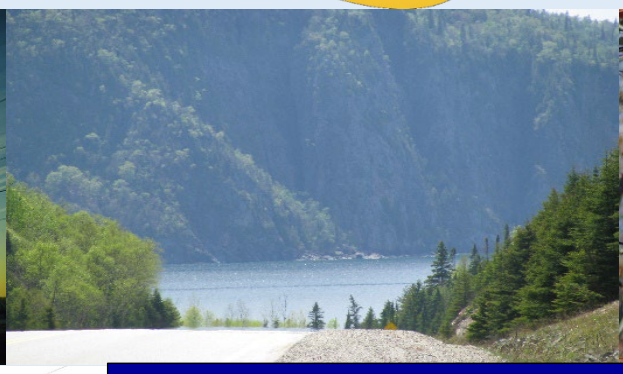
Attachment 1-SEC-3b

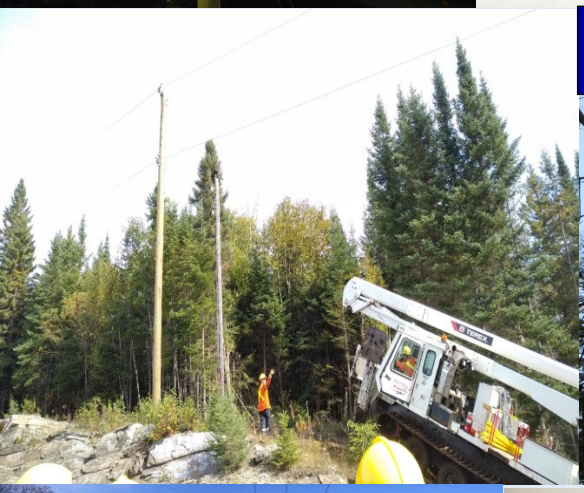
2024-2028 Business Plan

Algoma Power Inc.
EB-2024-0007

Algoma Power Inc.
A FORTIS ONTARIO Company


2024-2028 Five-Year Business Plan













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APPENDICES

1.0 EXECUTIVE SUMMARY

The primary focus of the 2024-2028 Five-Year Business Plan (the "Plan") of Algoma Power Inc. ("API" or the "Company") centers on management achieving continued improvement in overall operational efficiencies, making prudent rate base investments, and driving regulatory performance to enhance earnings while pursuing further expansion of its core regulated distribution business in the Algoma district. The Plan reflects a planning horizon from 2024 to 2028 and includes a comprehensive set of financial forecasts in support of the initiatives for that period.

Management has identified the following areas that represent the most important strategic issues facing the Company over the next five years:

1. Safety and Reliability
2. Financial Performance
3. Operational Performance
4. Regulatory
5. Information Technology
6. Human Resources

The Plan outlines specific objectives and targets in support of API's overall corporate vision of being recognized throughout Ontario as a well-respected, well-managed, and profitable growth vehicle for its parent company, FortisOntario Inc. ("FortisOntario").

2.0 CORPORATE PROFILE

API is a Northern Ontario-based electricity distribution utility, with approximately 1,850 kilometers of lines in a service area of approximately 14,200 square kilometers, which includes Wawa, Goulais River, Desbarats, St. Joseph's Island, Dubreuilville, and Bruce Mines, serving a diverse range of approximately 12,500 customers.

2.1 *CORPORATE VISION*

API will be recognized throughout Ontario as a respected, well managed, and profitable growth vehicle for its parent company, FortisOntario, through its sustained commitment to core business growth and increased returns from existing operations. API will strive to deliver results that

continue to enhance shareholder value while maintaining an unwavering commitment to its Core Values.

OBJECTIVES

The Company will continue to focus on these primary objectives:

i) Earnings: Generate annual net earnings from its distribution business sufficient to achieve a return on equity commensurate with well-run Canadian utilities.

ii) Operational Performance: Ensuring the safe and effective management of its core utility business functions and the achievement of its key performance benchmarks.

CORE VALUES

Our Core Values define what the Company is and how it operates. They reflect the beliefs, philosophy, and commitment of the Company's employees and shareholders. A demonstrated commitment to these values is a prerequisite for individual employee success. Management will treat Respect for People as a condition of employment.

All employees are expected to demonstrate a commitment to the Company's Core Values and will be held accountable for behaving in a manner consistent with these Core Values.

THE CORE VALUES OF ALGOMA POWER INC.

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 within our workplace and 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 our environment.

FINANCIAL SUCCESS: Produce solid earnings, with dividends that meet the expectations of 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 these needs, do so. When you cannot, tell them that 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: Effective teamwork combined with employee innovation produces productivity gains. Employees are encouraged to pursue opportunities to implement new ideas and methods that enhance overall individual and team performance. 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 us. This means time as much as money. Success is measured by the reaction of community leaders and the opinions expressed by community residents.

3.0 SAFETY AND RELIABILITY

3.1 HEALTH, SAFETY & ENVIRONMENT ("HSE")

MANAGEMENT SYSTEMS

API's integrated Health, Safety and Environmental Management System ("HSEMS") is consistent with ISO 45001 and ISO 14001. A number of ongoing and future initiatives support the HSEMS framework, which is built upon ongoing assessments and continual improvement. To prevent complacency in the workplace, Management is renewing its focus on effectiveness and compliance of leading indicators.

The following are objectives, targets, and initiatives, which are supported through management programs and teams.

NEW MEASUREMENT OF SAFETY

The Fortis Operating Group ("FOG") Safety group has evaluated the newly proposed classification and safety measurement processes for suitability and recommended it for implementation across all Fortis subsidiaries. The FOG Safety group has developed a "Safety Measurement" strategic plan to implement the process. This plan will improve the relevancy of safety performance metrics through Severity-Based Lagging Indicator ("SBLI"), in which the Edison Electric Institute ("EEI") research team has produced a safety event classification model that produces more consistency when classifying incidents and promotes focus on high energy hazards. The Safety Classification and Learning ("SCL") model also provides a framework for using lagging indicators (incidents) as learning opportunities that are more readily shared due to common terminology and format. More importantly, the SCL model seeks to improve leading indicators (work observations, job planning, job safety analyses) through High Energy Control Assessments ("HECA") and a focus on controlling hazards to improve safety capacity. The goal over the next few years is to achieve zero Serious Injury and Fatalities ("SIF's") and integrate a measurement of safety performance using a balanced approach of leading and lagging Indicators that is comparable across all Fortis subsidiaries.

SAFETY LEADING INDICATORS

The Company will be focusing on four leading indicator themes that have been identified as building organizational safety capacity as the Company moves to execute the leading indicators to a higher standard. FortisOntario's levels were determined using a self- assessment tool to provide a baseline that will be used to measure the progress of each element and ensure maturity enhancement.

The four leading indicators are: (1) observation and site visits, (2) safety meetings, (3) safety training and education, and (4) a good catch program. As part of an action plan each leading indicator was evaluated using the Safety Culture Maturity Model and placed in one of four dimensions, which include (1) regulatory, (2) directive; (3) engagement, and (4) collaborative. Each leading indicator had a unique criterion used to place the leading indicator into one of the four dimensions. The level of maturity is a four-step continuum from base level dimension (1) to world class dimension (4). This will enable a consistent approach to measurement, monitoring, and progress across all Fortis companies.

FORTIS OPERATIONS GROUP ("FOG") SAFETY GROUP INITIATIVE BEST PRACTICE REVIEW

The FOG safety team has been engaged in sharing best practice reviews with all Fortis companies. Teams will review, identify, and share best practices, polices, and processes. Topics will consist of technical and cultural safety items, including, safety leadership development, communications, and leading indicators. The FOG safety team will communicate the results and recommendations from the best practice reviews to FortisOntario, which will review and endorse the recommendations that will be implemented at all Fortis companies. The FOG safety team developed a baseline survey of Leading Indicators for all Fortis companies to complete, which identified individual baselines of maturity levels for safety observation and site visits, safety meetings, safety training and education, and good catches.

FOG ENVIRONMENTAL GROUP INITIATIVE BEST PRACTICE INITIATIVES

The FOG environmental team has been focused on sharing environmental issues and best practice initiatives with all Fortis companies. Teams will focus on best practices,

policies, processes, and different legislative requirements. Topics will include biodiversity and greenhouse gas initiatives, sustainability, waste management, Canadian Electricity Association ("CEA") designation. The FOG environmental team will communicate initiatives to FortisOntario for further review and potential future implementation.

EMPLOYEE ENGAGEMENT

Consistent with ISO 14001 and 45001, FortisOntario continues to encourage the participation of workers in our HSE processes including incident investigation as required, significant environmental aspects and impacts, and hazard identification risk assessment controls that are evaluated annually.

3.2 SYSTEM RELIABILITY

The Company's 2023 goal for system reliability (SAIDI) is 3.83. As of September 30, 2023, the SAIDI was 3.77. The future year targets are estimated by using the 'previous 3-year rolling average less 5%' approach. A number of initiatives will be taken to achieve the targets, including improving system protection and control, vegetation management, system automation, reducing outage restoration time, and focusing on sustaining capital investment.

4.0 ECONOMIC OUTLOOK [1]

Ontario's economy will expand by 0.9 per cent this year and 1.4 per cent next year. The slowdown in 2023 compared to last year's robust 3.7 per cent rise is elevated interest rates which takes 18 months to one year to be felt. The economy will expand by 2.7 per cent by 2025, when interest rates moderate. Household spending will be sluggish this year as high interest rates and persistent inflation erode disposable income. Automakers and the province have announced they are investing millions in expansions and in battery plants across the cities, which will give a boost to the construction sector. The tight labour market will ensure employment prospects remain strong and support wage growth. High immigration rate will see Ontario's population expand rapidly sustaining household demand.

[1] Ontario's Three-Year Outlook, Conference Board of Canada June 26, 2023

Based on the 2023 Fall Statement released by Ontario on November 2, 2023, a deficit of $5.6 billion is forecasted for 2023-2024 compared to a deficit of $1.3 billion in the March 2023 Provincial Budget. The decline is attributable to lower tax revenues and less economic growth. The result for 2022-2023 was a deficit of $5.9 billion. Ontario is only forecasting a small surplus of $0.5 billion in 2025-2026.

Ontario's key economic indicators for 2022 to 2025 are as follows:

	2022A	2023F	2024F	2025F
REAL GDP (%Δ)	3.7%	0.9%	1.3%	2.7%
CPI (%Δ)	6.8%	3.6%	2.3%	2.1%
UNEMPLOYMENT	5.6%	5.5%	5.9%	5.9%
HOUSING STARTS (000S)	96	86	88	92

In June 2023, the Independent Electricity System Operator ("IESO") released its Reliability Outlook for the period of July 2023 to December 2024. Ontario's electricity system is expected to be available to meet electricity demand and maintain operating reserves during the 18-month period. Under extreme weather forecast, supply is lower than what is required to meet demand and maintain required reserves during the summer months. If available supply is below requirement, the IESO imports power and/or defers generator maintenance outages to meet the requirement,

In 2023, electricity demand is expected to decreased by 0.4 per cent reaching 136.1 TWh. Energy consumption in 2024 is expected to reach 138.8 TWh representing an increase of 1.9 per cent over 2023.

API is expecting load growth over the forecast period from planned mining developments, community developments and related off-spins.

5.0 REGULATORY

5.1 REGULATORY FRAMEWORK

The OEB's Renewed Regulatory Framework for Electricity Distributors ("RRFE") provides three rate-setting methods for distributors including 4th Generation Incentive Rate-Setting ("4th Generation IR"), Custom Incentive, and an Annual Incentive Rate-Setting Index. The

RRFE is applicable to the API distribution business unit. In 2023, API applied for rates under the 4th Generation IR rate-setting method.

The following table provides a summary of the key regulatory indicators of API:

ALGOMA POWER	
OEB-APPROVED TEST YEAR AMOUNTS	
Most Recent Test Year	2020
Rate Base ($000's)	$119,721
Revenue Requirement ($000's)	$25,510
Return on Equity	8.52%
2024 RATE ADJUSTMENTS	
Rate Setting Method (2022)	4th Generation IR
Inflation Factor	4.8%
Productivity Factor	0%
Stretch Factor	0.6%
Distribution Rate Adjustment	4.2% - IR 3.54% - RRRP [1]
UPCOMING REBASING AND RENEWALS	
Type of Rebasing / Renewal	OEB Cost of Service
Next Rebasing/Renewal Year	2025
Rate Setting Mechanism	4th Generation IR

1- Rate adjustments in all years (Test and IR) for API Residential and General Service customers are prescribed by legislation. The RRRP is an electricity subsidy program applicable to customers in rural and remote areas, funded through a province-wide charge on electricity bills.

5.2 REBASING OUTLOOK

API's next rebasing is planned for rates effective January 1, 2025. In its 2022 and 2023 IRM applications, API requested and was approved for ACM funding for its Sault Ste. Marie Facility ("SSM Facility", $12.7M) and Echo River TS ("ERTS", $7.5M) projects, respectively. The ACM/ICM provides for interim cost recovery of qualifying projects during IRM years that is a proxy for the increased revenue requirement that would result from including these projects in rate base. At the next rebasing, API will apply for the total project costs associated with the SSM Facility and ERTS projects in excess of the amounts currently being recovered.

5.3 OEB INITIATIVES AND GOVERNMENT POLICY

Following the implementation of governance reforms in Q3/Q4 2020, the OEB continues to implement various policy initiatives and other programs, primarily focused on energy transition. Key developments include:

- Distribution Energy Resources ("DERs"): The OEB amended the Distribution System Code to standardize and streamline the connection of DERs. The updates clarified definitions, clarified cost responsibility, and created a separate procedure manual and templates. These changes initially came into force October 1, 2022, with further improvements effective June 7, 2023, and September 18, 2023. Furthermore the OEB released a report permitting distributors to apply for incentives for the use of DERs as non-wires alternatives ("NWAs"). Currently, the OEB is preparing guidelines for a cost-benefit analysis for the use of DERs as NWAs, which will consider both distribution and bulk system benefits.

- Electric Vehicle ("EV") Charging: Currently the OEB's filing requirements require distributors to demonstrate they have planning processes in place to address future capacity needs, including in relation to EVs. The Ministry of Energy made data available to LDCs regarding the purchase of EVs by postal code. The OEB has a policy initiative investigating alternative delivery rate designs for commercial EV charging (public charging stations and fleet charging).

- Resiliency and Reliability: Under separate policy initiatives, the OEB has been reviewing resiliency and reliability. The focus of the resiliency policy consultation is on preparing the electricity system to withstand and recover from extreme weather events caused by climate change, in a manner which balances affordability considerations. The reliability initiatives focus on increased reliability reporting (more detailed cause information, customer-specific reliability metrics, loss of supply reporting), which aim to drive improvements in reliability benchmarking and performance.

6.0 OPERATIONAL PERFORMANCE

6.1 DISTRIBUTION SYSTEM PLAN ("DSP")

API continues to implement the OEB accepted DSP in the Cost of Service application. Major investment areas include:

- Express feeder-rebuilding projects;
- Pole replacement programs;
- System automation projects;
- Rebuild or upgrade three distribution substations; and
- Signed agreement with Hydro One to add another 230/34.5 kV, 25 MVA power transformer in 2023.

API completed several major projects identified in the 2020–2024 DSP filed during the 2019 rate application, including the addition of the Echo River TS (Hydro One owned) second power transformer, construction of the Sault new office building, sub-transmission line upgrades, deteriorated assets replacement, and customer driven projects. Currently, API is preparing a new DSP for the 2025–2029 period for the next rate application. As Hydro One will rebuild Batchawana TS and Goulais TS during the next couple years, API's next major investment areas will include the distribution system upgrade and rebuild supplied by these two new transmission substations, along with customer driven projects and asset replacements. These two substations are located along Trans-Canada Highway 17. Currently the loads in the areas are low and are supplied partially by 7.2 kV single phase lines. API requested Hydro One to supply and install 115 kV to 12.5 and 25 kV dual secondary voltage transformers and make the substation ready to be converted to 25 kV in the future. API will rebuild the lines in these areas to 25 kV, 3-phase system in the future to service the potential EV charging load in the future.

6.2 SYSTEM INSPECTION AND MAINTENANCE

The Company will continue inspection and maintenance programs to minimize equipment life cycle costs, including:

- Equipment inspection and maintenance programs based on OEB and CSA requirements and good utility practice;
- Vegetation management programs; and
- Pole testing programs.

6.3 DISTRIBUTION CAPITAL INVESTMENTS

API will invest approximately $55.56 million over the forecast period in its distribution system. The following table summarizes the net capital investment planned:

	2024	2025	2026	2027	2028	5-Year Total
API DIST	10,506	9,983	10,318	14,100	10,656	55,563

6.4 OPERATIONAL EFFICIENCIES AND INNOVATION

While focusing on sustaining investment and system performance, API is also exploring opportunities in efficiency gain and innovation. One area under development is the system control and automation plan. Following the successful completion of the SCADA pilot project, API intends to pursue full implementation and will develop distribution automation strategy. Alongside the sustainment investment program, API is looking at a medium term voltage conversion, which will ensure API is better positioned to support the forecasted supply requirements, while also reduced system losses. A plan will be developed to electrify its small fleet and install EV charging stations when financially justifiable. API is also looking for projects in areas of micro grid and distributed energy resource to improve operation efficiency and improve system reliability.

6.5 CUSTOMER SERVICE

CUSTOMER SERVICE ANALYSIS

The Company continues to focus on identifying efficiencies and enhancing the customer experience through the consolidation of services and the development of technology. Focus also continues on developing talent within the Company to improve alignment with business requirements and employee retention. Due to the complex nature of the work involved, and SOX based control measures, it is critical that skilled employees are

developed to meet those challenges for entry level positions and support succession planning strategies.

The customer service environment has changed significantly over the past few years. This includes complexity of regulation governing the Ontario utility space as well as customer expectations to support those changes by continuing to provide clear messaging along with complete and accurate billing information in a timely manner. Given the three FortisOntario locations, all with unique requirements and customer demographics, customer service will be reviewing the “as built” environment in terms of major processes with the intent of assessing current deficiencies, risks and where we are getting it right. This project will extend beyond 2023, to properly determine and possibly re-engineer business processes to better align with current company requirements.

CUSTOMER ENGAGEMENT

The Company’s customer engagement plan includes recording and tracking engagement activities and implementing methods to objectively measure the level of engagement with customers and the respective impact the activities are providing.

A customer communication framework is being developed that will accomplish the following objectives:

- Actively encourage customers to register with the new customer self-serve portal, which creates an improved and more independent experience. This will continue to be promoted through annual campaign messaging via social media, and direct customer service team member calls.
- Continued development of new smart forms delivered to customers within the customer self-serve portal allowing easier submission of common activities such as new customer connection, move-out requests, and pre-authorized debit enrollment.
- Actively communicate with customers during major power outages. The Company intends to "push" outage information to customers during major power outages by using customer preferred communication channels. This is being supported by providing line staff with mobile devices and allowing them to actively change the status of an outage in the OMS, which will accurately update information to customers. This technology

deployment has essentially been completed in API and will be used as the corporate model for replication in other FortisOntario locations.

COLLECTIONS

Credit and collection activities have increased. The disconnection moratorium on residential customers required greater focus on managing arrears. Review of the credit and the collection process will be ongoing as part of continuous improvement. Specifically, the responsiveness of customers to all dunning activities is being measured to gauge what is working most effectively to reduce the average days of receivables. Such review looks at developing best practices for all account collection processes and ensuring consistency across FortisOntario. Where possible, configuration to SAP will be made to further increase automation and reduce the need for manual intervention. Receivables are affected during the months of November through April during the disconnection moratorium in Ontario. Arrears increase during this period and will require ongoing recovery efforts. Focus will be on the larger outstanding amounts (>$500) while also encouraging payment arrangements in accordance with the OEB's mandate to work cooperatively with customers.

7.0 INFORMATION TECHNOLOGY ("IT")

API strives to provide high quality and efficient technology solutions that support and enhance corporate and operations' functions. Delivering products and tools that improve accuracy and effectiveness while working closely with stakeholders is a key part of the Company's philosophy.

Between 2024 and 2028, significant investment and growth are expected in the following technology areas:

- Cybersecurity – IT and Operational Technology ("OT");
- SAP CIS & ERP Upgrade Planning and Ongoing Enhancements; and
- Cloud Adoption and Technology Enhancements.

CYBERSECURITY – IT AND OT

In maintaining and striving to exceed compliance in both OEB and Fortis cybersecurity frameworks, which are based upon energy sector-specific sections of the Cybersecurity

Capability Maturity Model ("ES-C2M2"), the Company is working to reduce cybersecurity risk and enhance its maturity in a number of security-related practices.

The Company is continuing with its plan to enhance cybersecurity controls and practices between 2024 and 2028, using its 2019 Cybersecurity Risk Management Program ("CRMP") as the foundation for its cybersecurity risk reduction improvements. A mid-program assessment in 2022 confirmed that significant progress has been made in reducing IT risk, while the next three to five years will focus heavily on integrating OT technology administration and oversight into IT in delivering on the CRMP's commitment to sustainable cybersecurity risk across all technology areas. Some of the next five years' cybersecurity enhancements include:

- Integrate a passive network monitoring solution in the OT network as a first line of defense against network attacks on the SCADA operational network and gain visibility into network performance issues or potential threat vectors.
- Implement a Privileged Identify and Access Management ("PIAM") solution to control and monitor all access to and use of administrative accounts across both IT and OT environments.
- Integrate Data Loss Prevention ("DLP") technology into the Company's corporate network to prevent the leaking and sharing of unauthorized and/or confidential information, and to establish a better classification method for company data.
- Complete an asset inventory of OT equipment and devices, and ensure that a robust mechanism for tracking useful life, patch levels, criticality, and other important information is in place and governed by a documented change management framework.

SAP ERP UPGRADE & ONGOING ENHANCEMENTS

The current release of SAP (called SAP ECC 6.0 with SAP for Utilities) will be at the end of mainstream vendor maintenance in 2027. However, it is possible to contract with SAP for extended maintenance until the end of 2030. Over the next couple of years, the Company will be assessing the viability of SAP's next release (SAP S/4HANA) to determine if an

upgrade can be justified to bring significant value to the Company in comparison to the cost and effort required to upgrade or re-implement the current system.

Ahead of any system upgrades or decisions about future direction, the Company continues to enhance and improve the current system, with the intention of all investments being fully compatible with an upgraded ERP solution over the course of 2024-2028. As business requirements change to meet unpredictable market modifications, planned work is continually reassessed and reprioritized to ensure critical changes are implemented within prescribed deadlines.

CLOUD ADOPTION & TECHNOLOGY ENHANCEMENTS

The IT industry is seeing a rapid move away from on-premise infrastructure to hosted, cloud-based systems. Cloud services offer security, high availability, and redundancy in excess of what most organizations could afford to build on-premise, and reduces the need for hardware and software maintenance tasks. With careful planning, costly on-premise system replacements will be moved to the cloud. While this will shift a large portion of IT capital expenses to operating expenses, the benefits realized by the Company in terms of cybersecurity, reliability, and better use of human resources will justify the cloud adoption. Additionally, software continues to move away from perpetual (i.e., capital cost) licenses to subscription-based models, further decreasing technology capital spending in and shifting it towards annual operating expenses. To help mitigate this industry change, the Company is dedicating resources to evaluating the use of technology across all businesses and finding efficiencies and consolidations of products where possible. Leveraging core capabilities of products available as part of the Microsoft 365 suite and other platforms will help alleviate the shift from capital to operating and minimize the need for standalone, niche software.

8.0 HUMAN RESOURCES ("HR")

8.1 LEADERSHIP DEVELOPMENT

The Company has 59 full-time equivalents ("FTEs") working throughout API, which is expected to remain fairly stable in the coming years. The Company remains committed to retaining and attracting skilled employees to meet ongoing business requirements. API

initiated a practice of hiring co-op students or apprentices in technical areas to facilitate training and assess skills in preparation for anticipated future vacancies due to retirement. This will also provide an opportunity to "retool" the business as required so that skill sets meet future business needs. The Company continues to work with department managers to ensure that future staffing requirements are met. There has been a higher number of retirements in the last few years, becoming increasingly difficult to attract qualified candidates, in particular technical positions. The Company has been working with recruiting firms to assist in recruitment.

API is looking holistically at its leadership development program, and to date, there have been a number of undertakings such as a mentoring program, 360 benchmark programs, and Confident Coach Supervisory training. Together these programs have supported the goal of ensuring the Company has the right people in critical roles to meet the Company's strategic objectives. In 2023, the Company, in conjunction with the Confident Coach facilitator, launched leadership development programs for its people leaders. In addition, the FortisOntario group of companies is working together and has delivered a leadership development program, specific to Fortis for top talent at the manager and director levels across the organization. The Company is committed to ensuring a developmental roadmap it created so there is clear direction for leadership development moving forward.

8.2 SUCCESSION PLANNING

The Company has a succession plan in place for managers and key supervisors, which is updated regularly. As part of the ongoing planning process, the Company enhanced this plan with more detailed supporting work history and biographic information for candidates and identification of gaps where there are no in-house candidates available to be groomed for succession opportunities. In addition, the Company coordinates key information from this process in support of the broader FortisOntario talent management process. A developmental roadmap will be created for high potential candidates.

8.3 LABOUR RELATIONS

Approximately 51 per cent of the workforce is unionized and has an agreement with the PWU union. The Company has harmonious labour relations and is focused on strategies

to maintain positive labour relations. Meetings between labour and management are held semi-annually and as required with the bargaining unit. API's four-year collective agreement expires December 2023, and the Company will look to previous settlements within the FortisOntario group of companies with respect to negotiations.

The Company remains focused and will continue its effort on the benefit administration process, streamlining across FortisOntario where possible. In support of this effort, an analysis of health plans has been undertaken to ensure that the Company's health and medical plans are structured to effectively manage anticipated cost increases due to industry trends. As a result, health and benefit costs have decreased and lower fund management fees (defined contribution pension plan) were renegotiated with the plan sponsor. A harmonized health and medical benefit plan were rolled out to all non-unionized employees in 2022. A benefits committee was established to discuss industry trends and feedback regarding the new harmonized plan.

8.4 DIVERSITY, EQUITY AND INCLUSION ("DEI")

DEI is included in API's Core Values to 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. It also supports its relationships with FortisOntario's First Nations partners. The Company relaunched its DEI plan to employees and has an established a DEI leadership team comprised of a cross-section of employees throughout the organization to continue to create and maintain a welcoming environment that encourages and promotes diversity, cross-culture working experiences, strong relationships within the Company, and with the Company's Indigenous communities and partners. Ongoing awareness will continue to be generated through the digital bulletin boards, companywide training, and other Company initiatives to encourage 'Starting the Conversation'.

8.5 CORPORATE COMMUNICATIONS

A corporate communications strategy is being designed that will align with its business plans and provide guidance for future communications initiatives. While certain communications efforts tend to be reactive by nature (e.g., responding to a crisis, major outage), other communications require proactive communications. For example,

communications can be used for supporting various operational areas such as health and safety, and infrastructure projects that are part of organic growth.

API continues to focus on improved employee communications to foster consistent messaging across all locations. A communications framework to establish a consistent set of standards was rolled out to managers. These standards include inter/intra departmental communications, regular managers' meetings, and improving dissemination of information through the use of technology, such as the intranet and other IT systems. The new intranet is being leveraged as a consistent means of communicating with all employees. From on-boarding to Company policies, all pertinent information is stored on the intranet. An analysis to optimize the system's capabilities is ongoing and increased use of virtual meetings is expected to continue. Microsoft Teams software is used extensively to facilitate enhanced communication across the organization.

To further enhance communication, digital bulletin boards are being utilized at all work locations, which replaced traditional bulletin boards and enabled information to be disseminated quickly and consistently throughout the Company. Townhall meetings are also scheduled for all locations as well as annual safety awareness days. Further enhancement of the intranet will be ongoing to leverage increased digital engagement throughout the Company.

9.0 CORPORATE TARGETS

API will use the following key corporate targets to measure performance against plan. This objective approach promotes accountability while ensuring focus on key success factors and identifying areas where improvement is required.

CORPORATE TARGETS							
FINANCIAL	**2022 ACTUAL**	**2023 FORECAST**	**2024 TARGET**	**2025 TARGET**	**2026 TARGET**	**2027 TARGET**	**2028 TARGET**
NET EARNINGS ($'MILLIONS)	4.7	5.1	5.3	6.1	6.2	6.2	6.0
OPERATING EXPENSE ($' MILLIONS)	14.1	14.7	15.0	15.3	15.6	15.9	16.2
GROSS CAPITAL EXPENDITURES ($' MILLIONS)	8.9	10.0	10.9	33.1	9.1	11.6	9.2
SYSTEM RELIABILITY							
SAIDI	4.42	4.61	3.79	3.64	3.52	3.43	3.80
HEALTH & SAFETY							
HIGH RISK LOST TIME INJURY	0	0	0	0	0	0	0
PLANNED WORK OBSERVATIONS & WORKPLACE INSPECTIONS (% OF PLAN)	117	100	100	100	100	100	100
CUSTOMER SERVICE							
CUSTOMER SATISFACTION RATING (%)	95	95	95	95	95	95	95
ACCOUNTS RECEIVABLE OVER 30 DAYS (%)	15	15	15	15	15	15	15
SERVICE LEVEL (% CALLS WITHIN 30 SEC.)	86	83	83	83	83	83	83
HUMAN RESOURCES							
ABSENTEEISM (DAYS/EMPLOYEE)	5.71	3.65	3	3	3	3	3
FTE (YEAR-END)	59	59	59	59	59	59	59

10.0 FINANCIAL PERFORMANCE

10.1 FINANCIAL FORECAST

	2022 ACTUAL	2023 FORECAST	2024 PLAN	2025 FORECAST	2026 FORECAST	2027 FORECAST	2028 FORECAST
Sales (GWh)	256	291	299	301	302	304	305
Revenue net of energy purchases	27,223	28,543	30,238	32,501	33,151	33,814	34,490
Operating expenses	14,053	14,719	14,984	15,282	15,589	15,901	16,219
Depreciation	4,188	4,515	4,634	5,089	5,297	5,591	5,842
Operating income	8,982	9,309	10,620	12,131	12,265	12,322	12,429
Other (income) and expense	3,990	3,800	4,955	5,331	5,331	5,331	5,331
Income taxes	259	403	406	696	780	821	1,069
Net Income	4,733	5,106	5,259	6,104	6,154	6,170	6,029
Dividends paid	-	-	3,000	4,000	4,000	5,000	6,000

The 2023 forecast earnings of $5.1 million are expected to be $0.3 million higher than plan due to increases in interest income and decreases in income tax expenses.

The 2024 plan earnings of $5.3 million are up $0.2 million from the 2023 earnings forecast.

The Cost of Service 2020 approved rate base was $119.7 million, an increase of $21.6 million or 4.1 per cent compound annual growth rate ("CAGR") over the 2015 approved rate base. API is expected to rebase again in 2025, and the forecasted rate base is $172.5 million, an increase of $52.8 million or 7.6 per cent CAGR since 2020.

Over the business planning period for goodwill analysis purposes, financial modeling assumes electricity distribution rates in non-rebasing years grow at 5.94 per cent in 2024, 2.00 per cent in 2026, 2.00 per cent in 2027, and 2.00 per cent in 2028 (combination of incentive regulation, load growth and ACM) and operating expenses grow by 2.0 per cent. API will rebase in 2025.

Detailed financial statements for the forecast period have been attached (Appendix A), along with the forecast capital budget (Appendix B) and the major assumptions in the plan (Appendix C).

10.2 FINANCING

API maintains a capital structure of approximately 60 per cent long-term debt and 40 per cent equity, similar to the OEB's deemed capital structure. Financing requirements of the regulated operations will be supported by a combination of short-term borrowings from the non-regulated operations as well as short-term bank borrowings, until the short-term debt is large enough to be replaced by financing from capital markets. The Business Plan assumes the borrowing of the external debt of $50.0 million at API in 2023.

10.3 SCENARIO ANALYSIS

API's most recently approved cost of service application was for rates effective January 1, 2020. The allowed ROE was determined by the OEB in October 2019, to be 8.52 per cent. A one per cent change in the assumed allowed ROE would change API earnings by approximately $590,000.

APPENDIX A

Financial Statements

[*attached*]

Algoma Power Inc.
Balance Sheet
As at December 31

	Actual 2022	Forecast 2023	Budget 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Current assets							
Cash and temporary investments	**$ 1,994**	**$ 6,804**	**$ 4,178**	$ 8,107	$ 8,318	$ 5,336	$ 3,705
Accounts receivable	**6,039**	**6,160**	**6,283**	6,409	6,537	6,668	6,801
Inventory	**175**	**178**	**182**	184	186	188	189
Regulatory assets	**978**	**800**	**800**	800	800	800	800
Other current assets	**200**	**204**	**208**	208	208	208	208
	9,483	**14,146**	**11,651**	15,708	16,049	13,200	11,703
Utility plants							
Cost	**202,805**	**212,584**	**223,283**	256,176	265,120	276,548	285,521
Less: accumulated amortization	**(74,259)**	**(78,608)**	**(83,238)**	(88,323)	(93,615)	(99,202)	(105,039)
	128,546	**133,976**	**140,045**	167,853	171,505	177,346	180,482
Accrued pension benefit asset	**9**	**1,000**	**2,000**	2,040	2,081	2,122	2,165
Intangible assets	**14,170**	**13,729**	**13,257**	12,753	12,240	11,717	11,183
Regulatory assets, non current	**26,939**	**37,439**	**35,000**	10,000	10,200	10,404	10,612
Other assets	**65**	**1,200**	**2,500**	-	-	-	-
Total assets	**$ 179,212**	**$ 201,490**	**$ 204,453**	$ 208,354	$ 212,075	$ 214,789	$ 216,145
Current liabilities							
Bank indebtedness	**$ 20,000**	**$ -**	**$ -**	$ -	$ -	$ -	$ -
Accounts payable and accrued liabilities	**6,836**	**6,971**	**7,111**	7,253	7,399	7,546	7,697
Customer deposits	**95**	**124**	**124**	126	129	131	134
Due to affiliates	**5,350**	**1,000**	**1,000**	1,000	1,000	1,000	1,000
	32,281	**8,095**	**8,235**	8,379	8,528	8,677	8,831
Long-term customer deposits	**667**	**576**	**576**	576	576	576	576
Long-term debt	**51,683**	**101,701**	**101,717**	101,734	101,751	101,768	101,785
Affiliate long-term debt	**12,750**	**-**	**-**	-	-	-	-
Accrued post retirement benefit liability	**5,963**	**7,000**	**7,140**	7,283	7,428	7,577	7,729
Future income taxes payable	**9,025**	**10,239**	**10,311**	11,483	12,603	13,693	14,559
Regulatory liabilities	**1,276**	**3,000**	**3,000**	3,060	3,121	3,184	3,247
Contributions	**6,633**	**6,836**	**7,170**	7,434	7,509	7,584	7,659
Shareholder's equity							
Common and preferred shares	**44,008**	**44,008**	**44,008**	44,008	44,008	44,008	44,008
Retained earnings	**14,926**	**20,035**	**22,296**	24,397	26,551	27,722	27,751
Total shareholder's equity and liabilities	**$ 179,212**	**$ 201,490**	**$ 204,453**	$ 208,354	$ 212,075	$ 214,789	$ 216,145
Total debt	**60%**	**62%**	**61%**	**60%**	**59%**	**59%**	**59%**
Shareholder's equity	**40%**	**38%**	**39%**	**40%**	**41%**	**41%**	**41%**

Algoma Power Inc.
Statement of Cash Flows
For the Period Ending December 31

	Actual 2022	Forecast 2023	Budget 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
Operating activities							
Net earnings for the period	**$ 4,733**	**$ 5,106**	**$ 5,259**	$ 6,104	$ 6,154	$ 6,170	$ 6,029
Amortization	**4,188**	**4,964**	**5,243**	5,711	5,931	6,238	6,502
Change in working capital	**9,550**	**(24,034)**	**9**	14	17	19	17
Deferred pension costs	**7,555**	**(991)**	**(1,000)**	(40)	(41)	(42)	(42)
Future income taxes	**1,401**	**1,214**	**72**	1,172	1,120	1,090	866
Regulatory assets and liabilities	**(22,760)**	**(8,776)**	**2,439**	25,060	(139)	(142)	(144)
Other asset	**(50)**	**(1,130)**	**(1,300)**	-	-	-	-
Loss (gain) on disposal of property, plant and equipment	**(32)**	**-**	**-**	-	-	-	-
Deferred post retirement benefits	**(625)**	**1,037**	**140**	143	146	149	152
Cash from operations	**3,960**	**(22,610)**	**10,862**	38,164	13,188	13,482	13,380
Financing activities							
Dividend paid	**-**	**-**	**(3,000)**	(4,000)	(4,000)	(5,000)	(6,000)
Change in long-term debt	**-**	**37,262**	**17**	17	17	17	17
Affiliate long-term debt	**79**	**(91)**	**-**	-	-	-	-
Contributions	**3,363**	**242**	**385**	315	128	128	130
Cash from (used in) financing activities	**3,442**	**37,413**	**(2,598)**	(3,668)	(3,855)	(4,855)	(5,853)
Investing activities							
Net additions to utility plant	**(8,169)**	**(9,779)**	**(10,699)**	(32,894)	(8,944)	(11,428)	(8,973)
Additions to intangibles	**(195)**	**(214)**	**(192)**	(174)	(178)	(181)	(185)
Proceeds of sale of utility capital assets	**63**	**-**	**-**	-	-	-	-
Change in other assets	**-**	**-**	**-**	2,500	-	-	-
Cash used in investing activities	**(8,301)**	**(9,993)**	**(10,891)**	(30,568)	(9,122)	(11,609)	(9,158)
Increase (decrease) in cash	**(899)**	**4,810**	**(2,626)**	3,928	211	(2,982)	(1,631)
Cash, beginning of period	**2,893**	**1,994**	**6,804**	4,178	8,107	8,318	5,336
Cash (bank indebtedness), end of period	**$ 1,994**	**$ 6,804**	**$ 4,178**	$ 8,107	$ 8,318	$ 5,336	$ 3,705

Algoma Power Inc.
Income Statement
For the Period December 31

	Actual 2022	Forecast 2023	Budget 2024	Forecasted 2025	Forecasted 2026	Forecasted 2027	Forecasted 2028
Revenue							
Sale of energy	**$ 29,361**	**$ 34,718**	**$ 40,339**	$ 40,944	$ 41,558	$ 42,181	$ 42,814
Distribution revenue	**26,500**	**27,925**	**28,330**	31,837	32,474	33,123	33,785
Other revenue	**723**	**618**	**1,908**	664	677	691	705
	56,584	**63,261**	**70,577**	73,445	74,709	75,995	77,304
Purchased power	**29,361**	**34,718**	**40,339**	40,944	41,558	42,181	42,814
	27,223	**28,543**	**30,238**	32,501	33,151	33,814	34,490
Operating expenses							
Distribution	**7,416**	**7,789**	**7,929**	8,088	8,250	8,415	8,583
General	**5,545**	**5,309**	**5,610**	5,722	5,837	5,954	6,073
Customer Service	**950**	**1,157**	**1,094**	1,116	1,138	1,161	1,184
Municipal and other taxes	**142**	**464**	**350**	357	364	371	379
	14,053	**14,719**	**14,984**	15,282	15,589	15,901	16,219
Depreciation and amortization	**4,188**	**4,515**	**4,634**	5,089	5,297	5,591	5,842
Operating income	**8,982**	**9,309**	**10,620**	12,131	12,265	12,322	12,429
Other income							
Interest on Investments	**95**	**902**	**700**	200	200	200	200
Services and miscellaneous revenue	**3**	**1**	**-**	-	-	-	-
Gain (loss) on disposals	**(32)**	**-**	**-**	-	-	-	-
	69	**903**	**700**	200	200	200	200
Other income deductions							
Loan interest expense	**3,494**	**4,347**	**5,483**	5,483	5,483	5,483	5,483
Intercompany interest expense	**441**	**232**	**48**	48	48	48	48
Regulatory expenses	**124**	**124**	**124**	-	-	-	-
	4,059	**4,703**	**5,655**	5,531	5,531	5,531	5,531
Earnings before income taxes	**4,992**	**5,509**	**5,665**	6,800	6,934	6,991	7,098
Provision for income taxes	**259**	**403**	**406**	696	780	821	1,069
Net income	**$ 4,733**	**$ 5,106**	**$ 5,259**	$ 6,104	$ 6,154	$ 6,170	$ 6,029
Return on Equity	**8.4%**	**8.3%**	**8.1%**	**9.1%**	**8.9%**	**8.7%**	**8.4%**

APPENDIX B

Capital Budget

[*attached*]

Algoma Power Inc.
5 Year Capital Budget
(000's)

APPENDIX B

	2022 Actual	2023 Forecast	2024 Budget	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
Algoma Power							
Substation Upgrades [1]	4,438	(4,344)	3,905	11,589	1,723	4,007	1,543
Line Replacements and Customer Extensions	9,376	12,022	5,244	5,307	5,190	5,328	5,470
Meters	133	115	133	150	153	156	159
Tools and Equipment	69	95	110	112	115	117	119
Distribution Rebuilds - Storms	12	95	-	-	-	-	-
Scada System Development	66	90	140	143	146	138	70
Land Easement and R.O.W. Procurement	159	36	39	40	41	42	43
R.O.W. Expansions	-	100	122	124	127	129	132
Vehicles	581	760	585	850	950	1,007	1,027
Buildings & Service Centre [1]	(6,593)	401	134	14,223	138	139	40
Distribution Transformers/Reclosers/Regulators	377	447	326	395	404	411	420
IT	260	178	152	135	135	135	135
Total Algoma Power	**8,878**	**9,995**	**10,890**	**33,068**	**9,122**	**11,609**	**9,158**
Contributions	**3,363**	**242**	**385**	**315**	**128**	**128**	**130**
Grand Total (Net)	**5,515**	**9,753**	**10,505**	**32,753**	**8,994**	**11,481**	**9,028**

APPENDIX C

Forecast Assumption

[*attached*]

ALGOMA POWER INC.

2024-2028 PLAN AND FORECAST

ATTACHMENT C - ASSUMPTIONS

The following assumptions were made in developing the 2024 plan and 2025-2028 forecast:

DISTRIBUTION ENERGY SALES (GWH)

	2022A	2023F	2024P
RESIDENTIAL	105	123	130
COMMERCIAL/OTHER	151	168	169
TOTAL ENERGY SALES	256	291	299
% CHANGE FROM PRIOR YEAR		13.7%	2.7%

DISTRIBUTION – CONNECTED CUSTOMERS

	2022A	2023F	2024P
RESIDENTIAL	11,213	11,759	12,305
COMMERCIAL/OTHER	1,108	1,127	1,146
TOTAL CUSTOMERS	12,321	12,886	13,451
% CHANGE FROM PRIOR YEAR		4.6%	4.4%

T&D RATE INCREASES

	2024	2025	2026	2027	2028
API [(1)]	5.94%	Rebase	2.00%	2.00%	2.00%

(1) In non-rebasing years, combination of IRM, load increase and ACM.

	2024	2025	2026	2027	2028
DIVIDENDS ($'000)	3,000	4,000	4,000	5,000	6,000
CORPORATE INCOME TAX RATE	26.50%	26.50%	26.50%	26.50%	26.50%
RATE BASE ($'M)	148	173	179	183	187
% CHANGE FROM PRIOR YEAR (%)	3.8%	16.8%	3.7%	2.4%	2.2%

EXPENSES

- General expenses rise at an average of 2.0% per annum beyond 2024.
- 2024 annual expense for pension and post- retirement benefits:

($ '000)	
DEFINED BENEFIT	52
DEFINED CONTRIBUTION	148
SERP	3
POST RETIREMENT	517
	720

- Assumptions:

  Investment Rate: 5.75%
  Discount rate: 4.85%

- 2024 composite depreciation rate is 2.1%

APPENDIX D

OEB Scorecard

[*attached*]

Scorecard - Algoma Power Inc.

Performance Outcomes	Performance Categories	Measures		2018	2019	2020	2021	2022	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		98.63%	97.10%	100.00%	100.00%	98.64%	up	90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%	flat	90.00%	
		Telephone Calls Answered On Time		86.06%	81.61%	84.84%	88.36%	85.46%	up	65.00%	
	Customer Satisfaction	First Contact Resolution		99.97%	99.96%	99.93%	99.95%	99.99%			
		Billing Accuracy		99.86%	99.87%	99.87%	99.82%	99.92%	up	98.00%	
		Customer Satisfaction Survey Results		93%	95%	94%	93%	97%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness		82.00%	83.00%	83.00%	83.00%	82.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	flat		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	flat		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		7.51	7.33	6.79	3.61	4.43	down		7.36
		Average Number of Times that Power to a Customer is Interrupted [2]		2.20	3.39	2.93	1.77	2.08	down		3.16
	Asset Management	Distribution System Plan Implementation Progress		Completed	Completed	Completed	Completed	Completed			
	Cost Control	Efficiency Assessment		5	5	5	5	5			
		Total Cost per Customer [3]		$2,182	$2,235	$2,212	$2,338	$2,479			
		Total Cost per Km of Line [3]		$13,831	$12,107	$12,203	$13,025	$14,501			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Connection of Renewable Generation**	Renewable Generation Connection Impact Assessments Completed On Time [4]									
		New Micro-embedded Generation Facilities Connected On Time		100.00%				100.00%	flat	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.07	0.69	0.77	0.43	0.26			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.42	1.36	1.30	1.32	1.44			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.30%	9.30%	8.52%	8.52%	8.52%			
			Achieved	8.22%	8.44%	9.25%	9.38%	10.53%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor 's reported information.
4. Value displayed for 2021 reflects data from the first quarter, as the filing requirement was subsequently removed from the Reporting and Record-keeping Requirements (RRR).

Legend:

5-year trend
up down flat

Current year
target met target not met

2022 Scorecard Management Discussion and Analysis ("2022 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2022 Scorecard MD&A:

Scorecard - Performance Measure Descriptions (oeb.ca)

Scorecard MD&A - General Overview

- In 2022, API met or exceeded all of its performance targets, consistent with the strong performance in prior years.
- In 2023, API expects to continue to maintain and improve its overall scorecard performance results. Sustaining and improving performance are expected as a result of enhanced system reliability due to API's investment in its distribution system and continued responsiveness to customer feedback.

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2022, API connected 99% of the 220 new eligible low-voltage residential and small business customers within the Ontario Energy Board's prescribed five-day timeline. Since 2011, API has consistently exceeded the Ontario Energy Board's target of 90%.

- **Scheduled Appointments Met On Time**

In 2022, API met 100% of its 190 appointments within the prescribed timelines set out by the Ontario Energy Board. Since 2013, API has consistently attended 100% of its schedule appointments on time.

- **Telephone Calls Answered On Time**

In 2022, customer service representatives answered 85.5% of API's 8,769 calls within 30 seconds. This exceeds the Ontario Energy Board's mandated 65% target. Longer call processing times due to the complexity of customer calls are affecting the call answering statistics. API continues to offer and promote self-serve options and utilizes social media to engage and inform customers in an effort

to offer customers additional channels to interact with the Company.

Customer Satisfaction

- **First Contact Resolution**

API measured First Contact Resolution by tracking the number of escalated calls as a percentage of total calls taken by the customer service center. In 2022, only 0.01% of calls were escalated, resulting in a first contact resolution of 99.99%.

- **Billing Accuracy**

For 2022, API issued 149,546 invoices and 99.92% were accurate. This is above the industry target of 98%.

- **Customer Satisfaction Survey Results**

API conducts its customer satisfaction surveys through a third-party survey provider, UtilityPULSE, consistent with many other LDCs in the province. Phone numbers were randomly selected so that 85% per cent of the interviews were conducted with residential customers and 15% with general service customers. API's 2022 satisfaction score was 97%. The Ontario benchmark assessed by UtilityPULSE is 90%.

The survey provides useful information to better meet the needs of API's customers and is incorporated into API's distribution system plan, capital planning and overall company objectives.

Safety

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

The Electrical Safety Authority has developed a survey on public awareness of electrical safety. The Electrical Safety Authority is responsible for developing the survey methodology and questions. The design and scoring are standardized across the province and set by the Electrical Safety Authority. In 2022, API engaged UtilityPulse to complete the survey in relation to "Public Awareness of Electrical Safety". On completion of this survey, UtilityPulse generated a "Public Safety Awareness Index Score" for API. 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. This survey on "Public Awareness of Electrical Safety" is completed on a two-year cycle and will be completed again by API in 2024.

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

This component includes the results of an Annual Audit, Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. All the elements are evaluated as a whole and determine the status of compliance (Non-Compliant, Needs Improvement, or Compliant).

API's status as evaluated by the ESA is Compliant.

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

"Serious electrical incidents", as defined by Regulation 22/04, make up Component C. The metric details the number of and rate of "serious electrical incidents" occurring on a distributor's assets and is normalized per 10, 100 or 1,000 km of line (10km for total lines under 100km, 1000km for total lines over 1000km, and 100km for all the others).

API had zero incidents in 2022.

System Reliability

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

API's customers experienced an increase in the average duration of electrical service disruptions in 2022 compared to 2021. The 2022 result is 40% better than API's performance target.

The average number of hours that power to a customer is interrupted, which are adjusted for Loss of Supply and Major Event Days, shows a decreasing trend. This indicates a general improvement in reliability for items within API's control. The four main outage causes in API's service area are Tree Contacts, Loss of Supply, Scheduled Outages and Defective Equipment.

API continues to invest in grid modernization to gain visibility on the state of the distribution system and improve overall response and restoration times. Grid modernization initiatives include the deployment of automated devices, implementation of a SCADA system and further development of API's outage management system. Outages in Northern Ontario can have significant impact to our customers, which is why API has continued to invest in asset contingency planning, ensuring redundancy in critical supplies and equipment. API has also continued to prioritize the management of its right-of-ways through its integrated vegetation management program.

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

API's customers experienced a slight increase in the average number of electrical service disruptions in 2022 as compared to 2021, the result is 35% lower than API's performance target of 3.16, and shows an improving trend during the most recent five-year period.

API reviews outage statistics on a monthly basis 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 asset condition assessments to identify assets that present a risk of impacting system reliability. API uses reliability indicators and asset condition assessment data as key drivers into the system planning process.

API's outage reduction strategy is based on a cyclical asset preventative maintenance program through inspections and testing, and continues to prioritize management of right-of-ways through it's integrated vegetation management program. API has implemented a renewal based sustainment plan, whereby older, at end-of-life assets are replaced

Asset Management

- **Distribution System Plan Implementation Progress**

In 2022, API continued to see an increase in non-discretionary projects, through customer and third-party requests. API continues to invest in this area as needed in order to provide customers access to electricity services and to ensure ongoing collaboration with third-party entities completing work in our service territory. In particular, API responded to several larger industrial connection requests as well as permit requests associated with the accelerated broadband initiatives.

API's system renewal investments continue to be focused on sustaining asset replacements through our line and express feeder rebuild programs. In 2022, API achieved its planned rebuild plans and began the land acquisition and pre-engineering processes for the Bruce Mines greenfield station project, which is slated to continue in 2023.

API's system service investment continued to be focused on improving system reliability through contingency planning improvements, protection and control upgrades and system configuration upgrades. In 2022, API's main focus continued to be the supply contingency improvements at the Echo River TS. API has also been working with the Transmitter on supply point upgrades at the Goulais TS and Batchawana TS (both led by Hydro One Sault Ste. Marie), ensuring that the refurbishment plans will support long-term projected system capacity needs and improve supply contingency in their respective areas.

API's general plant investments continued to be focused on the new Sault Facility project as well as a sustaining fleet replacement program. In 2022, the construction of the new Sault Facility was completed, and API successfully transitioned its operations to the new building.

Industry supply chain challenges continue to cause procurement delays in our Fleet replacement plan. API achieved other smaller investment plans associated with right-of-way access trail improvements, implementation of a SCADA system, etc.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the Ontario Energy Board to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. In reviewing the Pacific Economics Group benchmarking and report, API management does not believe that the model accurately predicts API's costs. 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 section below provides a more appropriate measure of API's efficiency and cost control.

- **Total Cost per Customer**

The statistical model developed by Pacific Economics Group (PEG) produces total capital and operating costs for each distributor that can be used for the purpose of comparing distributors. This amount is then divided by the total number of customers that API serves to determine Total Cost per Customer. The cost performance result for 2022 is $2,479 per customer which is a 6.0% increase over 2021.

Total cost in 2022, as assessed by PEG, increased 7% over 2021, while API's customer growth in this period was only 1%. API's operating expense component of total cost grew 2%, indicating API was able to manage costs at a rate lower than inflation in 2022. The capital cost component grew at a rate of 12%, driving the increase in total cost. API's Gross Capital Additions in 2022 were substantially *lower* than 2021, and the Capital Quantity assessed by PEG was stable, at 1% growth. The driver of the increase in Capital Cost (and in turn, the increase in total cost) was PEG's assessment of Capital Price, which is consistent across the industry, and grew by 10%, driven by increases in industry-wide inflation and cost of capital parameters.

Over the 2018 to 2022 period covered by the scorecard, API faced both inflationary cost increases, as well as cost increases associated with investments in programs for asset replacement, system improvement, and vegetation management that are sustainable in the long term. From 2018 to 2022, API's total customer count has not grown substantially (11,721 in 2018 vs. 12,332 in 2022), with a result that cost increases are not offset by customer growth.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the kilometers of line that API operates to serve its customers. API's 2022 result is $14,501 per km of line, an 11% increase over the result for 2021. The change in 2022 is driven by the increase in total cost, of 7%, as well as a decrease in the km of line (-4%) due to a reporting refinement.

The 7% increase in total costs is explained in the section above(Total Cost per Customer)

Many of API's significant cost drivers are directly related to its total kilometers of line. These cost drivers include most lines and vegetation management related activities, as well as support functions such as engineering and design. As discussed in the Efficiency Assessment section above, API management believes that total cost per km of line is a more accurate assessment of API's cost efficiency than the other measures discussed above.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

The 2022 liquidity current ratio for API per the scorecard is 0.26 (2021 - 0.43). The 2022 liquidity current ratio based on API's audited financial statements, adjusted to exclude due to related parties, is 0.35 (2021 - 0.75), which varied from last year primarily due to an increase in short-term loan payables as a result of cash flow needs associated with several large ongoing capital projects. It is expected that additional long-term debt financing will be secured, and that the liquidity ratio will move back towards a ratio of 1.00.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The Ontario Energy Board uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5. The combined 2022 debt to equity ratio for API is 1.44 (2021 - 1.32), which has not significantly changed from prior year. The 2022 debt to equity ratio based on API's audited financial statements, adjusted to include due to related parties, is 1.52 (2021 – 1.48). The leverage ratio is expected to be maintained at a level near the 1.5 deemed capital mix noted above.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

API's 2022 distribution rates were approved by the Ontario Energy Board as part of its 4th Generation Incentive Rate-Setting application. API's last Cost of Service application was for rates effective January 1, 2020 and this included an expected (deemed) regulatory return on equity of 8.52%. The Ontario Energy Board allows a distributor to earn within +/- 3% of the expected return on equity. Outside of this range,

the OEB may require a review of the distributor's over-/under- earning.

- **Profitability: Regulatory Return on Equity – Achieved**

API's return achieved in 2022 is 10.53% (2021 - 9.38%), which is within the +/- 3% range allowed by the Ontario Energy Board. API's achieved returns are higher in 2022 as compared to 2021 due to a $0.7 million (15.3%) increase in adjusted regulated net income and a $2.6 million (2.2%) increase in rate base. The primary driver of the increase in adjusted regulated net income was a reduction in the current income tax expense calculated for regulated Return on Equity purposes.

Note to Readers of 2022 Scorecard MD&A

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

Attachment 1-SEC-3d

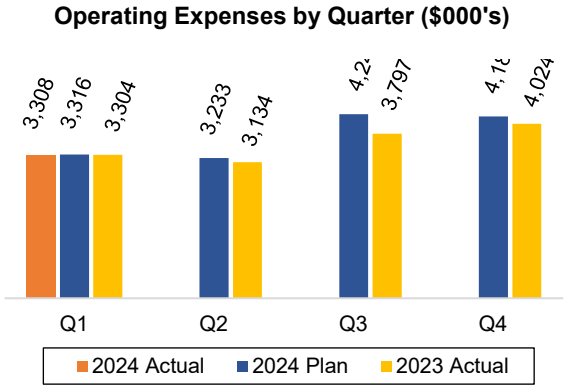
COS Update-Management Report

Algoma Power Inc.
EB-2024-0007

Management Report 2024

Operating Expenses

Quarterly operating expenses were $3.3 million, which was comparable to plan of $3.3 million and $3.3 million for the same period last year.



Capital Expenditures

Year-to-date gross capital expenditures were $2.4 million compared to plan of $3.0 million. The underspend compared to plan was due to timing.

Regulatory

API IRM Application – 2025 Application

On June 1, 2024, API submitted its application for 2025 distribution rates and other charges to the Ontario Energy Board ("OEB"). The application features a proposed Revenue Requirement of $35.8M, of which an estimated $21.2M is estimated to be collected through RRRP, with the remainder collected through distribution rates ($14.1M) and other revenues($0.7M).

The Application features a proposed rate base of $177.8M, which includes the addition to rate base of past large projects including the SSM Facility, the Echo River TS, and the #4 Circuit 10 MW project, as well as regular project spending on asset replacements, general plant, and new customer connections.

The proposed weighted average cost of capital is 7.06%, comprised of a deemed 56% long-term debt at an estimated rate of 5.59%, deemed 4% short-term debt at an estimated rate of 6.23%, and deemed 40% equity at an estimated rate of 9.21%. The rates are subject to change with the OEB's updated ROE and short-term debt rates later this year, as well as proposed updates once API's debt issuance is complete.

Bill impacts in the Application vary, with the Residential, Small Commercial and Large Commercial rate classes projected to have rate decreases as a result of a combination of rate protection program impacts (RRRP, Distribution Rate Protection), as well as material credit-value rate proposed rate riders. The Street Lighting and Seasonal Class rate proposals feature rate mitigation proposals to bring the total bill impact for these classes below 10%.

Attachment 2-SEC-11a

ERTS HOSSM CCRA

Algoma Power Inc.
EB-2024-0007

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – SIMPLIFIED - Echo River TS - Addition of a Hot Spare Transformer

THIS SIMPLIFIED CONNECTION AND COST RECOVERY AGREEMENT made between Hydro One Sault Ste. Marie LP **("HOSSM")** and Algoma Power Inc. **(the "Customer")** dated 12 day of May , 2021.

WHEREAS:

(a) The Customer has requested HOSSM to add a second 230/34.5kV power transformer at the Echo River TS to operate as a "Hot Spare" where it will normally be on potential and ready to carry load should the existing Transformer T1 be taken out of service, (the "Project"). The scope of work will consist of installation of this additional transformer and associated work including wave traps, HV circuit switcher, surge arrestors, PT, LV isolation switch, protection scheme additions, modifications and extension of bus work for the 230kV and 34.5kV buses and identified new equipment triggered by this new transformer installation; and

(b) HOSSM is agreeable to performing the work required for the Project on the following terms and conditions, including but not limited to the Project cost and the Project schedule being subject to the Customer executing and delivering this Agreement to HOSSM by no later than May 12th, 2021 (the **"Execution Date**").

NOW THEREFORE in consideration of the mutual covenants, agreements, terms and conditions herein and other good and valuable consideration, the receipt and sufficiency of which is hereby irrevocably acknowledged, the parties agree as follows:

1. Each of the parties hereto confirms the truth and accuracy of the recitals and agrees that the recitals form part of this Agreement.

2. Subject to Section 13 and the termination rights herein, the Agreement shall be in full force and effect and binding on the parties as of the date that HOSSM executes the Agreement **(the "Effective Date")** and shall expire on the date that the Customer pays HOSSM the final invoice in full for Work Chargeable to Customer or HOSSM issues a refund to the Customer in accordance with Section 10 hereof (**the "Term"**).

3. Each party represents and warrants to the other that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);

(b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;

(c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any Material contracts or instruments to which it is bound; or (iii) any Applicable Laws;

(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;

(e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;

(f) it is registered for purposes of Part IX of the Excise Tax Act (Canada). The HST registration number for HOSSM is

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – SIMPLIFIED - Echo River TS - Addition of a Hot Spare Transformer

833178213 RT0001 and the HST registration number for the Customer is as specified in Schedule "C" of the Agreement; and

(g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

Part A: Work Chargeable to Customer and Customer Work

4. The Customer and HOSSM shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, including, but not limited to the requirements of the Electrical Safety Authority, and using duly qualified and experienced people.

5. The parties acknowledge and agree that:

(a) HOSSM is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Work Chargeable to Customer;

(b) the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Work;

(c) the Customer shall perform the Customer Work at its own expense;

(d) the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities;

(e) the Customer shall provide HOSSM with Project data required by HOSSM, including, but not limited to: (i) the same technical information that the Customer provided the IESO during any connection assessment and facility registration process associated with the Customer's Facilities in the form outlined in the applicable sections of the IESO's public website and (ii) technical specifications (including electrical drawings) for the Customer's Facilities;

(f) HOSSM may participate in the commissioning, inspection or testing of the Customer Work at a time that is mutually agreed by HOSSM and the Customer and the Customer shall ensure that the work performed by the Customer and others required for successful commissioning, inspection or testing of protective equipment is completed as required to enable HOSSM witnessing and testing to confirm satisfactory performance of such systems;

(g) unless otherwise provided herein, HOSSM's responsibilities under the Agreement with respect to the connection of the New or Modified Connection Facilities to HOSSM's transmission system shall be limited to the performance of the Work Chargeable to Customer;

(h) HOSSM is not permitted to connect any new, modified or replacement Customer's Facilities unless any required connection authorizations, certificate of inspection or other applicable approval have been issued or given by the Ontario Electrical Safety Authority in relation to such facilities;

(i) HOSSM may require that the Customer provide HOSSM with test certificates certifying that the Customer's Facilities have passed all relevant tests and comply with the Transmission System Code, the Market Rules, Good Utility Practice, the standards of all applicable reliability organizations and any Applicable Laws, including, but not

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – SIMPLIFIED - Echo River TS - Addition of a Hot Spare Transformer

limited to any certificates of inspection that may be required by the Ontario Electrical Safety Authority;

(j) in addition to the Work Chargeable to Customer described in Schedule "A", HOSSM shall provide the Customer with such technical parameters as may be required to assist the Customer in ensuring that the design of the Customer's Facilities is consistent with the requirements applicable to HOSSM's transmission system and the basic general performance standards for facilities set out in the Transmission System Code, including Appendix 2 thereof;

(k) if HOSSM requires access to the Customer's Facilities for the purposes of performing the Work Chargeable to Customer or the Customer requires access to HOSSM's facilities for the purposes of the Customer's Work, the parties agree that Section 27.13 of the Connection Agreement shall govern such access and is hereby incorporated in its entirety by reference into, and forms an integral part of the Agreement. All references to "this Agreement" in Section 27.13 of the Connection Agreement shall be deemed to be a reference to this Agreement;

(l) the Customer shall enter into a Connection Agreement or amendment as required with HOSSM at least 14 calendar days prior to the connection; and

(m) the Customer shall provide HOSSM with copies of the documentation specified in Schedule "C" of the Agreement under the heading "Documentation Required", acceptable to HOSSM, within 120 calendar days after the Ready for Service Date. The Customer shall ensure that HOSSM may retain this documentation for HOSSM's ongoing planning, system design, and operating review. The Customer shall also maintain and revise such documentation to reflect changes to the Customer's Facilities and provide copies to HOSSM on demand and as specified in the Connection Agreement.

6. The Work Chargeable to Customer and HOSSM's rights and requirements hereunder, including, but not limited to HOSSM's:

(i) specifications of the protection equipment on the Customer's side of the Connection Point;

(ii) review and acceptance of power system components on the Customer's side of the Connection Point;

(iii) acceptance of the technical specifications (including electrical drawings) for the Customer's Facilities; and

(iv) participation in the commissioning, inspection and testing of the Customer's Facilities;

are solely for the purpose of HOSSM ensuring that the Customer's Facilities will not materially reduce or adversely affect the reliability of HOSSM's transmission system and do not adversely affect other customers connected to HOSSM's transmission system.

7. HOSSM shall use reasonable efforts to complete the Work Chargeable to Customer by **June 30th , 2023** (the **"Ready for Service Date**") provided that:

(a) the Customer is in compliance with its obligations under the Agreement;

(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of HOSSM, acting reasonably;

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – SIMPLIFIED - Echo River TS - Addition of a Hot Spare Transformer

(c) there are no delays resulting from HOSSM not being able to obtain outages from the IESO required for the Work Chargeable to Customer or from the IESO making changes to the Work Chargeable to Customer or the scheduling of all or a portion thereof;

(d) HOSSM does not have to use its employees, agents and contractors performing the Work Chargeable to Customer elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the Transmission System Code) or a Force Majeure Event;

(e) HOSSM is able to obtain the materials and labour required to perform the Work Chargeable to Customer with the expenditure of Premium Costs where required;

(f) there are no delays resulting from HOSSM being unable to obtain materials or equipment required from suppliers in time to meet the project schedule for any portion of the Work Chargeable to Customer provided that such delays are beyond the reasonable control of HOSSM; and

(g) the Customer executed the Agreement on or before the date specified as the Execution Date in the recitals.

8. Upon completion of the Work Chargeable to Customer, HOSSM shall own, operate and maintain all equipment and facilities installed by HOSSM as part of the Work Chargeable to the Customer in, under, on, over, along, upon, through and crossing HOSSM's Property(ies).

The Customer acknowledges that:

(i) ownership and title to the equipment referred to above shall throughout the Term and thereafter remain vested in HOSSM and the Customer shall have no right of property therein; and

(ii) that any portion of the equipment referred to above that is located on the Customer's Property(ies) shall be and remain the property of HOSSM and shall not be or become fixtures and/or part of the Customer's Property(ies).

9. The Customer acknowledges and agrees that HOSSM is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of HOSSM with regard to HOSSM's requirements to permit connection of the New or Modified Connection Facilities to HOSSM's transmission system and shall be installed, maintained and operated in accordance with all Applicable Laws, codes and standards, including, but not limited to, the Transmission System Code, at the expense of the Customer.

Where HOSSM has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of feeder connection, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's Facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by HOSSM for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of HOSSM's reclosing equipment.

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Part B: Work Chargeable to Customer

10. The Customer shall pay HOSSM's Engineering and Construction Cost (plus applicable Taxes) of the Work Chargeable to Customer which is estimated to be the amount specified in Schedule "C" of the Agreement in the manner specified in Schedule "C" of the Agreement.

Within 180 days after the Ready for Service Date, HOSSM shall provide the Customer with an invoice or a credit memorandum specifying the actual Engineering and Construction Cost of the Work Chargeable to Customer (plus applicable Taxes). Any difference between the Engineering and Construction Cost of the Work Chargeable to Customer (plus applicable Taxes) and the amount already paid by the Customer shall be paid within 30 days after the issuance of the invoice or credit memorandum by:

(a) HOSSM to the Customer, if the amount already paid by the Customer exceeds the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes); or

(b) the Customer to HOSSM, if the amount already paid by the Customer is less than the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes).

Part C: Events of Default

11. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under this Agreement, including any amount payable pursuant to Section 10 within the time stipulated for payment;

(b) breach by the Customer or HOSSM of any Material term, condition or covenant of the Agreement; or

(c) the making of an order or resolution for the winding up of the Customer or of its operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer.

For greater certainty, a dispute will not be considered an Event of Default under the Agreement. However, a party's failure to comply with the terms of a settlement or resolution of a dispute by the OEB will be considered an Event of Default under the Agreement.

12. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in Section 11(c) of this Agreement, for which no notice is required to be given by HOSSM), HOSSM shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to HOSSM's reasonable satisfaction within the 30 calendar day period, HOSSM may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to HOSSM under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the balance of the amounts payable by the Customer pursuant to Section 10.

13. Upon the occurrence of an Event of Default by HOSSM hereunder, the Customer shall give HOSSM written notice of the Event of Default and shall allow HOSSM 30 calendar days from the date of receipt of the notice to rectify the Event of Default at HOSSM's sole expense. If such Event of Default is not cured to the

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – SIMPLIFIED - Echo River TS - Addition of a Hot Spare Transformer

Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

14. All rights and remedies of HOSSM and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to HOSSM and the Customer respectively at law or in equity, and any one or more of HOSSM's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy HOSSM or the Customer may have or may have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

Part D: Disputes

15. All disputes, including, but not limited to, disputes related to:

(a) the cost and the allocation of the costs under this Agreement;

(b) the cost and the allocation of costs of the Work Chargeable To Customer and notwithstanding HOSSM's decision not to allocate or to allocate any part of the costs of this work to the Customer at this time; or

(c) any other costs and the allocation of any other costs associated with, related to, or arising out of the connection of the Project to HOSSM's transmission system or HOSSM's policies in respect of connections generally,

shall be dealt with in accordance with the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

16. If a dispute arises while HOSSM is performing the Work Chargeable to Customer, HOSSM shall not cease the work or slow the pace of the work without leave of the OEB.

Part E: Incorporation of Liability and Force Majeure Provisions

17. PART III: LIABILITY AND FORCE MAJEURE (with the exception of Section 15.5 thereof) and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into, and form an integral part of the Agreement. Unless the context otherwise requires, all references in PART III: LIABILITY AND FORCE MAJEURE TO "this Agreement" shall be deemed to be a reference to the Agreement and all references to the "the Transmitter" shall be deemed to be a reference to HOSSM.

For the purposes of this Section 17, the parties agree that the reference to:

(i) the Transmitter in lines 3 and 4 of Section 15.1 means the Transmitter or any party acting on behalf of the Transmitter such as contractors, subcontractors, suppliers, employees and agents; and
(ii) the Customer in lines 3 and 4 of Section 15.2 means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

The parties agree that the aggregate liability of HOSSM under the Agreement and in particular under this Section 17 shall at no time exceed the actual Engineering and Construction Cost of the Work Chargeable to Customer.

Part F: General

18. This Agreement is subject to the Transmission System Code and the OEB-Approved Connection Procedures. If any

provision of this Agreement is inconsistent with the:

(a) Transmission System Code, the said provision shall be deemed to be amended so as to comply with the Transmission System Code;

(b) OEB-Approved Connection Procedures, the said provision shall be deemed to be amended so as to comply with the OEB-Approved Connection Procedures; or

(c) Connection Agreement made between the parties, associated with the new customer connection facilities, the Connection Agreement governs.

19. The failure of any party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of any party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

20. Other than as provided in this Agreement, no amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

21. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to:

John Blackburn
Hydro One Sault Ste. Marie LP
483 Bay Street
6th Floor, North Tower
Toronto, ON M5G 2P5

Fax no: (416) 345-5957
E-mail: John.Blackburn@HydroOne.com

on behalf of HOSSM, and to the person at the address specified in the customer notice section of Schedule “C” on behalf of the Customer.

A notice, demand, consent, request or other communication shall be deemed to have been made as follows:

(a) where given or made by courier or other form of personal delivery, on the date of receipt;

(b) where given or made by registered mail, on the sixth day following the date of mailing;

(c) where given or made by fax, on the date of the sender's fax transmission report if received before 3 p.m. that day or on the next Business Day if received after 3 p.m. as indicated on the sender's facsimile transmission report; and

(d) where given or made by electronic mail, on the day and at the time when the notice, demand, consent, request or other communication is recorded by the sender’s electronic communications system as having been received at the electronic mail destination.

The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

22. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein, and,

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – SIMPLIFIED - Echo River TS - Addition of a Hot Spare Transformer

subject to Section 15, the courts of Ontario shall have exclusive jurisdiction to determine all disputes arising out of the Agreement.

23. The Agreement may be executed in counterparts, including email counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same Agreement.

24. The obligation to pay any amount due and payable hereunder, including, but not limited to, any amount due under Section 10 shall survive the termination of the Agreement.

25. Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including, but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.

26. This Agreement will supersede the terms of any purchase orders issued by the Customer to HOSSM in respect of the Project irrespective of whether same have been issued by Customer and/or accepted by HOSSM on or after the execution of this Agreement by the Customer.

27. This Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement. Appendix A attached hereto and Schedules "A", "B" and "C" are to be read with and form part of this Agreement.

28. In addition to the circumstances described in Section 7 of this Agreement, the Ready for Service Date is subject to any delays from HOSSM being unable to commence all or any part of the Work Chargeable to Customer and/or or delays that result in HOSSM having to cease performing all or any portion of the Work Chargeable to Customer from time to time due to the impacts that the COVID-19 pandemic may have on our company during these uncertain times, including, without limitation:

(a) HOSSM prioritizing work on other projects where the other customer must be prioritized as they are or will be performing an essential service in Ontario or are considered an essential construction project in Ontario;

(b) HOSSM may have limited availability of personnel which may mean re-deploying personnel working on the Project to perform HOSSM's own essential service work or work on other customer connection projects where customers either executed agreements with HOSSM prior to this one being executed or where the other customer must be prioritized as they are or will be performing an essential service in Ontario or are considered an essential construction project in Ontario ("**High Priority Customer Connection Work**");

(c) the productivity of HOSSM personnel being diminished or impacted including by reason of ensuring that our employees are appropriately social distanced;

(d) HOSSM contractors and supply chains being impacted by the pandemic such that HOSSM cannot obtain or must wait longer for services HOSSM requires from third parties or there are shortages in either availability of equipment or materials required to perform the HOSSM's Connection Work or the shortages are such that HOSSM needs to use or re-deploy the equipment or materials that HOSSM procured for the Project for HOSSM's own essential service work or for High Priority Customer Connection Work; and

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – SIMPLIFIED - Echo River TS - Addition of a Hot Spare Transformer

(e) HOSSM's work sites (such as stations) not being available or having limited availability including, without limitation, by reason of a person who was previously at that site develops symptoms of COVID-19 and the site must be deep cleaned.

29. HOSSM and the Customer are parties to a SIA/CIA and Connection and Cost Estimate Agreement in respect of the Project dated November 13, 2019;

a) pursuant to which the Customer provided an Advance Payment of $385,000.00 plus HST in the amount of $50,050.00 (the "SIA/CIA and CCEA Advance Payment") for performance of the Work (as that term is defined in the SIA/CIA and CCEA) (the "SIA/CIA and CCEA Work");

b) Hydro One has completed the performance of the SIA/CIA and CCEA Work;

c) the actual cost of the SIA/CIA and CCEA Work is $385,000.00 (excluding HST) ("Cost of SIA/CIA and CCEA Work") and, notwithstanding any term to the contrary in the SIA/CIA and CCEA, is included in the amounts payable by the Customer under the terms of this Agreement; and

d) notwithstanding any term to the contrary in the SIA/CIA and CCEA, the Advance Payment is credited against the amounts payable by the Customer under the terms of this Agreement.

The Parties acknowledge and agree that the SIA/CIA and CCEA is deemed to be amended to reflect the inclusion of the Cost of the SIA/CIA and CCEA Work and the SIA/CIA and CCEA Advance Payment in this Agreement and that there will be no separate true-up process under the terms of the SIA/CIA and CCEA.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper authorized signatories, as of the date written below.

ALGOMA POWER INC.

Name: Jie Han
Title: Vice President Operations

Name: Scott Hawkes
Title: President and Chief Executive Officer
I have the authority to bind the Corporation

HYDRO ONE SAULT STE. MARIE LP, by its general partner, **HYDRO ONE SAULT STE. MARIE INC.**

Name: Andrew Spencer
Title: President
Date: May 12 2021
I have the authority to bind the corporation.
The corporation has the authority to bind the Limited Partnership

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – SIMPLIFIED - Echo River TS - Addition of a Hot Spare Transformer

Appendix "A": Definitions

In the Agreement, unless the context otherwise requires, terms which appear therein without definition, shall have the meanings respectively ascribed thereto in the Transmission System Code and unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Agreement" means the Simplified Connection and Cost Recovery Agreement, Appendix "A" and Schedules "A", "B" and "C" attached hereto.

"Applicable Laws" means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or government department, commission board, court authority or agency.

"Business Day" means a day other than Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto, are not open for business during normal banking hours.

"Connection Agreement" means the form of connection agreement appended to the Transmission System Code as Appendix 1, Version A.

"Connection Point" means the point where the Customer's Facilities are connected to HOSSM's transmission system or are connected to third party facilities connected to HOSSM's transmission system, as the case may be.

"Customer Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "B" of this Agreement.

"Customer's Facilities" has the meaning set forth in the Transmission System Code.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Electricity Act, 1998" means the *Electricity Act, 1998* being Schedule "A" of *the Energy Competition Act*, S.O. 1998, c.15, as amended.

"Engineering and Construction Cost" means HOSSM's charge for equipment, labour and materials at HOSSM's standard rates plus HOSSM's standard overheads as well as interest during construction using HOSSM's capitalization rate in effect during the construction period.

"Force Majeure Event" has the meaning ascribed thereto in the Connection Agreement.

"Good Utility Practice" has the meaning set forth in the Transmission System Code.

"HOSSM's Property(ies)" means any lands owned by HOSSM in fee simple or where HOSSM now or hereafter has obtained easement rights.

"IESO" means the Independent Electricity System Operator continued under the Electricity Act, 1998.

"Market Rules" rules made under section 32 of the *Electricity Act, 1998* (Ontario), including, but not limited to Chapter 6 thereof.

"In Service Date" has the same meaning ascribed to the term "comes into service" in the Transmission System Code.

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – SIMPLIFIED - Echo River TS - Addition of a Hot Spare Transformer

"New or Modified Connection Facilities" means the facilities owned by HOSSM as specified in Schedule "C" of the Agreement.
"OEB" means the Ontario Energy Board.

"OEB-Approved Connection Procedures" means HOSSM's connection procedures as approved by the OEB from time to time.

"Ontario Energy Board Act" means the *Ontario Energy Board Act* being Schedule "B" of the *Energy Competition Act*, S.O. *1998*, c. 15, as amended.

"Premium Costs" means those costs incurred by HOSSM in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having HOSSM's employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"Ready for Service Date" means the date upon which the Work Chargeable to Customer is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Taxes" means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than taxes imposed upon income, payroll or capital).

"Transmission System Code" means the code of standards and requirements originally issued by the OEB on July 14, 2000, as it may be amended, revised or replaced in whole or in part from time to time in accordance with the Section 70.2 and 70.3 of the *Ontario Energy Board Act*.

"Work Chargeable to Customer" means the work to be performed by HOSSM described in Schedule "A" of this Agreement.

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – SIMPLIFIED - Echo River TS - Addition of a Hot Spare Transformer

Schedule "A" - Echo River TS - Addition of a Hot Spare Transformer

PROJECT SCOPE - WORK CHARGEABLE TO CUSTOMER

HOSSM will perform project management, engineering, equipment and materials procurement, construction, commissioning and energization for the following work:

- Install, One (1) new 230-34.5kV, 15/20/25MVA, 3 phase power transformer, and associated major equipment, including but not limited to:
  - One set of 3 phase 230kV wave trap
  - One set of 3 phase 230kV circuit switcher
  - One Transformer Neutral Grounding Reactor
  - Two (2) set of 3 phase 230kV and One set of 3 phase 34.5kV surge arrestors
  - Two (2) 3 phase 34.5kV isolating disconnect switches
  - One (1) 34.5kV Potential Transformer (PT)
  - Oil spill containment system completed with oil water separator

- Design, modify existing or construct new 230kV and 34.5kV connection facilities, including all new civil structures, foundations, power cables triggered by the new transformer installation.

- Design and install necessary protection, control and telecom additions and modifications that are triggered by the new transformer connection.

- Design and construct necessary structure(s) to facilitate 230kV phase transposing to bring P22G phase sequence in alignment with standardized sequence.

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – SIMPLIFIED - Echo River TS - Addition of a Hot Spare Transformer

Schedule "B" - Echo River TS - Addition of a Hot Spare Transformer

CUSTOMER WORK

The Customer will:

- None

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – SIMPLIFIED - Echo River TS - Addition of a Hot Spare Transformer

Schedule "C" - Echo River TS - Addition of a Hot Spare Transformer

Part 1: Estimate of Engineering and Construction Cost of the Work Chargeable to Customer:

The estimate of the Engineering and Construction Cost of the Work Chargeable to Customer (excluding HST) is summarized as follows:

Project Description	Estimated Engineering and Construction Cost of the Work Chargeable to Customer ($K)
Project Management	$689,000
Engineering	$799,000
Equipment & Materials	$2,060,000
Construction	$2,320,000
Commissioning	$622,000
Past Cost (for Detail Estimates)	$393,000
Sub-Total	$6,883,000
Contractor's Contingency	$883,000
AFUDC* & Overheads	$0
Total Project Price ($K)	$7,766,000
Previous payment	-$385,000
Total Price ($K)	$7,381,000

Notes:

1. AFUDC means the Allowance for Funds Used During Construction and is the term used in the OEB accounting procedures meaning interest during construction if applicable.
2. Price for preliminary engineering is included in any of the prices above.
3. Contingency of 10% is included in the total.
4. Capital overheads are included in the total price.
5. Capital interest is included in the total price.
6. HST is not included in the estimate.

Part 2: Manner of Payment

The Engineering and Construction Cost of the Work Chargeable to the Customer is estimated to be $7,760,000.00 plus HST in the amount of $1,008,880.00 (the **"Estimated Cost"**). Should the Customer default in paying any amount to HOSSM, HOSSM reserves the right to add the AFUDC as it deems necessary.

The Customer shall pay HOSSM the Estimated Cost by making the progress payments specified below on or before the Payment Milestone Date specified below. If applicable, HOSSM will invoice the Customer for the second payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Work Chargeable to Customer ($K)	HST ($K)	Total Payment Required (incl. HST)
1.SIA,CIA and CCEA Paid on Dec 24, 2019	$385,000	$50,050	$435,000
2. Upon CCRA Execution	$3,690,500	$479,800	$4,170,300
3. Twelve (12) Months Following Execution	$3,690,500	$479,800	$4,170,300

2.2 Scope Change

Any change in the Project Scope as detailed and documented in Schedule "A" whether they are initiated by the Customer or not may result in a change to the Project costs estimated in this Schedule "C" and the Project schedule, including the Ready for Service Date.

All Customer initiated scope changes to this Project must be in writing to HOSSM.

HOSSM will advise the Customer of any cost and schedule impacts of any Customer initiated scope changes.

HOSSM will not implement any Customer initiated scope changes until written approval has been received from the Customer accepting the new pricing and schedule impact.

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) – SIMPLIFIED - Echo River TS - Addition of a Hot Spare Transformer

Part 3: Miscellaneous

New or Modified Connection Facilities:
The existing Echo River TS is being modified for this project.

Customer's HST Registration Number: HST# 82249 4290

Documentation Required (after In Service Date): N/A

Revenue Metering: IESO compliant revenue metering to be provided by the Customer

Customer Notice Info:

Algoma Power Inc.
2 Sackville Road, Suite A | Sault Ste. Marie, ON P6B 6J6

Attention: Michael Degilio
Supervisor, Distribution Engineering

Attachment 2-SEC-19

Vehicle Listing

Algoma Power Inc.
EB-2024-0007

API Fleet Listing

Unit No.	Fleet Type	Description	Year of Manufacture	Year of Proposed Replacement
12.34	Light Pick-Ups	Dodge Ram1500 4 x 4 Quad Cab	2012	2024
13.37	Light Pick-Ups	Ford F150 4 x 4 Supercab	2013	2024
14.42	Light Pick-Ups	Ford F150 4 x 4 Supercab	2014	2024
14.43	Light Pick-Ups	Ford F150 4x4 Crew Cab	2014	2024
15.48	Heavy Pick-Ups	Ford F250 4x4 Crew Cab	2015	2024
16.53	Light Pick-Ups	Ford F150 4 x 4 Supercab	2017	2024
16.54	Heavy Pick-Ups	Ford F250 Super Duty Crew Cab, 8 ft. box	2017	2024
11.30	Material Handler	Freightliner M2106 Posi Plus 400-46A Single Bucket Material Handler	2011	2025
13.40	Material Handler	Freightliner M2 106 Posi Plus 400-46A Single Bucket Material Handler	2013	2025
14.47	Material Handler	Freightliner FM2 55 ft. Altec AM55E	2014	2026
15.50	Forestry Lift	Freightliner FM2 Altec LR7-60E70	2015	2026
44.76	Reel Trailer	Timberland Q80 Tensioner	1993	2027
52.38	Pole Trailer	Brooks PTB 141-15KE Pole	2011	2027
15.51	Service Trucks	Dodge 3500 4 X 4 dually diesel	2015	2027
15.52	Light Pick-Ups	Ford F150 1/2 ton 4 x 4	2015	2027
55.44	Snowmobile	Ski Doo Skandic SWT	2015	2027
55.50	Landscape Trailer	Advantage GLS 16 ft. landscape trailer	2016	2027
16.55	Material Handler	Freightliner M2 106 55 ft. Double Bucket. Posi-Plus 500-55AUE	2017	2027
17.60	Heavy Pick-Ups	Chevrolet 2500 HD 4 X 4 LT, 6.5 ft. box	2018	2027
18.65	Heavy Pick-Ups	Ford F250 F250 Super Duty Crew Cab, 6.75 ft. box	2019	2027
48.24	Snowmobile	Polaris Widetrack 500 liquid Polaris Widetrack	2008	2028
55.57	Brush Chipper	Vermeer BC1500 diesel	2017	2028
17.58	Material Handler	Freightliner M2-106 55 ft. Double Bucket. Posi-Plus 500-55AUE	2018	2028
19.69	Light Pick-Ups	Dodge Ram 1500 4x4 Crew Cab (Classic)	2019	2028
19.70	Light Pick-Ups	Ford F150 1/2 ton 4* 4 Crew Cab 5ft. 8 in box	2019	2028
19.71	Heavy Pick-Ups	Ford F250 4X4 Crew Cab, 8 ft. box	2019	2028
20.76	Light Pick-Ups	Ford F150 4 X 4 Crew Cab	2020	2028
20.77	Heavy Pick-Ups	Ford F250 4 X 4 Crew Cab	2020	2028
43.10	Fork Lift	Cat R80 Fork Truck diesel	1990	2029
54.43	Off-Road Vehicles	Argo 8 wheel	2013	2029
55.47	Enclosed Trailer	Misson 116 Enclosed	2015	2029
19.67	Radial Book Derrick	Freightliner M2 106 Wajax C-5052 Corner Mount RBD	2019	2029
55.75	Brush Chipper	Vermeer BC1500 diesel	2020	2029
21.81	Light Pick-Ups	Ford F150 4x4 Crew Cab	2021	2029
22.87	Heavy Pick-Ups	Ford F250 4X4 Crew Cab, 6 ft. box	2022	2029
22.88	Heavy Pick-Ups	Dodge Ram 2500	2022	2029
44.77	Reel Trailer	Timberland Q80 Tensioner	1993	Beyond 2029
51.36	Snowmobile	Arctic Cat XT 570 Bearcat	2011	Beyond 2029
52.40	Enclosed Trailer	Mission MES 101 X 12 Enclosed Snowmobile	2012	Beyond 2029
53.41	Enclosed Trailer	Pace Outback OB6 12' Enclosed	2013	Beyond 2029
14.45	Material Handler	Freightliner FM2 Altec AN50E-OC Material Handler	2014	Beyond 2029

API Fleet Listing

Unit No.	Fleet Type	Description	Year of Manufacture	Year of Proposed Replacement
54.42	Enclosed Trailer	Look VWL 16' Enclosed	2014	Beyond 2029
55.45	Snowmobile	Ski Doo WT Skandic	2015	Beyond 2029
55.46	Off-Road Vehicles	Polaris Ranger	2015	Beyond 2029
55.49	Off-Road Vehicles	Polaris Ranger	2015	Beyond 2029
55.51	Landscape Trailer	Advantage GLS 14 ft landscape trailer	2016	Beyond 2029
55.59	Pole Trailer	Util Equip Pole Trailer 60 ft. Pole Trailer	2017	Beyond 2029
55.61	Enclosed Trailer	Mission XOV Enclosed Snowmobile Trailer	2018	Beyond 2029
55.62	Landscape Trailer	Highland Landscape 7 ft. X 14 ft.	2018	Beyond 2029
55.63	Landscape Trailer	Highland Landscape 7 ft. X 14 ft.	2018	Beyond 2029
55.64	Off-Road Vehicles	Polaris Ranger	2018	Beyond 2029
55.66	Snowmobile	Ski Doo Skandic Wide Track - Ecotec	2019	Beyond 2029
55.72	Off-Road Vehicles	Argo 8 wheel	2019	Beyond 2029
55.73	Pole Trailer	Util Equip Pole Trailer 60 ft. Pole Trailer	2019	Beyond 2029
20.74	Radial Book Derrick	Freightliner M2 106 Wajax C-5052Corner Mount RBD	2020	Beyond 2029
22.85	Material Handler	Freightliner M2106 55 ft. Altec AM55E	2020	Beyond 2029
21.79	Radial Book Derrick	Freightliner M2 106 Wajax C-5052 Corner Mount RBD	2021	Beyond 2029
55.78	Enclosed Trailer	NEO NEO NDO Enclosed Snowmobile Trailer 8.5 ft. X 14 ft.	2021	Beyond 2029
55.80	Landscape Trailer	Advantage Landscape 16 ft. galvanized landscape trailer	2021	Beyond 2029
22.83	Service Trucks	Ford F550 4X4 Diesel Chip Dump	2022	Beyond 2029
22.90	Light Pick-Ups	Dodge RAM 1500 4x4 Crew Cab (Classic)	2022	Beyond 2029
55.82	Snowmobile	Polaris 2022 Titan 800 Titan Adventure 155	2022	Beyond 2029
2-76	Light Pick-Ups	Ford F150 4x4 Crew Cab	2022	Beyond 2029
22.91	Light Pick-Ups	Ford F150 4x4 Crew Cab - EV	2023	Beyond 2029
23.86	Forestry Lift	Freightliner FM2 Versalift VO270REV	2023	Beyond 2029
23.92	Light Pick-Ups	Dodge 1500 4 X 4	2023	Beyond 2029
45.89	Fork Lift	Raymond EZ-R40TT Electric indoors	2023	Beyond 2029
55.84	Snowmobile	Ski Doo Skandic Skandic WT	2023	Beyond 2029
1-57	Light Pick-Ups	Dodge Ram 1500 4 X 4 Crew Cab	2023	Beyond 2029
55.93	Snowmobile	Ski-Doo Tundra 600 EFI Charger	2024	Beyond 2029

Attachment 3-SEC-20

Updated Load Forecast(Excel Only)

Algoma Power Inc.
EB-2024-0007