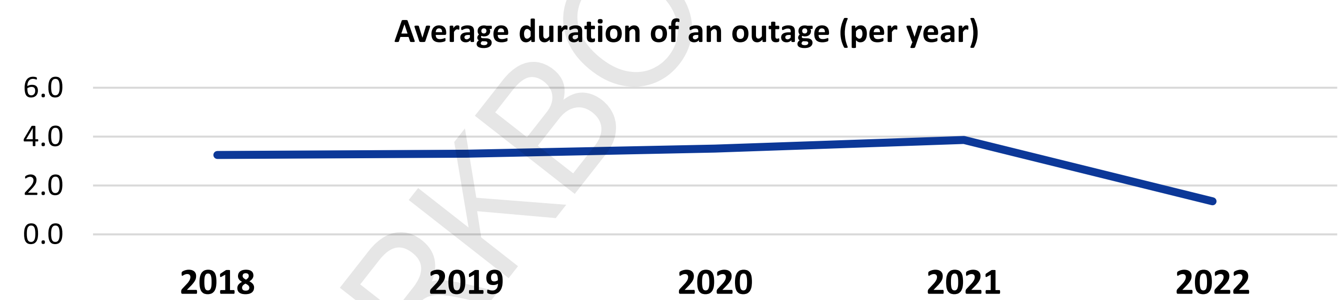
Since reliable electricity service is so important to customers, before we move on, we want to ask you about which specific areas you feel that Algoma Power should focus on over the next five years.

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.

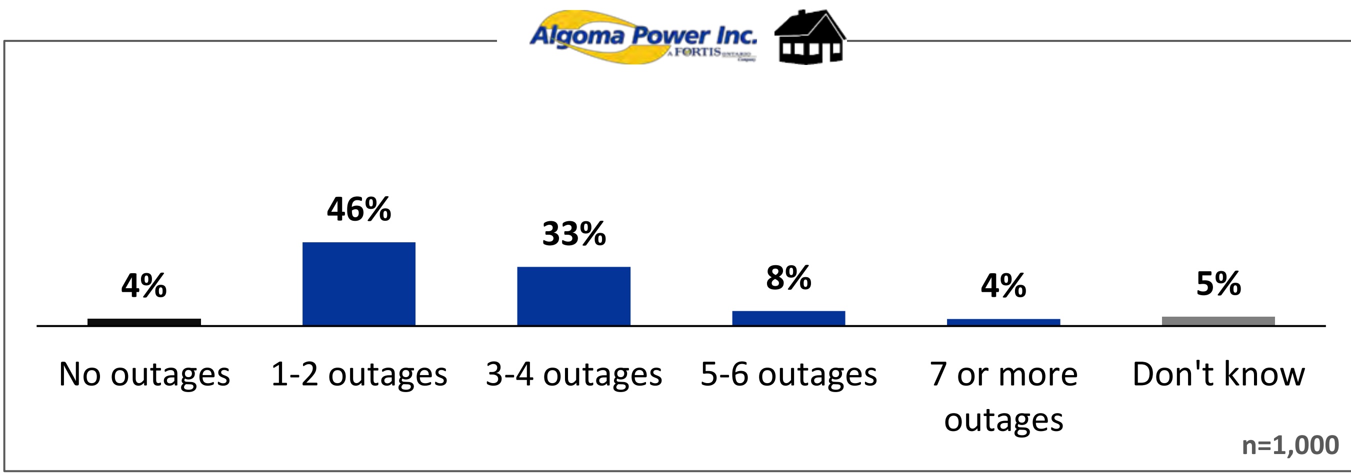
The tables and figures above include outages related to extreme weather events and transmission loss of supply events (which Algoma Power has relatively lower ability to control).

Online Workbook

Number of Outages Experienced

Residential

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%

Online Workbook

Planning for the Future: 2025-2029 Rate Application

Residential

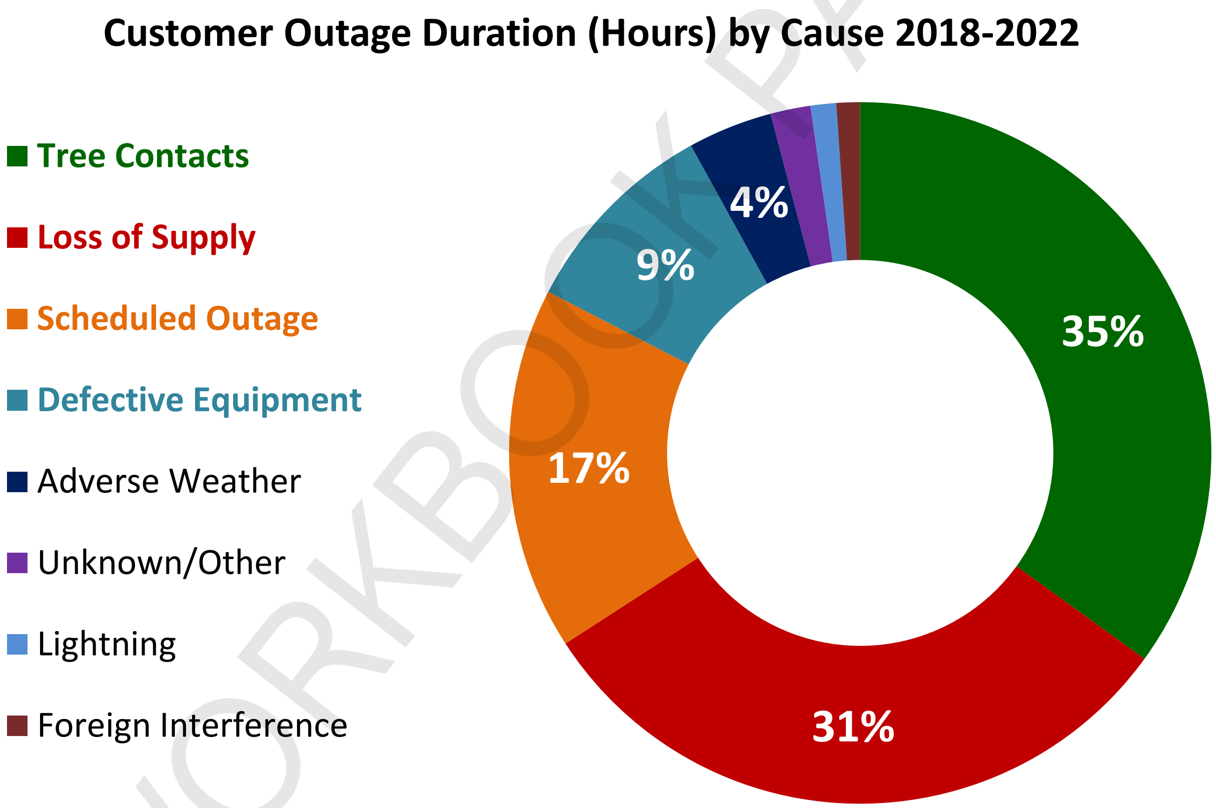
Background Context

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.



Online Workbook

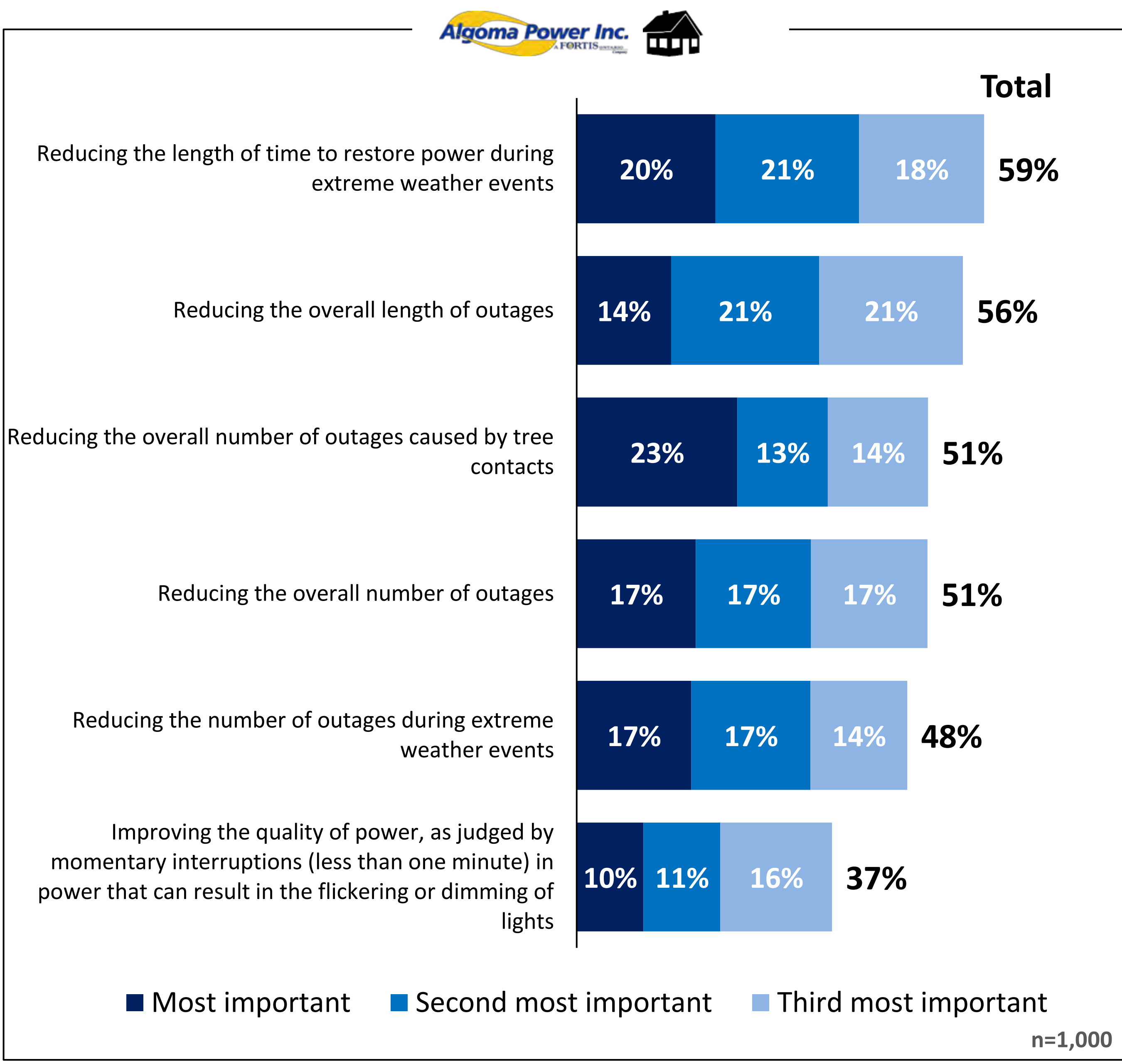
Reliability Priorities

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%

INNOVATIVE RESEARCH GROUP

Online Workbook

Planning for the Future: 2025-2029 Rate Application

Residential

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**.

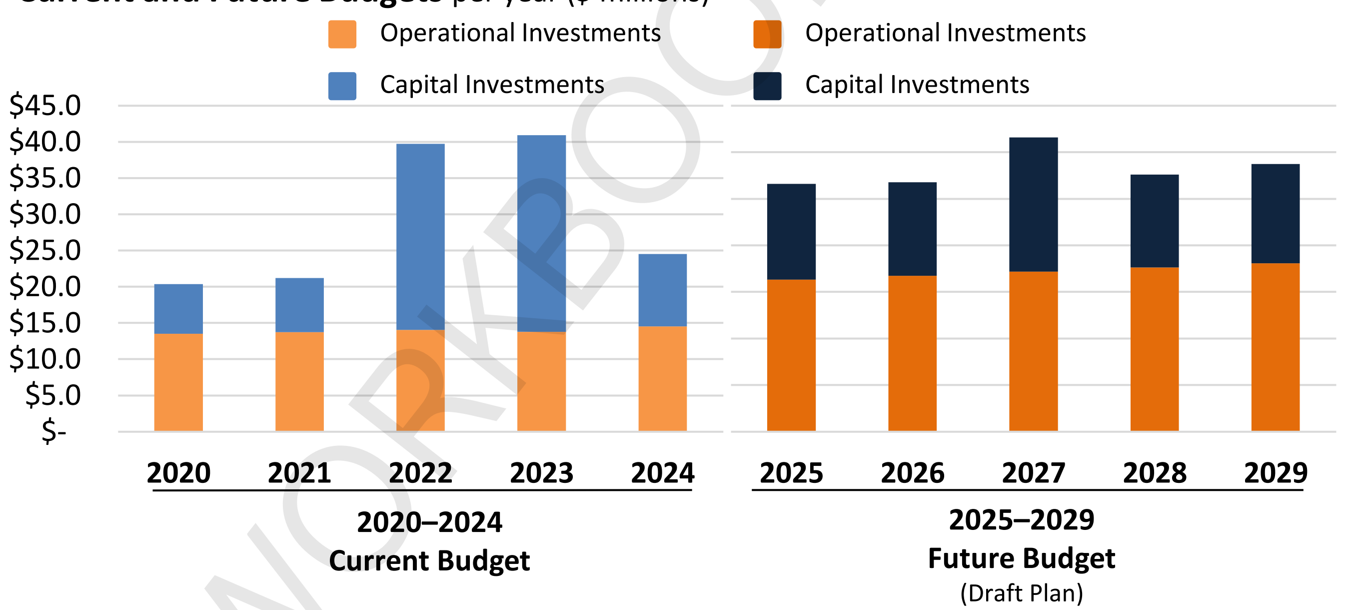
Between 2025 and 2029, Algoma Power is proposing to spend $141.3 million, a 3.7% decrease relative to the past five years.

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

Planning for the Future: 2025-2029 Rate Application

Residential

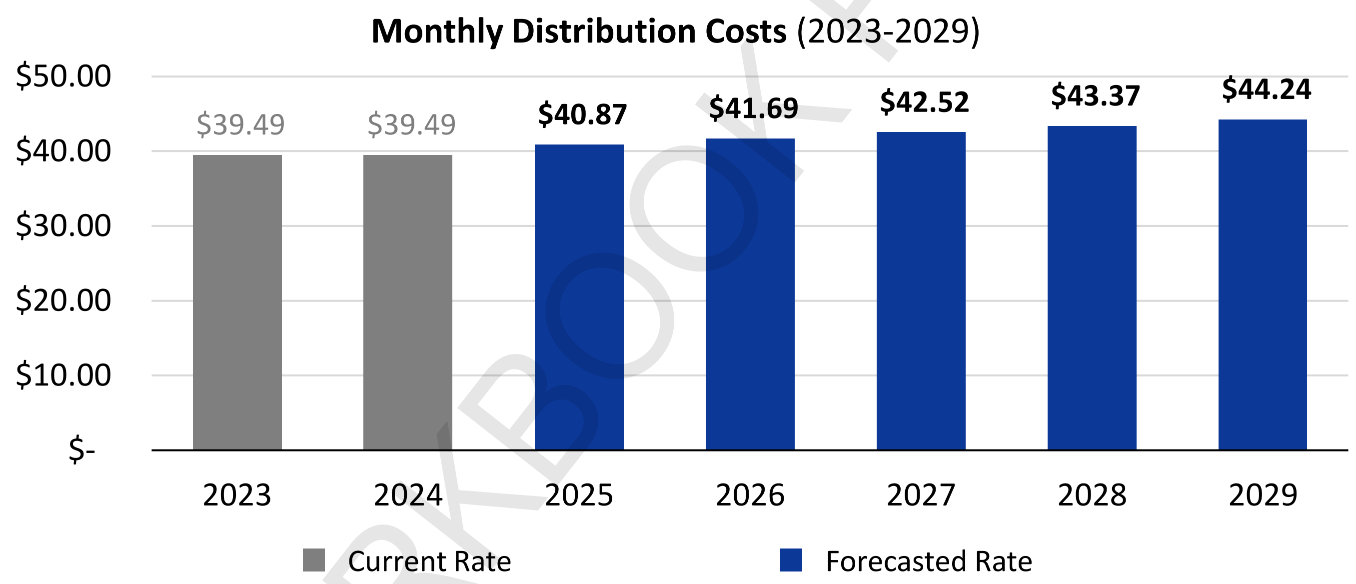
Algoma Power Background

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.

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**.

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

Residential

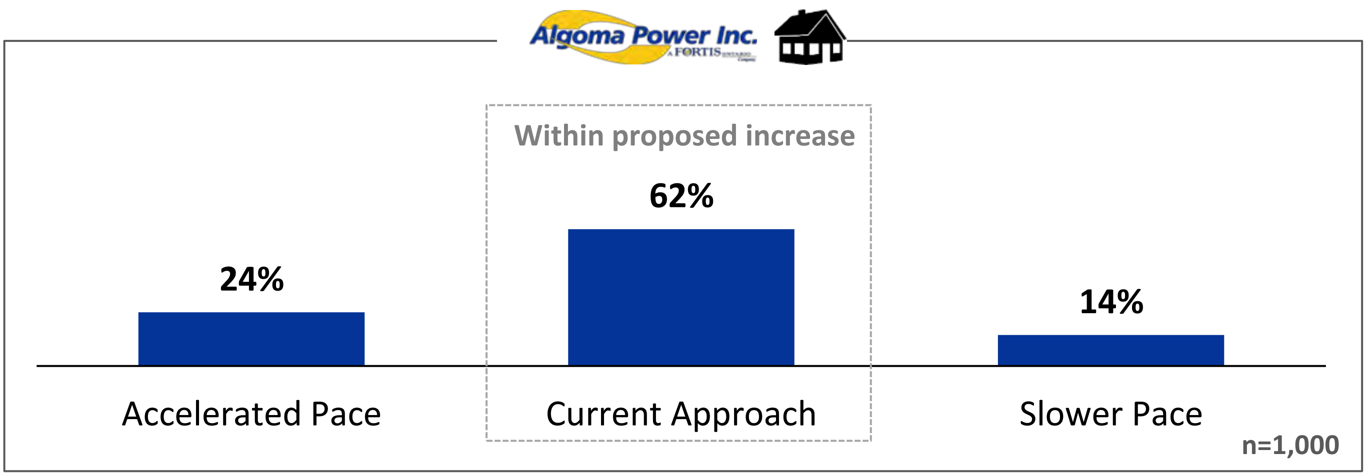
Which of the following options do you prefer?		
Option	Poles Replaced	Expected Outcome
Accelerated Pace ***$1.51*** *more on monthly bill by 2030*	Proactively replace 550 poles per year for the next five years.	• Increase the current pole replacement pace by 50 per year. • Potentially see reliability 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 ***$1.51*** *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

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%

INNOVATIVE RESEARCH GROUP

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

INNOVATIVE RESEARCH GROUP

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

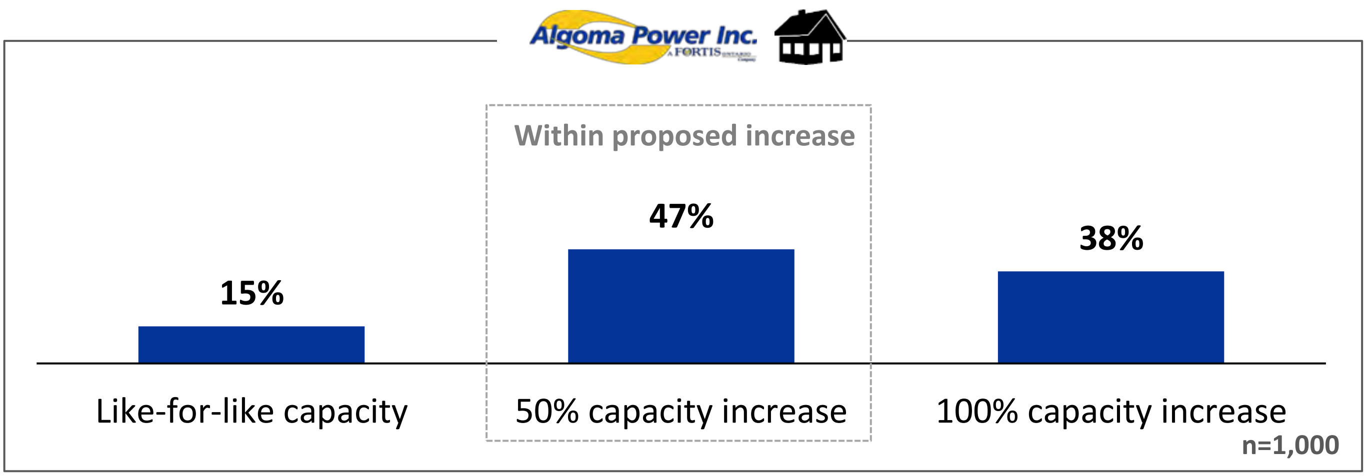
Which of the following options do you prefer?		
Option	Transformer Size	Expected Outcome
Like-for-like capacity ***$0.17*** *less on monthly bill by 2030*	Procure and install a power transformer that is similar in capacity to the existing transformer.	Increased risk of premature transformer replacement 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%

INNOVATIVE RESEARCH GROUP

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

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

Which of the following options do you prefer?

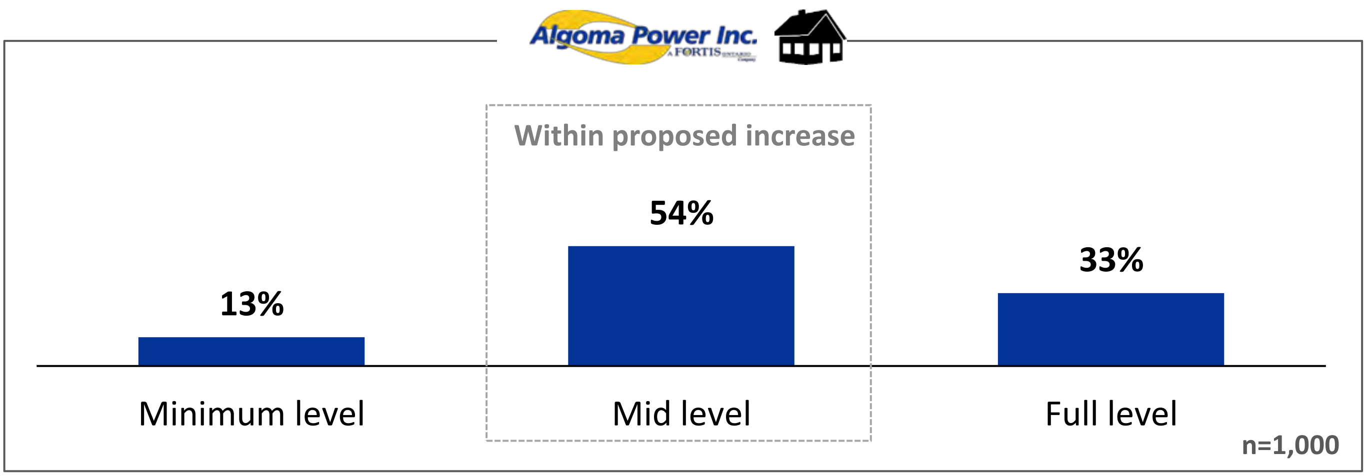
Option	% Upgraded	Expected Outcome
Minimum Level ***$0.13*** *less on monthly bill by 2030*	Upgrade and convert approximately 25% of the identified area's distribution system to a higher voltage.	• Reduce the risk of voltage reliability and power quality issues for approximately 995 customers. • Lower 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

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%

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

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

Choice 4: Preparing for increased electricity demand

Residential

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.

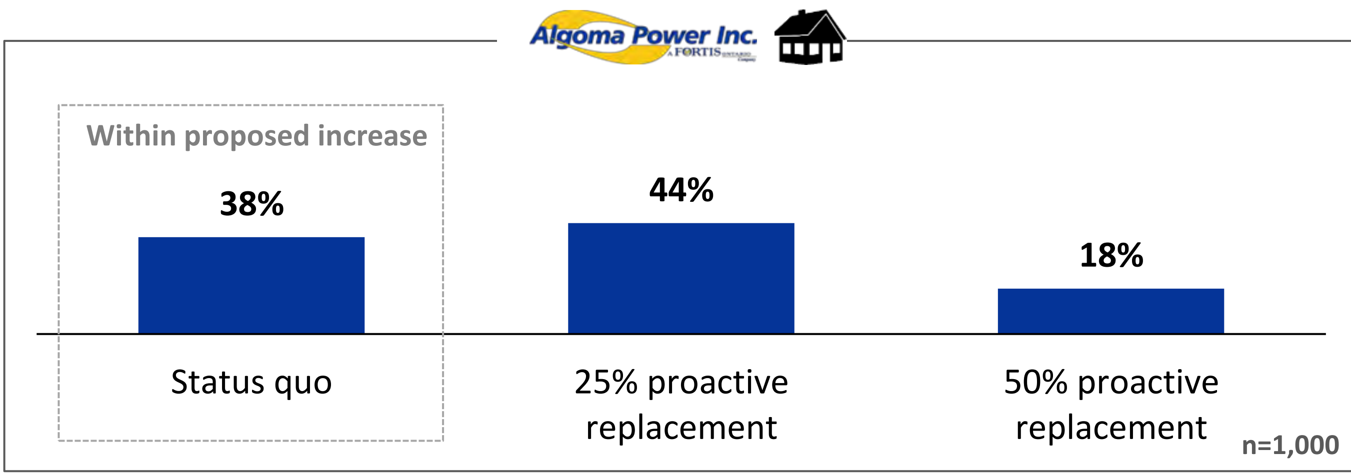
Additional Feedback (Optional)

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%

Online Workbook

Choice 4: Preparing for increased electricity demand

Residential

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

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

Which of the following options do you prefer?

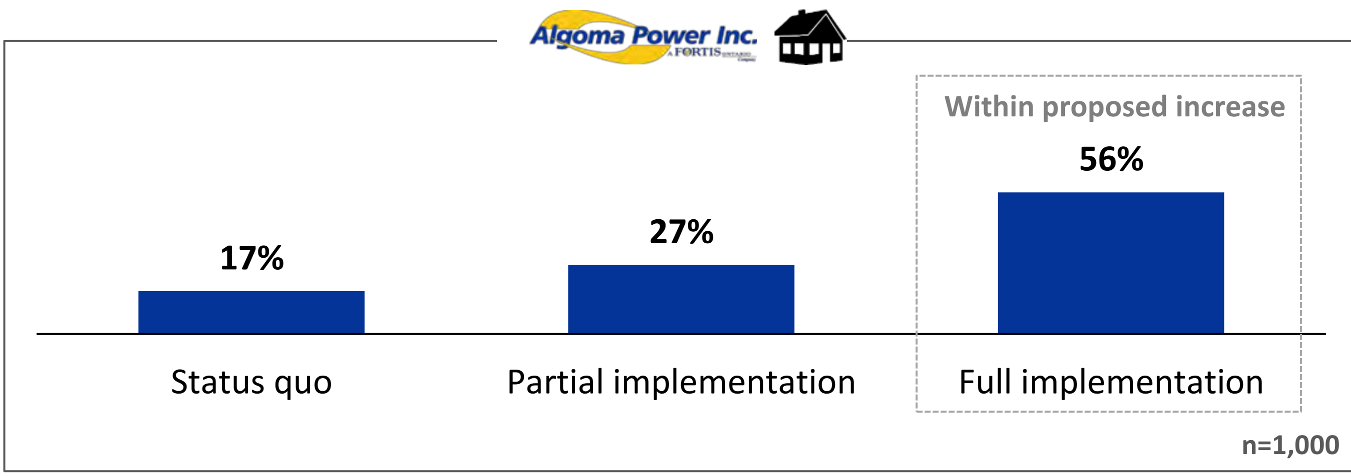
Option	Automated Switches	Expected Outcome
Status Quo ***$0.67*** *less on monthly bill by 2030*	No additional automated switches or software purchased and installed.	Across this stretch of the system, Algoma Power continues to manually locate outages and restore power, typically taking between 4 and 8 hours on average.
Partial Implementation ***$0.33*** *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

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

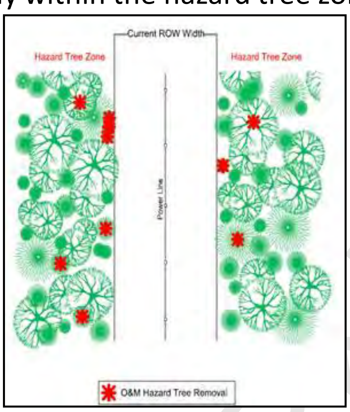
Making Choices (6 of 6)

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

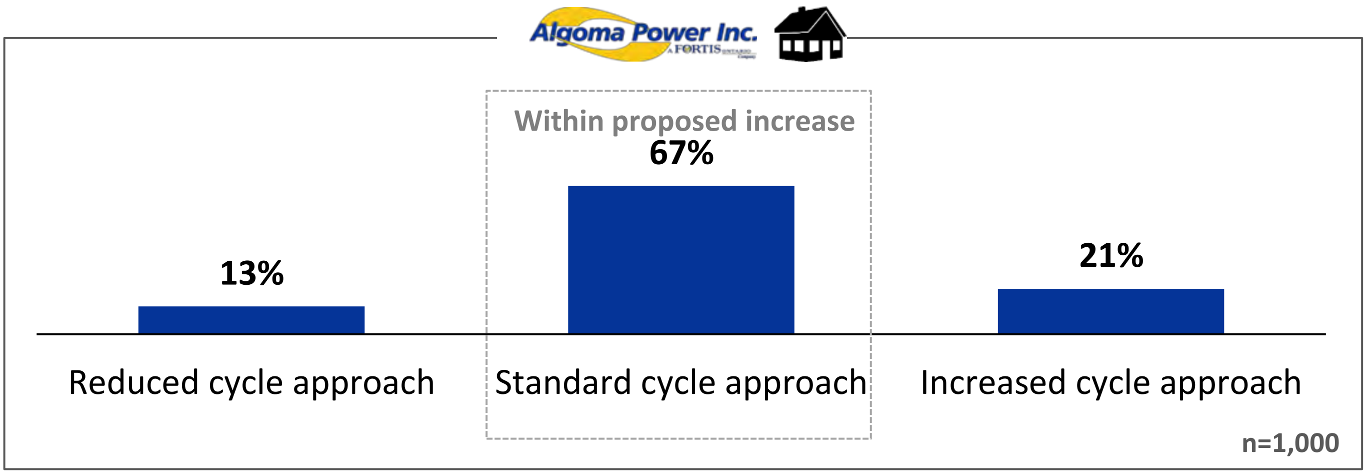
Which of the following options do you prefer?		
Option	Approach	Expected Outcome
Reduced Cycle Approach ***$1.43*** *<u>less</u> on monthly bill by 2030*	Reduce the level of "hazard tree zone" monitoring by 300 km per year.	• Increased exposure of hazard trees to the powerlines • Potential for decreased 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%

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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

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.

Impact of Choices

Do You Want to Change Your Choices?

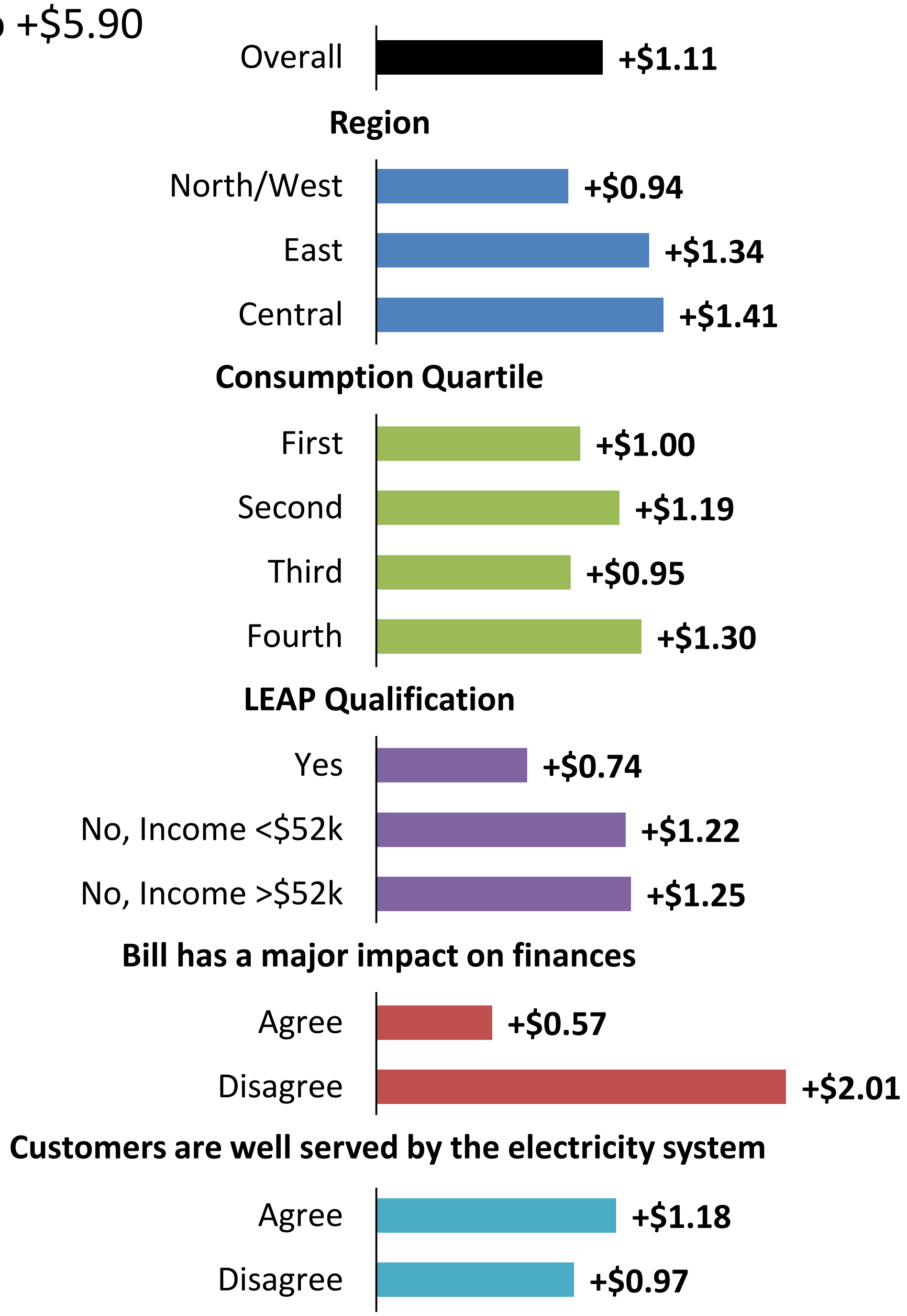
Residential

Impact of Choices

Investment alternative summary

Residential Customer Final Magnitude of Bill Impact BY key segments **(MEAN)**

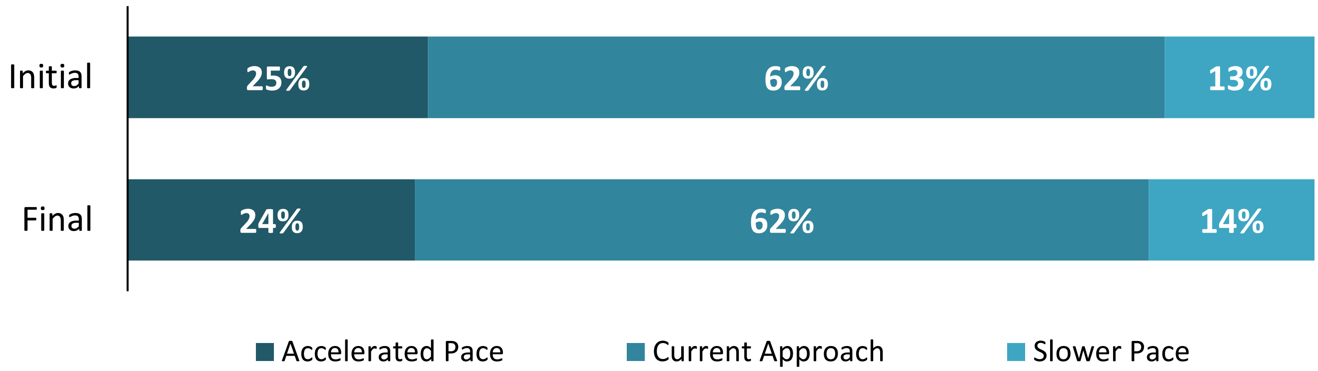
Range of Impacts
-$3.91 to +$5.90



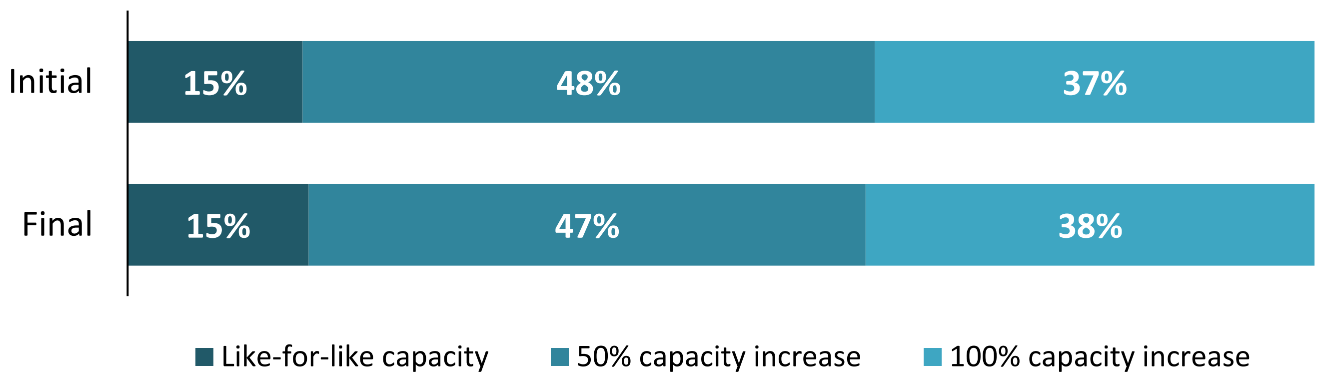
Making Choices
Impact of Choices

Residential

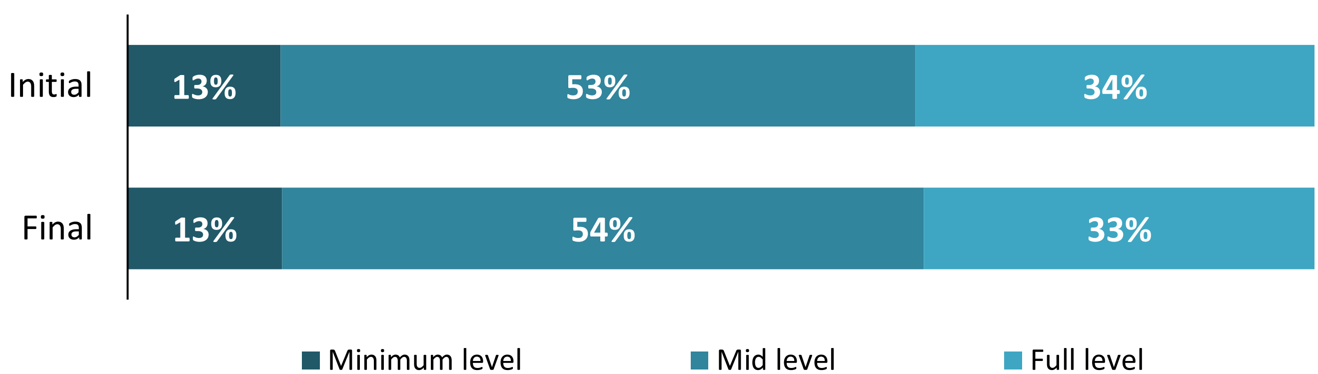
Pole and Line Replacement



Substation Rebuild



Voltage Conversion



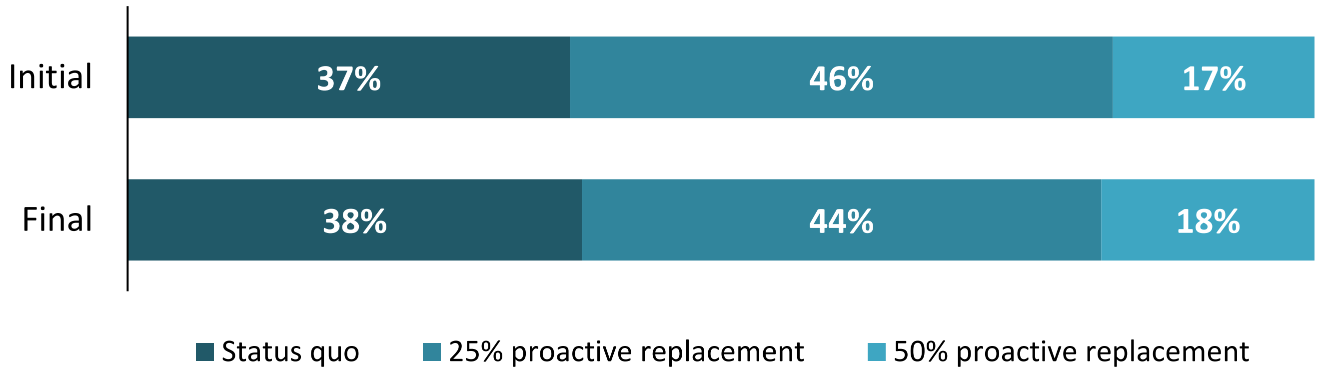
INNOVATIVE RESEARCH GROUP

Making Choices

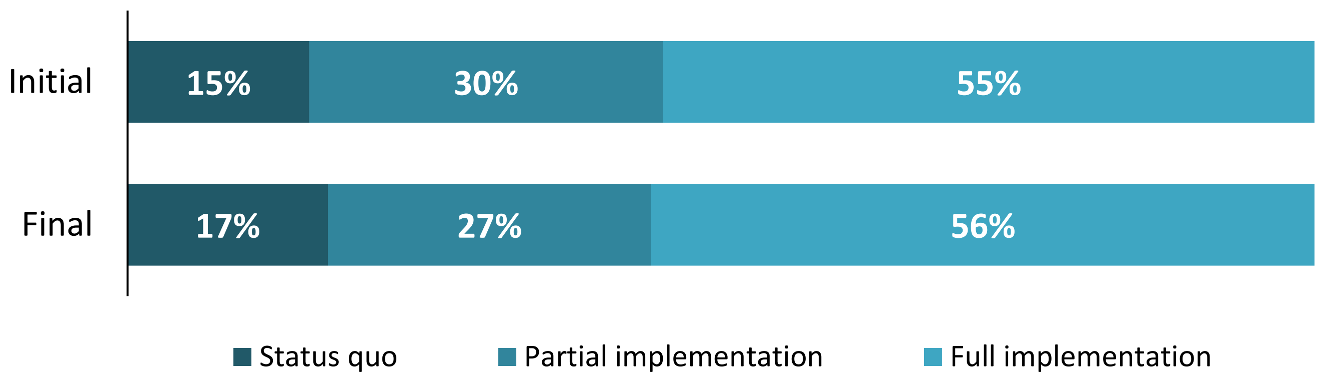
Impact of Choices

Residential

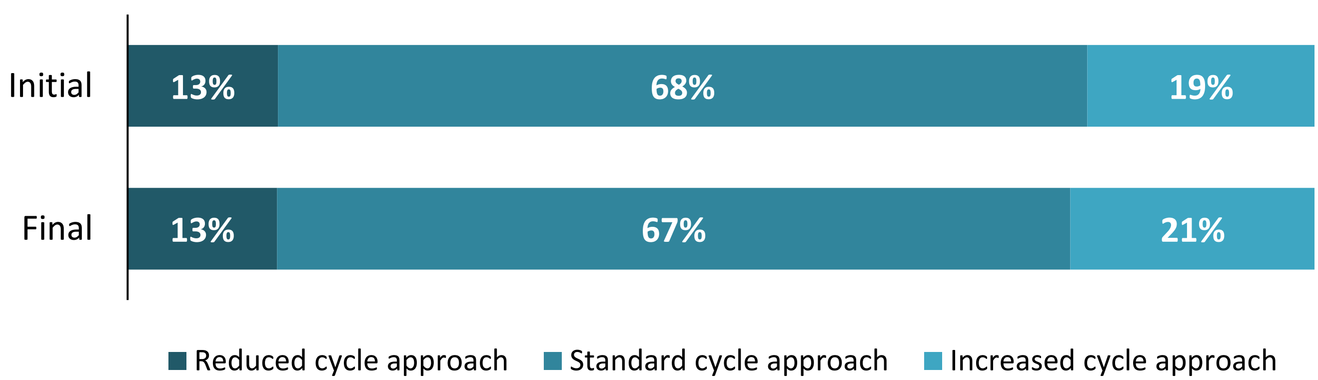
Preparing for increased electricity demand



Automated “intelligent” switches



Vegetation Management



INNOVATIVE RESEARCH GROUP

Online Workbook

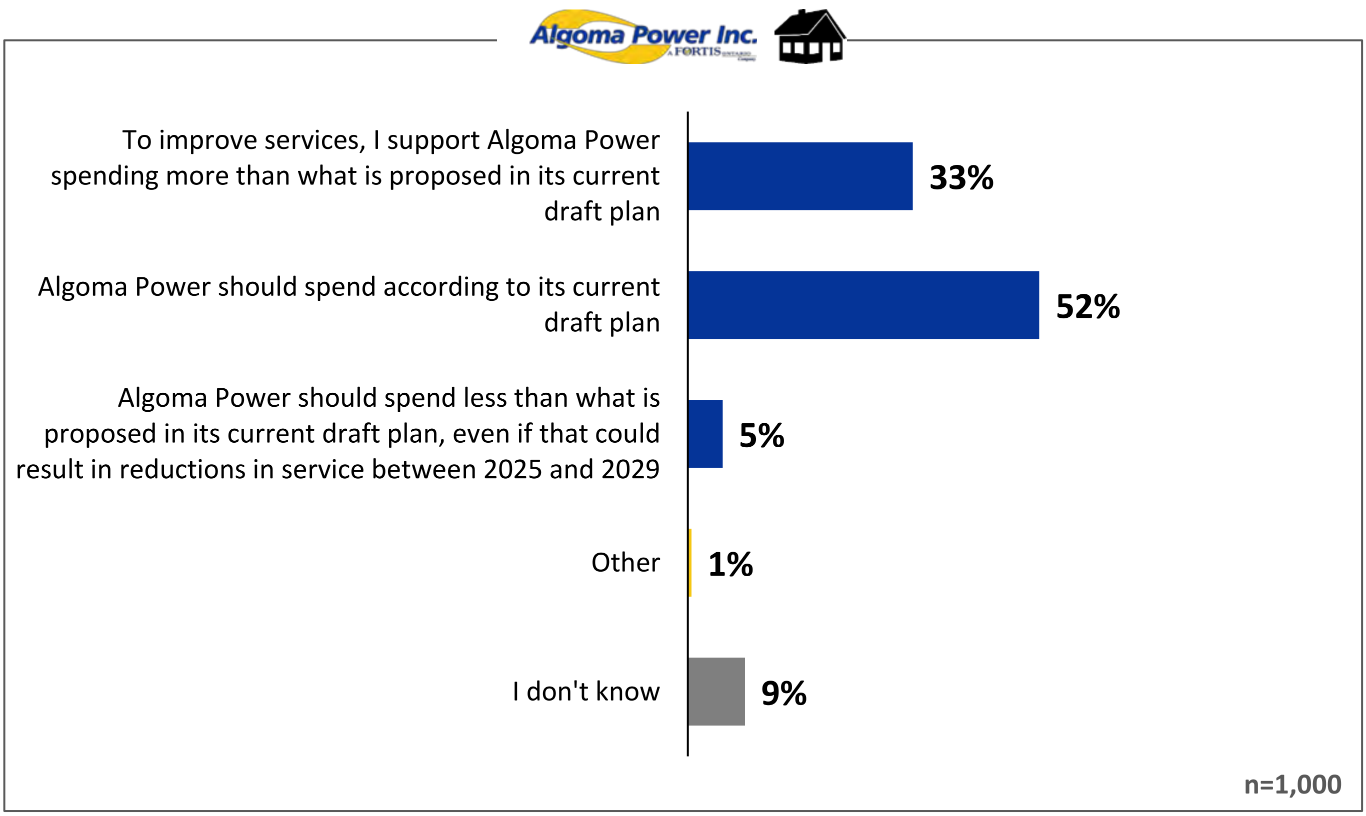
Overall Plan Evaluation

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

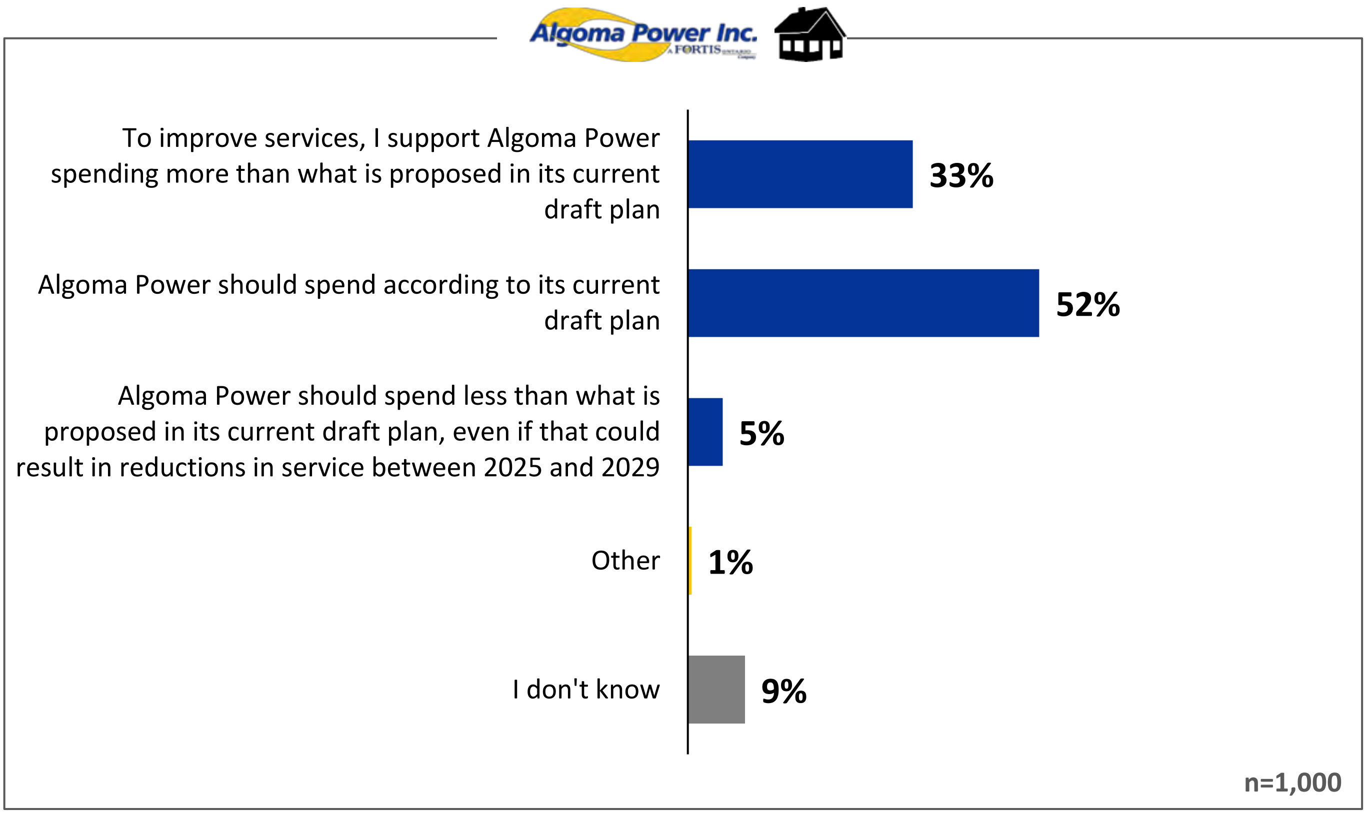
Overall Plan Evaluation

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

Residential Customers

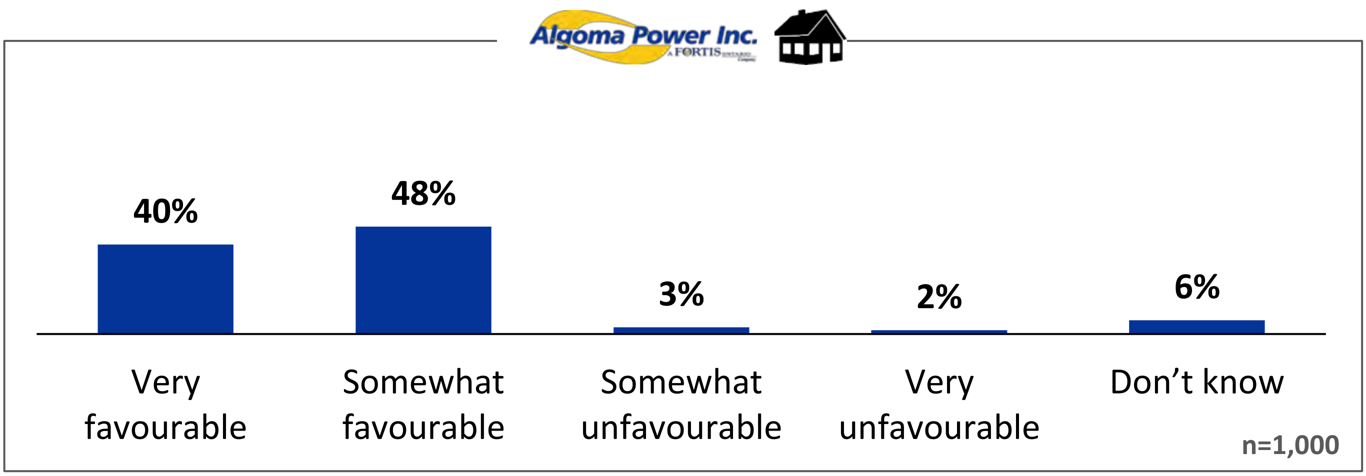
Workbook Diagnostics

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%**

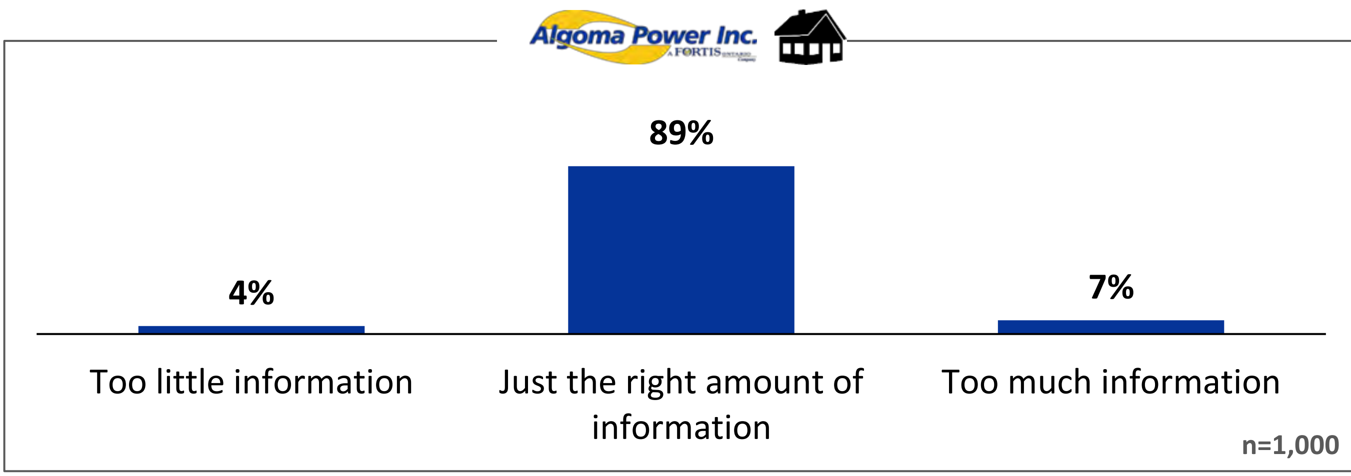
INNOVATIVE RESEARCH GROUP

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

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)

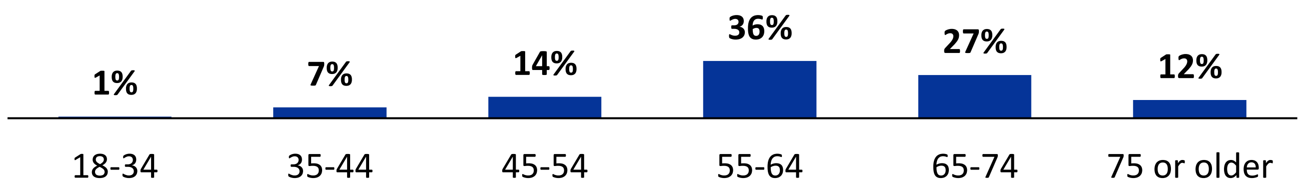
Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Online Workbook

Demographic breakdown

Seasonal

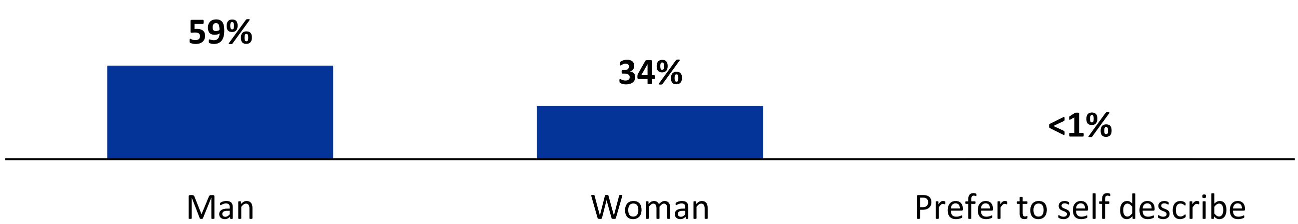
Q Age



“Prefer not to say”(3%) not shown.

n=350

Q Gender



“Prefer not to say”(7%) not shown.

n=350

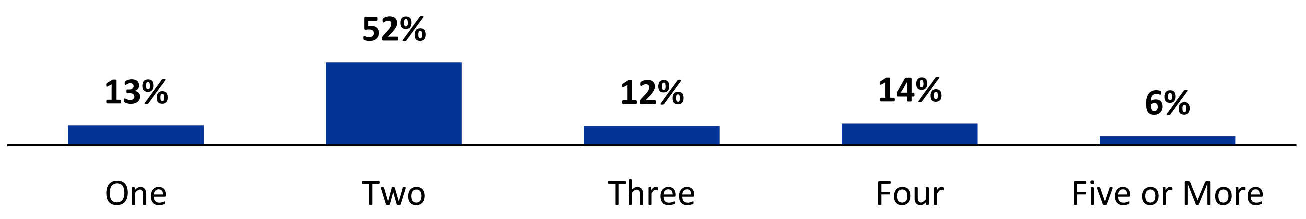
INNOVATIVE RESEARCH GROUP

Online Workbook

Demographic breakdown

Seasonal

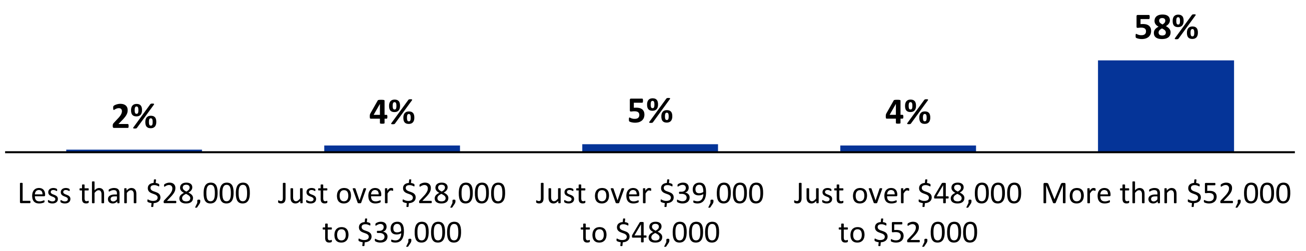
Q Household Size



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

n=350

Q After Tax Household Income



"Prefer not to say" (27%) not shown.

n=350

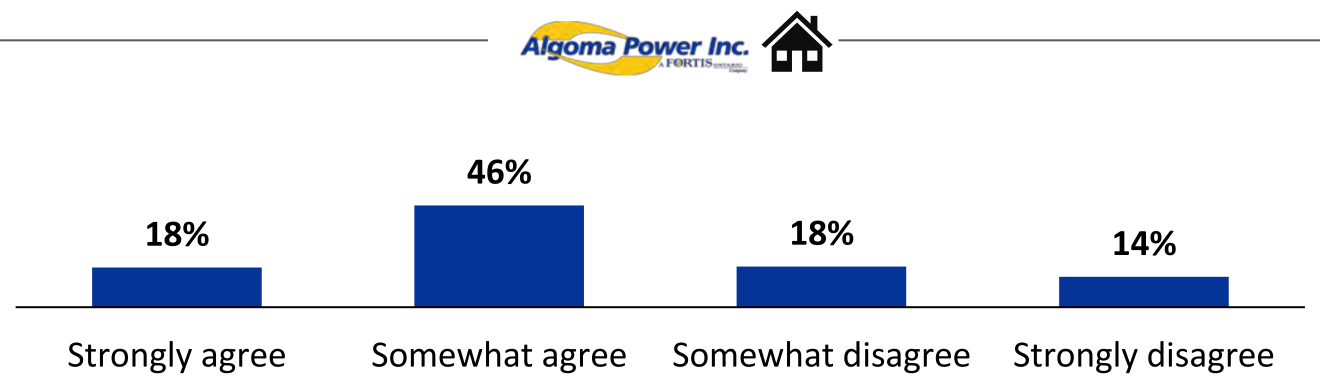
INNOVATIVE RESEARCH GROUP

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?

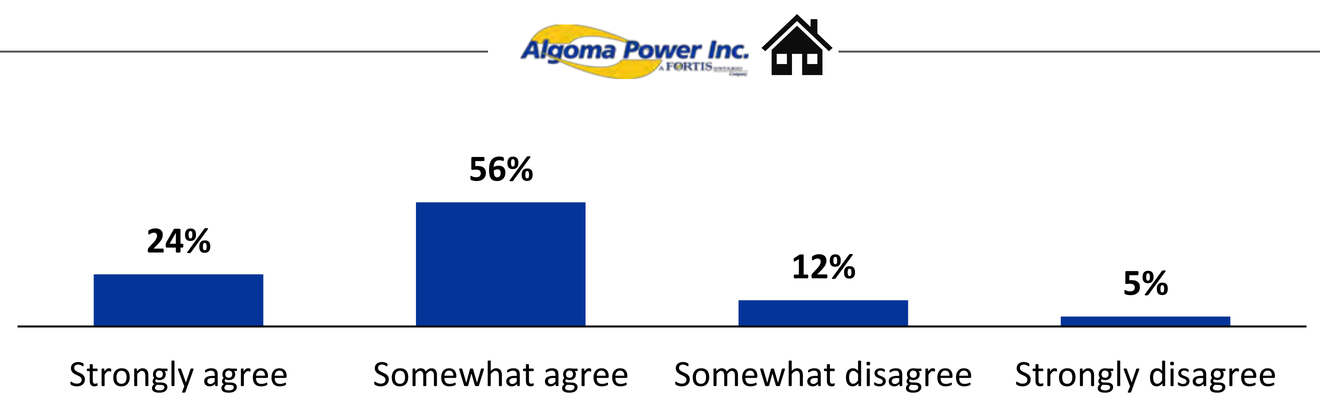
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



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

n=350

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



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

n=350

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.

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.

Algoma Power's role in Ontario's electricity system

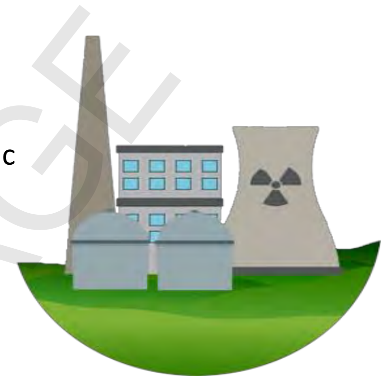
Ontario's electricity system is owned and operated by public, private and municipal corporations across the province. It is made up of three key components: **generation**, **transmission** and **distribution**.

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.

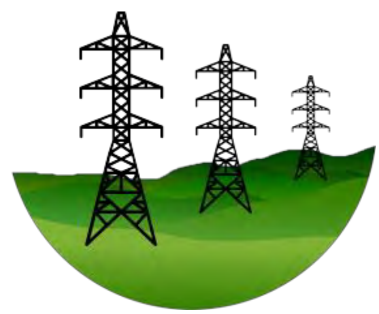
Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from multiple generators who have contracts with the grid operator to provide power from a variety of sources.



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.

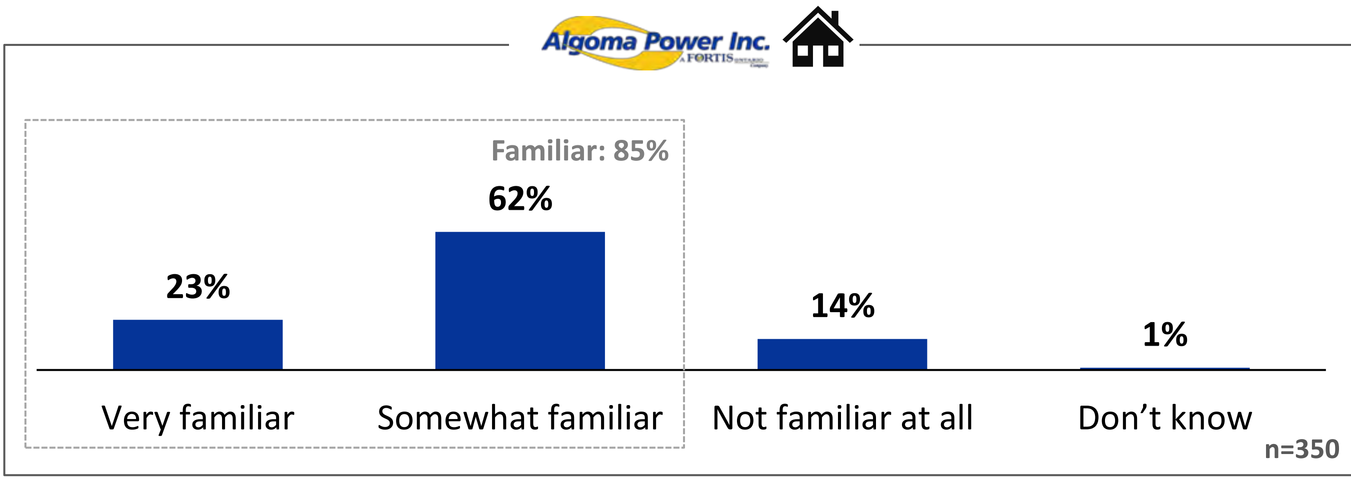
- Algoma Power manages all aspects of the electricity distribution business throughout the Algoma District of northern Ontario.
- In your community, amongst other functions, Algoma Power is responsible for:
    - Building and maintaining the local electricity distribution system
    - Responding to outage 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?



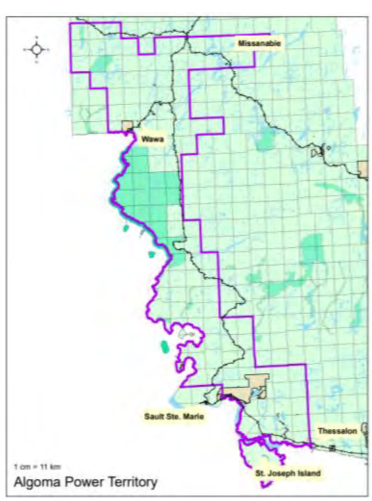
	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Very familiar	22%	24%	18%	22%	23%	27%
Somewhat familiar	63%	61%	69%	59%	61%	60%
Not familiar at all	14%	14%	11%	16%	16%	13%
Don't know	1%	1%	1%	3%	--	--
Familiar (Very + Somewhat)	**85%**	**85%**	**87%**	**81%**	**84%**	**87%**

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

Seasonal

Planning for the Future: 2025-2029 Rate Application

Electricity 101

How much of my electricity bill goes to Algoma Power?

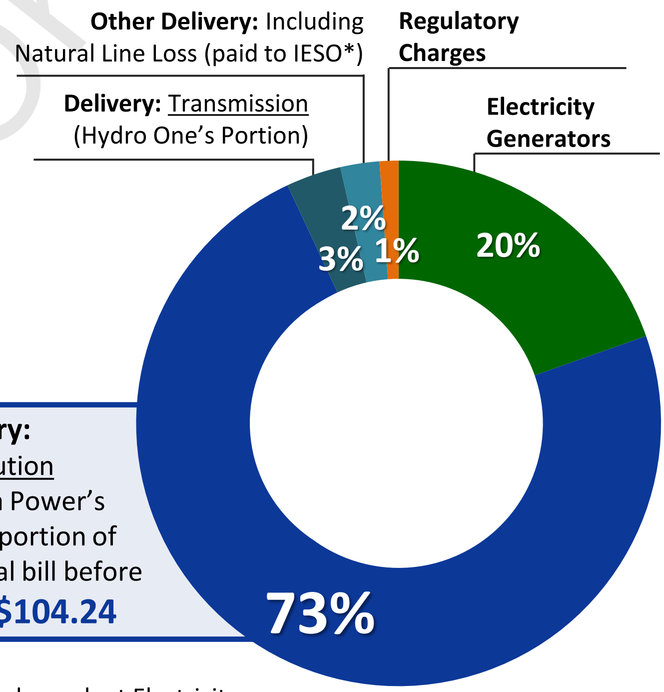
- Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While Algoma Power is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion of the delivery charge. The delivery charge also includes Hydro One transmission costs and system losses.
- **Distribution makes up about 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.

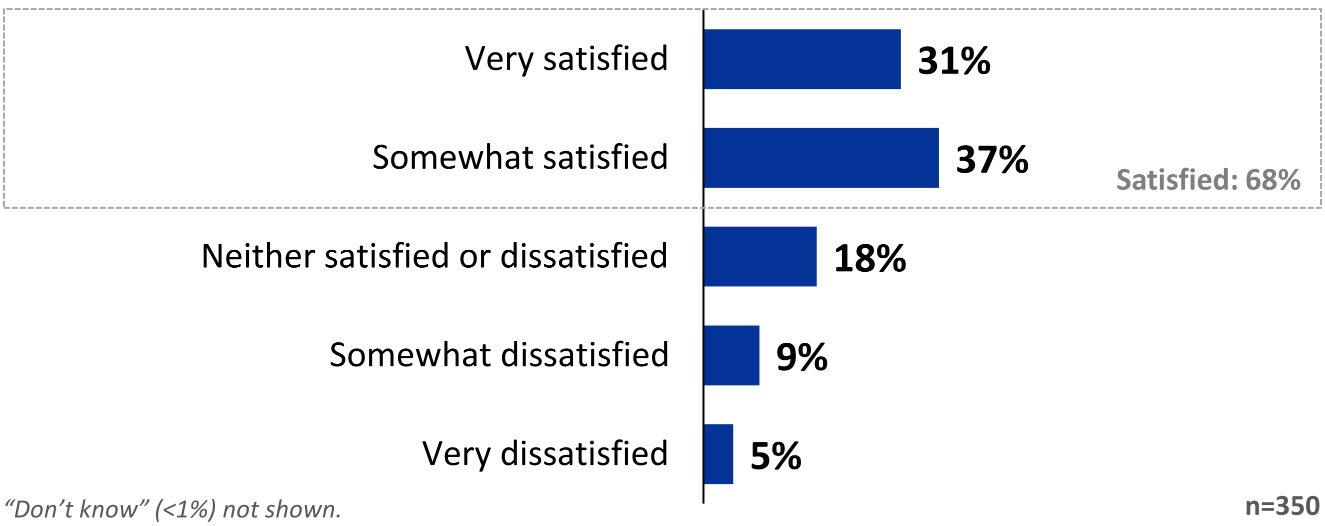
The sample bill above uses an average consumption level of 250kWh per month, however your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

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?



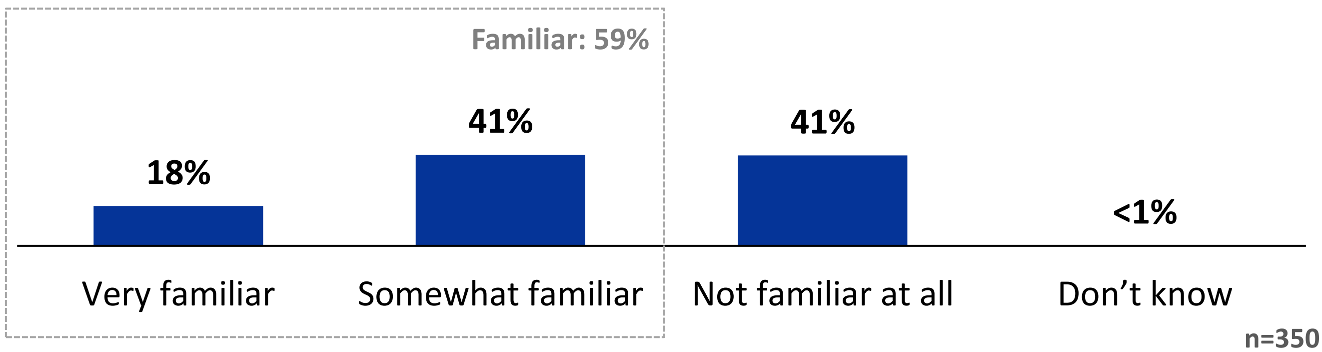
	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Very satisfied	34%	28%	33%	30%	35%	27%
Somewhat satisfied	37%	37%	35%	39%	32%	42%
Neither satisfied nor dissatisfied	19%	17%	20%	15%	21%	16%
Somewhat dissatisfied	6%	13%	10%	9%	5%	11%
Very dissatisfied	4%	6%	1%	7%	6%	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

How Algoma Power can Improve Services to Customers

Seasonal

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

Online Workbook

Setting Priorities within Algoma Power's Plans

Seasonal

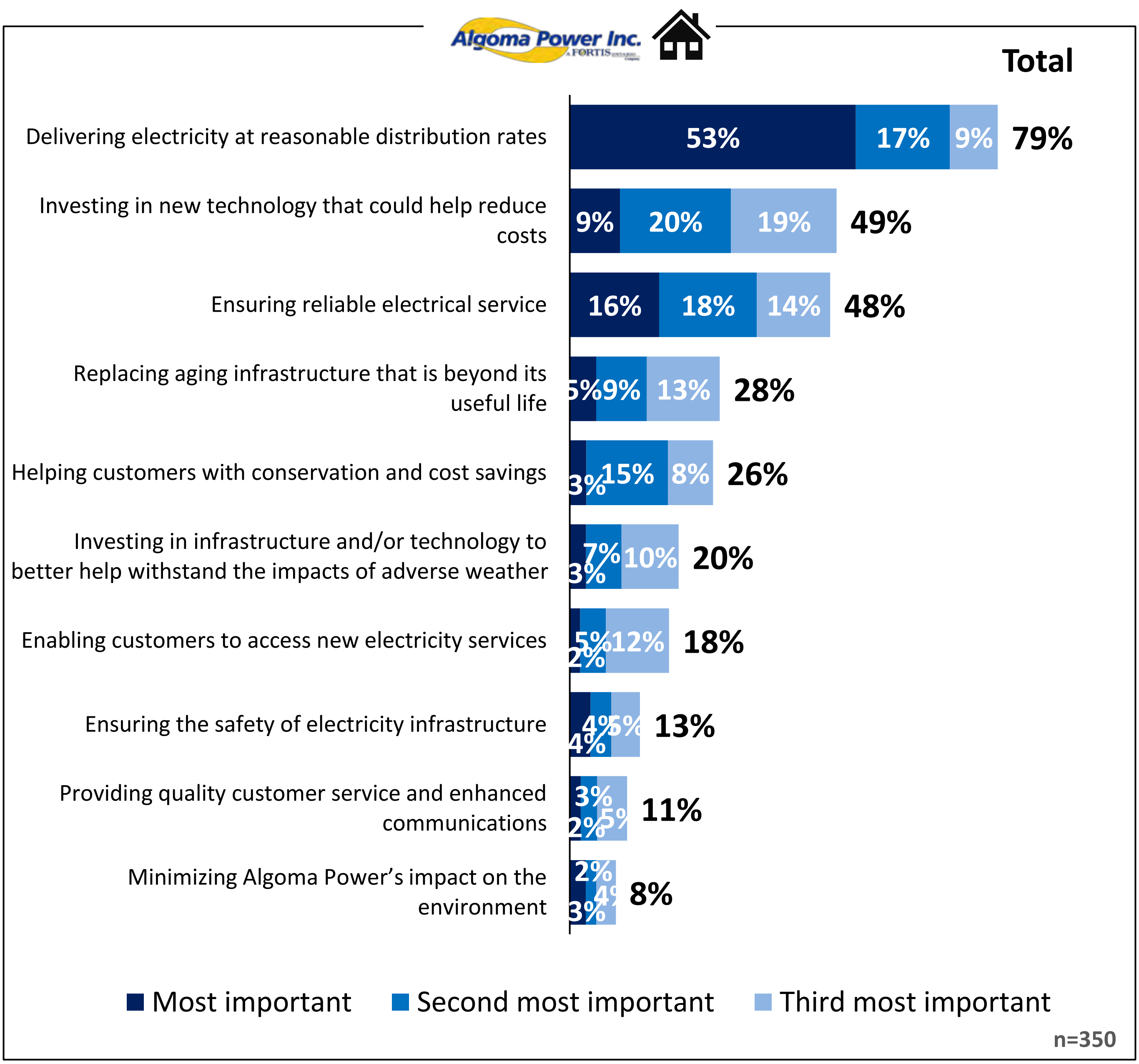
Q

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

Setting Priorities within Algoma Power's Plans

Seasonal

% 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

Background Context

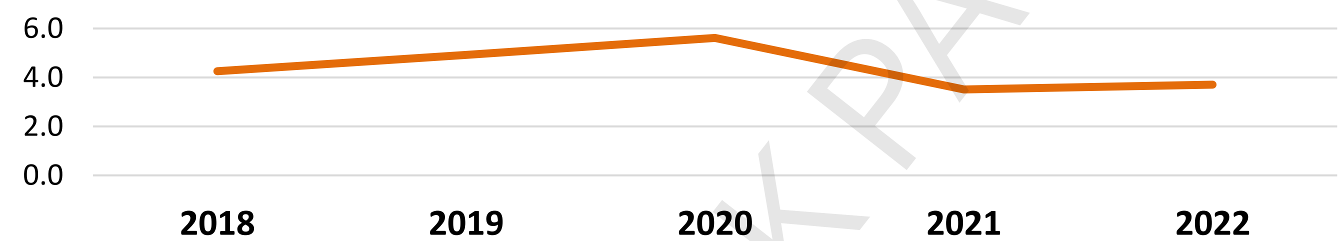
Focus on Reliability

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**.

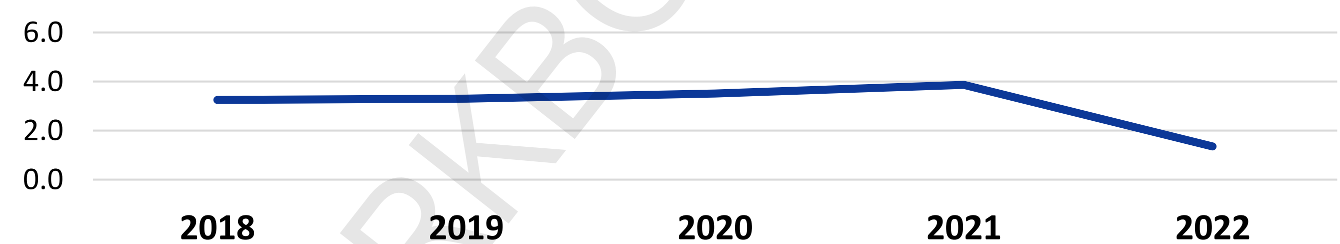
Between 2018 and 2022, the typical Algoma Power customer has experienced about **4 and a half outages per year**.

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.

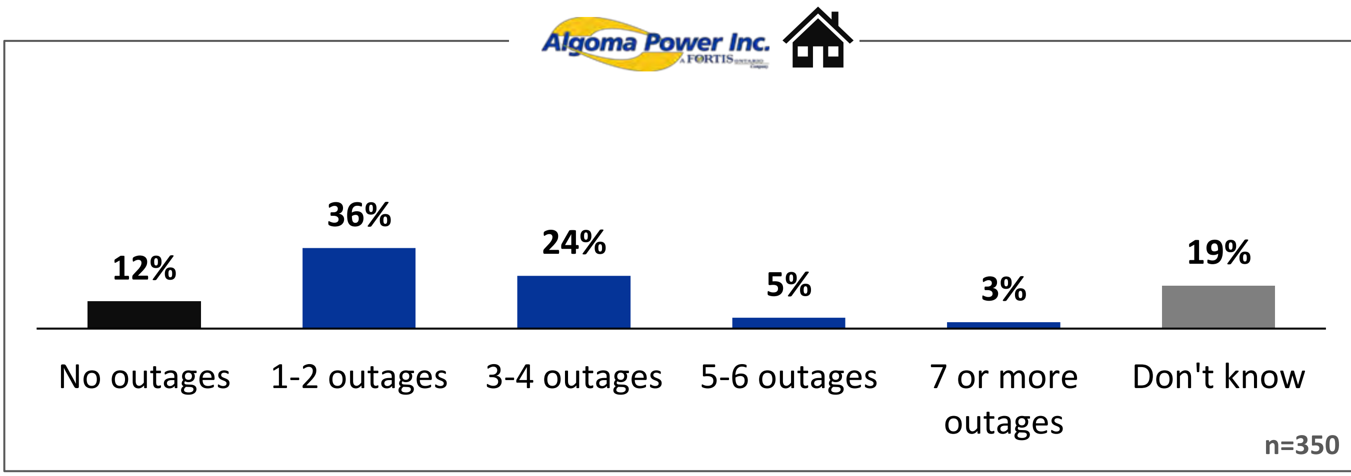
The tables and figures above include outages related to extreme weather events and transmission loss of supply events (which Algoma Power has relatively lower ability to control).

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%

Background Context

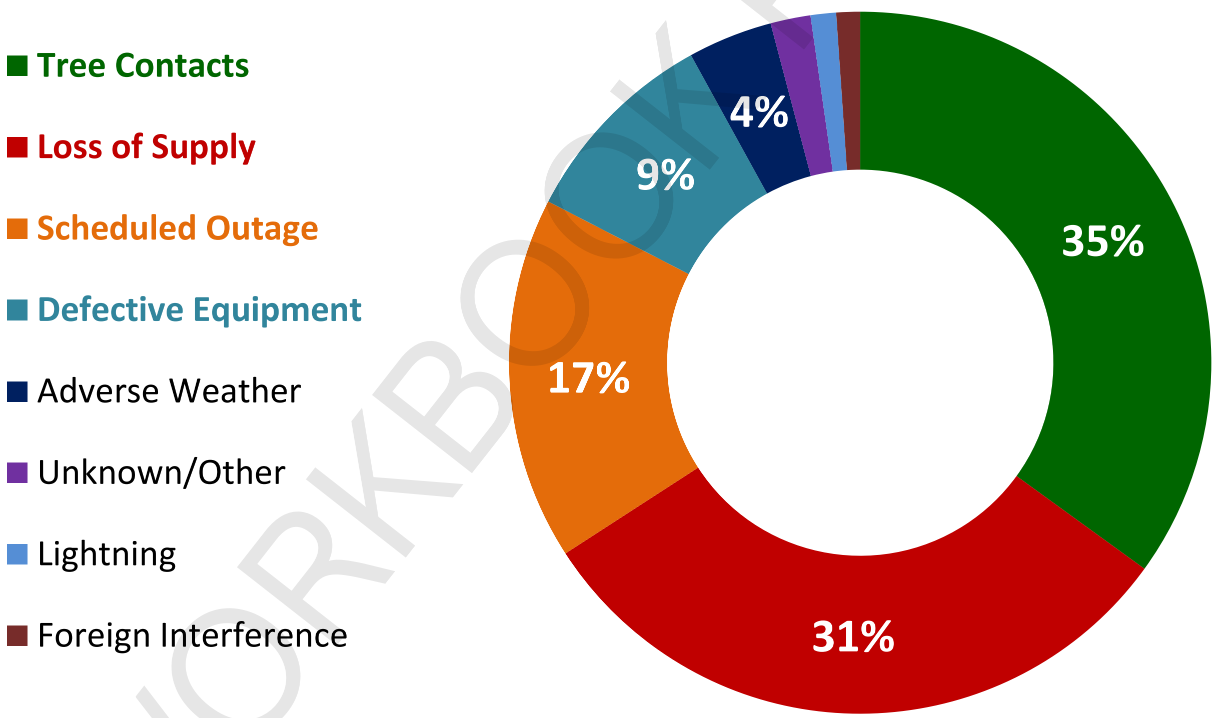
Focus on Reliability

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

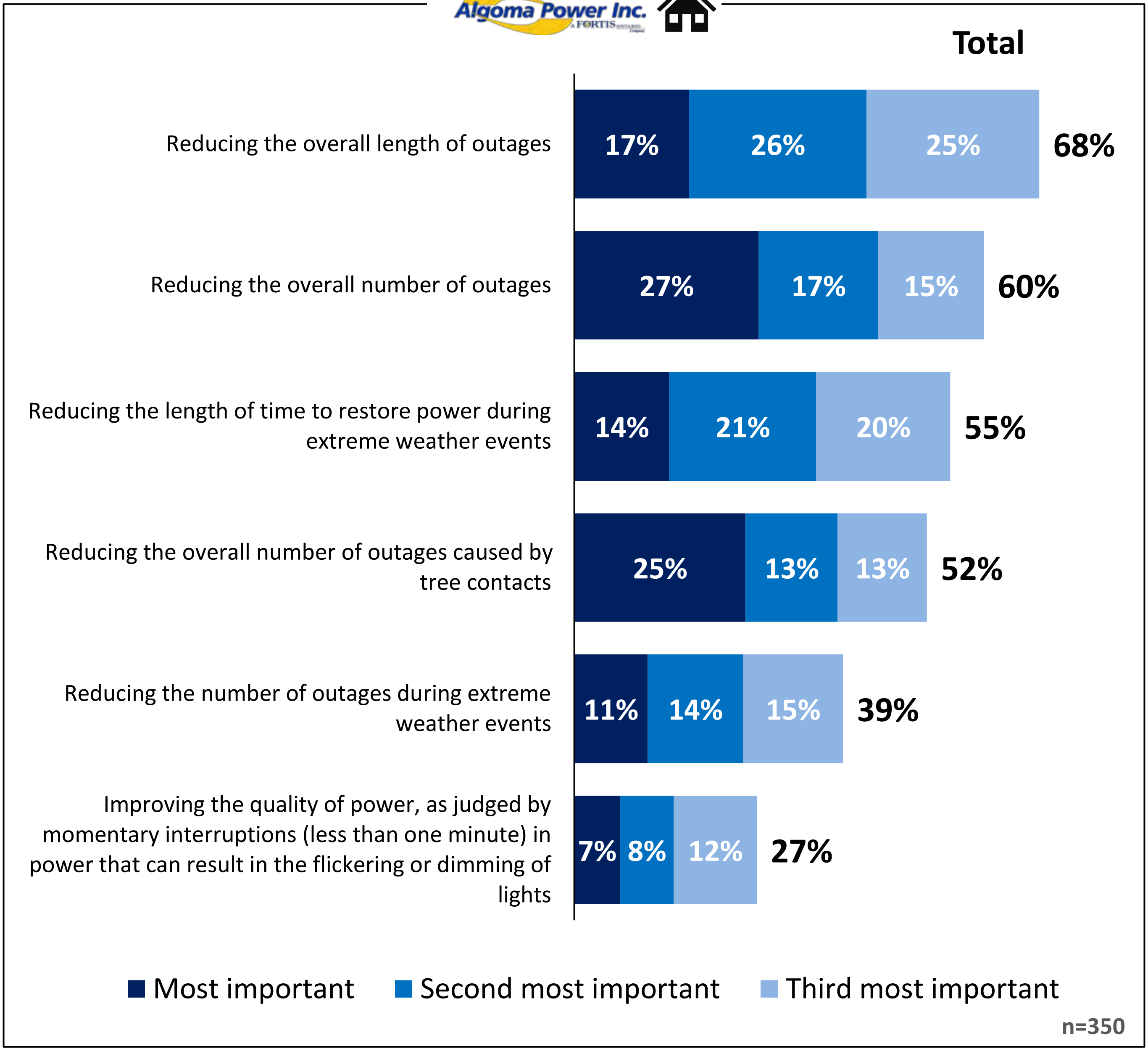
Reliability Priorities

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%

How does Algoma Power propose to spend your money?

As mentioned, a portion of <u>all</u> 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**.

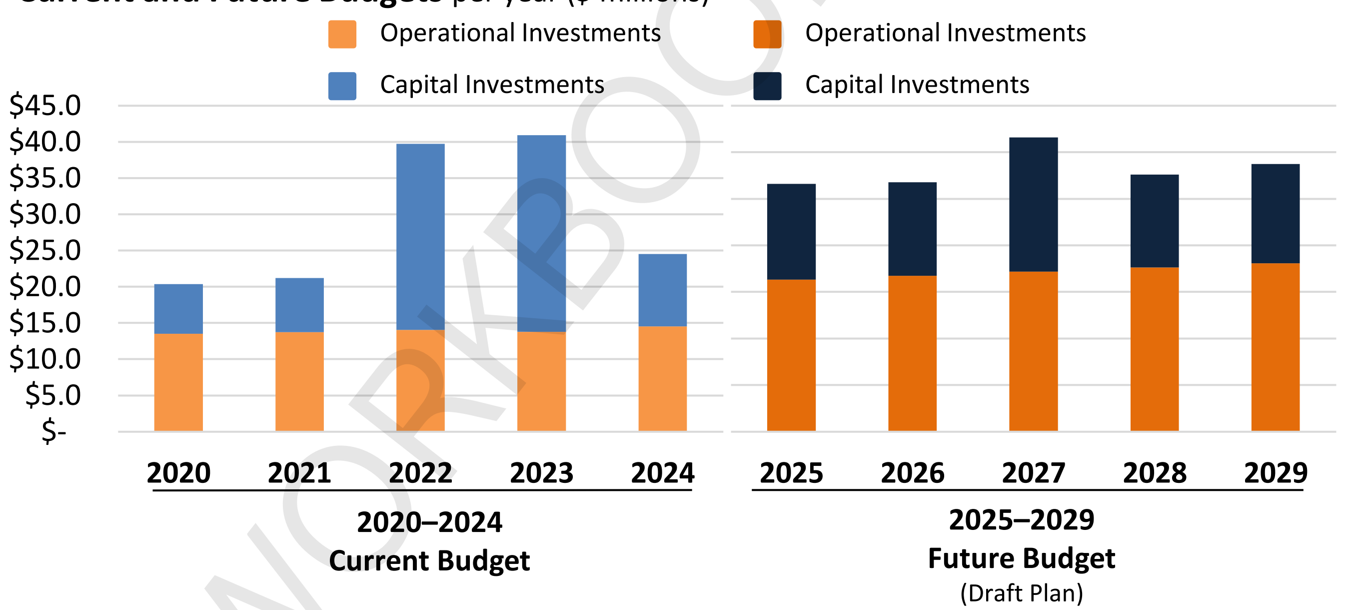
Between 2025 and 2029, Algoma Power is proposing to spend $141.3 million, a 3.7% decrease relative to the past five years.

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.

Algoma Power Background

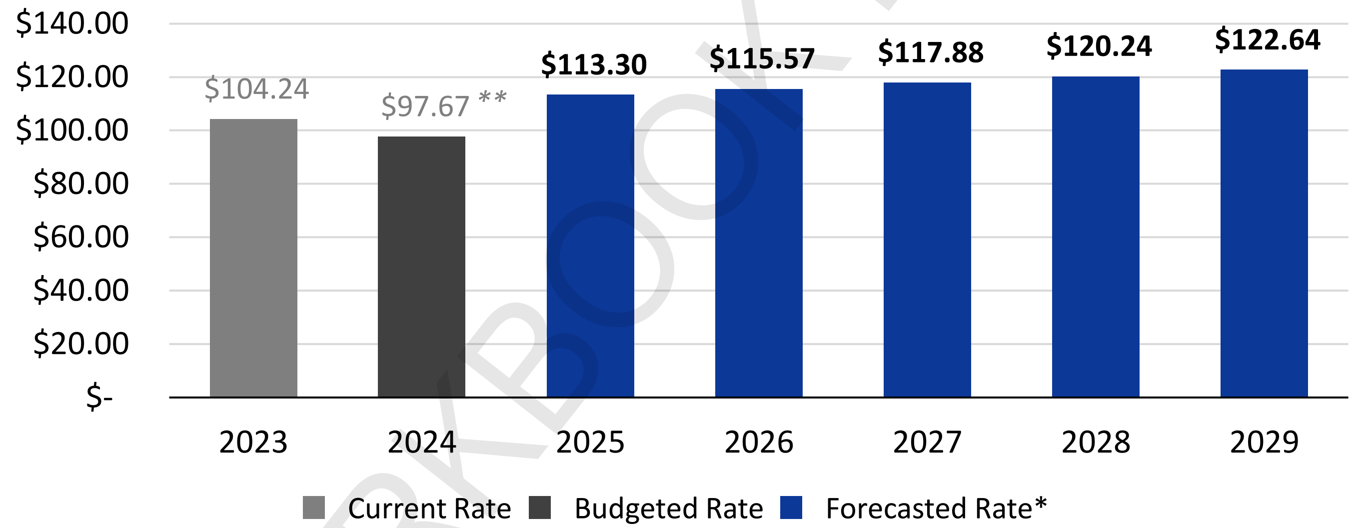
How much will Algoma Power's draft plan cost me?

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.

Monthly Distribution Costs (2023-2029)



** 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.

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**.

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

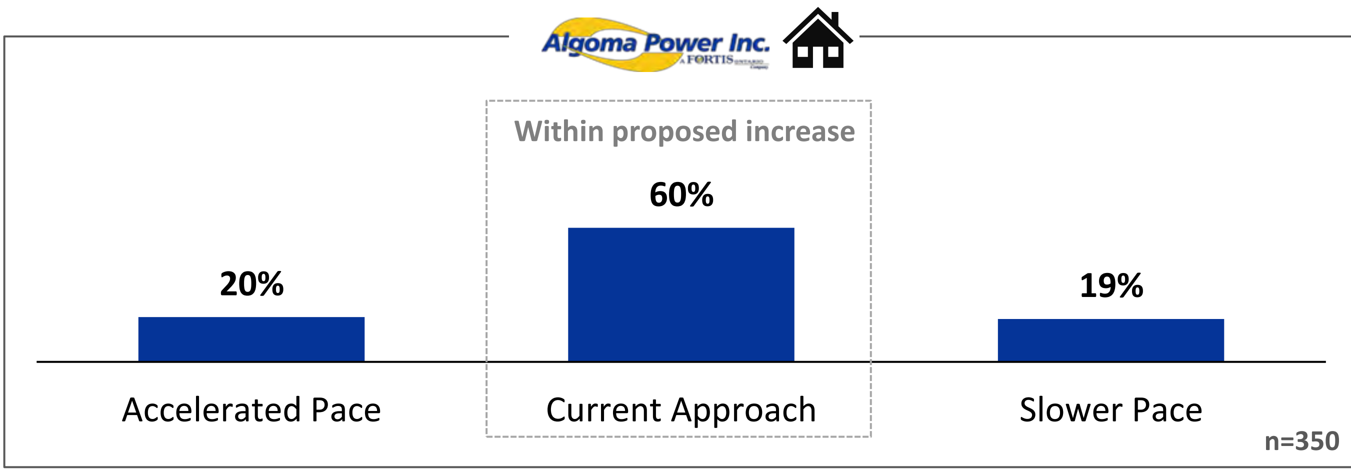
Which of the following options do you prefer?		
Option	Poles Replaced	Expected Outcome
Accelerated Pace ***$0.83** more on monthly bill by 2030*	Proactively replace 550 poles per year for the next five years.	• Increase the current pole replacement pace by 50 per year. • Potentially see reliability improvements 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

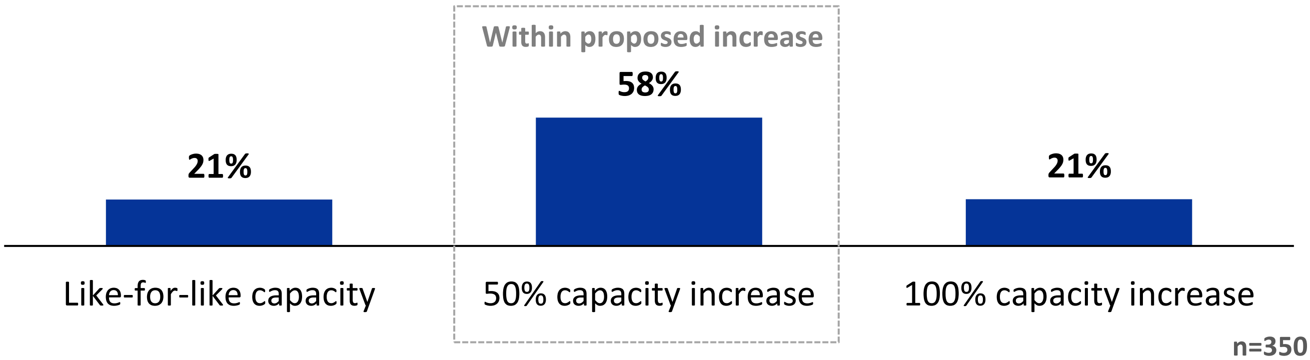
Which of the following options do you prefer?		
Option	Transformer Size	Expected Outcome
Like-for-like capacity ***$0.09*** *less on monthly bill by 2030*	Procure and install a power transformer that is similar in capacity to the existing transformer.	Increased risk of premature transformer replacement 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 ***$0.09*** *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

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%

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

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

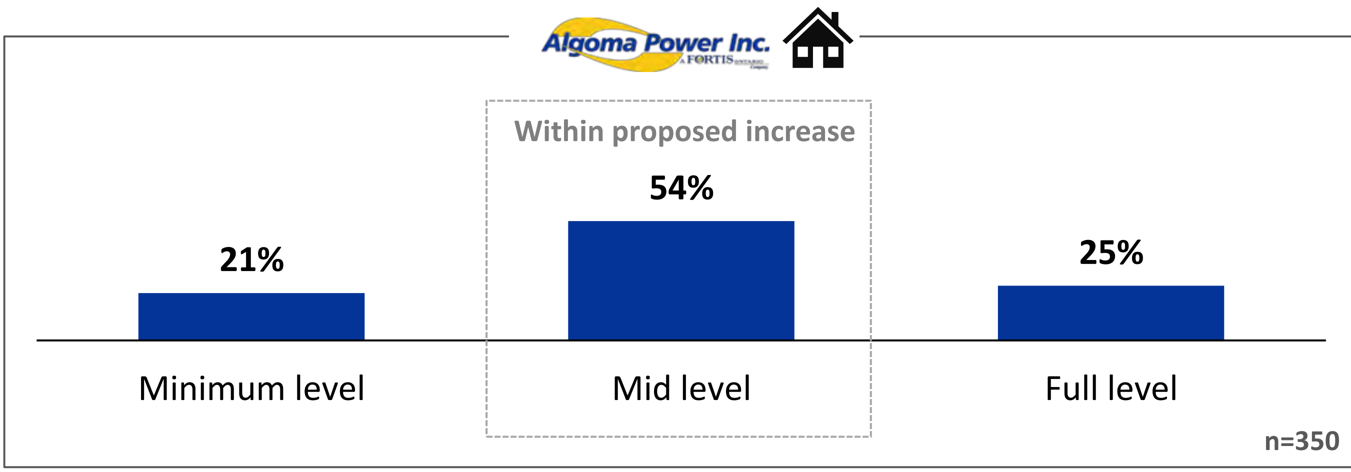
Which of the following options do you prefer?		
Option	**% Upgraded**	**Expected Outcome**
Minimum Level ***$0.07*** *less on monthly bill by 2030*	Upgrade and convert approximately 25% of the identified area's distribution system to a higher voltage.	• Reduce the risk of voltage reliability and power 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%

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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

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

Choice 4: Preparing for increased electricity demand

Which of the following options do you prefer?

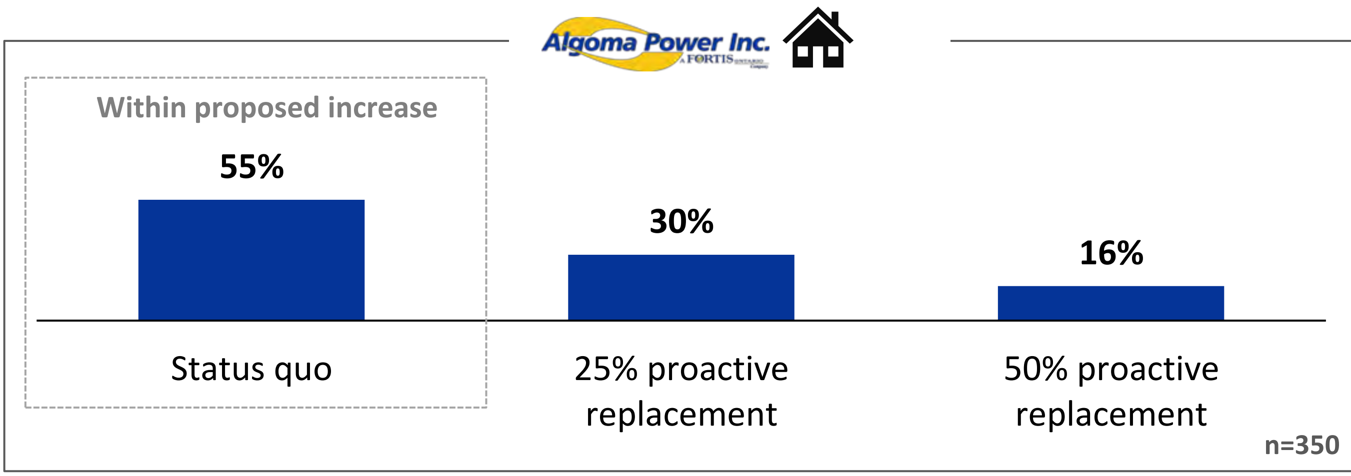
Option	Transformers Replaced	Expected Outcome
Status Quo *Within proposed rate increase*	Based on historical data, reactively replace approximately 12 transformers per year as they fail.	• Maximize the useful life of current transformers. • Potential for higher levels of unplanned outages due to transformer 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

Choice 4: Preparing for increased electricity demand

Seasonal

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%

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

Planning for the Future: 2025-2029 Rate Application

Seasonal

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

Choice 5: Automated “intelligent” switches

Which of the following options do you prefer?

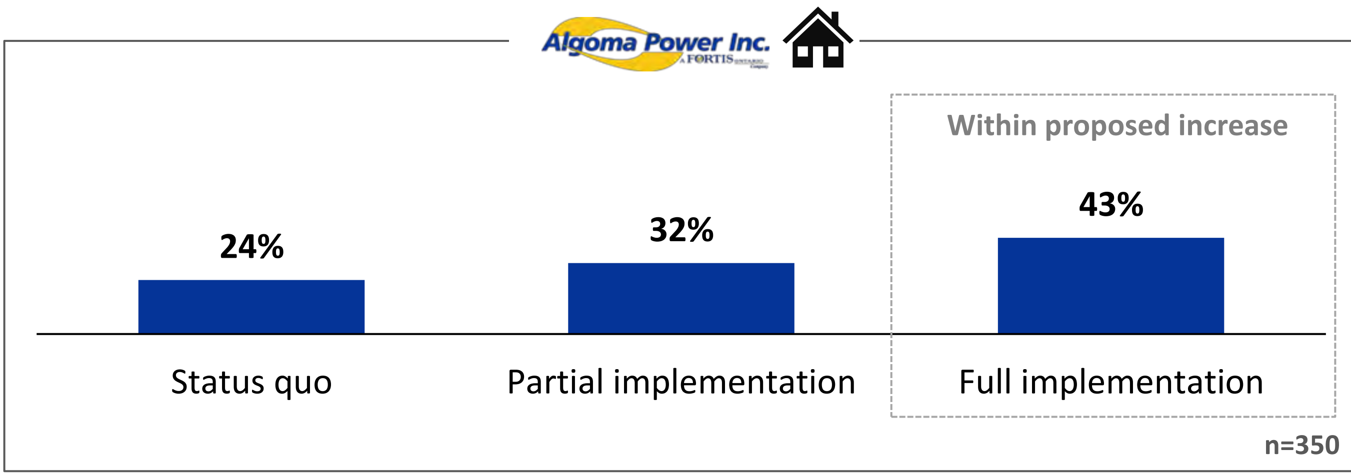
Option	Automated Switches	Expected Outcome
Status Quo *__$0.37__ <u>less</u> on monthly bill by 2030*	No additional automated switches or software purchased and installed.	Across this stretch of the system, Algoma Power continues to manually locate outages and restore power, typically taking between 4 and 8 hours on average.
Partial Implementation *__$0.18__ <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

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%

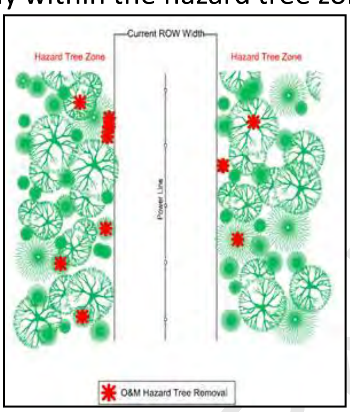
Note: Only responses >0.1% shown

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

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.

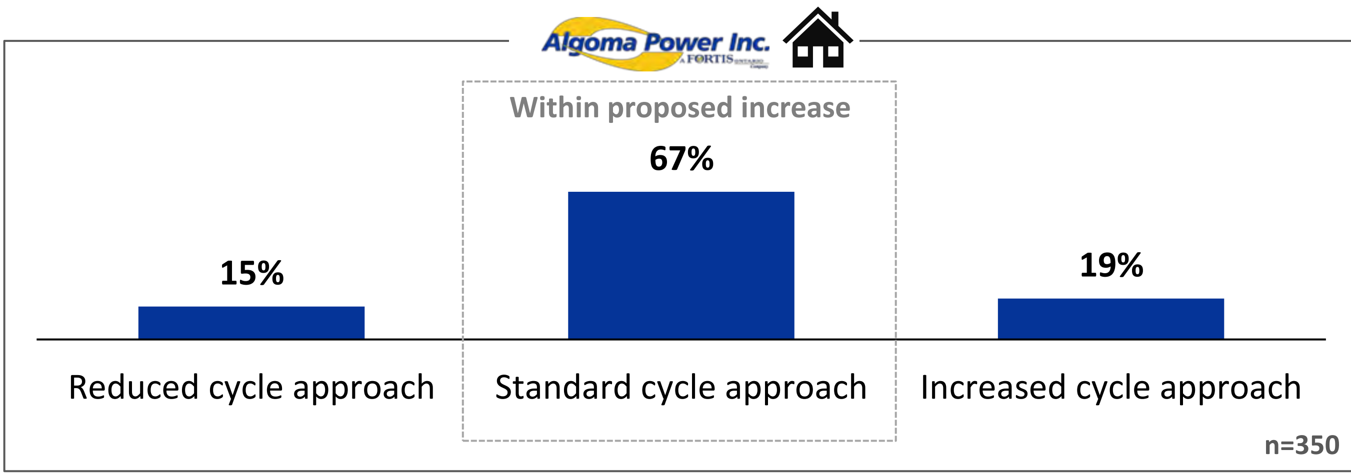
Additional Feedback (Optional)

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%

INNOVATIVE RESEARCH GROUP

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?

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.

Impact of Choices

Do You Want to Change Your Choices?

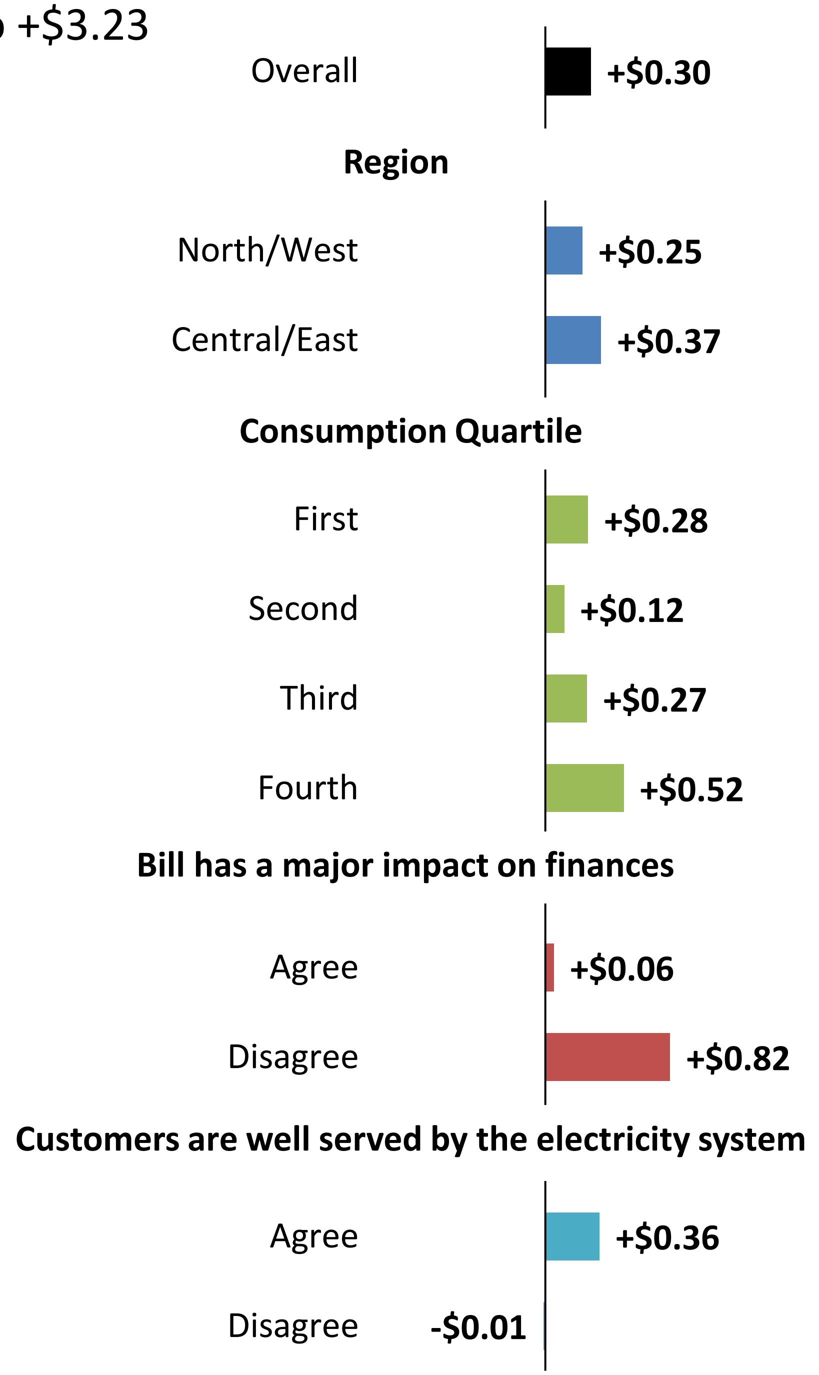
Seasonal

Impact of Choices

Investment alternative summary

Seasonal Customer Final Magnitude of Bill Impact BY key segments **(MEAN)**

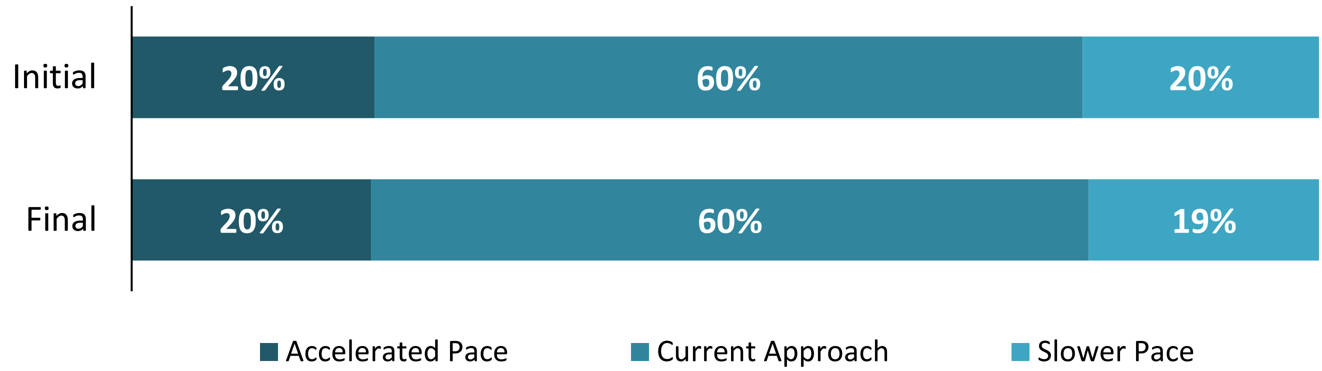
Range of Impacts
-$2.14 to +$3.23



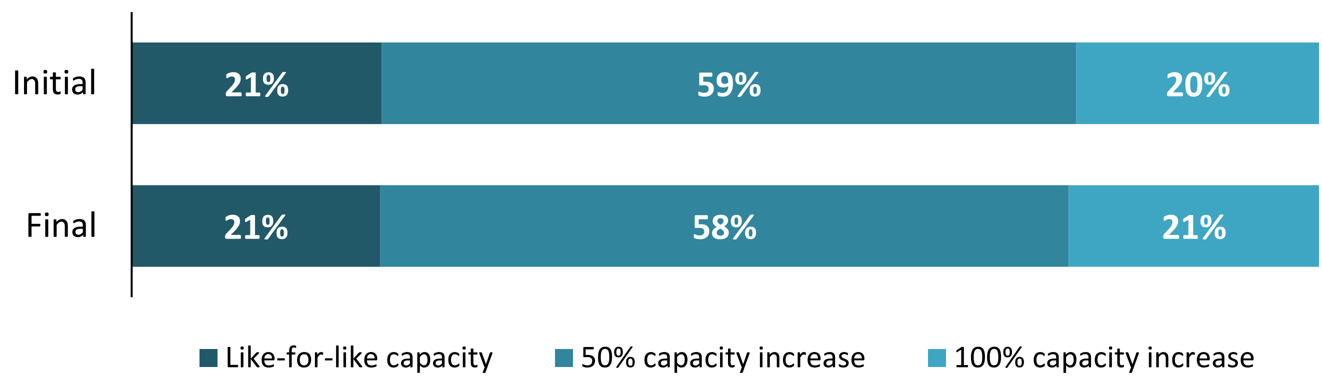
Making Choices

Impact of Choices

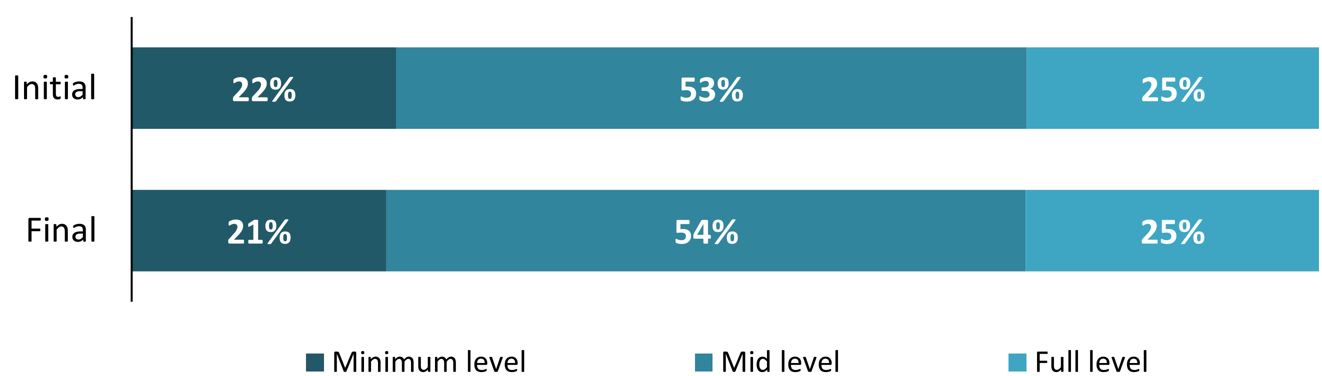
Pole and Line Replacement



Substation Rebuild



Voltage Conversion

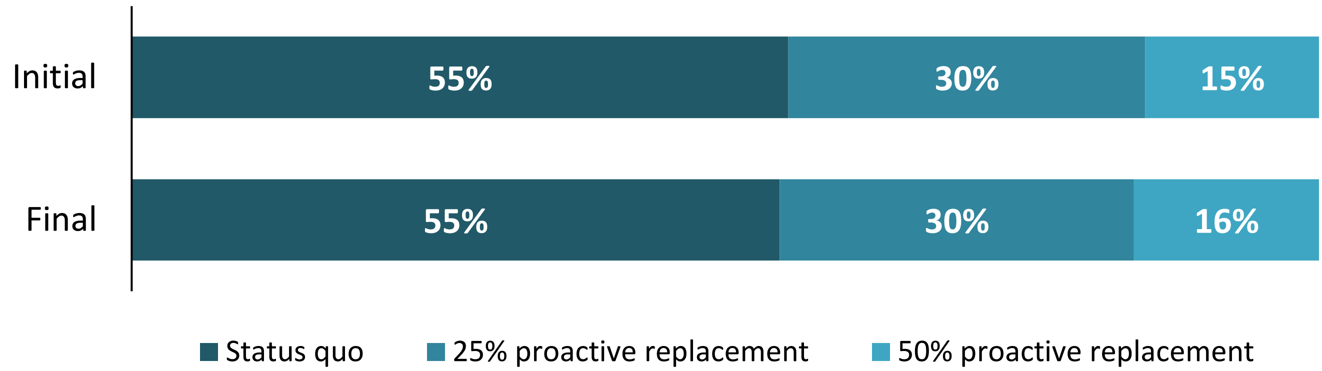


Making Choices

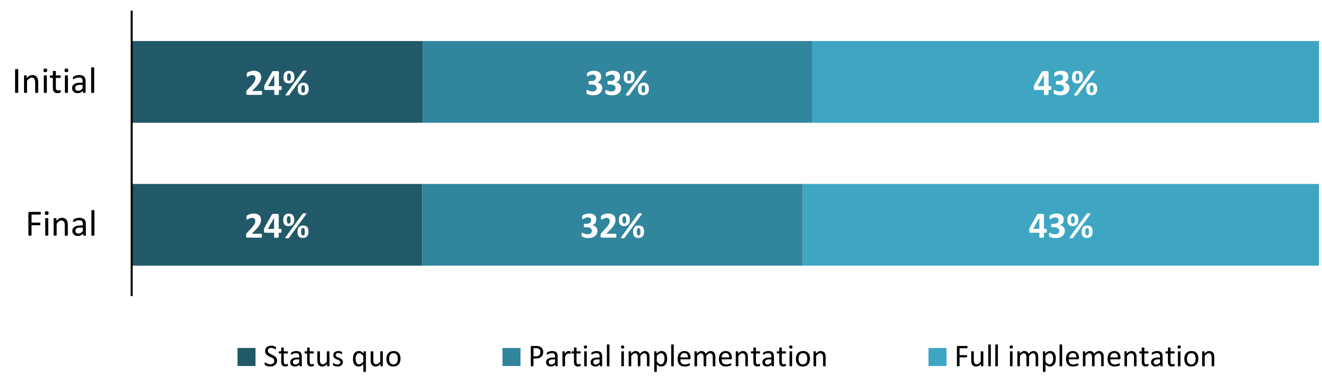
Impact of Choices

Seasonal

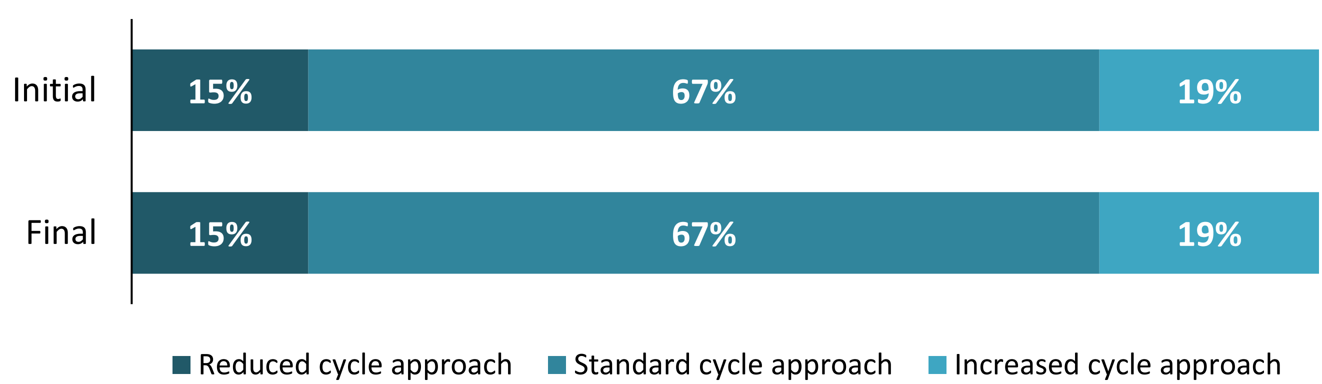
Preparing for increased electricity demand



Automated "intelligent" switches



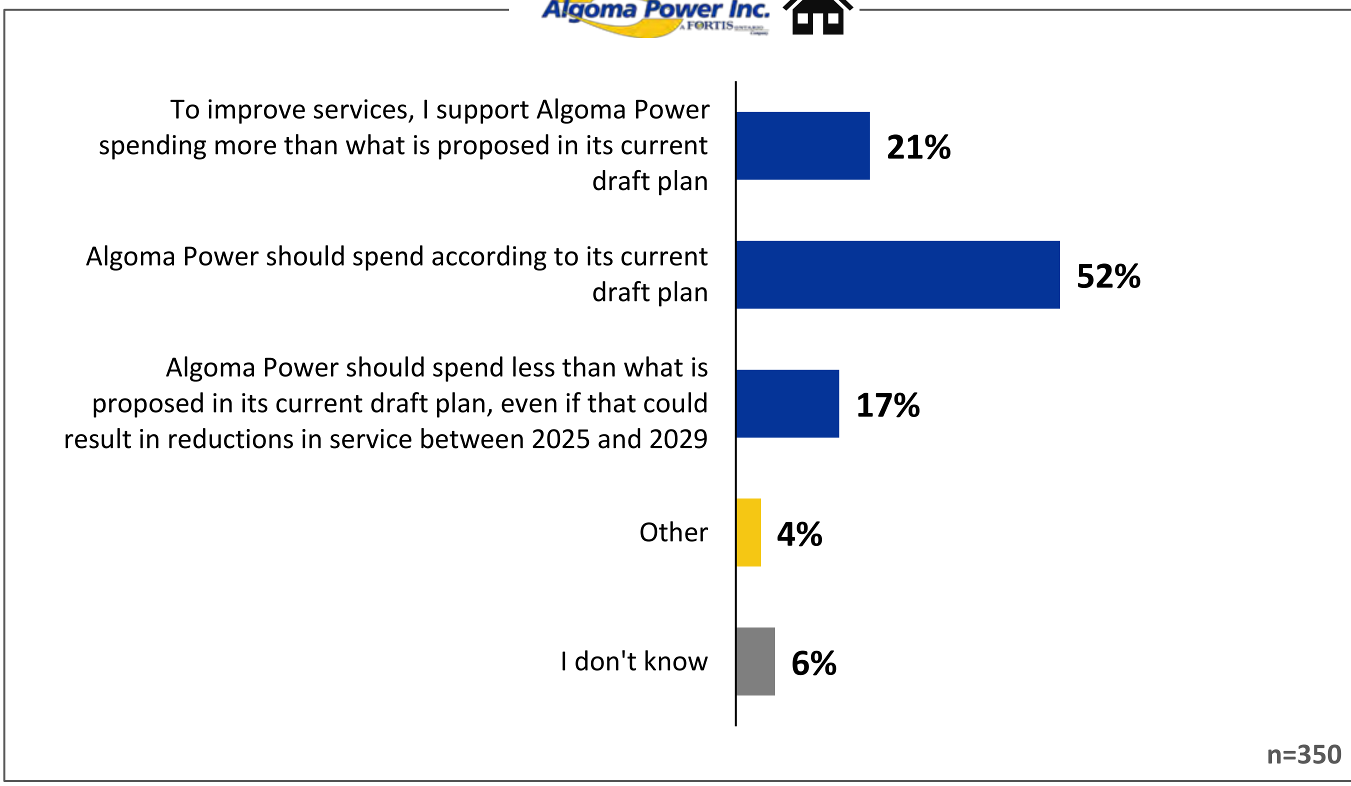
Vegetation Management



Online Workbook
Overall Plan Evaluation

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

Seasonal Customers

Workbook Diagnostics

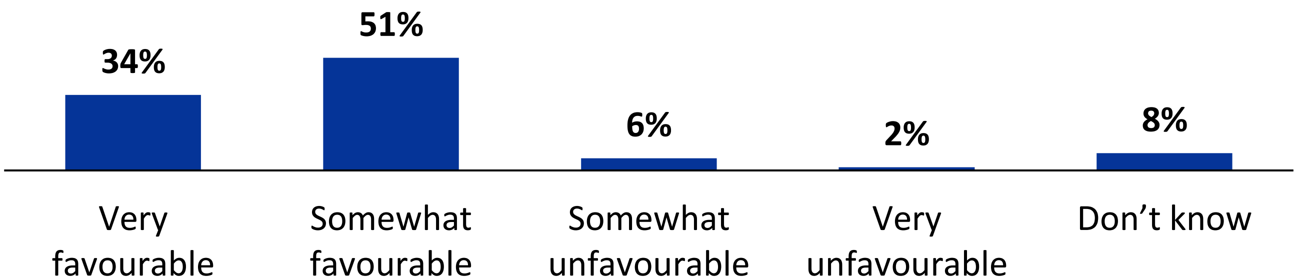
Online Workbook

Workbook Impression

Seasonal

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?

Algoma Power Inc.



n=350

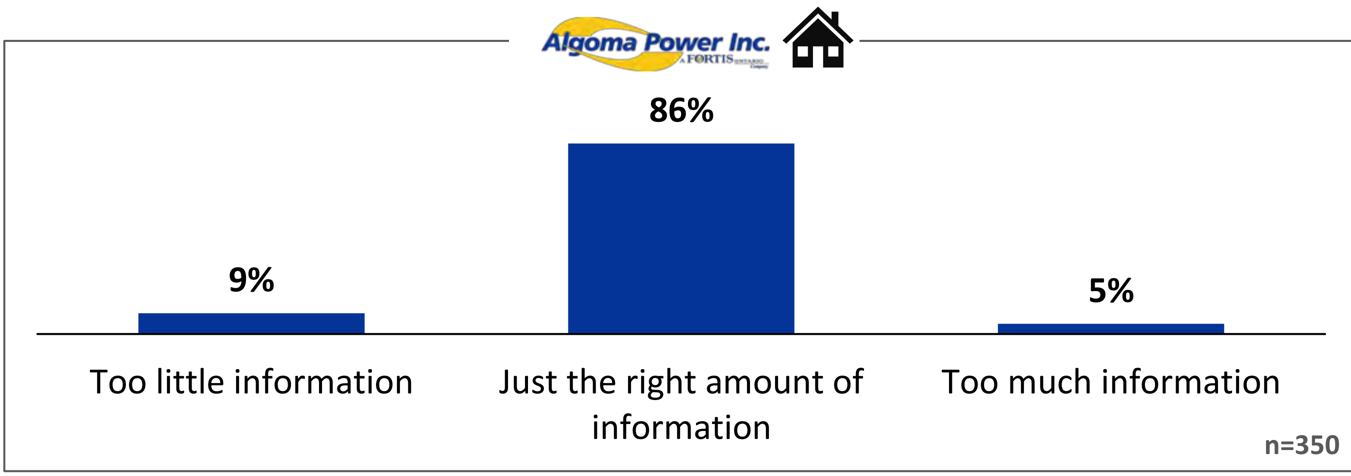
	Region		Consumption Quartiles			
	North/West	Central/East	First	Second	Third	Fourth
Very favourable	37%	30%	37%	29%	38%	33%
Somewhat favourable	45%	59%	55%	52%	43%	54%
Somewhat unfavourable	7%	4%	3%	7%	7%	5%
Very unfavourable	2%	1%	1%	1%	2%	2%
Don't know	9%	6%	3%	12%	10%	6%
Favourable (Very + Somewhat)	**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

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

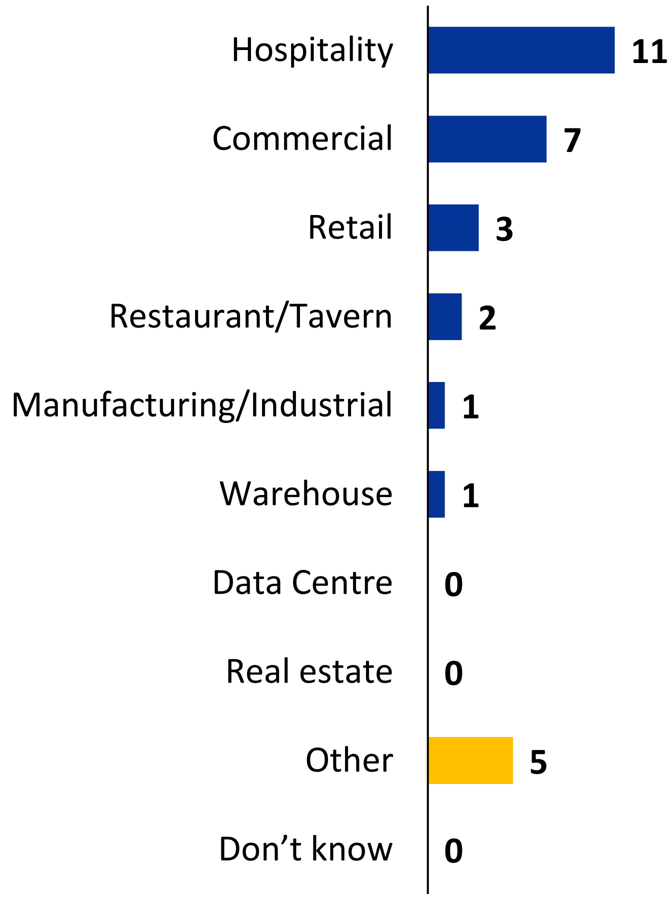
Due to the small sample size, the sample for Algoma Power’s small business customers has not been weighted. Throughout the report, results are represented in frequencies rather than percentages.

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

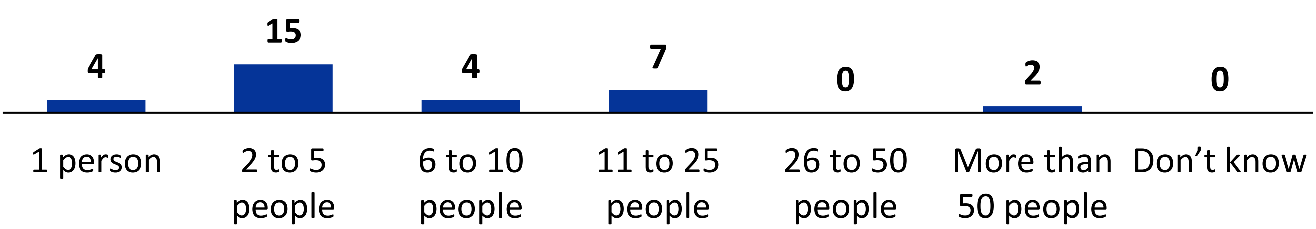
Q Business Sector



"Prefer not to say"(5) not shown.

n=35

Q Number of Employees



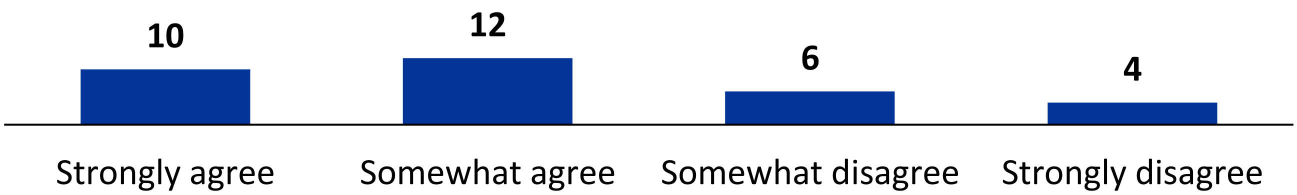
"Prefer not to say"(3) not shown.

n=35

Online Workbook
Environmental Controls

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?

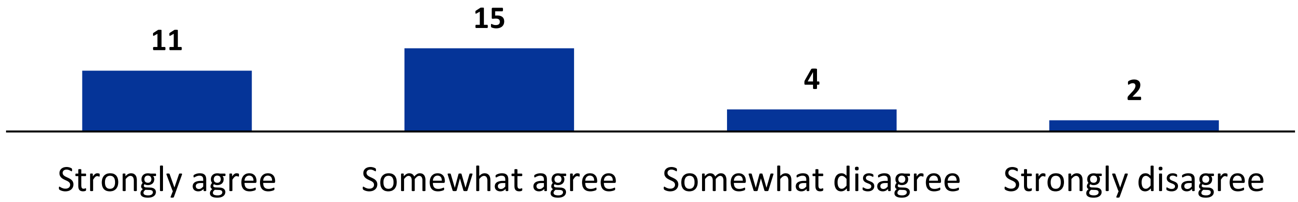
Q The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/No opinion" (3) not shown.

n=35

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



"Don't know/No opinion" (3) not shown.

n=35

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.

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

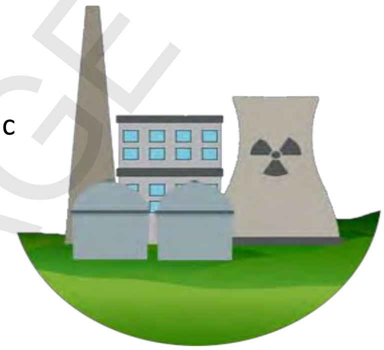
Electricity 101

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

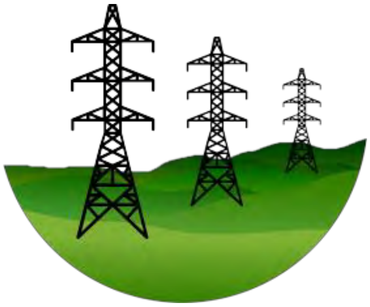


Ontario gets its electricity from a mix of energy sources. More than half comes from nuclear power. The remainder comes from a mix of hydroelectric and natural gas, and to a lesser extent, wind and solar.

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.

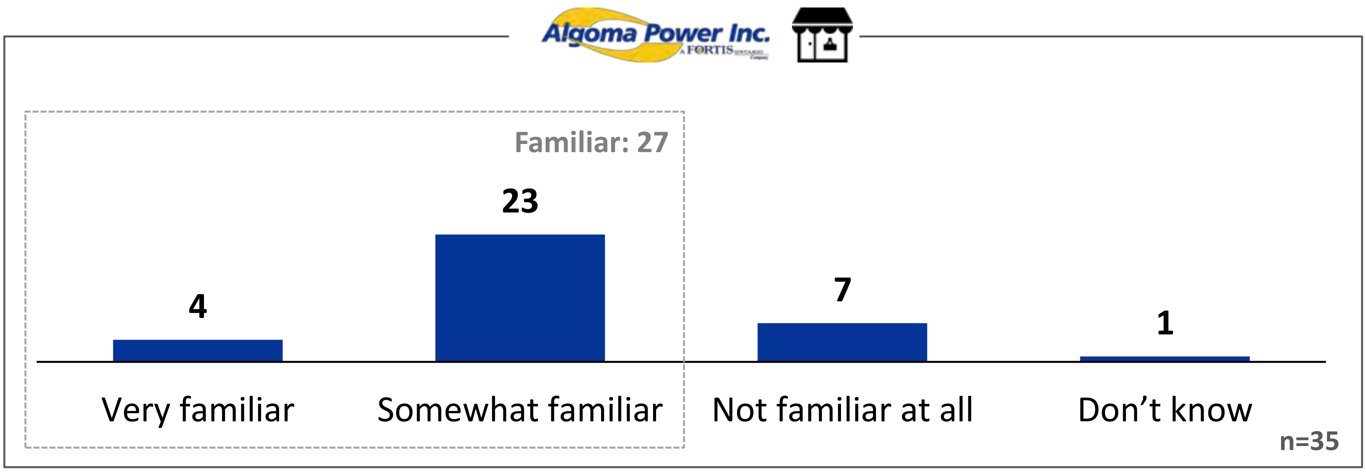
- Algoma Power manages all aspects of the electricity distribution business throughout the Algoma District of northern Ontario.
- In your community, amongst other functions, Algoma Power is responsible for:
    - Building and maintaining the local electricity distribution system
    - Responding to outage 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?

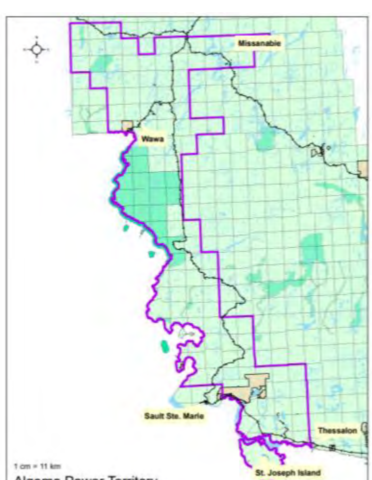


Electricity 101

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

Electricity 101

How much of my organization's electricity bill goes to Algoma Power?

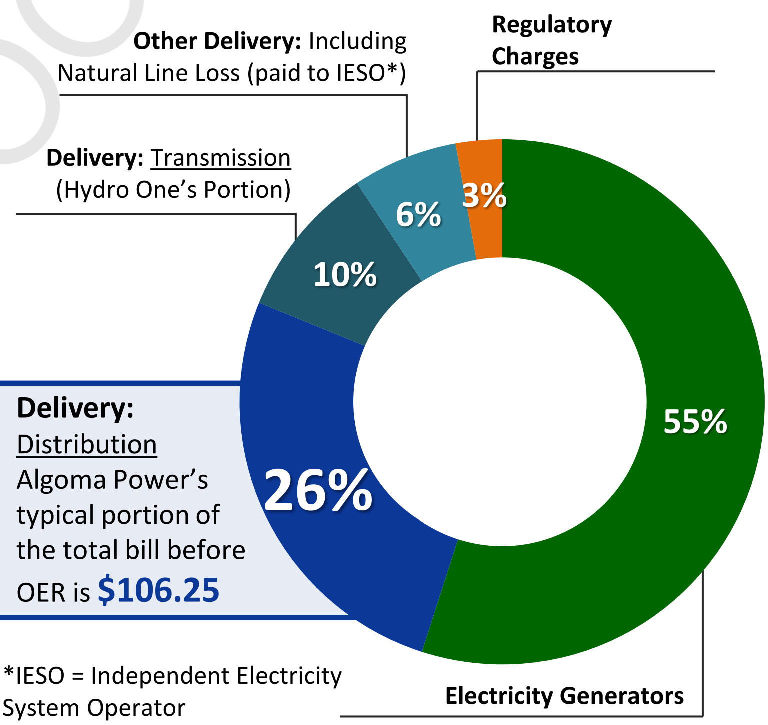
- Every item and charge on your organization's bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.
- While Algoma Power is responsible for collecting payment for the entire electricity bill, it retains only the distribution portion 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.

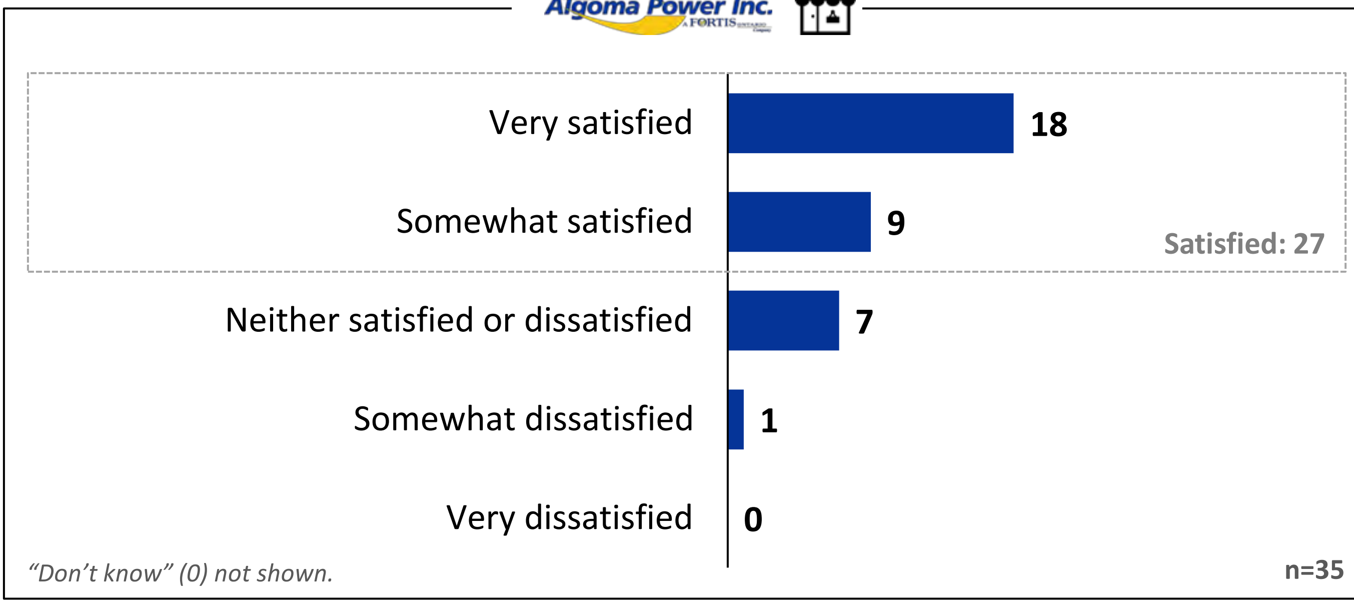
The sample bill above uses an average consumption level of 2,000kWh per month, however your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

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?

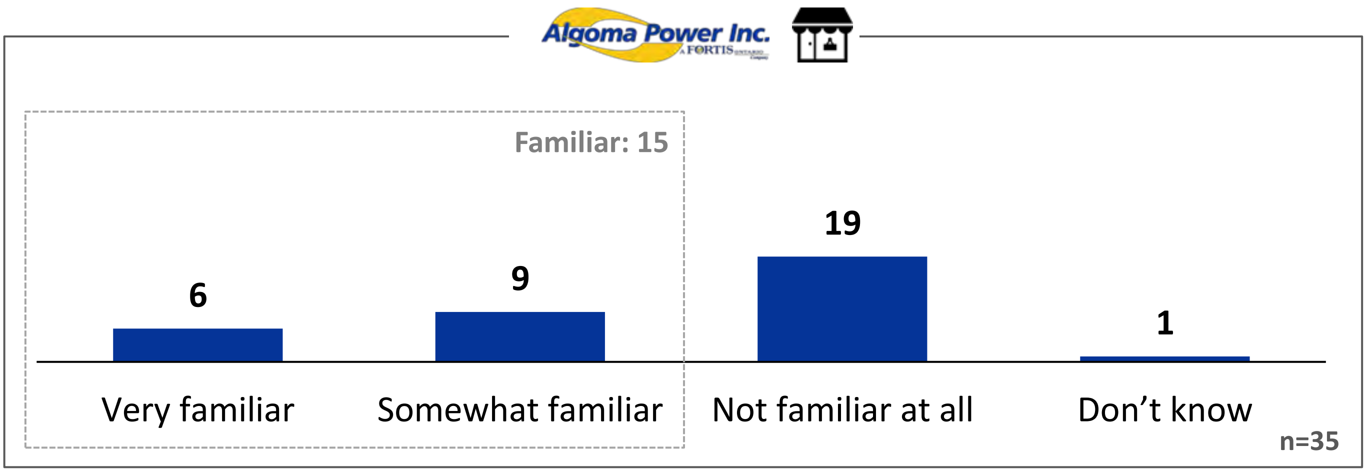


Online Workbook

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

How Algoma Power can Improve Services to Customers

Small Business

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.

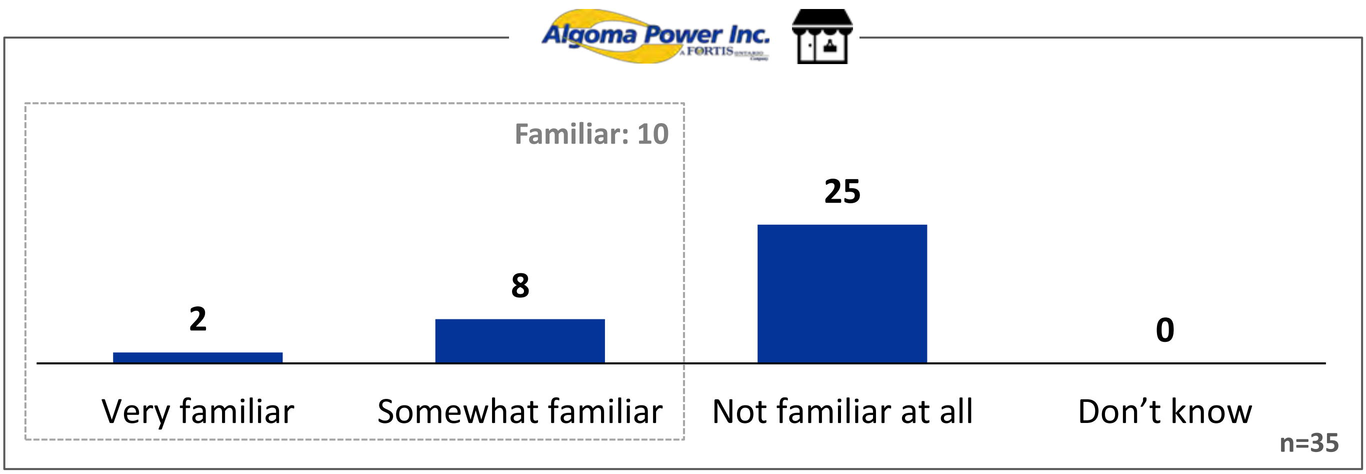
- As of this year, the maximum monthly base distribution charge has been set at **$106.25**.
- That means, as long as these protections remain in place, customers like yourself won't pay more than the maximum amount set by the program.

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

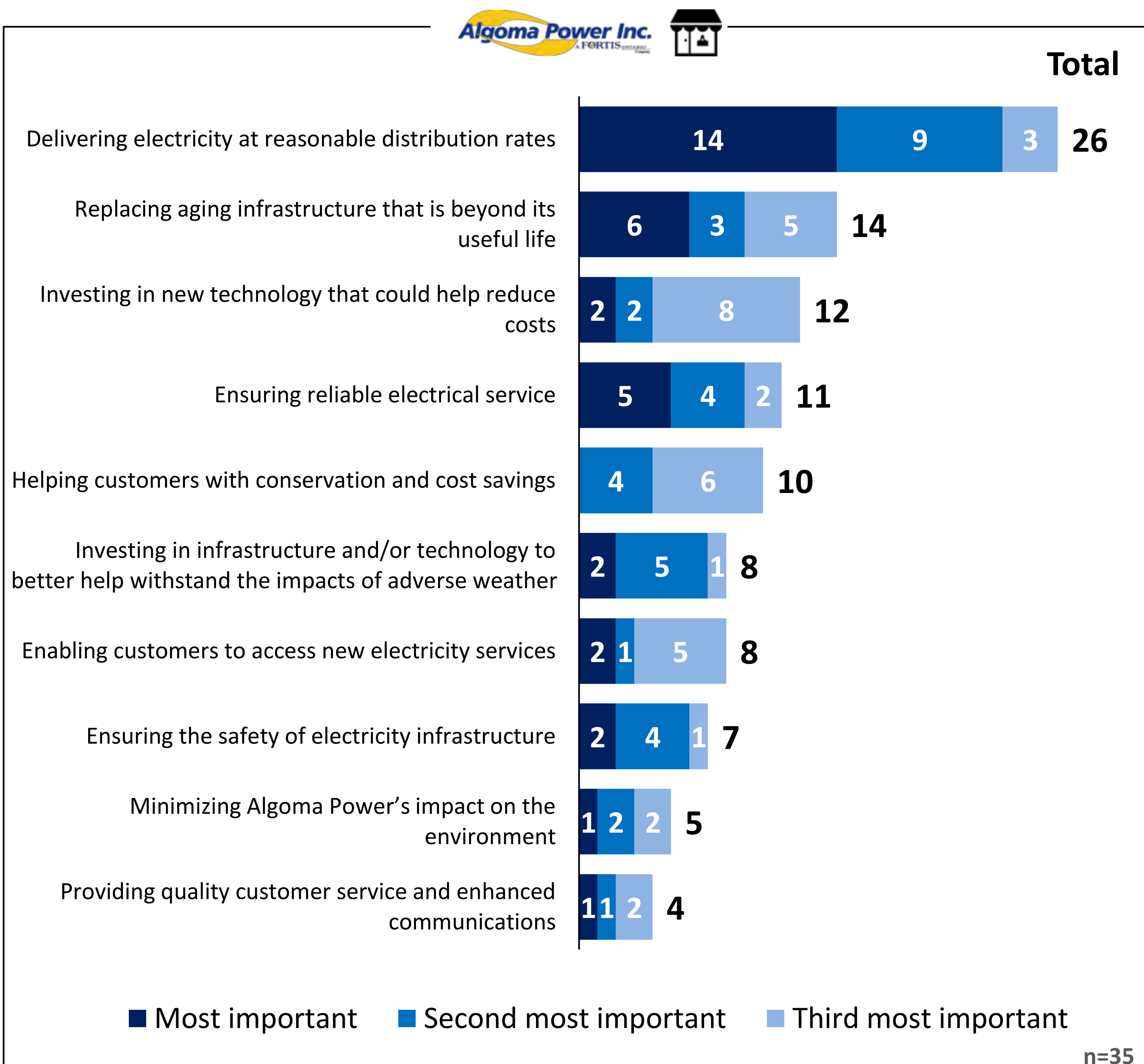
Q

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

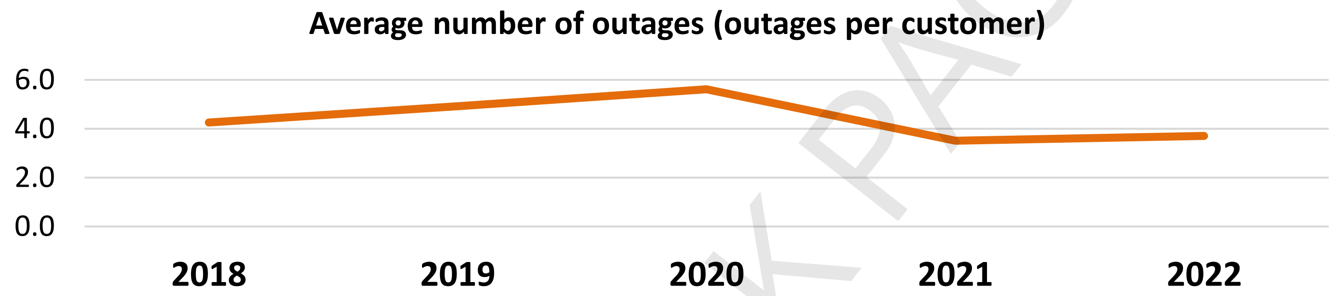
Background Context

Focus on Reliability

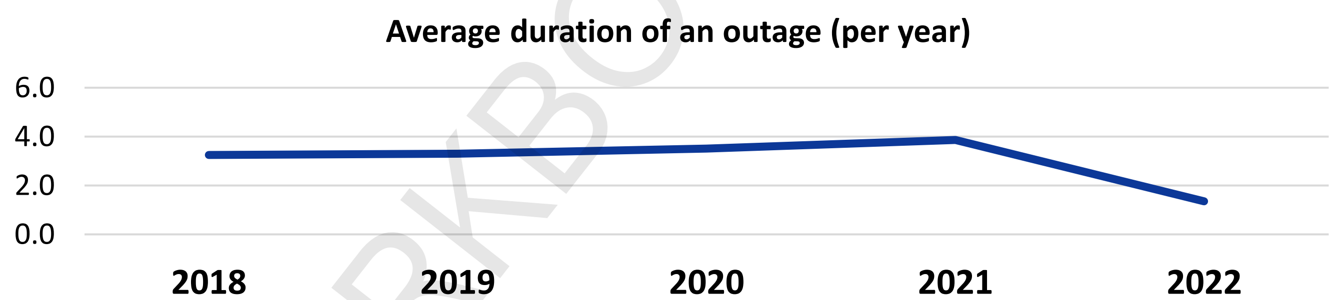
Since reliable electricity service is so important to customers, before we move on, we want to ask you about which specific areas you feel that Algoma Power should focus on over the next five years.

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.

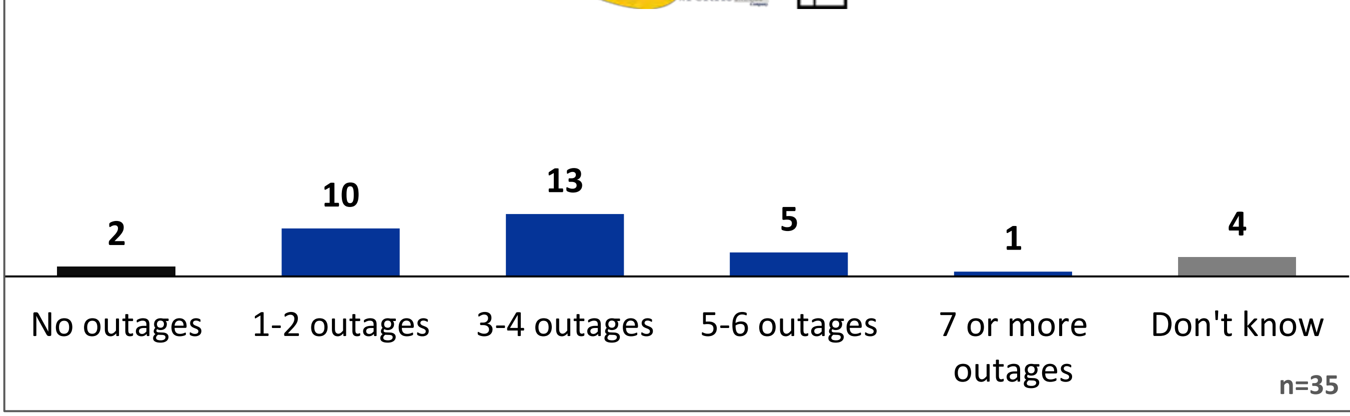
- Generally speaking, the further away a customer is from the distribution substation, the more outages the customer will likely experience, as longer distribution lines have a higher probability of being damaged.
- Some customers connected to newer lines may not experience any outages, while others 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

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

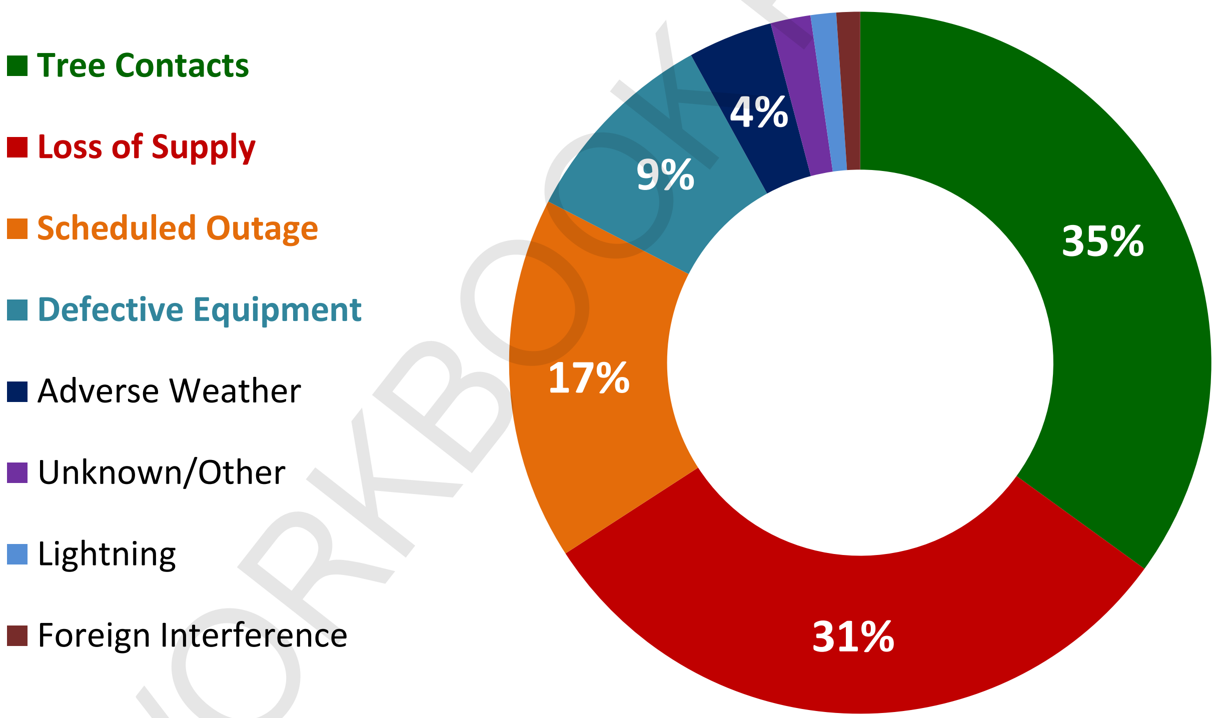
Focus on Reliability

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

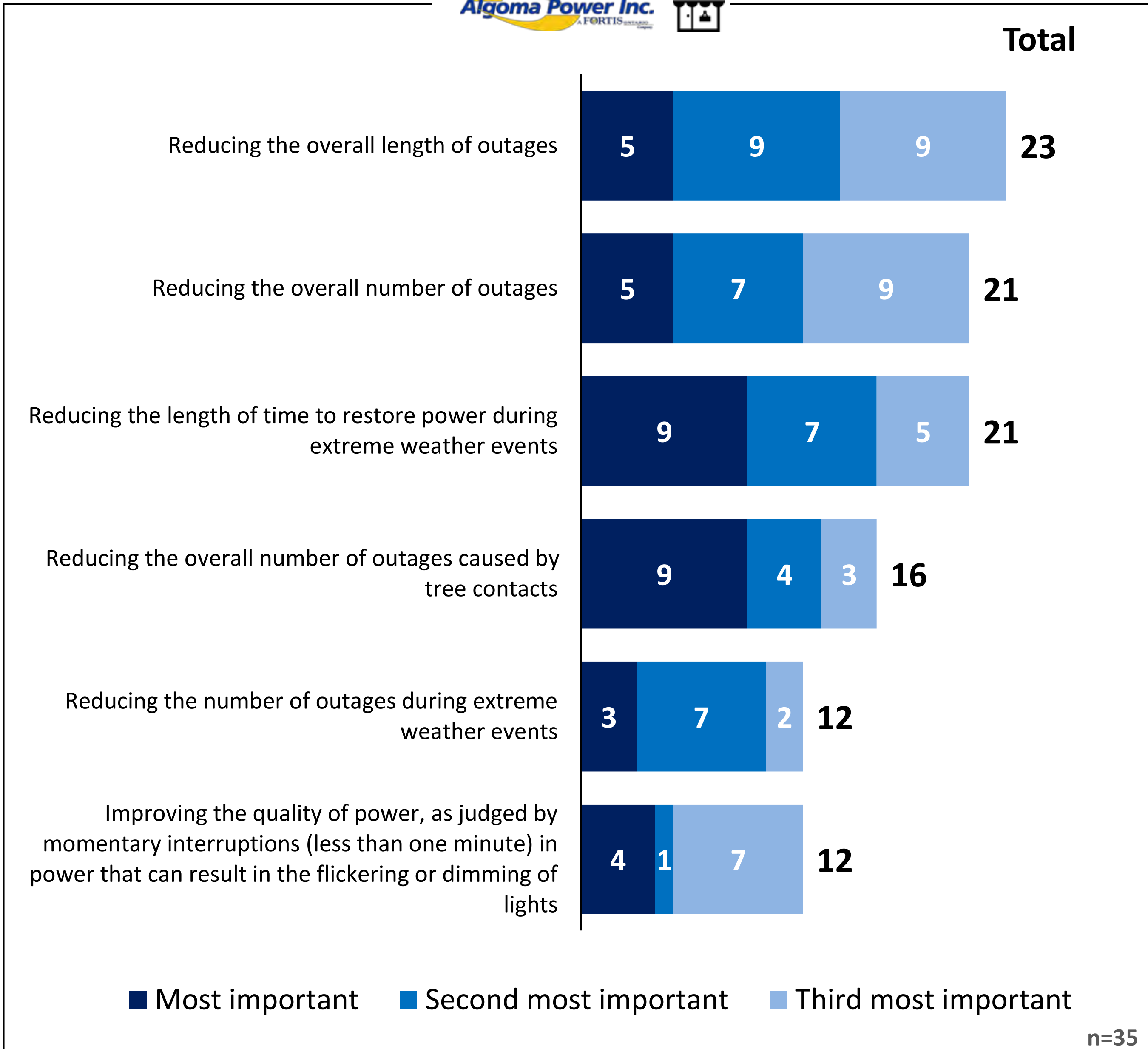
Reliability Priorities

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.



Algoma Power Background

How does Algoma Power propose to spend your money?

As mentioned, a portion of <u>all</u> 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**.

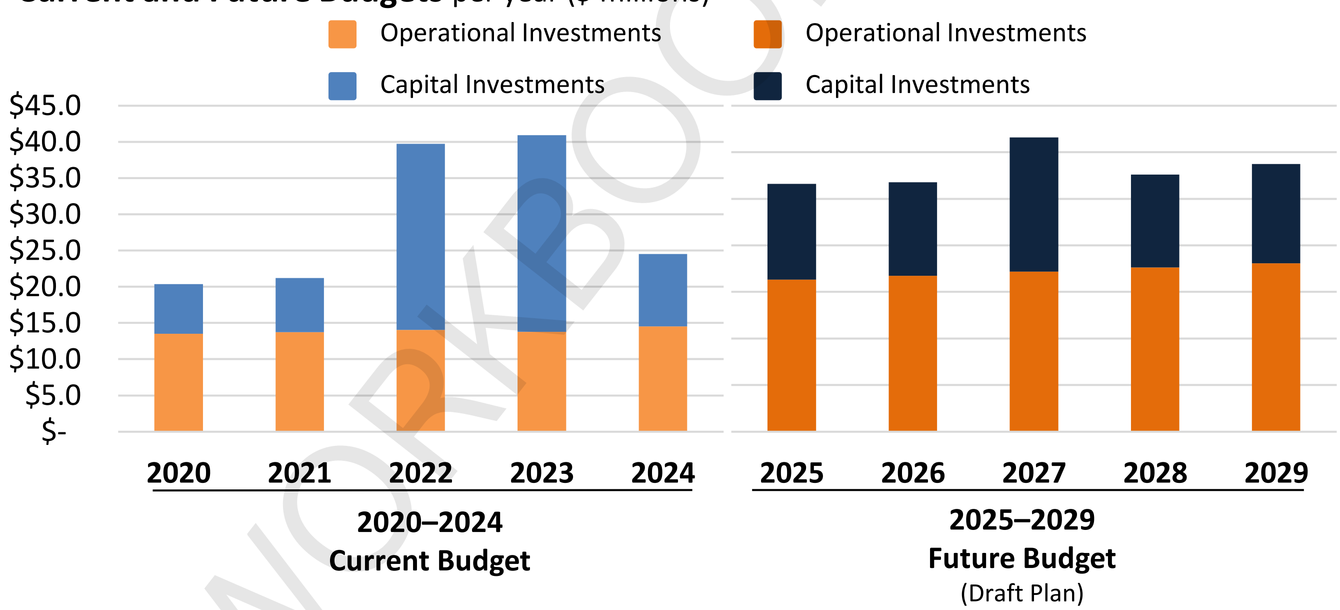
Between 2025 and 2029, Algoma Power is proposing to spend $141.3 million, a 3.7% decrease relative to the past five years.

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

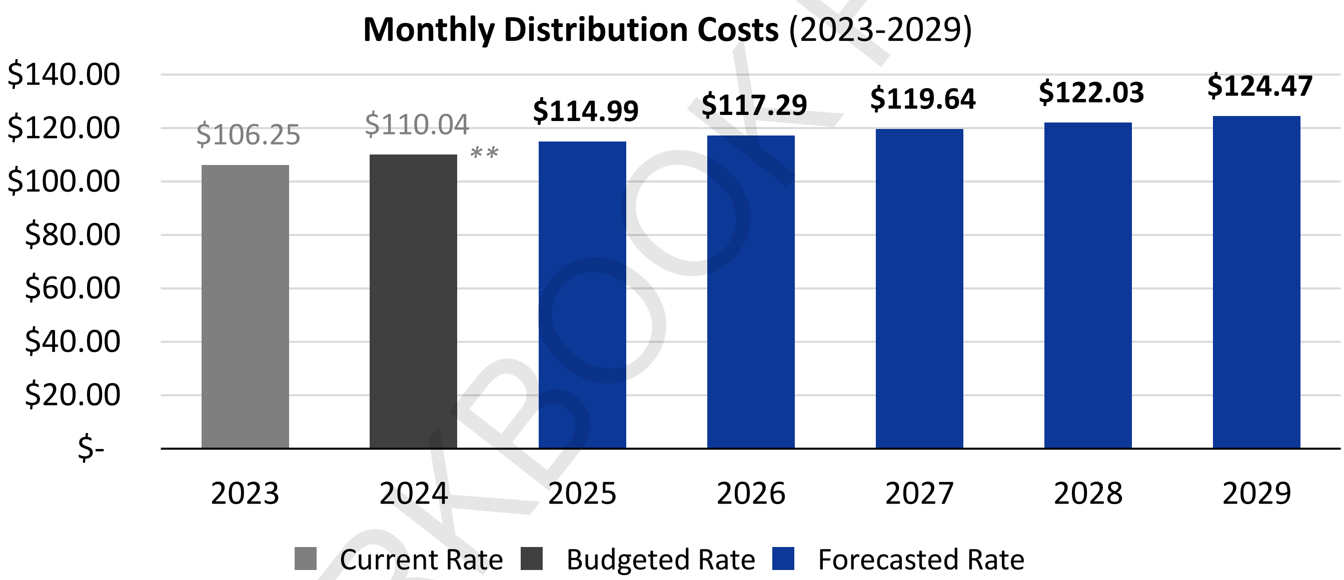
Algoma Power Background

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.

Online Workbook

Small Business

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**.

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

Which of the following options do you prefer?

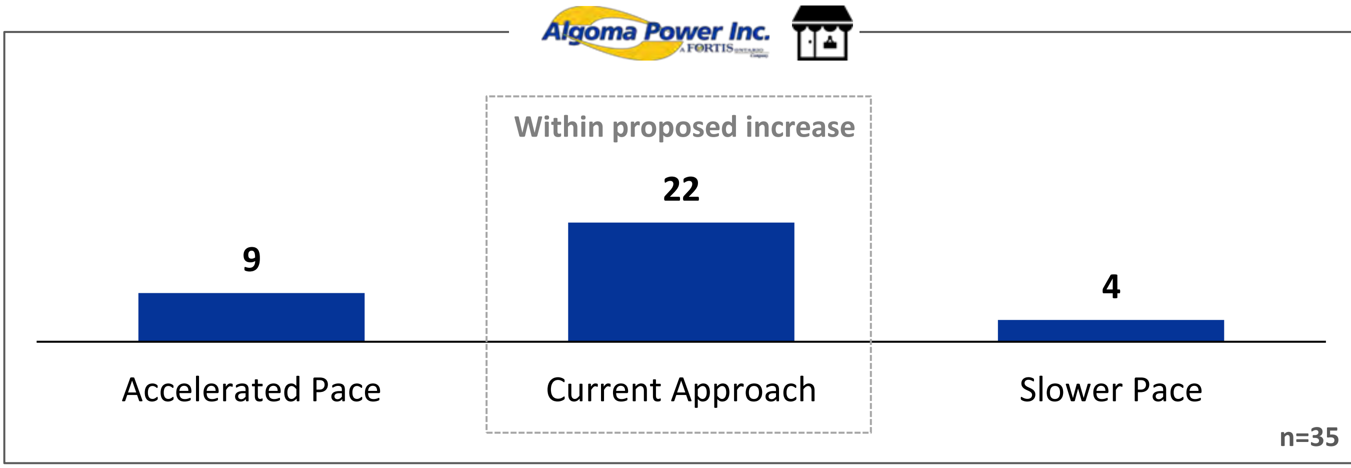
Option	Poles Replaced	Expected Outcome
Accelerated Pace ***$2.10*** *more on monthly bill by 2030*	Proactively replace 550 poles per year for the next five years.	• Increase the current pole replacement pace by 50 per year. • Potentially see reliability improvements due to decreased likelihood of pole 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"

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

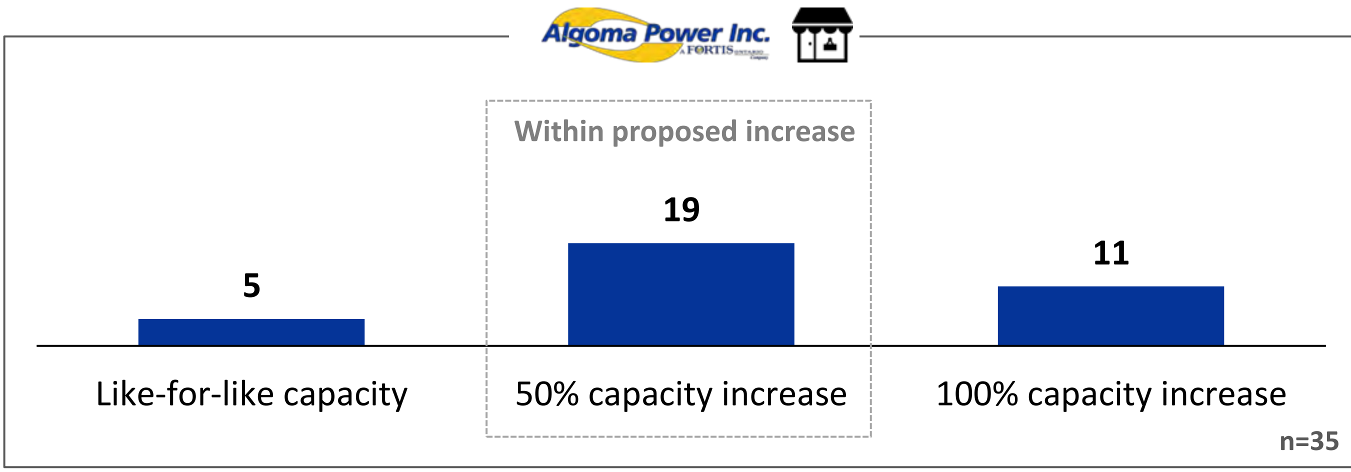
Which of the following options do you prefer?		
Option	Transformer Size	Expected Outcome
Like-for-like capacity ***$0.24*** *<u>less</u> on monthly bill by 2030*	Procure and install a power transformer that is similar in capacity to the existing transformer.	Increased risk of premature transformer replacement 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”

Online Workbook

Small Business

Planning for the Future: 2025-2029 Rate Application

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

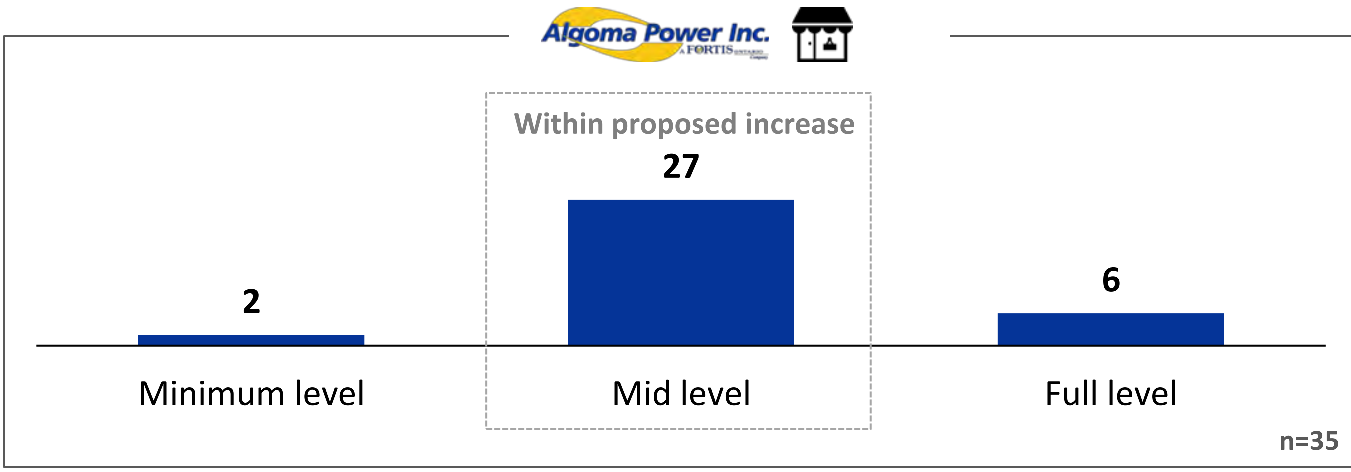
Small Business

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

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."

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

Choice 4: Preparing for increased electricity demand

Small Business

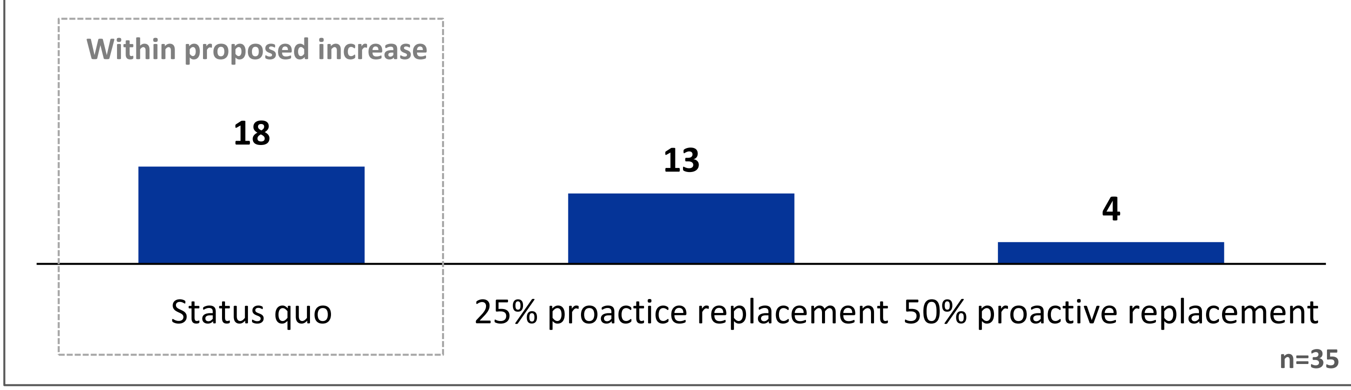
Which of the following options do you prefer?		
Option	Transformers Replaced	Expected Outcome
Status Quo *Within proposed rate increase*	Based on historical data, reactively replace approximately 12 transformers per year as they fail.	• Maximize the useful life of current transformers. • Potential for higher levels of unplanned outages due to transformer failures.
25% proactive replacement ***$1.06*** *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 ***$2.13*** *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

Choice 4: Preparing for increased electricity demand

Small Business

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.”

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

Which of the following options do you prefer?

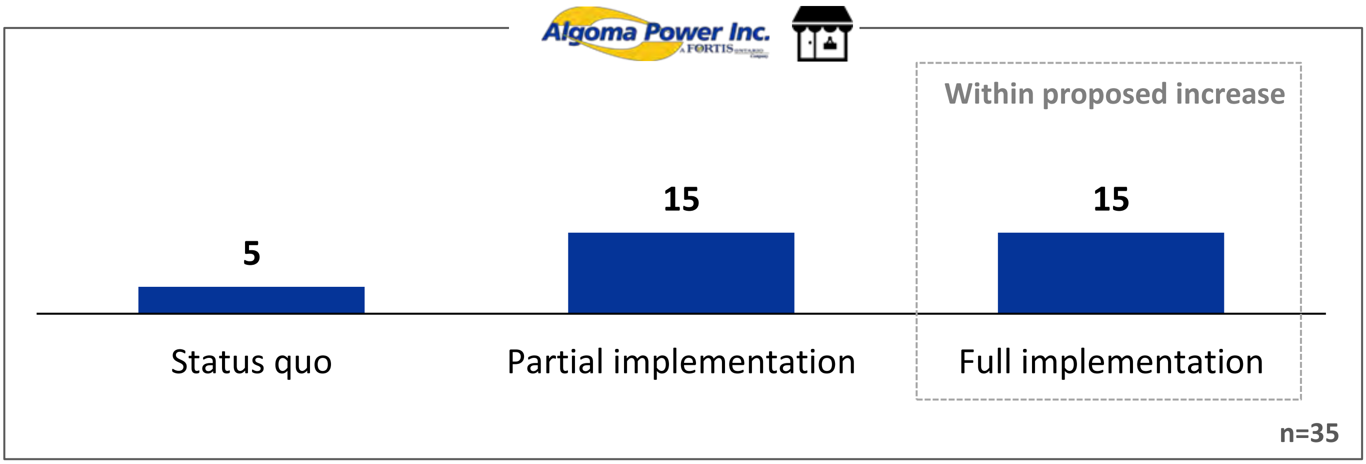
Option	Automated Switches	Expected Outcome
Status Quo *__$0.94__ <u>less</u> on monthly bill by 2030*	No additional automated switches or software purchased and installed.	Across this stretch of the system, Algoma Power continues to manually locate outages and restore power, typically taking between 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)		

Online Workbook

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 ??”

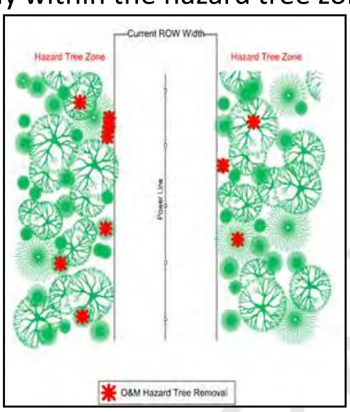
Making Choices (6 of 6)

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

Small Business

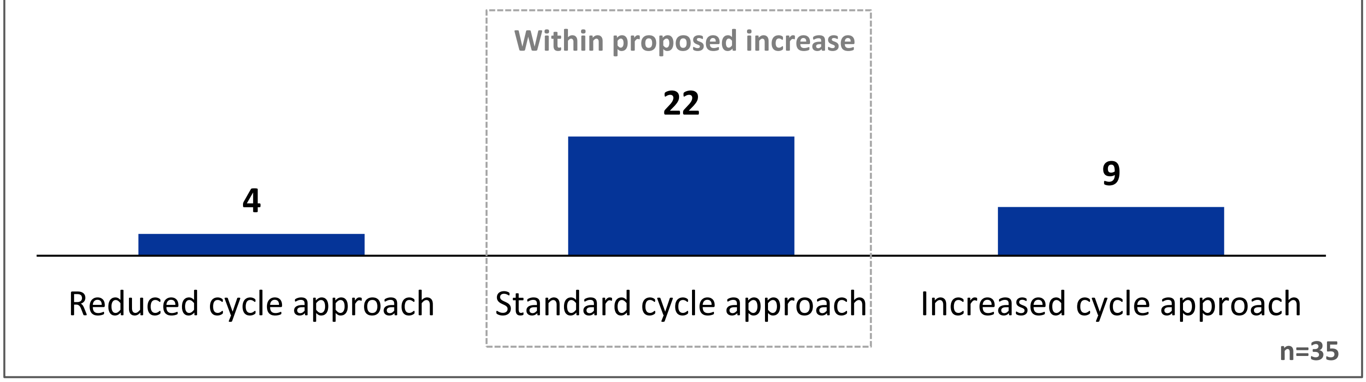
Which of the following options do you prefer?		
Option	Approach	Expected Outcome
Reduced Cycle Approach ***$1.98*** *less on monthly bill by 2030*	Reduce the level of "hazard tree zone" monitoring by 300 km per year.	• Increased exposure of hazard trees to the powerlines • Potential for decreased reliability 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?



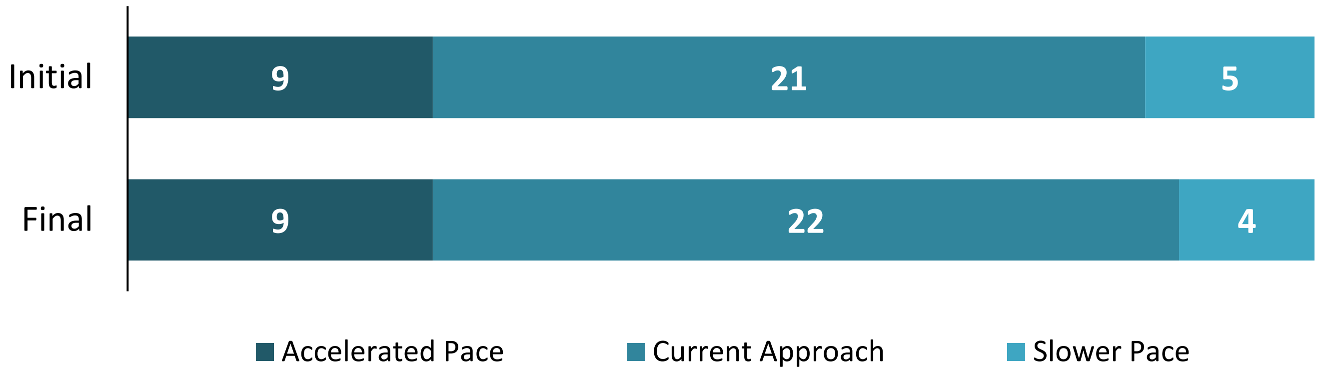
Additional comments (optional)
"I think the last few years the power supply has been good and there will always be some tree problems"
"This one strikes a nerve...am still not over losing a century old cedar tree to the "vegetation management" of Algoma power. It was not a threat to any line in its 100+ 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

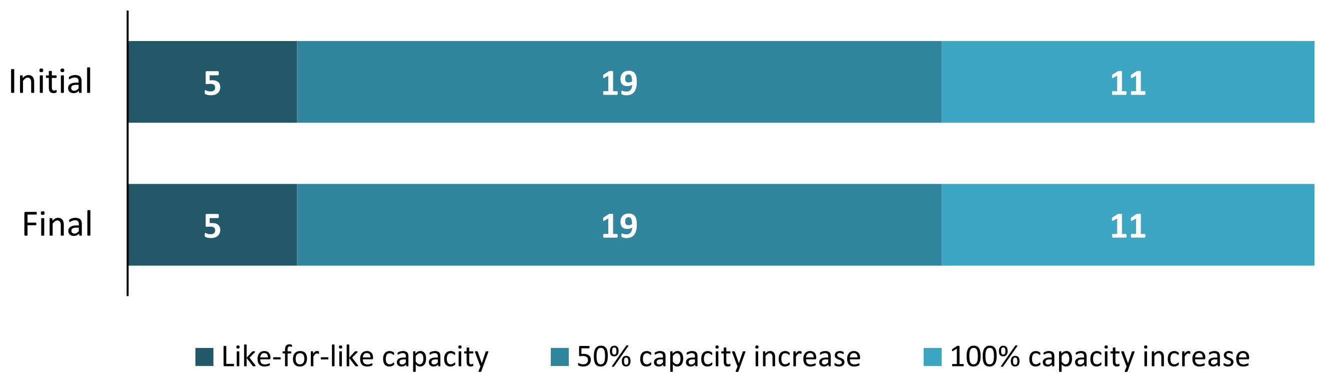
Impact of Choices

Small Business

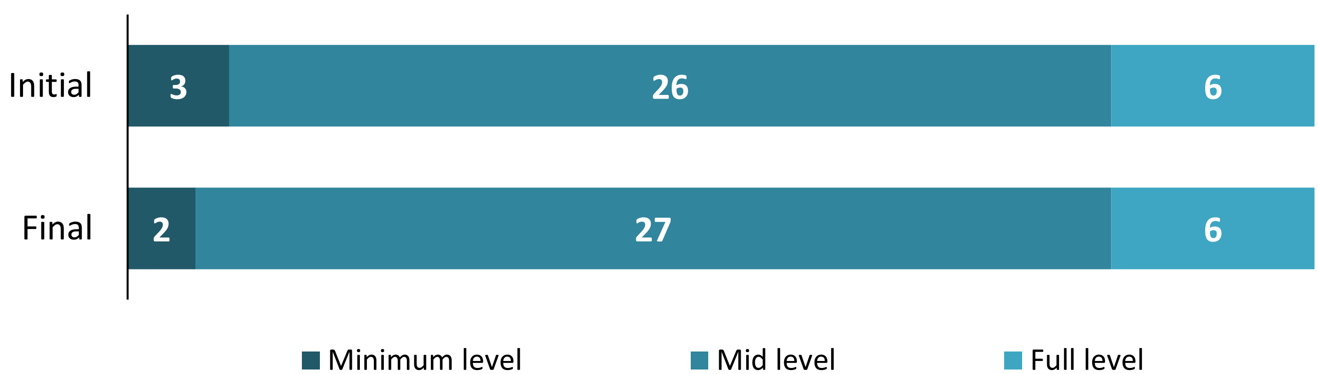
Pole and Line Replacement



Substation Rebuild



Voltage Conversion

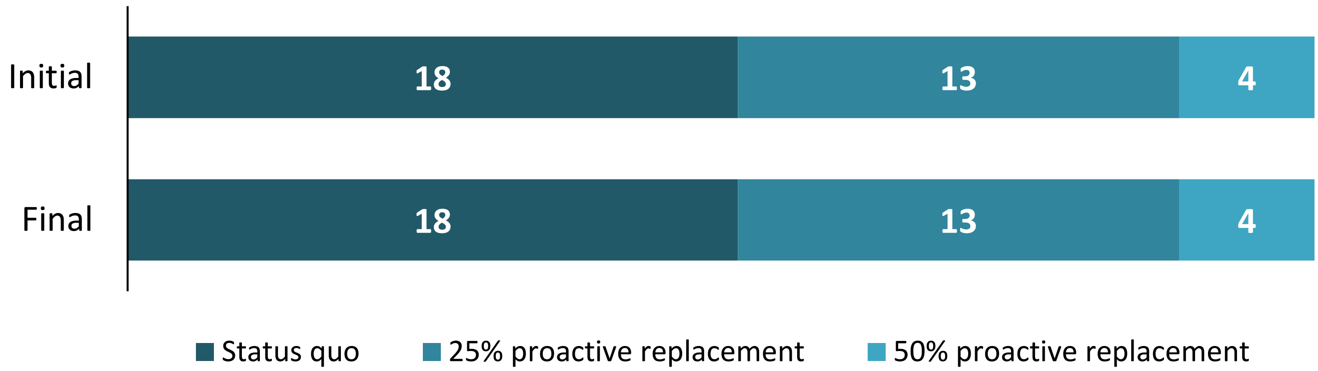


Making Choices

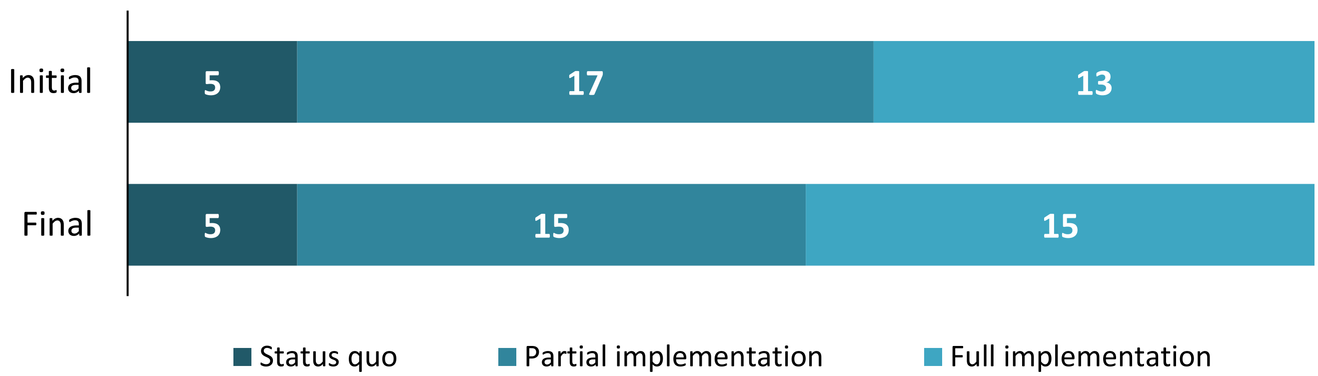
Impact of Choices

Small Business

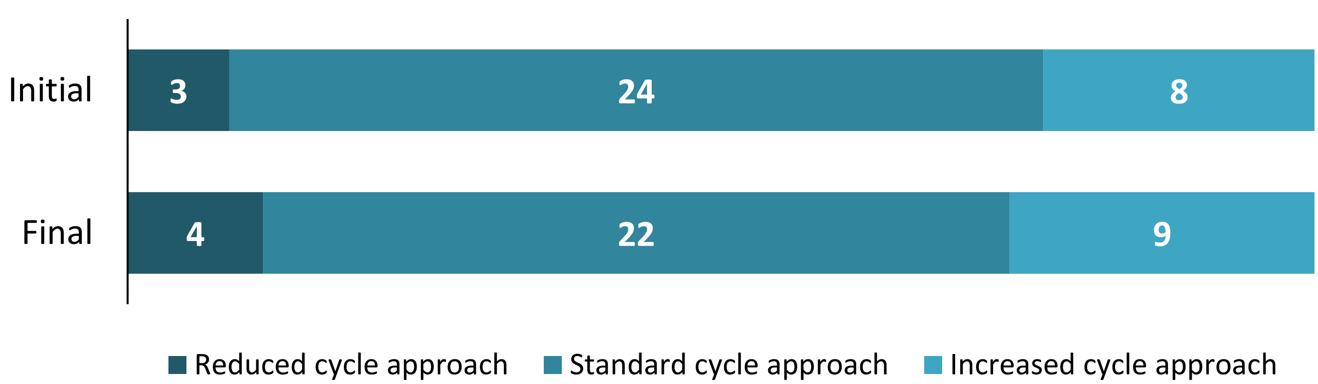
Preparing for increased electricity demand



Automated "intelligent" switches



Vegetation Management



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Online Workbook

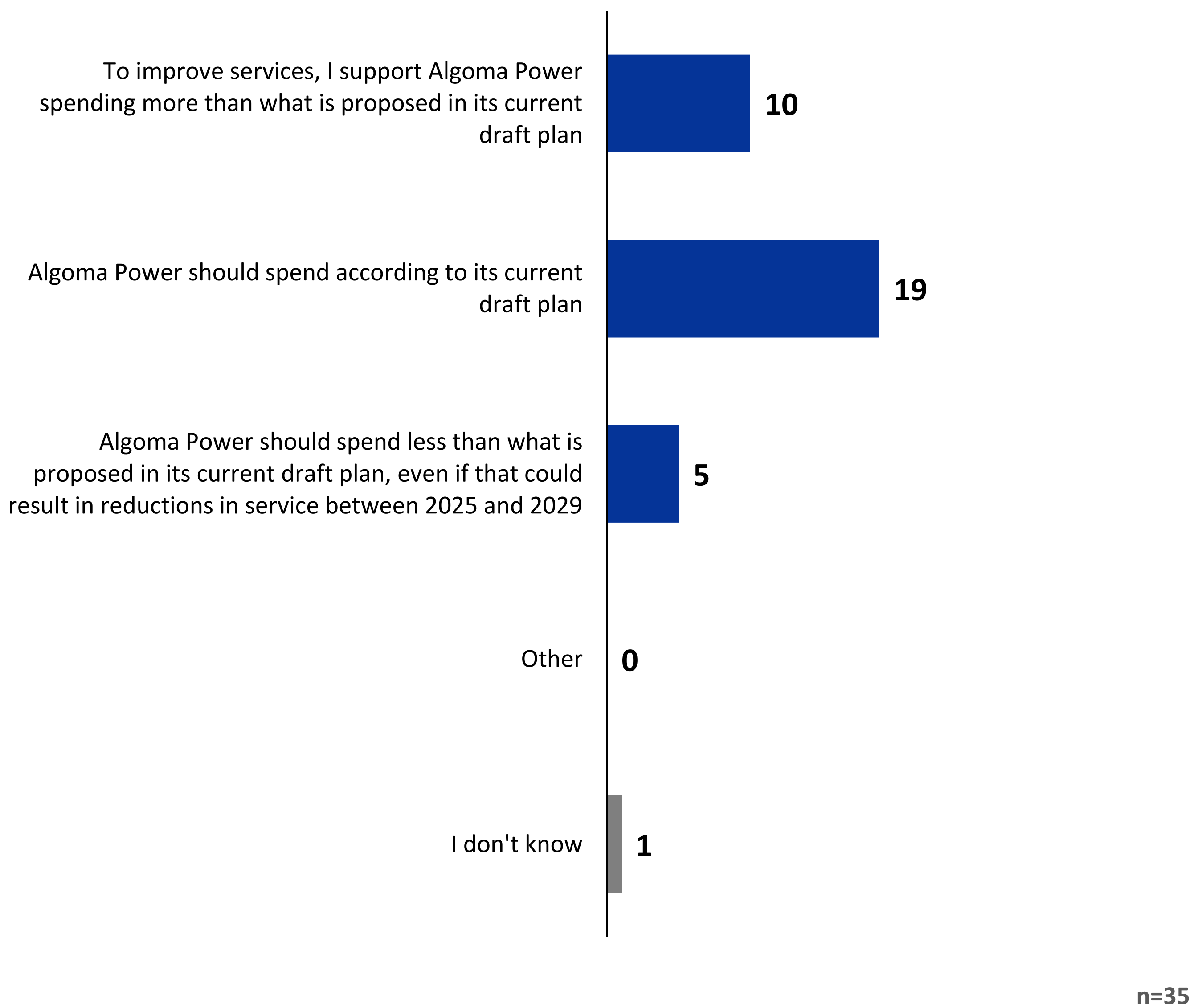
Overall Plan Evaluation

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?



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RESEARCH GROUP

Small Business Customers

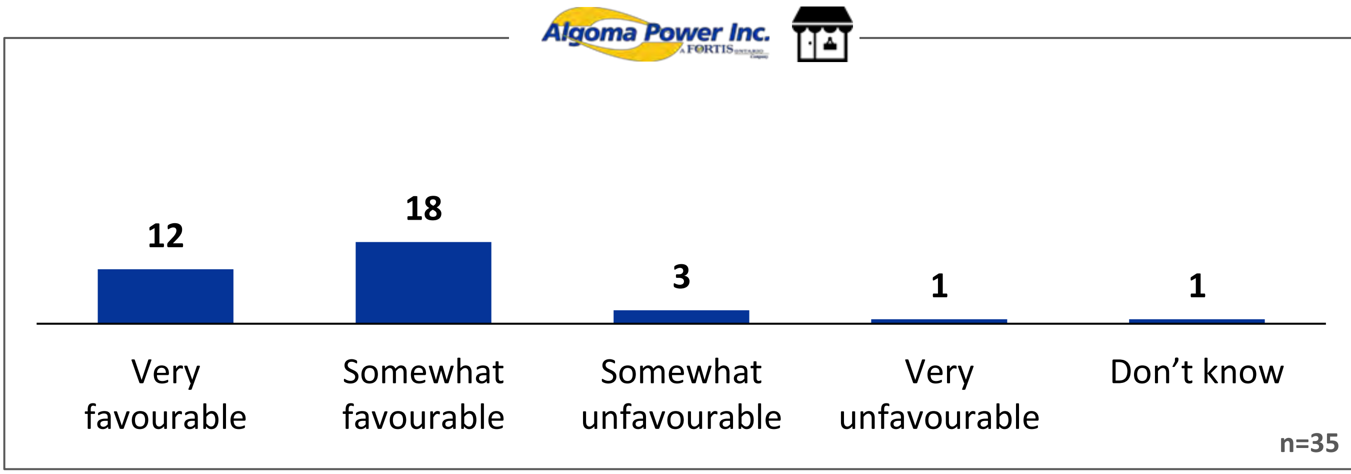
Workbook Diagnostics

Online Workbook

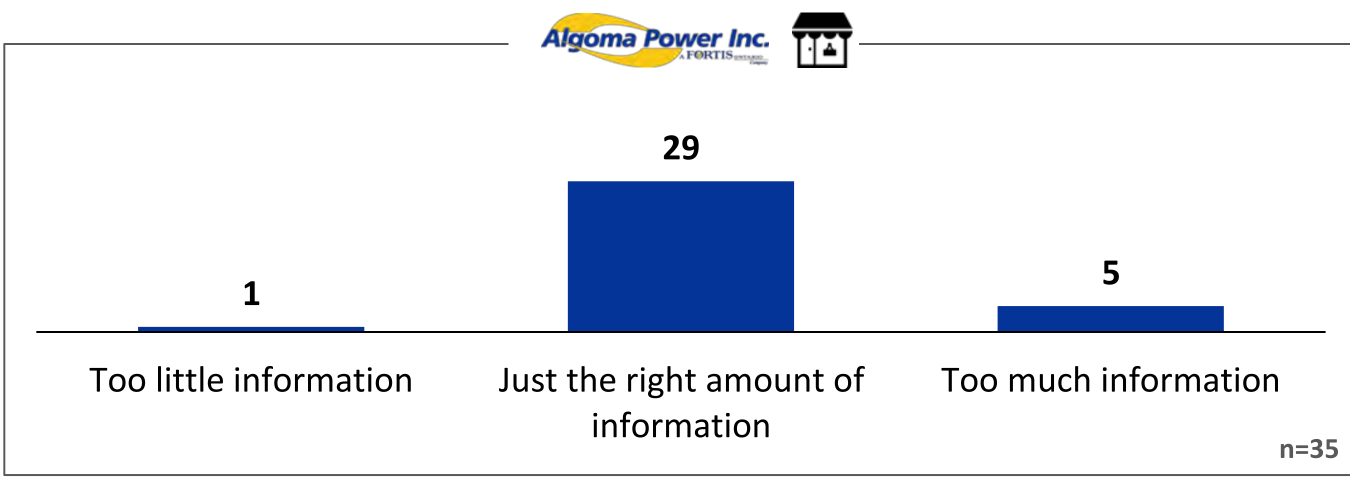
Workbook Diagnostics

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

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”

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	-

Online Workbook

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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Algoma Power Inc.

Distribution System Plan

Appendix G

Algoma Power Inc.

Communication Feasibility Study

Sault Ste. Marie, ON

Technical Report
Feasibility Study

BBA Document No. / Rev.: 6258004-0000000-4C-ERA-0001 / R00

December 22, 2021

FINAL

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Client Project No.: RFT 21-021

Communication Feasibility Study
Technical Report
Feasibility Study

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REVISION HISTORY

Revision	Document Status – Revision Description	Date
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EXECUTIVE SUMMARY

Algoma Power Inc. (API) owns and operate power distribution assets located across the Algoma District in northern Ontario from Wawa to Thessalon serving 12,000 customers. There is currently no communication network interconnecting its assets with a central control center, but API has an electrical SCADA system (Survalent) linked to a few assets via LTE WAN links.

API would like to be able to monitor and control these assets remotely and has mandated BBA to perform a feasibility study to assess and recommend the best solutions for interconnecting these assets with a central control center.

During the study we considered multiple WAN technologies to interconnect API's assets, including 4G LTE, Microwave Radio, DSL, Fiber Optics and Satellite. A desktop study and site survey revealed that all API assets in the scope of this study, except Hollingsworth substation, had excellent, good or acceptable 4G LTE coverage and that Hollingsworth substation could be covered by satellite service.

Two options were considered for the Electrical SCADA network architecture:

A. The first option consist of having a WAN linking the control center node(s), aggregation nodes in substations and other nodes not in the vicinity of a substation as well as having a substation LANs linking IEDs within the vicinity of a substation to an aggregation node (RTAC) at the substation;

B. The second option consists of having a WAN linking the control center node(s) and all the IEDs on API's electrical grid directly without aggregation nodes.

Even though API initially proposed Option A, a budget estimate exercise (combined CAPEX and OPEX) showed that Option B was significantly less expensive (by $296,000 CAPEX+OPEX 5-YEARS - lower engineering, equipment, and construction costs). Option B is also easier and faster to deploy while offering the same benefits as Option A. See Appendix A: WAN Service Availability and Budgetary Estimate. Accordingly, Option B shall be used for the design of the Electrical SCADA network architecture.

A phased deployment plan has been designed with a proof of concept phase to reduce the technical and financial risks of the project and to maximise the positive outcomes.

The next steps where BBA can help API should be to get the overall study and budgetary estimate approved and get a budget approved to proceed with the proof of concept phase.

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APPENDICES

1. Introduction

Algoma Power Inc. (API), a wholly-owned subsidiary of FortisOntario Inc., owns and operates power transmission and distribution assets located across the Algoma District (Northern Ontario) from Wawa to Thessalon serving 12,000 customers with more than 1,800 kilometers of distribution lines in an area that covers over 14,000 square kilometers. There is currently no communication network interconnecting its assets with a central control center, but API has an electrical SCADA system (Survalent) linked to a few assets via LTE WAN links.

1.1. Purpose

API would like to be able to monitor and control these assets remotely and has mandated BBA to perform a feasibility study to assess and recommend the best solutions for interconnecting these assets with a central control center.

The objective is to develop a long-term communication strategy for implementing an infrastructure that is flexible, reliable, secure and economical for the targeted service areas including the challenging rural areas with significant terrain and unreliable coverage. The communication infrastructure is required to enable intelligent electronic devices (“IEDs”) across the distribution system in substations and along distribution feeders to report critical information into the main SCADA control center located in the Sault Ste. Marie headquarters.

In addition, the ability to control the IEDs allows API staff to obtain vital fault information from devices remotely to assess abnormal events that may have occurred. These IEDs will consist of reclosers, regulators, capacitor banks, switch operators, transformer monitoring, load tap changers, real time automation controllers (“RTAC”), etc. The ultimate goal is to incorporate a distributed automated system in various parts of the distribution network to improve grid functionality and operating costs.

The strategy to outline the feasible communication solution for each of the distribution substations (“DS”) and the areas targeted with IEDs on distribution feeders that are requiring reliable and secure communication. The substations will contain multiple IEDs (reclosers, transformer monitoring, etc.) that will ultimately connect to a substation RTAC, which will deliver more data points to the main SCADA control center.

1.2. Abbreviations and acronyms

The table below lists abbreviations and acronyms used in this document along with their definition.

Table 1: Abbreviations and acronyms

Abbreviation or acronym	Definition
CAT 6	Category 6 – a twisted-pair network cable specification
DS	Distribution Substation
FO	Fibre Optic
GS	Generation Station
IDRAC	Integrated Dell Remote Access Controllers - a computer console network interface
IED	Intelligent Electronic Device
iLO	Integrated Lights-Out – a computer console network interface
IPsec	Internet Protocol Security – a VPN encryption protocol
ISP	Internet Service Provider
LDAP	Lightweight Directory Access Protocol
LEO	Low Earth Orbit
LTE	Long-Term Evolution – a wireless cellular network protocol
NAT	Network Address Translation
POC	Proof Of Concept
RADIUS	Remote Authentication Dial In User Service
RAID	Redundant Array of Independent Disks
RAIN	Redundant Array of Independent Nodes – a computer cluster
RTAC	Real-Time Automation Controller
SSL	Secure Socket Layer – a VPN encryption protocol
TLS	Transport Layer Security – a VPN encryption protocol
TS	Transmission Substation
VM	Virtual Machine
VPN	Virtual Private Network
WAN	Wide Area Network
WireGuard	A very performant VPN encryption protocol

1.3. Scope

API has fifty-nine (59) assets across Northern Ontario (see Appendix A*:* WAN Service Availability and Budgetary Estimate), each requiring a secure and reliable connection solution to allow monitoring and control from a central control centre. The current study serves to research various solutions to integrate the assets to a WAN network infrastructure, allowing communication with a control center at Sault Ste-Marie for the following asset types:

- RTAC and IEDs in substations and in their vicinity;
- IEDs (reclosers, regulators and capacitors) in isolated areas.

The following telecommunications technologies were considered in this study to provide reliable connectivity for all assets in the scope:

- 4G LTE router - Rogers and Bell;
- Microwave Radio;
- DSL;
- Fiber Optic;
- Satellite.

1.4. Methodology

A review of the assets provided pertinent information such as location, device type, data requirements, asset ownership, priority classification, etc. Communications between BBA and API also helped gather further data.

A desktop study was performed to assess the location and proximity between assets to help define an approach to select the best telecommunication solutions. Information regarding the types of assets lead to a priority-based grouping for a phased implementation plan recommendation. Communication with various ISP made it possible to identify the different services available in each asset area.

Twenty-four (24) assets were selected for site surveys based on their level of criticality, including all substations and reclosers in their vicinity.

Site surveys were performed by BBA to assess the LTE coverage and the availability of other potential telecommunication solutions.

Gathered information was analyzed to select the best WAN link solutions to use.

2. SCADA infrastructure components classification

According to NIST's definition, criticality level refers to the consequences of incorrect behavior of a system. The more serious the expected direct and indirect effects of incorrect behavior, the higher the criticality level.

For the purpose of this study a scale with four (4) levels, CL1 to CL4 was adopted to classify the components according to the consequences of their incorrect behavior within the Electrical SCADA Infrastructure.

IMPORTANT NOTE: The Criticality Level of the Electrical SCADA Infrastructure components is not the same as the Criticality Level of API's electrical grid assets. For instance, once the SCADA is deployed, there could be a local failure affecting the control center computers (like a fire in the datacenter). In that case, monitoring and control functions would be lost but without affecting API's ability to deliver electricity to its customers.

The Electrical SCADA Infrastructure components planned to be servicing the 59 electrical grid assets owned by API were classified according to their criticality level (CL) to help determine their resilience requirements, and to prioritize the integration of the assets they serve into the Electrical SCADA Infrastructure in phases.

The Electrical SCADA Infrastructure components classified by criticality level are:

- CL4: nodes of the control centre(s);
- CL3: nodes at substations when using an RTAC as an aggregator;
- CL2: nodes at all IEDs except for capacitors;
- CL1: nodes at the capacitors.

3. Desktop study

During the desktop study we located the towers of the cellular service providers around the assets and determined that LTE coverage was good for most substations according to the coverage maps supplied by cellular services providers.

We determined which IEDs could potentially be linked via microwave radio or Wi-Fi links to nearby substation aggregation nodes.

We also found potential fibre optic WAN link interconnection points from Bell around four (4) substations that were close enough to warrant obtaining budgetary CAPEX/OPEX but the cost of these WAN Links was prohibitively higher than that of LTE service WAN links. See details below.

In collaboration with API, BBA selected 24 asset sites to perform site surveys based on their criticality (substations) and proximity to substations.

3.1. LTE WAN Link

Rogers graciously provided a desktop LTE coverage study of the area around API's assets (See Appendix C). It showed that a Rogers LTE WAN link should be a good option for 54 out of 59 assets. See the *Site survey results* section that essentially confirmed what the desktop study predicted.

Bell declined to do the same for free. Bell wanted to get paid to tell us if they could provide LTE services around the assets. This option was not pursued.

LTE WAN link is the preferred option because of its availability, ease of deployment, and performance (up to 50 Mbps).

3.2. Satellite WAN Link

This solution can provide connectivity to sites where there is no LTE coverage and using fiber optics or microwave radio links would be too expensive or complex to deploy due to terrain topography. The following sections explain the current and future available options.

3.2.1. Geostationary Satellite Shared WAN Link

A shared geostationary WAN link, such as Xplornet, with 25 Mbps download, up to1 Mbps upload, and 150 MB/month cap would have a CAPEX of $500 and an OPEX of $120/month.

It is a good option for assets where there is no LTE coverage.

3.2.2. LEO Satellite Shared WAN Link

The emerging LEO satellite WAN link technology will offer very good value when it becomes available for business entities. For instance:

- Starlink with download speeds of 100-200 Mbps, upload speeds of 40 Mbps and a latency of 20-50 ms has a CAPEX of $720 and an OPEX of $129/month is currently only available for residential use;
- Oneweb with speeds of 50 Mbps download and 25 Mbps upload and a latency of 50 ms targets business and government entities through local carriers such as Bell, but it is not yet in service.

3.2.3. Dedicated Geostationary Satellite WAN Link

A dedicated full-duplex 10 Mbps geostationary satellite WAN link would have a CAPEX of $15,000-$80,000 depending on the level of reliability required and its location, and an OPEX of $30,000-$50,000/month. That is totally overpriced given the requirement of this project and the availability of alternatives.

3.3. Fiber Optic WAN Link

Fiber optic WAN Link was reviewed as a possible solution. As a rule of thumb, the cost of getting fibre optic cable supplied and built runs between $15,000/km and $20,000/km for aerial installation on the side of a road where there is no particular difficulties. It can run between $25,000/km and $45,000/km on more difficult terrain.

The only ISP that gave us an overview of the FO available around API's assets was Bell and none of the substations had fiber optic around them (See Appendix D). Bell provided some costing for building fibre optic cable for five (5) assets for which the interconnection point was less than 250 meters away. The answer was the following:

> *Those 5 locations would require Business Internet DEDICATED which would be approx. $750/m per location on a 5 yr term. We typically find most constructions fees to land between $5K and $ 20K per site. Given the territory, let's assume worst case between $10K and $20K and based on the contract above with all locations there is possibility for Bell to cover a portion of the construction costs. – Richard Laboni, Bell Account Manager*

This is too expensive to compete with other available WAN link solutions unless very high bandwidth is required at specific locations.

The federal government has been distributing subsidies to carriers to extend fiber optic networks in rural areas through the Universal Broadband Fund program. The impact for API is that there could eventually be some additional fibre optic connection points closer to its assets, but it will not change the current cost and rates detailed above.

3.4. DSL WAN Link

The option of DSL WAN Link was not considered until a few weeks after BBA returned from the site survey because it was assumed from the discussions with API that it was not likely available and also because workable alternatives had been found for all sites.

It is only when we found a column indicating copper availability at asset locations in a fibre optic availability matrix from Bell (late in the study) that we decided to contact Bell to find out if DSL WAN connectivity was actually available for those locations. Bell said that they didn't know and did not actually want to dig to provide the information despite BBA insisting that they do. We did not get information about the availability of this option to publish it here. If Bell eventually comes through, BBA will share the information with API.

3.5. Microwave Radio WAN Link

Microwave radio was considered for WAN links, but the topography of the terrain, the prohibitive cost of erecting towers and the fact that much cheaper alternatives were found to be available for all API assets made us rule out this option.

4. LTE WAN Link Site Survey

Site surveys were performed at the previously selected 24 asset sites to validate the LTE coverage as well as the quality of the connection provided using the following procedure:

- Validate that the asset corresponds to the one on the schedule;
- Identify the LTE towers surrounding the asset (See Appendix B);
- Measure signal level with a Wilson Pro Quad-Band Signal meter with an SC230E antenna;
- Execute speed test with Bell and Rogers;
- Make a video call to test the quality of the link (throughput, jitter, latency);
- If required (video quality not optimum), make an audio call to test the quality of the link;
- Inspect the area to assess the potential availability of other types of telecommunication services;
- Take pictures around the assets.

4.1. Site survey results

Site survey results showed that:

- Twenty (20) had excellent, good or acceptable LTE coverage from both Rogers and Bell within the asset site perimeter allowing LTE WAN link redundancy if desired;
- Three (3) had excellent, good or acceptable LTE coverage from either Rogers or Bell within the asset site perimeter (no LTE WAN link redundancy possible);
- Only one (1) had no usable LTE coverage (Hollingsworth GS);
- There were some phone lines and FO cabling markers found around the asset sites but no service availability validation was performed during the site surveys.

See Appendix F: Site Survey Detailed Results.

5. Electrical SCADA Infrastructure Design Criteria

The Electrical SCADA Infrastructure that API will eventually be deploying will be composed of communication lines, computing, storage, communication and security device hardware and software to provide monitoring and control of API's electrical grid assets.

The SCADA infrastructure components shall provide reliability, integrity, scalability, and cybersecurity for the monitoring and control functions of API's electrical grid. Redundancy should apply only to more critical components of the SCADA infrastructure such as aggregation and central control nodes.

Efforts shall be made to design the most economical solutions (CAPEX and OPEX) in all aspects of the SCADA Infrastructure while providing required functions and features.

5.1. Resilience

Depending on the criticality level of the SCADA Infrastructure component groups they will require more or less resilience, and this is what shall dictate the level of redundancy to be applied to these component groups.

Accordingly, the SCADA Infrastructure component groups with criticality level:

- CL4 shall have:
  - computing, networking and storage nodes redundancy;
  - dual firewalls;
  - dual power supply when available;
  - a primary double-conversion UPS with 8 hours of runtime and a secondary double-conversion UPS with 15 minutes of runtime;
  - the grid as its primary power source and a genset as its backup power source each feeding one UPS;
  - redundancy of WAN links with ISP diversity and path diversity;
  - An uptime requirement of 99.97% allowing for a maximum of 3 hours total of downtime per year.
- CL3 shall have :
  - computing and networking nodes redundancy;
  - dual firewalls;
  - dual power supply when available;
  - a primary double-conversion UPS with 8 hours of runtime and a secondary double-conversion UPS with 15 minutes of runtime;
  - the grid as its only power source feeding both UPS;
  - redundancy of WAN links with ISP diversity, path diversity and ideally technology diversity;
  - an uptime requirement of 99.72% allowing for a maximum of 24 hours total of downtime per year.
- CL2 shall have:
  - no computing and networking nodes redundancy;
  - single firewall or router with firewall functions;
  - single power supply;
  - single UPS with 8 hours of runtime;
  - the grid as its only power source feeding the UPS;
  - a single ISP WAN link;
  - an uptime requirement of 99.17% allowing for a maximum of 72 hours (3 days) total of downtime per year.

- CL1 shall have:
  - no computing and networking nodes redundancy;
  - single firewall or router with firewall functions;
  - single double-conversion power supply;
  - single UPS with 8 hours of runtime;
  - the grid as its only power source feeding the UPS;
  - a single ISP WAN link;
  - an uptime requirement of 98.35% allowing for a maximum of 144 hours (6 days) total of downtime per year.

In the budgetary estimate, it is assumed that the HQ where the control center will reside already has a backup genset, so the estimate contains no provision for this.

A stock of spare parts shall be maintained to ensure that the uptime requirements of each CL component group is met. Computerized maintenance records shall be maintained to monitor it and corrective measures shall be applied when it is not met.

5.2. Cybersecurity

Industrial cybersecurity is about maintaining the highest possible level of system availability, integrity, and confidentiality in order to avoid costly downtime. Any aspect of the systems or any activity that contributes to this goal falls under cybersecurity.

In accordance with cybersecurity standard IEC 62443 and NERC CIP, best practices such as defense in depth, network segregation, and traffic control between sectors and security domains shall be applied during the design and implementation of the Electrical SCADA Infrastructure.

5.3. Network infrastructure

Two options were considered for the Electrical SCADA network architecture:

A. The first option consists of having a WAN linking the control center node, aggregation nodes in substations and other nodes not in the vicinity of a substation as well as having a substation LANs linking IEDs within the vicinity of a substation to its aggregation node (RTAC);

B. The second option consists of having a WAN linking the control center node and all the IEDs on API's electrical grid directly without aggregation nodes.

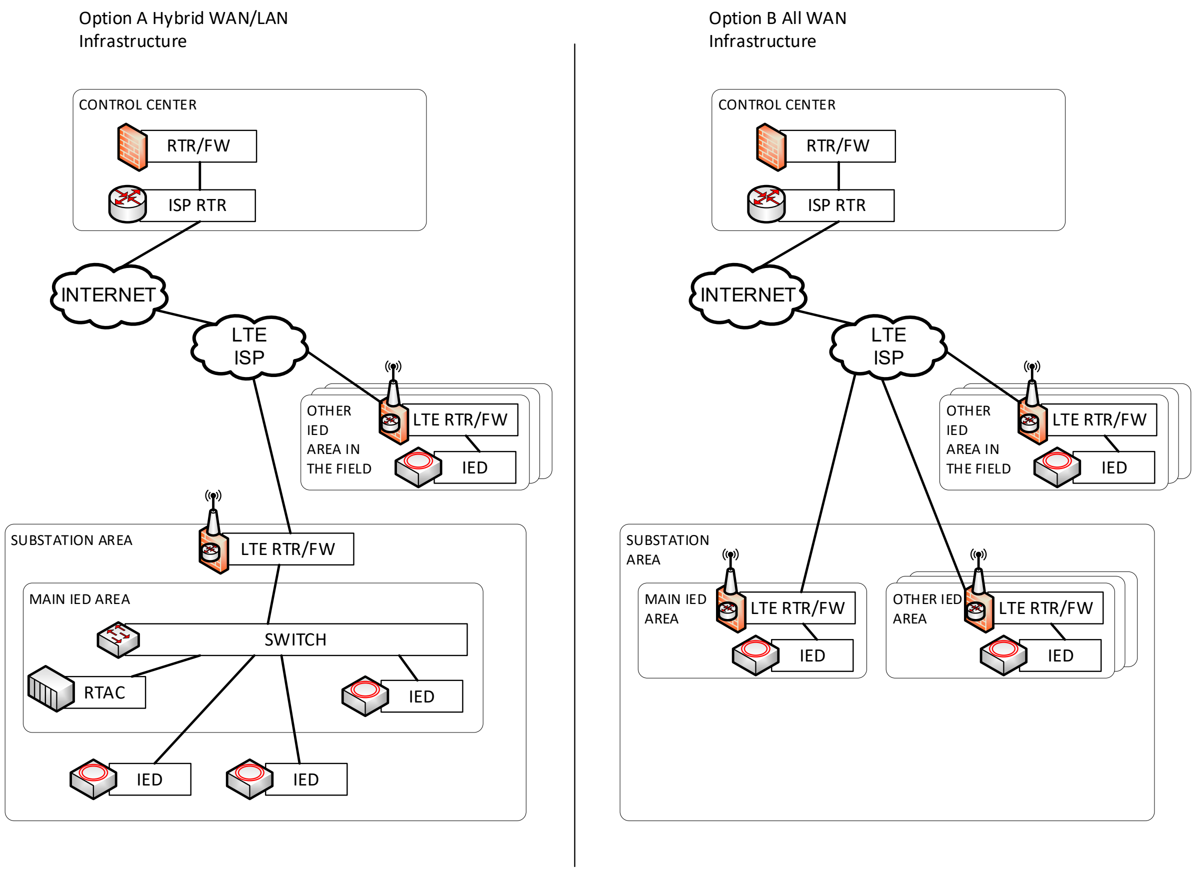


Figure 1: Network Architecture Option A and B

Figure 1 shows Option A and Option B SCADA network architectures. The functions of the WAN router and firewall devices illustrated in Figure 1 shall be integrated into a single device for nodes servicing a single IED, which is possible with a device like the Sierra Wireless RV55 LTE Router.

Moreover, the RV55 is programmable with the ALEOS Application Framework. If so desired, API could program it to buffer data in case of WAN service outage, perform pre-processing or perform control functions at the edge. API could program it to keep a high sample rate of IED data points in local buffers for 10 minutes, normally sending only a low sample rate data flow to the control center and sending high rate data points around an event after an outage occurred for SOE (Sequence of Events) root cause analysis. Its GPS synchronized clock should allow it to attach very precise timestamps to data points.

Deploying a powerful little device like this one that integrates all the required functions makes it possible to reduce the cost, complexity and engineering required and its ease of deployment allows API's staff to deploy it with minimal training and remote assistance all contributing to the lower cost of Option B. The only additional things missing to complete the solution are antennas, cabling, an enclosure and a double-conversion UPS to protect it and keep it alive during grid outage periods.

Even though, API initially proposed Option A, a budget estimate exercise (combined CAPEX and OPEX) showed that Option B was significantly less expensive (by $296,000 CAPEX+ OPEX 5-YEARS - lower engineering, equipment, and construction costs). Option B is easier and faster to deploy while offering the same benefits as Option A. See Appendix A: WAN Service Availability and Budgetary Estimate.

Accordingly, Option B shall be used for the design of the Electrical SCADA network architecture.

5.3.1. WAN

The existing office building of the control centre where the core of the Electrical SCADA system will reside already has a wired Internet access WAN link. A redundant WAN link with a 4G LTE ISP shall be added to provide redundancy.

Given that the desktop study and site surveys allowed us to confirm that excellent, good or acceptable 4G LTE coverage was available for almost all API assets, 4G LTE shall be used to link all API's assets to the control centre, except for Hollingsworth substation that shall use a geostationary satellite service. If LEO satellite service becomes commercially available by the time Hollingsworth substation is about to be deployed, this satellite service shall be used instead for that substation.

See Appendix A: WAN Service Availability and Budgetary Estimate.

5.3.2. Substation Local Area Network

If network architecture Option A is ever selected despite its higher cost, the substation LAN links could be wired (FO or CAT6 Cable) or wireless (Wi-Fi or Microwave). The LAN link type selection shall be made at detailed engineering taking into consideration the construction cost that will be different for each substation site. Wireless LAN links shall be favored over wired links (usually more economical, and easy to deploy in existing substations).

5.3.3. Network switch

Ethernet switches shall be "managed type", capable of using secure protocols such as SSH and SCP, have a built-in "automatic archive to server on save" feature, capable of logging events and reporting diagnostic information to a server and be RADIUS/TACACS+ compatible for centralized authentication. To ensure durability and reliability, a rugged grade switch shall be installed on the nodes.

All network communications shall be based on Ethernet using copper for local loops (90 m or less) and fibre optic cable for the IEDs in longer local loops.

Where cable would not be economical or practical, microwave wireless links shall be used as long as the available bandwidth meets the applications requirements.

5.3.4. Firewalls

Each WAN node shall be equipped with either a firewall or a router with the following firewall functions/features, as a minimum requirement:

- Network-to-Network encrypted VPN using one of the following protocols: OpenVPN (SSL/TLS), IPsec or Wireguard;
- Stateful Packet Inspection;
- NAT;
- Routing;
- RADIUS and LDAP authentication;
- For CL3 and CL4 component groups only:
  - Multi-WAN;
  - Secure Remote Access through encrypted VPN using one of the following protocols: OpenVPN (SSL/TLS), IPsec or Wireguard.

Because all WAN traffic will transit over public networks, it shall be encrypted. Remote access to any WAN node shall be protected with two-factor authentication (managed centrally through RADIUS, LDAP, and an Active Directory server). All unnecessary TCP and UDP service ports facing the Internet, or the internal WAN network shall be shutdown and blocked by the firewalls letting through only the minimum required authorized traffic.

To ensure durability and reliability an industrial grade firewall shall selected for field installations. Firewalls or routers with firewall function shall be from reputable manufacturers, such as Juniper, Fortinet, Palo Alto, Checkpoint, Netgate and Cisco.

5.3.5. Cabinets

The WAN or LAN node enclosures/cabinets shall be at least NEMA 4 enclosures with mounting attachment appropriate for the application.

5.4. Servers

The SCADA application servers could either run on hosts (physical servers) installed on premises or in the cloud. They shall be configured to achieve a high level of security and reliability. The following technologies and features shall be included in the design:

- Server Virtualisation (VMware, KVM, etc.);
- Local synchronous data replication (RAID, RAIN, etc.);
- Continuous data replication (asynchronous replication) with off-site destination;
- Data backup software solution;
- Network virtualization (VLAN, virtual switch);
- Out-of-band VM management (idrac, iLo, cloud console).

These requirements will ensure data integrity and availability in the event of a system failure or planned maintenance. These requirements will also ensure scalability to accommodate future expansion.

6. Deployment strategy

In order to reduce the technical and financial risk of the project and to maximise positive outcomes, it is strongly recommended that API starts with a proof of concept phase.

The recommended phases of deployment for the Electrical SCADA system would be:

- Phase 0 – Proof of concept
  - Use API's existing Survalent SCADA server at the control centre and deploy a proof of concept for Option A and another one for Option B SCADA Network Infrastructure to:
    - Test WAN technology components;
    - Adjust WAN node components as required;
    - Assess and tune the actual amount of bandwidth requirements;
    - Compare both options for ease and cost of implementation and operation;
  - Option A (Hybrid LAN/WAN): Deploy an aggregation LTE WAN node connected to the main IED of a substation (Dubreuilville 86 was suggested by API) and link some of the IEDs in the vicinity of that substation to that node with LAN links (FO, CAT6 or Wi-Fi);
  - Option B (All WAN): Deploy LTE WAN nodes connected to the IED of assets distributed strategically across the service territory as follows:
    - a couple of assets east of Sault Sainte-Marie;
    - a couple of assets north of Sault Sainte-Marie;
    - a couple of assets in the Wava/Dubreuilville area;
- Phase 1 – Control centre, substations and some nearby IEDs
  - Deploy SCADA infrastructure node at the control centre;
  - Deploy SCADA infrastructure nodes at the IEDs in the vicinity of the substations;
- Phase 2 – Other regulators and reclosers IEDs
  - Deploy SCADA nodes at the regulators and the rest of the reclosers;
- Phase 3 – The rest of the IEDs
  - Deploy SCADA nodes at the capacitors;

Appendix A: WAN Service Availability and Budgetary Estimate

Appendix A.1 WAN Service Availability and Budgetary Estimate (All WAN Infrastructure)

#	ASSET (DEVICES ID)	ASSET TYPE	Depl. Phase /Priority	LTE BELL	LTE ROGERS	SS LAN (Wi-Fi, CAT6, FO)	FO	MW	Xplornet SAT	DSL	IED COUNT at LOCATION	LTE Bell CAPEX Amount	LTE Rogers CAPEX Amount	SS LAN (Wi-Fi, CAT6, FO) Amount	Xplornet SAT CAPEX Amount	LTE Bell OPEX Amount /Month	LTE Rogers OPEX Amount /Month	Xplornet SAT OPEX Amount /Month
1	Northern Avenue TS	TS	1	P	A		A				1	5 500 $	- $	- $	- $	10 $	- $	- $
2	Garden River DS	DS	1	P	A						1	5 500 $	- $	- $	- $	10 $	- $	- $
3	SW3120-10	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
4	SW3110-7	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
5	Echo River TS	TS	1	A	P						1	- $	5 500 $	- $	- $	- $	10 $	- $
6	SW038	Recloser	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
7	Bar River DS	DS	1	P	A						1	5 500 $	- $	- $	- $	10 $	- $	- $
8	SW3210-91	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
9	SW3220-88	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
10	REG-ER1	Regulator	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
11	CAP3210-118	Capacitor	3		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
12	SW2020	Recloser	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
13	Desbarats DS	DS	1	P	A		A				1	5 500 $	- $	- $	- $	10 $	- $	- $
14	CAP3400-140	Capacitor	3		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
15	FUTURE RECLOSER	Recloser	2	A	P						1	- $	5 500 $	- $	- $	- $	10 $	- $
16	REG3600-163	Regulator	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
17	SW3610D-92	Recloser	2	A	P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
18	REC052	Recloser	1		P		A	A			1	- $	5 500 $	- $	- $	- $	10 $	- $
19	SW2005	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
20	SW2010	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
21	SW3400-136	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
22	SW3400-9	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
23	SW2007	Switch	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
24	CAP2022	Capacitor	3		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
25	Bruce Mines DS	DS	1	A	P						1	- $	5 500 $	- $	- $	- $	10 $	- $
26	SW2012	Recloser	2		P		A	A			1	- $	5 500 $	- $	- $	- $	10 $	- $
27	SW3820-2	Recloser	2		P		A	A			1	- $	5 500 $	- $	- $	- $	10 $	- $
28	CAP3820-188	Capacitor	3		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
29	Andrews TS	TS	1	A	P						1	- $	5 500 $	- $	- $	- $	10 $	- $
30	Mackay TS	TS	1	P	A						1	5 500 $	- $	- $	- $	10 $	- $	- $
31	Batchewanna TS	TS	1	P	A						1	5 500 $	- $	- $	- $	10 $	- $	- $
32	SW5200-1	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
33	SW5221-64	Regulator	2	A	P						1	- $	5 500 $	- $	- $	- $	10 $	- $
34	SW5221-63	Regulator	2	P	A						1	5 500 $	- $	- $	- $	10 $	- $	- $
35	SW5220-62	Regulator	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
36	SW5210-72	Regulator	2	P	A						1	5 500 $	- $	- $	- $	10 $	- $	- $
37	Goulais TS	TS	1	P	A		A				1	5 500 $	- $	- $	- $	10 $	- $	- $
38	SW5130-2	Recloser	2		P		A	A			1	- $	5 500 $	- $	- $	- $	10 $	- $
39	SW5110-198	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
40	SW5120-200	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
41	SW5121B-149	Regulator	2	P	A						1	5 500 $	- $	- $	- $	10 $	- $	- $
42	SW5120B-174	Recloser	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
43	SW5120A-106	Recloser	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
44	SW5121-71	Recloser	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
45	Hawk Junction DS	DS	1	P	A						1	Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope
46	Da Watson TS	TS	1	P	A						1	5 500 $	- $	- $	- $	10 $	- $	- $
47	SW9410E-31	Recloser	2	A	P						1	- $	5 500 $	- $	- $	- $	10 $	- $
48	Wawa No 1 DS	DS	1	A	P		A				1	- $	5 500 $	- $	- $	- $	10 $	- $
49	SW9110-24	Recloser	2		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
50	SW9120-25	Recloser	2		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $

Appendix A.1 WAN Service Availability and Budgetary Estimate (All WAN Infrastructure)

#	ASSET (DEVICES ID)	ASSET TYPE	Depl. Phase /Priority	LTE BELL	LTE ROGERS	SS LAN (Wi-Fi, CAT6, FO)	FO	MW	Xplornet SAT	DSL	IED COUNT at LOCATION	LTE Bell CAPEX Amount	LTE Rogers CAPEX Amount	SS LAN (Wi-Fi, CAT6, FO) Amount	Xplornet SAT CAPEX Amount	LTE Bell OPEX Amount /Month	LTE Rogers OPEX Amount /Month	Xplornet SAT OPEX Amount /Month
51	Wawa No 2 DS	DS	1	A	P						1	- $	5 500 $	- $	- $	- $	10 $	- $
52	SW9400-84	Recloser	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
53	SW2036	Recloser	2		P	A		A			1	- $	5 500 $	- $	- $	- $	10 $	- $
54	SW9200-1	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
55	SW9200-2	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
56	SW1119	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
57	SW1120	Recloser	1		P	A					1	- $	5 500 $	- $	- $	- $	10 $	- $
58	Hollingsworth TS/GS	TS	1				A		P		1	- $	- $	- $	500 $	- $	- $	210 $
59	Dubreuilville 86 DS	DS	1		P				A		1	- $	5 500 $	- $	- $	- $	10 $	- $
60	Dubreuilville 87 DS	DS			P				A			Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope
99	Control Center	CC	1		P						1	240 000 $	(see Appendix H. Budgetary BOM)		- $	- $	100 $	- $

P	Primary
S	Secondary
A	Preferred Alternative
A	Alternative

Totals	**300 500 $**	**253 000 $**	**- $**	**500 $**	**110 $**	**560 $**	**210 $**
Phase 1	284 000 $	132 000 $	- $	500 $	80 $	340 $	210 $
Phase 2	16 500 $	99 000 $	- $	- $	30 $	180 $	- $
Phase 3	- $	22 000 $	- $	- $	- $	40 $	- $

	All Phases	Phase 1	Phase 2	Phase 3
CAPEX HW/SW+Constr.	**554 000 $**	**416 500 $**	**115 500 $**	**22 000 $**
CAPEX Eng., Const. Mgmt	**294 000 $**	**221 031 $**	**61 294 $**	**11 675 $**
CAPEX TOTAL	**848 000 $**	**637 531 $**	**176 794 $**	**33 675 $**
OPEX TOTAL/MONTH	880 $	662 $	183 $	35 $
OPEX TOTAL/Year	10 560 $	7 939 $	2 202 $	419 $
OPEX TOTAL/5-Year	**52 800 $**	**39 695 $**	**11 008 $**	**2 097 $**
CAPEX+ OPEX 5-YEAR	**900 800 $**	**677 226 $**	**187 802 $**	**35 772 $**
Contingency (15%)	135 120 $	101 584 $	28 170 $	5 366 $
BUDGETARY ESTIMATE (+/- 15%)	**1 036 000 $**	**779 000 $**	**216 000 $**	**41 000 $**
Diff. w/other option	(296 000) $			

CAPEX for Engineering and Construction Management (Field Engineering) is composed of:
1 x General @ $ 120,000 + 58 x Assets @ $3,000 = $294,000

Appendix A.2 WAN Service Availability and Budgetary Estimate (Hybrid WAN/LAN Infrastructure)

#	ASSET (DEVICES ID)	ASSET TYPE	Depl. Phase /Priority	LTE BELL	LTE ROGERS	SS LAN (Wi-Fi, CAT6, FO)	FO	MW	Xplornet SAT	DSL	IED COUNT at LOCATION	LTE Bell CAPEX Amount	LTE Rogers CAPEX Amount	SS LAN (Wi-Fi, CAT6, FO) RTAC+ACC Amount	Xplornet SAT CAPEX Amount	LTE Bell OPEX Amount /Month	LTE Rogers OPEX Amount /Month2	Xplornet SAT OPEX Amount /Month
1	Northern Avenue TS	TS	1	P	A		A				1	5 500 $	- $	3 000 $	- $	50 $	- $	- $
2	Garden River DS	DS	1	P	A						1	5 500 $	- $	20 000 $	- $	50 $	- $	- $
3	SW3120-10	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
4	SW3110-7	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
5	Echo River TS	TS	1	A	P						1	- $	5 500 $	3 000 $	- $	- $	50 $	- $
6	SW038	Recloser	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
7	Bar River DS	DS	1	P	A						1	5 500 $	- $	20 000 $	- $	50 $	- $	- $
8	SW3210-91	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
9	SW3220-88	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
10	REG-ER1	Regulator	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
11	CAP3210-118	Capacitor	3		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
12	SW2020	Recloser	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
13	Desbarats DS	DS	1	P	A		A				1	5 500 $	- $	20 000 $	- $	50 $	- $	- $
14	CAP3400-140	Capacitor	3		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
15	FUTURE RECLOSER	Recloser	2	A	P						1	- $	5 500 $	- $	- $	- $	10 $	- $
16	REG3600-163	Regulator	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
17	SW3610D-92	Recloser	2	A	P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
18	REC052	Recloser	1		P		A	A			1	- $	5 500 $	- $	- $	- $	10 $	- $
19	SW2005	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
20	SW2010	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
21	SW3400-136	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
22	SW3400-9	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
23	SW2007	Switch	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
24	CAP2022	Capacitor	3		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
25	Bruce Mines DS	DS	1	A	P						1	- $	5 500 $	20 000 $	- $	- $	50 $	- $
26	SW2012	Recloser	2		A		P	A			1	- $	- $	5 000 $	- $	- $	- $	- $
27	SW3820-2	Recloser	2		A		P	A			1	- $	- $	5 000 $	- $	- $	- $	- $
28	CAP3820-188	Capacitor	3		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
29	Andrews TS	TS	1	A	P						1	- $	5 500 $	3 000 $	- $	- $	50 $	- $
30	Mackay TS	TS	1	P	A						1	5 500 $	- $	3 000 $	- $	50 $	- $	- $
31	Batchewanna TS	TS	1	P	A						1	5 500 $	- $	3 000 $	- $	50 $	- $	- $
32	SW5200-1	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
33	SW5221-64	Regulator	2	A	P						1	- $	5 500 $	- $	- $	- $	10 $	- $
34	SW5221-63	Regulator	2	P	A						1	5 500 $	- $	- $	- $	10 $	- $	- $
35	SW5220-62	Regulator	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
36	SW5210-72	Regulator	2	P	A						1	5 500 $	- $	- $	- $	10 $	- $	- $
37	Goulais TS	TS	1	P	A		A				1	5 500 $	- $	3 000 $	- $	50 $	- $	- $
38	SW5130-2	Recloser	2		A		P	A			1	- $	- $	5 000 $	- $	- $	- $	- $
39	SW5110-198	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
40	SW5120-200	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
41	SW5121B-149	Regulator	2	P	A						1	5 500 $	- $	- $	- $	10 $	- $	- $
42	SW5120B-174	Recloser	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
43	SW5120A-106	Recloser	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
44	SW5121-71	Recloser	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
45	Hawk Junction DS	DS	1	P	A						1	Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope
46	Da Watson TS	TS	1	P	A						1	5 500 $	- $	3 000 $	- $	50 $	- $	- $
47	SW9410E-31	Recloser	2	A	P						1	- $	5 500 $	- $	- $	- $	10 $	- $
48	Wawa No 1 DS	DS	1	A	P		A				1	- $	5 500 $	20 000 $	- $	- $	50 $	- $
49	SW9110-24	Recloser	2		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
50	SW9120-25	Recloser	2		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $

Appendix A.2 WAN Service Availability and Budgetary Estimate (Hybrid WAN/LAN Infrastructure)

#	ASSET (DEVICES ID)	ASSET TYPE	Depl. Phase /Priority	LTE BELL	LTE ROGERS	SS LAN (Wi-Fi, CAT6, FO)	FO	MW	Xplornet SAT	DSL	IED COUNT at LOCATION	LTE Bell CAPEX Amount	LTE Rogers CAPEX Amount	SS LAN (Wi-Fi, CAT6, FO) RTAC+ACC Amount	Xplornet SAT CAPEX Amount	LTE Bell OPEX Amount /Month	LTE Rogers OPEX Amount /Month2	Xplornet SAT OPEX Amount /Month
51	Wawa No 2 DS	DS	1	A	P						1	- $	5 500 $	20 000 $	- $	- $	50 $	- $
52	SW9400-84	Recloser	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
53	SW2036	Recloser	2		P			A			1	- $	5 500 $	- $	- $	- $	10 $	- $
54	SW9200-1	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
55	SW9200-2	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
56	SW1119	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
57	SW1120	Recloser	1		A	P					1	- $	- $	5 000 $	- $	- $	- $	- $
58	Hollingsworth TS/GS	TS	1				A		P		1	- $	- $	3 000 $	500 $	- $	- $	210 $
59	Dubreuilville 86 DS	DS	1		P				A		1	- $	5 500 $	20 000 $	- $	- $	50 $	- $
60	Dubreuilville 87 DS	DS			P				A			Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope	Out of Scope
99	Control Center	CC	1		P						1	240 000 $	(see Appendix H. Budgetary BOM)		- $	- $	100 $	- $

P	Primary
S	Secondary
A	Preferred Alternative
A	Alternative

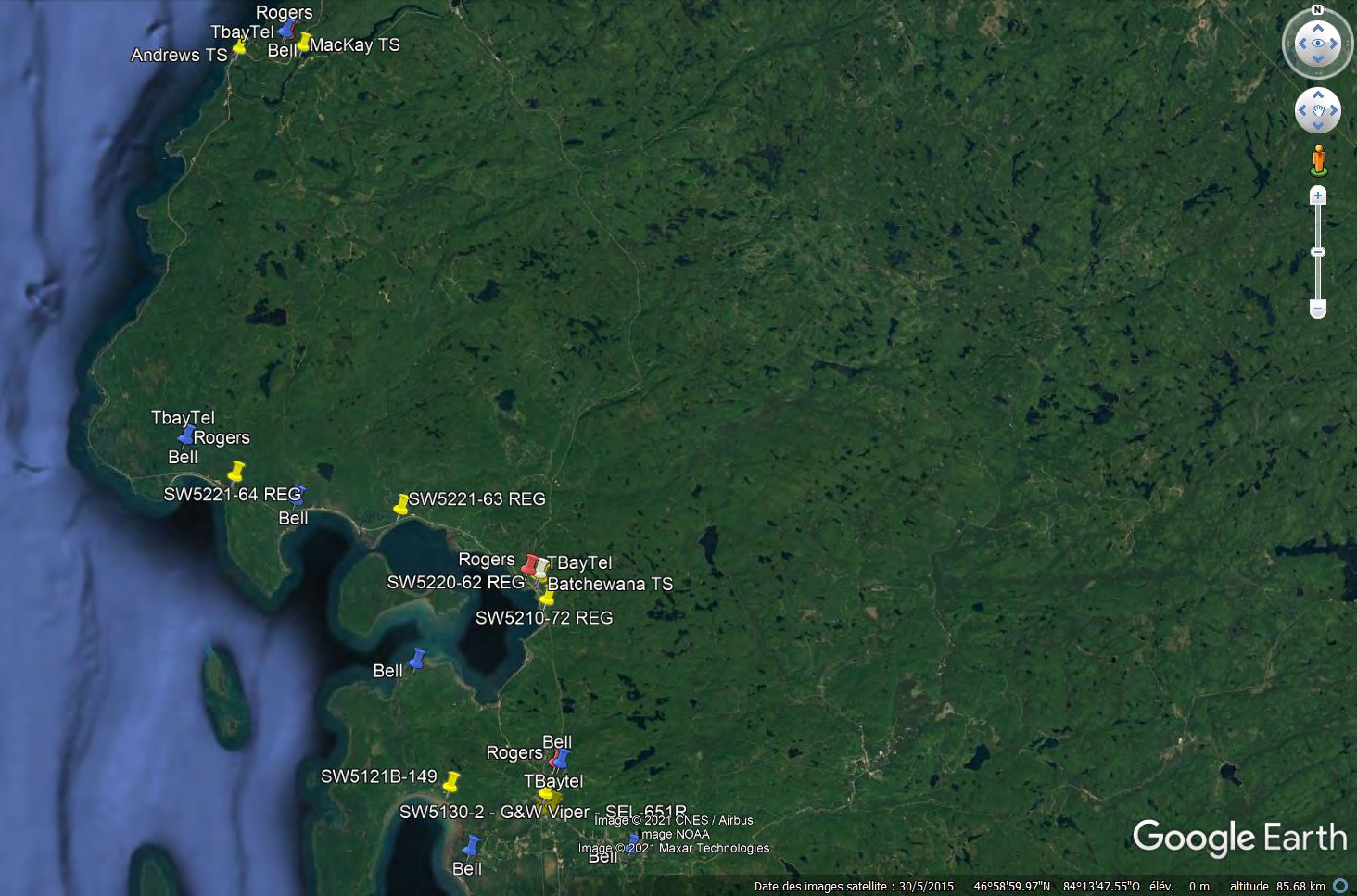
	LTE Bell CAPEX	LTE Rogers CAPEX	SS LAN CAPEX	Xplornet SAT CAPEX	LTE Bell OPEX	LTE Rogers OPEX	Xplornet SAT OPEX
Totals	**300 500 $**	**132 000 $**	**274 000 $**	**500 $**	**430 $**	**580 $**	**210 $**
Phase 1	284 000 $	38 500 $	249 000 $	500 $	400 $	410 $	210 $
Phase 2	16 500 $	71 500 $	25 000 $	- $	30 $	130 $	- $
Phase 3	- $	22 000 $	- $	- $	- $	40 $	- $

CAPEX for Engineering and Construction Management (Field Engineering) is composed of:
1 x General @ $ 120,000 + 51 x Assets @ $3,000
+ 7 x Asset/Aggregation Stations @ $15,000 = $378,000

	All Phases	Phase 1	Phase 2	Phase 3
CAPEX HW/SW+Constr.	**707 000 $**	**572 000 $**	**113 000 $**	**22 000 $**
CAPEX Eng., Const. Mgmt	**378 000 $**	**305 822 $**	**60 416 $**	**11 762 $**
CAPEX TOTAL	**1 085 000 $**	**877 822 $**	**173 416 $**	**33 762 $**
OPEX TOTAL/MONTH	1 220 $	987 $	195 $	38 $
OPEX TOTAL/Year	14 640 $	11 845 $	2 340 $	456 $
OPEX TOTAL/5-Year	**73 200 $**	**59 223 $**	**11 700 $**	**2 278 $**
CAPEX+ OPEX 5-YEAR	**1 158 200 $**	**937 044 $**	**185 115 $**	**36 040 $**
Contingency (15%)	173 730 $	140 557 $	27 767 $	5 406 $
BUDGETARY ESTIMATE (+/- 15%)	**1 332 000 $**	**1 078 000 $**	**213 000 $**	**41 000 $**
Diff. w/other option	296 000 $			

Appendix B: Cellular Towers Location


Dubreuilville 87 DS
TbayTel
Rogers
Dubreuilville 86 DS
TbayTel HJ
Hawk Junction
Rogers
SW2036 - G&W Viper - SEL-651R
SW9400-84 - G&W Viper - SEL-651R
Bell
Hollingsworth TS/GS Demarc.
Bell
Rogers
TbayTel
Rogers
Bell
DA Watson TS
Bell
Rogers
Bell
TbayTel
Image Landsat / Copernicus
Image NOAA
Google Earth


Rogers
TbayTel
Andrews TS
Bell
MacKay TS
TbayTel
Rogers
Bell
SW5221-64 REG
Bell
SW5221-63 REG
Rogers
TBayTel
SW5220-62 REG
Batchewana TS
SW5210-72 REG
Bell
Bell
Rogers
TBaytel
SW5121B-149
SW5130-2 - G&W Viper - SEL-651R
Image © 2021 CNES / Airbus
Image NOAA
Image © 2021 Maxar Technologies
Bell
Bell
Google Earth
Date des images satellite : 30/5/2015
46°58'59.97"N
84°13'47.55"O
élév.
0 m
altitude
85.68 km

SW3120-10 - G&W Viper - SEL-651R
Goulais River DS
Rogers
SW3110-7 - G&W Viper - SEL-651R
Rogers
Bell
Bell
Bell
Rogers
Bell
Bell
Rogers
Rogers
Bell
Bell
Echo River TS
SW038 - VWVE38X - Form 6 Control
Bell
Bell
Bell
SW3210-91 - G&W Viper - SEL-651R
Bar River DS
SW3220-88 - G&W Viper - SEL-651R
SW2020 - G&W Viper - SEL-651R
Rogers
Bell
Desbarats DS
CAP3400-140
Bell
SW3400-9 - Kyle VXE-15
SWXXXX - G&W Viper - SEL-651R
CAP2022
Bell
Bruce Mines DS
SW3820-2 - G&W Viper - SEL-651R
Bell
REG3600-163 - Cooper - CL7 Controller
SW3610D-92 - G&W Viper - S
Image © 2021 CNES / Airbus
Image © 2021 Maxar Technologies
Google Earth
Date des images satellite : 31/5/2015
46°24'40.40"N
84°00'31.45"O
élév.
0 m
altitude
52.13 km

Appendix C: Cellular Coverage by Rogers

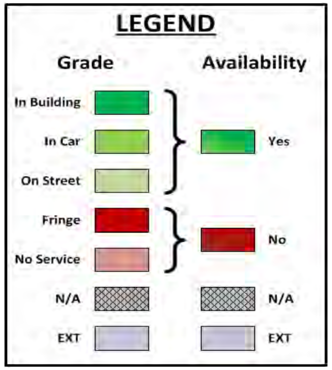
Info1	lat	long	4G_Coverage_Available	4G_Coverage_Grade	LTE_Coverage_Available	LTE_Coverage_Grade	LTE-A_Coverage_Available	LTE-A_Coverage_Grade	LTE Extended Coverage	4G Extended Coverage
1	46.535447	-84.328214	Yes	In Building	Yes	In Building	Yes	In Building	Rogers LTE	Rogers 4G
2	46.549347	-84.164172	Yes	In Building	Yes	In Car	Yes	In Car	Rogers LTE	Rogers 4G
3	46.549439	-84.164433	Yes	In Building	Yes	In Car	Yes	In Car	Rogers LTE	Rogers 4G
4	46.549328	-84.163964	Yes	In Building	Yes	In Car	Yes	In Car	Rogers LTE	Rogers 4G
5	46.520642	-83.996058	Yes	On Street	Yes	On Street	No	No Service	Rogers LTE	Rogers 4G
6	46.511669	-84.048203	Yes	In Car	Yes	On Street	Yes	On Street	Rogers LTE	Rogers 4G
7	46.450258	-84.046203	Yes	In Building	Yes	In Building	Yes	In Car	Rogers LTE	Rogers 4G
8	46.450447	-84.046556	Yes	In Building	Yes	In Building	Yes	In Car	Rogers LTE	Rogers 4G
9	46.450233	-84.046608	Yes	In Building	Yes	In Building	Yes	In Car	Rogers LTE	Rogers 4G
10	46.450356	-84.045872	Yes	In Building	Yes	In Building	Yes	In Car	Rogers LTE	Rogers 4G
11	46.44725	-84.046589	Yes	In Building	Yes	In Building	Yes	In Car	Rogers LTE	Rogers 4G
12	46.440644	-84.046592	Yes	In Building	Yes	In Building	Yes	In Car	Rogers LTE	Rogers 4G
13	46.343089	-83.933172	Yes	In Car	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
14	46.352544	-84.046044	Yes	In Building	Yes	In Building	Yes	In Car	Rogers LTE	Rogers 4G
15	46.341414	-84.0243	Yes	In Building	Yes	In Building	Yes	In Car	Rogers LTE	Rogers 4G
16	46.335425	-83.937258	Yes	In Car	No	Fringe	No	No Service	No	Rogers 4G
17	46.278044	-83.972697	Yes	On Street	No	No Service	Yes	In Car	No	Rogers 4G
18	46.261217	-84.013922	Yes	In Car	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
19	46.341853	-83.932531	Yes	In Car	No	Fringe	No	No Service	No	Rogers 4G
20	46.342989	-83.933292	Yes	In Car	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
21	46.343025	-83.933453	Yes	In Car	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
22	46.343094	-83.933031	Yes	In Car	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
23	46.343203	-83.933386	Yes	In Car	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
24	46.342972	-83.933192	Yes	In Car	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
26	46.322044	-83.790294	Yes	In Building	Yes	In Building	Yes	In Building	Rogers LTE	Rogers 4G
27	46.321467	-83.790756	Yes	In Building	Yes	In Building	Yes	In Building	Rogers LTE	Rogers 4G
28	46.322422	-83.790136	Yes	In Building	Yes	In Building	Yes	In Building	Rogers LTE	Rogers 4G
29	46.322431	-83.785478	Yes	In Building	Yes	In Building	Yes	In Building	Rogers LTE	Rogers 4G
30	47.238142	-84.6439	Yes	In Building	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
31	47.239514	-84.583094	Yes	In Car	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
32	46.892453	-84.362436	Yes	In Building	Yes	On Street	No	No Service	Rogers LTE	Rogers 4G
33	46.892297	-84.362581	Yes	In Building	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
34	46.959683	-84.651539	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
35	46.937203	-84.494056	Yes	In Car	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
36	46.89355	-84.364847	Yes	In Building	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
37	46.877447	-84.356186	Yes	In Car	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
38	46.750778	-84.359981	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
39	46.751372	-84.359481	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
40	46.750894	-84.360331	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
41	46.750803	-84.360319	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
42	46.756719	-84.450192	Yes	In Building	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
43	46.741828	-84.365	Yes	In Building	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
44	46.743339	-84.353458	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
45	46.740819	-84.353128	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
46	47.911064	-84.719119	Yes	On Street	No	Fringe	No	No Service	No	Rogers 4G
47	47.961717	-84.794675	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
48	47.999094	-84.779253	Yes	In Building	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
49	47.999414	-84.779011	Yes	In Building	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
50	47.999264	-84.779569	Yes	In Building	Yes	In Car	No	No Service	Rogers LTE	Rogers 4G
51	47.987861	-84.778747	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
52	47.986872	-84.777369	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
53	47.986803	-84.776869	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
54	47.987961	-84.778833	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
55	47.987956	-84.778647	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
56	47.987753	-84.778797	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
57	47.987675	-84.778642	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
58	47.959156	-84.505028	No	Fringe	No	No Service	No	No Service	No	No
59	48.349853	-84.545686	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G
60	48.360431	-84.530622	Yes	In Building	Yes	In Building	No	No Service	Rogers LTE	Rogers 4G

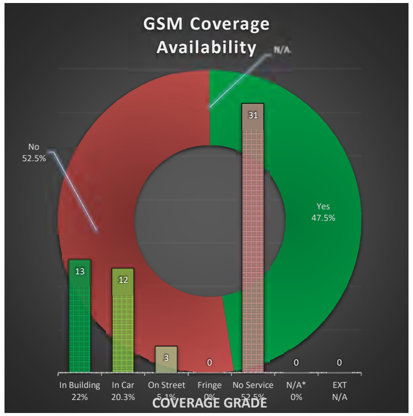
Count of Customer Locations with Rogers Coverage Grade & Availability

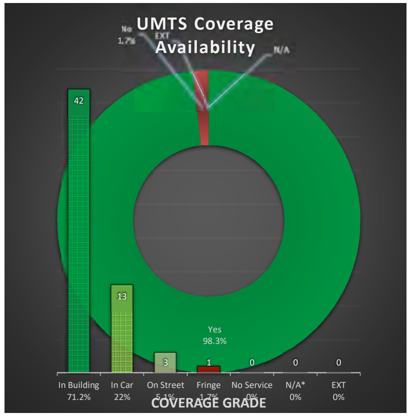
ROGERS

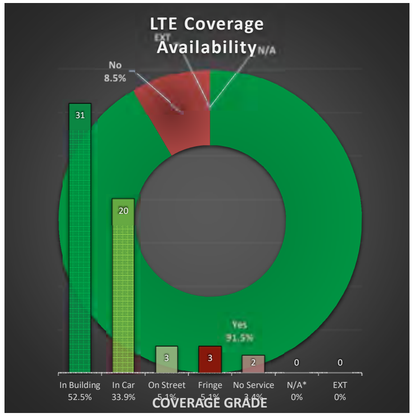
Availability	Grade	GSM Count (Grade)	GSM Count (Availability)	GSM % (Availability)	UMTS Count (Grade)	UMTS Count (Availability)	UMTS % (Availability)	LTE Count (Grade)	LTE Count (Availability)	LTE % (Availability)	LTE-A Count (Grade)	LTE-A Count (Availability)	LTE-A % (Availability)
Yes	In Building	13	28	47.5%	42	58	98.3%	31	54	91.5%	5	18	#REF!
	In Car	12			13			20			12		
	On Street	3			3			3			1		
No	Fringe	0	31	52.5%	1	1	1.7%	3	5	8.5%	0	41	#REF!
	No Service	31			0			2			41		
N/A*	N/A*	0	0	0.0%	0	0	0.0%	0	0	0.0%	0	0	#REF!
Extended	N/A**	N/A	N/A	N/A	0	0	0.0%	0	0	0.0%	#REF!	#REF!	#REF!
Total		59			59			59			#REF!		

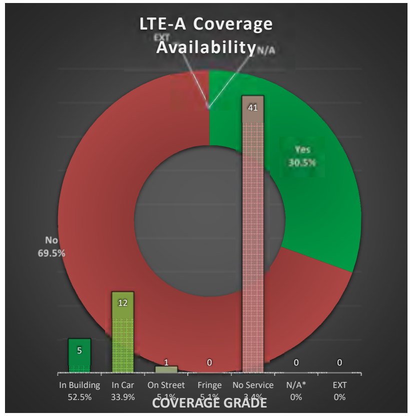
** No match with provided postal code || ** Grade (Signal Strength) not available for extended network*











Location Analysis

The coverage analysis is based on the location provided by the customer at which the signal strength levels are predicted.

The grade of coverage is evaluated using thresholds determined by user experience with the Rogers network.

Extended coverage is available to Rogers customers with a compatible device, who sometimes travel outside Rogers coverage area. Extended coverage is not available to those who permanently reside in this coverage area. Certain services/features may not be available or may have limited functionality.

Note that for the same geographic area, the grade "In Building" includes coverage for both "In Car" and "On Street". Similarly, "In Car" coverage includes "On Street" coverage for the same area but does not include "In Building" coverage for that area.

Note that the signal levels are predicted at street level and the actual grade of coverage may vary due to nearby obstructions and building materials.

The 2G - GSM/EDGE/GPRS thresholds are defined as follows:

Greater than -70dBm	In Building
Between -70dBm and -84dBm	In Car
Between -84dBm and -94dBm	On Street
Between -94dBm and -105dBm	Fringe
Less than -105dBm	No Service
N/A	No Match to Postal Code
EXT	N/A to GSM

The 4G - HSPA+/UMTS thresholds are defined as follows:

Greater than -84dBm	In Building
Between -84dBm and -96dBm	In Car
Between -96dBm and -102dBm	On Street
Between -102dBm and -115dBm	Fringe
Less than -115dBm	No Service
N/A	No Match to Postal Code

The LTE thresholds are defined as follows:

Greater than -98dBm	In Building
Between -98dBm and -110dBm	In Car
Between -110dBm and -116dBm	On Street
Between -116dBm and -124dBm	Fringe
Less than -124dBm	No Service
N/A	No Match to Postal Code
EXT	Extended Coverage

The LTE-A thresholds are defined as follows:

Greater than -98dBm	In Building
Between -98dBm and -110dBm	In Car
Between -110dBm and -116dBm	On Street
Between -116dBm and -124dBm	Fringe
Less than -124dBm	No Service
N/A	No Match to Postal Code
EXT	Extended Coverage

s

Appendix D: Fiber Optic Report by Bell

INPUT								OUTPUT - For External Use												
ID	Address	City	Province	Postal Code	LAT	LON	Location CLLI	Address Match Type	Address	City	Province	Country	Postal Code	Bell Fibre at Location	Targeted Bell Fibre Completion Date	Bell Copper at Location	Estimated Distance to Nearest Fibre Interconnection (km)	Central Office CLLI	Central Office Name	Geo-Coding Accuracy
GARDI	160 Whisk	Garden Riv	On	P6A 6Z9				Valid	160 WHISKE	GARDEN RIV	ON	CAN	P6A 6Z9	Unknown		Unknown	0.78	SSMRON94	SAULT STE. MA	Good
BAR R	540 Gover							Valid	540 GOVERI	ECHO BAY	ON	CAN	P0S 1C0	Unknown		Unknown	3.66	ECBAON93	ECHO BAY	Good
NEW [	50 Main St							Valid	50 MAIN ST	DESBARATS	ON	CAN	Postal code u	Unknown		Unknown	0.04	DSBRON90	DESBARATS	Good
BRUCE	653 Caribc							Valid	653 CARIBO	BRUCE MIN	ON	CAN	P0R 1C0	Unknown		Unknown	4.7	BCMNON91	BRUCE MINES	Good
#1 WA	2 Beck Ave							Valid	2 BECK AVE	WAWA	ON	CAN	P0S 1K0	No		Yes	0.24	WAWAON01	WAWA	Good
#2 WA	105 Mills [							Valid	105 MILLS [	WAWA	ON	CAN	Postal code u	No		Yes	2.05	WAWAON01	WAWA	Good
HAWK	127 Montg							Approximat	127 AV MO	HAWK JUN(	ON	CAN	P0S 1G0	Unknown		Unknown		WAWAON01	WAWA	Poor
DUBRI	1 Chemin I							Approximat	1 PARC IND	DUBREUILV	ON	CAN	Postal code u	Unknown		Unknown		DBVLON60	DUBREUILVILL	Good
DUBRI	6A Parc In							Valid	6A PARC INI	DUBREUILV	ON	CAN	Postal code u	Unknown		Unknown		DBVLON60	DUBREUILVILL	Good
ANDRI	4 Twilight							Invalid												Poor
BATCH	7340 Hwy							Approximat	7340 HIGHV	GOULAIS RI	ON	CAN	P0S 1E0	Unknown		Unknown	7.59	GOULON95	GOULAIS	Good
ECHO	157 Birch I							Valid	157 BIRCH L	ECHO BAY	ON	CAN	P0S 1C0	No		Yes	9.38	ECBAON93	ECHO BAY	Good
GOUL	3467 Hwy							Approximat	3467 HWY 1	GOULAIS RI	ON	CAN	P0S 1E0	Unknown		Unknown	0.09	GOULON95	GOULAIS	Good
HOLLII	Limer, ON							Invalid												Poor
MACK	None (Mo							Invalid												Poor
NORTI	2 Sackville							Valid	2 SACKVILLE	SAULT STE.	ON	CAN	P6B 6J6	No		Yes	0.27	SSMRON94	SAULT STE. MA	Good
WATS	24 High Fa							Valid	24 HIGH FAI	WAWA	ON	CAN	Postal code u	Unknown		Unknown	8.34	WAWAON01	WAWA	Good
SW94	30 Pinewo							Valid	30 PINEWO	WAWA	ON	CAN	P0S 1K0	No		Yes	2.09	WAWAON01	WAWA	Good
REG36	2248 F&G							Valid	2248 F & G	RICHARDS L	ON	CAN	P0R 1J0	Unknown		Unknown		SJILON92	ST. JOSEPH ISL	Poor
SW36	1094 Echo							Invalid												Poor
SW03	1092-1094							Invalid												Poor
SW20	464 Gover							Valid	464 GOVERI	ECHO BAY	ON	CAN	P0S 1C0	Unknown		Unknown	3.18	ECBAON93	ECHO BAY	Good
CAP32	550 Gover							Valid	550 GOVERI	ECHO BAY	ON	CAN	P0S 1C0	No		Yes	4.88	ECBAON93	ECHO BAY	Good
CAP20	32 Kensing							Valid	32 KENSING	DESBARATS	ON	CAN	P0R 1E0	Yes		Yes	0.51	DSBRON90	DESBARATS	Bell defined
CAP38	731 Conce							Invalid												Poor
CAP34	2473 Gove							Valid	2473 GOVEI	DESBARATS	ON	CAN	Postal code u	Unknown		Unknown	0.4	DSBRON90	DESBARATS	Good
SW34	968 MacLe							Valid	968 MACLEI	DESBARATS	ON	CAN	P0R 1E0	No		Yes	3.68	DSBRON90	DESBARATS	Good
SW51	90 ON-552							Valid	90 ON-552	GOULAIS RI	ON	CAN	Postal code u	Unknown		Unknown	0.78	GOULON95	GOULAIS	Good
SW51	3040 High							Valid	3040 HIGHV	GOULAIS RI	ON	CAN	P0S 1E0	Unknown		Unknown	1.35	GOULON95	GOULAIS	Good
SW51	245 ON-55							Valid	245 ON-552	GOULAIS RI	ON	CAN	Postal code u	Unknown		Unknown	1.34	GOULON95	GOULAIS	Good
SW51	917 Goulai							Valid	917 MISSIOI	GOULAIS RI	ON	CAN	P0S 1E0	No		Yes	9.55	GOULON95	GOULAIS	Good
SW52	7008 High							Corrected	7008 HWY 1	GOULAIS RI	ON	CAN	P0S 1E0	Unknown		Unknown		GOULON95	GOULAIS	Poor
SW52	9741 High							Valid	9741 HIGHV	BATCHAWA	ON	CAN	Postal code u	No		Yes	1.91	BWBAON89	BATCHAWANA	Good
SW52	12461 High							Invalid												Poor