AGENDA 9

BOARD OF DIRECTORS' MEETING

COST OF SERVICE APPLICATION

EXPLANATORY NOTE

The purpose of this agenda item is to review and approve the filing by Algoma Power Inc.'s 2020 Cost of Service Rate Application with the Ontario Energy Board ("OEB").

This agenda item includes: (1) an Executive Summary, (2) an Application Summary, (3) a Customer Summary, and (4) a resolution is attached for the Board's consideration.

1.2 INTRODUCTION AND EXECUTIVE SUMMARY

1.2.1 INTRODUCTION

Algoma Power Inc. ("API") is pleased to present its Cost of Service application (the "Application") for rates effective January 1, 2020. This application consists of the following Exhibits, and live Excel models in support of the evidence presented in this Application.

Exhibits:

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

Models:

- API 2020 Benchmarking Forecast Model
- API 2020 Cost Allocation
- API 2020 LRAMVA Workform
- API 2020 PILs Workform
- API 2020 Rev Requirement Workform
- API 2020 RTSR Workform
- API 2020 Load Forecast Model
- API 2020 COS Checklist
- API 2020 DVA Continuity Schedule

- API 2020 GA Analysis Workform
- API 2020 1595 Workform
- API 2020 Chapter 2 Appendices
- API 2020 Fixed Asset Continuity Schedules and Depreciation Schedules (Appendices 2-BA and 2-C)
- API 2020 Chapter 5 Appendix
- API 2020 Rate Design Model
- API 2020 Bill Impact Model
- API 2019 and 2020 Tariff Sheets
- API 2020 Advanced Capital Module

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

The application along with all supporting evidence will also be posted on the API's website once the application is posted on the OEB website.

1.2.2 SUMMARY OF APPLICATION INTENDED FOR API CUSTOMERS

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

1.2.3 EXECUTIVE SUMMARY AND BUSINESS PLAN

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

Key elements of the Application and Business Plan are:

1) Identification of six strategic customer focused objectives, that drive capital and O&M plans and related investments over the 2020-2024 period:
    a. Sustaining End of Life Asset Replacement
    b. Sustaining Vegetation Management
    c. Worker and Public Safety and Environmental Protection
    d. Reliability Improvement – Focus on Reducing Outage Duration
    e. Facilities Improvements to Support Productivity and Efficiency
    f. Flexible Approach to Emerging Technology and Public Policy
2) A Distribution System Plan ("DSP") with projects and programs aligned with the strategic objectives listed above;
3) API's goals for the 2020-2024 period are to implement its planned projects and programs that are aligned with the objectives identified above, and to meet or exceed all targets for performance metrics identified in the DSP and the Business Plan;
4) Enhanced customer engagement to ensure that the preferences of API's customers were identified and considered in determining the strategic objectives listed above;
5) Evaluation and forecasting of performance metrics that are consistent with the OEB's Renewed Regulatory Framework ("RRF");
6) Request for the Advanced Capital Module ("ACM") treatment of a large substation project in 2021 and a large facility project in 2022;
7) An alternative proposal for ACM cost recovery to allow alignment of OEB policy with the Rural and Remote Rate Protection ("RRRP") framework, which is designed to limit distribution rate increases for the majority of API's customers;

8) Complete integration of assets and customers that API proposes to acquire from Dubreuil Lumber Inc. (“DLI”), in a manner that does not increase costs to API’s existing customers;
9) A request for the OEB to extend certain exemptions in API’s Distribution Licence in order to ensure that API is not required to make uneconomic investments in additional smart metering infrastructure;
10) A request for the OEB to make decisions on items 6 to 8 above as Preliminary Issues in this Application;
11) A 2020 Cost Allocation Study that incorporates the OEB’s changes to cost allocation policy for Street Lighting, and increases asset categorization for bulk delivery, to more accurately allocated API’s costs in a manner that reduces recent upward rate pressure on the Seasonal and Street Lighting rate classes; and,
12) Rate-setting approaches that are consistent with historical OEB-approved approaches to ensure alignment between OEB policies and the RRRP framework.

1.5 APPLICATION SUMMARY

This section is devoted to defining each element of API's 2020 cost-of-service, explaining how each element is determined and explaining the relationship between the various components. The major components covered in this application summary are as follows:

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

Revenue Requirement

The proposed Service Revenue Requirement for the 2020 test year of $25,937,065 reflects an increase of $2,654,124 or 11.4% relative to 2015 Board Approved. The Base Revenue Requirement on which rates are calculated is $25,885,176, reflecting other revenue offsets of $51,889.

Applying API's 2019 approved rates to its 2020 forecast of load, demand and customer counts produces a forecasted revenue of $23,692,323, resulting in a net revenue deficiency of $2,192,853. API is applying for 2020 rates and RRRP funding to eliminate this deficiency and recover its revenue requirement.

Table 2 – 2015-2020 Revenue Requirement

Particular	**MIFRS Last Board Approved**	**MIFRS 2015**	**MIFRS 2016**	**MIFRS 2017**	**MIFRS 2018**	**MIFRS 2019**	**MIFRS 2020**
OM&A Expenses	$12,304,881	$11,815,559	$11,803,904	$12,131,721	$12,134,596	$12,924,455	$13,677,187
Depreciation Expense	$3,899,209	$3,136,802	$3,326,205	$3,438,399	$3,600,160	$3,796,858	$4,043,341
Property Taxes	$107,800	$115,453	$112,102	$113,924	$115,938	$119,000	$118,600
Total Distribution Expenses	$16,311,890	$15,067,814	$15,242,211	$15,684,044	$15,850,694	$16,840,313	$17,839,128
Regulated Return On Capital	$6,561,398	$6,417,885	$6,830,093	$7,088,901	$7,299,850	$7,679,811	$7,763,963
Grossed up PILs	$409,653	$581,009	$440,903	$475,362	$560,067	$196,748	$333,974
Service Revenue Requirement	$23,282,941	$22,066,708	$22,513,207	$23,248,307	$23,710,612	$24,716,872	$25,937,065
Less: Revenue Offsets	-$466,758	$68,748	$144,840	$434,381	$164,157	$189,388	-$51,889
Base Revenue Requirement	$22,816,183	$22,135,456	$22,658,047	$23,682,688	$23,874,769	$24,906,260	$25,885,176

The primary drivers of the change in revenue requirement are an increase in rate base, an increase in OM&A and property tax expenses, and a decrease in other revenue offsets. An increase in depreciation expense and a decrease in income taxes contribute to a lesser degree. Each of these contributing factors is summarized in Section 6.3.2 of Exhibit 6. Table 3 below compares each component of API's proposed 2020 revenue requirement to 2015 Board Approved amounts.

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

	MIFRS	MIFRS	Difference	
	2015	2020	Absolute	%
Long Term Debt	5.15%	4.95%	-0.20%	-4%
Short Term Debt	2.16%	2.82%	0.66%	31%
Return on Equity	9.30%	8.98%	-0.32%	-3%
Weighted Debt Rate	4.95%	4.81%	-0.14%	-3%
Regulated Rate of Return on Rate Base	**6.69%**	**6.48%**	**-0.21%**	**-3%**
Controlable Expenses	$12,412,681	$13,795,787	$1,383,106	11%
Power Supply Expense	$23,068,924	$21,076,879	-$1,992,045	-9%
Working Capital Base	**$35,481,605**	**$34,872,667**	**-$608,938**	**-2%**
Working Capital Allowance Rate	10.00%	7.50%	-2.50%	-25%
Working Capital Allowance ("WCA")	**$3,548,161**	**$2,615,450**	**-$932,710**	**-26%**
Net Fixed Assets Opening Test Year	$91,900,401	$115,263,940	$23,363,539	25%
Net Fixed Assets Closing Test Year	$97,146,940	$119,252,035	$22,105,095	23%
Avgerage Net Fixed Assets	$94,523,671	$117,257,988	$22,734,317	24%
Working Capital Allowance	$3,548,161	$2,615,450	-$932,710	-26%
Rate Base	**$98,071,831**	**$119,873,438**	**$21,801,607**	**22%**
Deemed Interest Expense	$2,913,126	$3,458,109	$544,983	19%
Deemed Return on Equity	$3,648,272	$4,305,854	$657,582	18%
Regulated Return on Rate Base	**$6,561,398**	**$7,763,963**	**$1,202,565**	**18%**
Regulated Return on Rate Base	$6,561,398	$7,763,963	$1,202,565	18%
OM&A + Property Taxes	$12,412,681	$13,795,787	$1,383,106	11%
Depreciation Expense	$3,899,209	$4,043,341	$144,132	4%
Income Taxes	$409,653	$333,974	-$75,679	-18%
Revenue Offset	-$466,758	-$51,889	$414,868	-89%
Base Revenue Requirement	**$22,816,183**	**$25,885,176**	**$3,068,993**	**13%**

Budgeting and Accounting Assumptions

In preparing its cost forecasts for the Application, API has assumed an inflation rate of 1.5%, consistent with the rate used for 2019 IRM applications. API has not factored any additional growth into its forecasts since load forecasts and customer counts remain relatively flat and in line with historical weather-normalized values.

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

Load Forecast Summary

The load forecast for 2020 is based on a methodology that predicts class specific consumption using a multiple regression analysis that relates historical monthly wholesale kWh usage to monthly historical heating degree days and cooling degree days.

In API's case, variation in monthly electricity consumption is influenced by four main factors – weather (e.g. heating and cooling), which is by far the most dominant effect on most systems, the number of days per month and an "Employment" factor.

Weather normalized values are determined by using the regression equation with a "10-year average monthly degree days (2009-2018)". The 10-year average is consistent with recent years' weather and has been used in other electricity distribution rate applications accepted by the Board.

Allocation to specific weather sensitive rate classes (R1(i), R1(ii), R2, and Seasonal) is based on historical ratios of actual retail kWh (exclusive of distribution losses) to actual wholesale kWh for each class. Further adjustments are made to the R1(i), R1(ii) and R2 rate classes to account for the acquisition of customers from DLI. For the Street Lighting rate class, which is not weather sensitive, the forecasted 2019 and 2020 load is equal to 2018 actuals, plus a 2020 adjustment for street lights in Dubreuilville.

The resulting 2020 load forecast was further adjusted to take into account CDM impacts.

The 2020 load forecast is summarized on the following pages. Detailed explanations of the load forecast can be found in Exhibit 3.

Table 4 - Load Forecast

Customers or Connections

	Actual					Projected	
Customer Class Name	**Last Board Appr**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
R1(i)	7,531	7,480	7,544	7,596	7,640	7,722	8,116
R1(ii)	965	954	951	961	961	956	997
R2	50	42	42	38	40	39	37
Seasonal	3,138	3,176	3,140	3,108	3,076	3,018	2,960
Street Lighting	1,018	1,023	1,066	1,070	1,067	1,067	1,117
TOTAL	**12,702**	**12,675**	**12,743**	**12,774**	**12,784**	**12,802**	**13,227**

Consumption (kWh)

	Actual					Projected	
Customer Class Name	**Last Board Appr**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
R1(i)	80,045,884	80,876,150	75,910,136	76,321,856	82,834,418	75,387,475	79,805,566
R1(ii)	25,745,817	26,130,351	24,984,442	25,604,789	26,240,994	23,881,888	26,928,875
R2	83,288,188	86,528,984	89,578,886	94,512,143	109,202,680	99,385,190	91,043,719
Seasonal	7,731,414	6,868,390	6,205,026	6,042,453	6,043,635	5,500,303	5,502,049
Street Lighting	804,705	742,696	584,575	582,537	568,784	568,784	595,435
TOTAL	**197,616,008**	**201,146,571**	**197,263,065**	**203,063,777**	**224,890,511**	**204,723,640**	**203,875,644**

CDM Adjusted Consumption (kWh)

	Projected
Customer Class Name	**2020**
R1(i)	78,446,984
R1(ii)	25,484,758
R2	85,867,987
Seasonal	5,439,365
Street Lighting	595,435
TOTAL	**195,834,528**

Consumption (kW)

	Actual					Projected	
Customer Class Name	**Last Board Appr**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
R1(i)	0	0	0	0	0	0	0
R1(ii)	0	0	0	0	0	0	0
R2	198,901	208,261	217,369	210,836	234,800	229,529	210,264
Seasonal	0	0	0	0	0	0	0
Street Lighting	2,380	2,128	1,623	1,619	1,581	1,581	1,655
TOTAL	**201,281**	**210,389**	**218,992**	**212,455**	**236,381**	**231,110**	**211,919**

CDM Adjusted Consumption (kW)

							Projected
Customer Class Name							**2020**
R1(i)							0
R1(ii)							0
R2							196,648
Seasonal							0
Street Lighting							1,655
TOTAL							**198,303**

Primary Metering Adjustment	**0.99**	**0.99**
Customer Class Name	**Current Loss Factor**	**Proposed Loss Factor**
R1(i)	1.0917	1.0829
R1(ii)	1.0917	1.0829
R2	1.0917	1.0829
Seasonal	1.0917	1.0829
Street Lighting	1.0917	1.0829

Rate Base and DSP

The proposed Rate Base for the 2020 Test Year of $119,873,438 reflects an increase of $21,801,607, or 22.2% relative to 2015 Board Approved. API's 2015-2020 rate base trend is presented in the following table:

Table 5 – 2015-2020 Rate Base Trend

	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Net Fixed Assets:	**2015 Board Approved**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Opening Balance	91,900,401	88,818,527	95,921,772	100,921,057	104,081,529	107,305,666	115,263,940
Ending Balance	97,146,940	95,921,772	100,921,057	104,081,529	107,305,666	115,263,940	119,252,035
Average Balance	94,523,671	92,370,150	98,421,414	102,501,293	105,693,598	111,284,803	117,257,988
Working Capital Allowance	3,548,161	3,556,625	3,666,549	3,455,022	3,415,727	3,503,714	2,615,450
Total Rate Base	**98,071,831**	**95,926,775**	**102,087,963**	**105,956,315**	**109,109,325**	**114,788,517**	**119,873,438**
Year over year variance		-2.19%	6.42%	3.79%	2.98%	5.21%	4.43%

The decrease from 2015 Board Approved to 2015 Actual is primarily due to changes in shared asset allocations from an affiliate, as described in Section 1.3.12. Year over year increases in rate base are primarily driven by capital investments, consistent with API's 2015-2019 DSP. Table 6 below reproduces OEB Appendix 2-AB, which compares planned vs. actual spending over the historical period:

Table 6 – Historical Planned vs. Actual Capital and O&M

CATEGORY	Historical Period **(previous plan & actual)**			Historical Period **(previous plan & actual)**		
	2015			**2016**		
	Plan	**Actual**	**Var**	**Plan**	**Actual**	**Var**
	$ '000		%	*$ '000*		%
System Access	1,020	963	-5.6%	1,020	992	-2.8%
System Renewal	4,044	3,809	-5.8%	4,834	4,229	-12.5%
System Service	1,232	3,033	146.2%	538	990	84.0%
General Plant	2,679	3,084	15.1%	2,679	2,369	-11.6%
Capital Contributions	-100	-157	57.1%	-100	27	-127.3%
TOTAL EXPENDITURE	8,875	10,732	20.9%	8,971	8,607	-4.1%
System O&M (exclude Admin)	$6,761	$6,296	-6.9%	$6,897	$6,361	-7.8%

Table 6 (Cont'd)

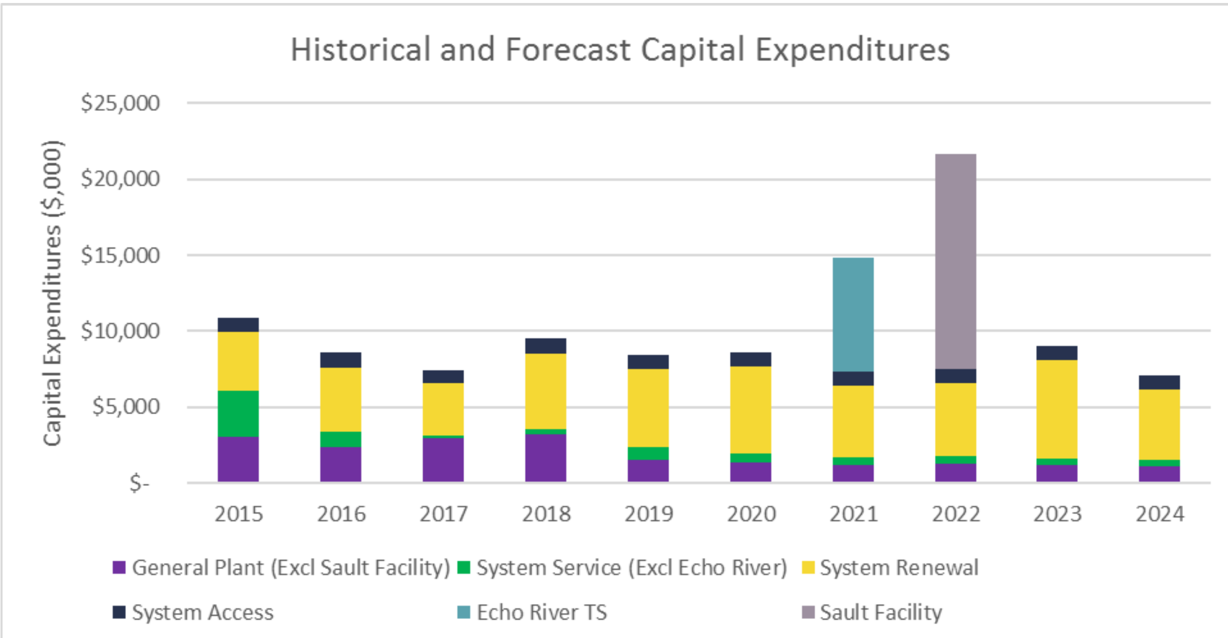
CATEGORY	Historical Period **(previous plan & actual)**			Historical Period **(previous plan & actual)**			Historical Period **(previous plan & actual)**		
	2017			**2018**			**2019**		
	Plan	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**
	$ '000		%	*$ '000*		%	*$ '000*		%
System Access	1,020	883	-13.4%	1,020	960	-5.9%	1,020	913	-10.5%
System Renewal	4,834	3,434	-29.0%	4,834	4,971	2.8%	4,834	5,144	6.4%
System Service	5,088	192	-96.2%	538	339	-37.0%	538	868	61.4%
General Plant	2,529	2,963	17.2%	2,029	3,240	59.7%	1,029	1,500	45.8%
Capital Contributions	-100	- 137	36.5%	-100	- 69	-30.7%	-100	-140	40.0%
TOTAL EXPENDITURE	13,371	7,336	-45.1%	8,321	9,441	13.5%	7,321	8,285	13.2%
System O&M (exclude Admin)	$7,035	$6,715	-4.5%	$7,175	$6,712	-6.5%	$7,319	$7,016	-4.1%

In developing its 2020-2024 DSP, API identified six strategic customer focused objectives that drive capital and O&M plans and related investments over the forecast period:

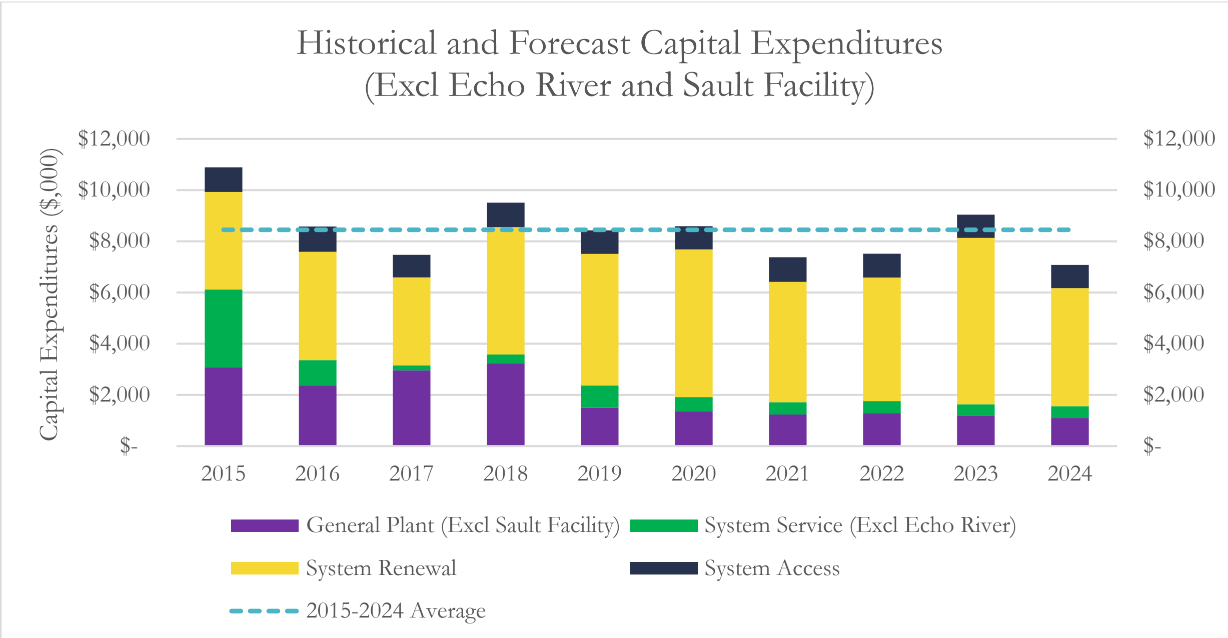
- Sustaining End of Life Asset Replacement
- Sustaining Vegetation Management
- Worker and Public Safety and Environmental Protection
- Reliability Improvement – Focus on Reducing Outage Duration
- Facilities Improvements to Support Productivity and Efficiency
- Flexible Approach to Emerging Technology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

API's 2020 Business Plan, included as Appendix 1B describes how the strategic objectives listed above are consistent with its core values and principles, the objectives of the OEB's Renewed Regulatory Framework, as well as the identified preferences of API's customers.

API's capital planning process strives for relatively consistent year to year spending in its sustaining end of life asset replacement programs as well as other programs of a recurring nature. This approach allows API to optimize the use of internal resources and ensures asset replacement on a pace that is consistent with the expected useful life of each type of asset. Larger one-time projects such as substation rebuilds and facility rebuilds are also paced to keep spending consistent, to the extent possible. Over the period covered by the 2020-2024 DSP, investments are required in the Echo River TS and the Sault Facility, resulting in large one-time variances from average levels of capital spending in both 2021 and 2022, as shown in the following chart:



The Echo River TS and Sault Facility projects are consistent with the 2020-2024 strategic initiatives identified above and additional justification for each project is provided in Section 4.4 of API's 2020-2024 DSP. API has requested ACM approval of these projects in 2021 and 2022, as summarized in Section 2.5.4 of Exhibit 2, and has requested an alternative approach to ACM cost recovery as described in Section 1.3.5. Excluding these two projects, actual and forecasted capital spending is relatively consistent over the 2015-2024 period as shown in the following chart:



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

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

Operations, Maintenance and Administration Expense

The proposed OM&A expenses for the 2020 test year of $13,677,187 reflects an increase of $1,372,306 or 11.2% relative to 2015 Board Approved. The following table summarizes API's OM&A trend from 2015 Board Approved to the 2020 Test Year.

Table 7 – 2015-2020 OM&A Trend

	2015 Board Approved	2015	2016	2017	2018	2019	2020
Operations	$1,642,392	$1,417,407	$1,296,572	$1,451,821	$1,566,232	$1,790,341	$1,782,437
Maintenance	$5,118,954	$4,879,021	$5,064,915	$5,263,562	$5,145,408	$5,225,959	$5,297,810
Billing and Collecting	$1,090,942	$964,836	$875,602	$874,404	$919,935	$970,387	$995,414
Community Relations	$22,102	$24,430	$32,308	$47,552	$141,890	$94,552	$96,558
Administrative and General	$4,430,491	$4,529,865	$4,534,507	$4,494,382	$4,361,131	$4,843,215	$5,504,968
Total	**$12,304,881**	**$11,815,559**	**$11,803,904**	**$12,131,721**	**$12,134,596**	**$12,924,455**	**$13,677,187**
%Change (year over year)		-4.0%	-0.1%	2.8%	0.0%	6.5%	5.8%

Historical year-over-year variances from 2015 actuals to 2018 actuals have ranged from 0-3%, mainly due to inflationary increases with annual variability in outage response costs, right of way maintenance costs, third-party admin and general services as well as temporary vacancies. Cost drivers for the 2019 Bridge Year and the 2020 Test Year include:

- Delayed recovery of certain costs related to the 2017-2019 interim operation of the distribution system owned by Dubreuil Lumber Inc. ("DLI"), as well as certain transaction and integration costs related to the acquisition of the customers and electricity distribution assets of DLI;
- Increases to rental and permit fees paid by API, partly due to increases in the OEB's generic joint use charges, and offset by increases in other revenues;
- Increased IT costs related to addressing the requirements of the OEB's Cybersecurity Framework;
- Increased finance staff to enhance processes and controls over financial and regulatory reporting;

- Lower than typical 2018 costs due to short-term staffing reductions in a number of Administrative areas due to vacancies and effort allocated to a non-distribution project;
- Filling a unionized position that became vacant in 2017 and was redefined in 2018;
- Increases in Sault Ste. Marie building rent following lease renewal/extension; and,
- Inflationary adjustments at 1.5% per year.

Table 9 on the following page presents API's 2015-2020 OM&A cost drivers, consistent with OEB Appendix 2-JB. Further cost driver analysis is provided in Section 4.2.2 of Exhibit 4.

2020 total compensation of $9,579,879 reflects an increase of $435,652 or 4.8% relative to 2015 Board Approved. This increase reflects a compound average growth rate of 0.94% from 2015 Board Approved, or 0.78% from 2015 Actual. Total compensation is summarized in Table 8 below, and analyzed in detail in Section 4.4 of Exhibit 4.

Table 8 – 2015-2020 OM&A Cost Drivers

	2015 Board Approved	2015	2016	2017	2018	2019 Bridge Year	2020 Test Year
Total Salary and Wages	$6,385,940	$6,659,768	$6,606,283	$6,455,559	$6,891,590	$7,231,903	$7,452,169
Total Benefits	$2,758,287	$2,553,105	$2,046,664	$2,246,996	$2,355,431	$2,483,587	$2,127,710
Total Compensation	**$9,144,227**	**$9,212,873**	**$8,652,947**	**$8,702,556**	**$9,247,021**	**$9,715,489**	**$9,579,879**

Table 9 – 2015-2020 OM&A Cost Drivers

OM&A	**Last Rebasing Year (2015 Actuals)**	**2016 Actuals**	**2017 Actuals**	**2018 Actuals**	**2019 Bridge Year**	**2020 Test Year**
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Opening Balance	12,304,881	11,815,559	11,803,904	12,131,721	12,134,596	12,924,455
Vehicle Depreciation Credit	258,000					
Load Dispatching	(66,000)					
AMI Metering Costs	(44,000)	33,000	38,000			
Outages	(148,000)	121,000	147,000	(273,000)		
Right of Way Maintenance Program	(70,000)	116,000	62,000	207,000		
Miscellaneous Customer Accounts Expenses	(89,000)	(52,000)	(13,000)	77,000		
G&A Outside Services Employed	(80,000)	231,000	(122,000)			
Technical Services Supervisor Vacancy		(47,000)	47,000			
Overhead Lines and Feeders Maintenance - Labour		(48,000)	30,000	23,000	22,000	
Regional Manager		(148,000)	110,000	25,000		
Utilityperson Hire			(60,000)	(60,000)	105,000	
Customer Engagement				109,000	(74,000)	
Maintenance on Poles, Towers and Fixtures, and Overhead Conductors and Devices				(44,000)	78,000	
Joint Use Pole Rental Paid					40,000	
Right of Way Land Fees					47,000	
Sault Ste Marie Building Rent						341,000
Regulatory Expenses						155,000
Shared Services Administrative Services From CNPI Distribution			116,000	(214,000)	294,000	71,000
Dubreuilville Interim License Internal Effort			(109,000)	40,000	19,000	50,000
Miscellaneous	(250,322)	(217,655)	81,817	112,875	258,859	135,732
Closing Balance	11,815,559	11,803,904	12,131,721	12,134,596	12,924,455	13,677,187

Cost of Capital

In this application, API seeks to recover a weighted average cost of capital of 6.48% through rates in the 2020 Test Year. API has followed the Report of the Board on Cost of Capital for Ontario's Regulated Utilities, December 11, 2009 in determining the applicable cost of capital.

In calculating the applicable cost of capital, API has used the OEB's deemed capital structure of 56% long-term debt, 4% short-term debt, and 40% equity, in conjunction with the cost of capital parameters in the OEB's letter of November 22, 2018, for the deemed debt rates and allowed return on equity. The following table summarizes API's capital structure, cost of capital, and the associated return on rate base included in its 2020 revenue requirement.

Table 10 - Overview of Capital Structure

Particulars	**Cost Rate**		**2020 Return on Rate Base**	
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$67,129,125	4.95%	$3,322,892
Short-term Debt	4.00%	$4,794,938	2.82%	$135,217
Total Debt	**60.0%**	**$71,924,063**	**4.81%**	**$3,458,109**
Equity				
Common Equity	40.00%	$47,949,375	8.98%	$4,305,854
Preferred Shares				
Total Equity	**40.0%**	**$47,949,375**	**8.98%**	**$4,305,854**
Total	**100.0%**	**$119,873,438**	**6.48%**	**$7,763,963**

API acknowledges that the OEB may adjust the cost of capital parameters applicable to rate changes effective in 2020, and therefore commits to updating its Application to reflect the revised 2020 parameters, if required.

Cost Allocation and Rate Design

API has prepared and is filing a 2020 Cost Allocation Study consistent with its understanding of the Directions and Policies in the Board's Reports of November 28, 2007 Application of Cost Allocation for Electricity Distributors and March 31, 2011 Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) (the "Cost Allocation Reports") and all subsequent updates.

The cost allocation study accepted in API's 2015 cost of service application (EB-2014-0055) found that revenue-to-cost ratios for the Seasonal and Street Lighting classes were below the OEB's policy range. As part of the Settlement Agreement in that application, the OEB approved the following adjustments over the 2015-2019 period:

Table 11 – Approved Revenue to Cost Ratios 2015-2019

	2015	2016	2017	2018	2019
Residential - R1	110.63%	Beneficiary			
Residential - R2	110.74%	Beneficiary			
Seasonal	60.00%	66.00%	72.00%	78.00%	85.00%
Street Lighting	25.04%	10% Total Bill Impact			

During the course of the EB-2014-0055 proceeding API proposed the possibility of a revising the cost allocation study to consider certain unique aspects of API's system configuration, such as its very low customer density and the use of bulk assets. The 2020 cost allocation study allocates a portion of the rate base amount for certain asset types to the "bulk delivery" category within the OEB Cost Allocation Model, to more accurately reflect the functionality of API's sub-transmission (express feeder) network. Further, API has used the direct allocation functionality within the OEB model to address the acquisition of assets and customers of DLI. All of the foregoing adjustments are detailed in Section 7.2.1 of Exhibit 7.

Consistent with past cost of service applications, the 2020 cost allocation study is based on the use "equivalent rates" for the R1 and R2 rate classes. These are the rates which would apply in the absence of RRRP funding, as further explained in Exhibits 7 and 8.

Since the 2020 status-quo ratio for the Street Lighting rate class exceeds the upper limit of the OEB's policy range, API proposes to adjust the 2020 ratios as shown in the following table:

Table 12 – Rebalancing Revenue to Cost Ratios

Name of Customer Class	**Previously Approved Ratios 2019**	**Status Quo Ratios 2020**	**Proposed Ratios 2020**	**Policy Range**
	%	**%**	**%**	**%**
Residential R1	105.07	104.57	104.57	85 - 115
Residential R2	105.06	88.46	89.09	80 - 120
Seasonal	85.00	89.98	89.98	80 - 120
Street Lighting	42.79	136.34	120.00	80 - 120

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

1. Determination of the amount of API's revenue requirement that is allocated to its RRRP-eligible rate classes;
2. Determination of the forecasted distribution rate revenue from API's RRRP-eligible rate classes, considering the most recently approved distribution rates adjusted by the RRRP Adjustment factor; and
3. Calculation of the annual RRRP amount payable to API as the amount by which the revenue requirement identified in Step 1 exceeds the revenue forecasted in Step 2.

API's proposed 2020 rate design in the context of the RRRP framework is detailed in Section 8.2 of Exhibit 8. API confirms that the proposed approach to 2020 rate design is consistent with the approach approved by the OEB in API's prior cost of service applications, and that the transition towards fully fixed rates for Residential – R1(i) and Seasonal customers is consistent with the OEB's decisions on adjustments during the 2016-2019 IRM years. Since the OEB has already approved longer transition periods for API and total bill impacts do not exceed 10%, no bill impact mitigation is required.

1 The table below shows APIs existing rates in comparison to the 2020 proposed rates:

2 **Table 13 – Distribution Rate Summary**

Rate Class and Charge	**Unit**	**2019 Approved**	**2020 Proposed**
Residential - R1(i)			
Monthly Service Charge	$	42.23	47.17
Distribution Volumetric	$/kWh	0.0172	0.0126
Residential - R1(ii)			
Monthly Service Charge	$	25.64	26.21
Distribution Volumetric	$/kW	0.0361	0.0369
Residential - R2			
Monthly Service Charge	$	659.94	674.59
Distribution Volumetric	$/kW	3.4194	3.4953
Seasonal			
Monthly Service Charge	$	54.75	58.75
Distribution Volumetric	$/kWh	0.1494	0.1703
Street Lighting			
Monthly Service Charge	$	2.05	1.37
Distribution Volumetric	$/kWh	0.3310	0.3279

3

Deferral and Variance Accounts

API proposes to dispose of a credit of $960,461 related to Group 1 and a credit of $26,045 related to Group 2 Variance/Deferral Accounts. These credit balances include carrying charges up to and including December 31, 2018, as well as interest projected to December 31, 2019.

API also proposes to dispose of a net debit balance of $510,390 recorded in account 1568 being the Lost Revenue Adjustment Mechanism Variance Account, and is requesting an extension of its Seasonal Rate Mitigation Plan rate rider to December 31, 2023 as summarized in Section 1.3.8.

Group 1 and Group 2 DVA balances are proposed to be disposed of over a period of 12 months. The rate rider for account 1568 – LRAMVA Balance is proposed to be recovered over a period of 48 months in consideration of the impact on customer rates.

Based on API's billing process, there is no Global Adjustment ("GA") variance for Class A customers. For Class B customers, OEB Account 1589 captures the difference between GA amounts billed to non-RPP customers and the actual GA amount paid for those customers to the IESO. The rate rider for disposition of OEB Account 1589 is therefore applicable to Class B non-RPP customers only. API applied historical RPP/non-RRP percentages to the 2020 load forecast amounts to arrive at estimated non-RPP kWhs for calculation of the 2020 rate rider. An allowance was also made to allocate a portion of the Account 1589 balance to calculate a separate rate rider for one customer that transitioned from Class B to Class A in 2018.

API is requesting three new standard OEB 1595 sub-accounts for the 2020 rate year. API is not requesting to create any other accounts or discontinue the use of any existing accounts.

Table 14 on the following page summarizes the DVA balances sought for disposition in 2020. Exhibit 9 provides detailed calculation of the resulting rate riders, all of which have been factored into 2020 bill impact calculations.

Table 14 – DVA Balances Sought for Disposition

		Amounts from Sheet 2	Allocator
LV Variance Account	1550	0	kWh
Smart Metering Entity Charge Variance Account	1551	(6,137)	# of Customers
RSVA - Wholesale Market Service Charge	1580	(552,366)	kWh
RSVA - Retail Transmission Network Charge	1584	110,430	kWh
RSVA - Retail Transmission Connection Charge	1586	362,391	kWh
RSVA - Power (excluding Global Adjustment)	1588	(76,314)	kWh
RSVA - Global Adjustment	1589	(662,317)	Non-RPP kWh
Disposition and Recovery/Refund of Regulatory Balances (2016)	1595	(47,220)	%
Total of Group 1 Accounts (excluding 1589)		**(209,216)**	
Misc. Deferred Debits	1525	(26,045)	kWh
Total of Group 2 Accounts		**(26,045)**	
LRAM Variance Account ***(Enter dollar amount for each class)***	1568	**340,689**	
(Account 1568 - total amount allocated to classes)		340,690	
Variance		**(1)**	
Variance WMS - Sub-account CBR Class B (separate rate rider if no Class A Customers)	**1580**	**(9,437)**	**kWh**
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**425,601**	
Total of Account 1580 and 1588 (not allocated to WMPs)		**(628,680)**	
Balance of Account 1589 Allocated to Non-WMPs		**(662,317)**	
Group 2 Accounts (including 1592, 1532)		**(26,045)**	
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh
Total Balance Allocated to each class for Accounts 1575 and 1576		**0**	
Account 1589 reference calculation by customer and consumption			
Account 1589 / Number of Customers	($61.24)		
1589/total kwh	($0.0038)		

Bill Impacts

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

Table 15 – Bill Impact Summary

Customer Classification and Billing Type	Energy kWh	Demand kW	Sub-Total A $	Sub-Total A %	Sub-Total B $	Sub-Total B %	Sub-Total C $	Sub-Total C %	Total Bill $	Total Bill %
Residential - R1(i) (RPP)	269	-	$ 1.03	2.8%	$ 0.86	2.2%	$ 1.42	3.3%	$ 1.48	2.1%
Residential - R1(i) (RPP)	750	-	$ 2.33	6.6%	$ 1.86	4.6%	$ 3.40	6.7%	$ 3.55	2.9%
Residential - R1(i) (Retailer)	750	-	$ 2.33	6.6%	-$ 31.55	-85.5%	-$ 30.01	-63.5%	-$ 31.53	-22.5%
Residential - R1(ii) (RPP)	2,000	-	$ 7.44	7.9%	$ 6.19	5.8%	$ 10.30	7.6%	$ 10.74	3.3%
Residential - R1(ii) (Retailer)	2,000	-	$ 7.44	7.9%	-$ 82.90	-85.5%	-$ 78.79	-63.3%	-$ 82.80	-22.3%
Residential - R2 (non-RPP)	90,000	225	$ 199.56	16.0%	-$ 3,804.46	-870.0%	-$ 3,633.94	-225.3%	-$ 4,208.38	-29.1%
Residential - R2 (Class A)	2,500,000	5,000	$ 4,123.65	30.0%	$ 3,745.65	33.1%	$ 7,534.79	20.1%	$ 5,680.27	1.4%
Seasonal (RPP)	50	-	$ 5.25	8.2%	$ 5.21	8.1%	$ 5.31	8.1%	$ 5.58	7.6%
Seasonal (RPP)	153	-	$ 7.85	9.6%	$ 7.74	9.3%	$ 8.05	9.4%	$ 8.45	8.1%
Seasonal (RPP)	750	-	$ 22.96	12.2%	$ 22.23	11.4%	$ 23.77	11.5%	$ 24.93	8.8%
Seasonal (Retailer)	750	-	$ 22.96	12.2%	-$ 10.81	-5.8%	-$ 9.27	-4.7%	-$ 96.46	-32.3%
Street Lighting (non-RPP)	3,308	9	$ 100.19	8.1%	-$ 54.52	-4.4%	-$ 49.48	-3.9%	-$ 52.07	-3.0%

The primary driver of the large total bill decreases for the non-RPP rate classes is a relatively high credit rate rider related to disposition of Global Adjustment variances. This credit is not reflected in the higher consumption R2 scenario since the rate rider does not apply to Class A customers.

For the Residential – R1 and Residential – R2 rate classes, the Sub-Total A bill impacts presented above are affected by the December 31, 2019 expiry of a credit rate rider. Further comparison of bill impacts resulting from changes to base rates in isolation of changes to rate riders is provided in Section 8.3.13.

2020 Cost of Service Application

Customer Summary

ABOUT ALGOMA POWER

Algoma Power provides local distribution service to a rural area that extends approximately 93 km east and 255 km north of the City of Sault Ste. Marie. Algoma Power delivers electricity over 1861 km of distribution lines to approximately 12,000 customers.

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

ABOUT THE APPLICATION

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

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

The pass-through transmission rates that Algoma Power charges to its customers are reviewed and approved by the OEB each year. For low-volume customers, the OEB also approves Time of Use and Tiered Electricity Rates (for generation costs) on a province-wide basis. Since Algoma Power's revenue from these pass-through rates is typically different than its actual costs, every rate application includes requests for "rate riders" that true-up any past differences. Depending on the year, these rate riders can either be charges or credits.

CUSTOMER ENGAGEMENT AND PERFORMANCE METRICS

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

Algoma Power also conducted online customer surveys specific to this application, which provided multiple opportunities for customers to identify their need and priorities, and to provide feedback on programs and spending levels.

Algoma Power has considered feedback from all of the above activities with a goal of meeting the needs and preferences of our customers.

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

ALGOMA POWER'S GOALS

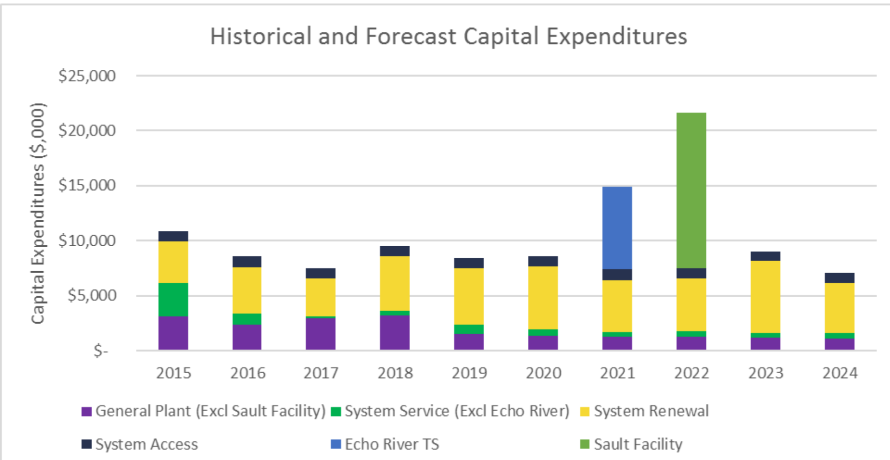
Algoma Power operates according to six core values: Respect for People; Safety and the Environment; Financial Success; Customer Service; Productivity; and Community Involvement. Based on a combination of these values, customer preferences and OEB expectations (discussed above), Algoma Power identified six strategic objectives for its Five-Year Plan, which are discussed in Algoma's 2020 Business Plan (Appendix 1B of Exhibit 1 of the application).

2020 Cost of Service Application

Customer Summary

SUMMARY OF ALGOMA POWER'S FIVE-YEAR PLAN

Algoma Power prepared a 2020-2024 Distribution System Plan that outlines its strategy and proposed spending levels for capital investments, and the ongoing operation and maintenance of its system. The following chart summarizes Algoma Power's actual and planned capital investments for 2015-2024:



OTHER PROPOSALS AND REQUESTS

The chart above shows large one-time projects planned for 2021 and 2022. Algoma Power is proposing an approach that would help pay these additional costs, while avoiding rate increases for the majority of customers that are eligible for rate subsidies (see "Rate Setting and Rate Relief").

Algoma Power's 2020 costs include integrating the distribution system in Dubreuilville, and Algoma Power is proposing an approach that avoids passing these costs onto its existing customers.

Algoma Power is also requesting a continued exemption from using time-of-use rates in the most remote portions of its system to avoid additional costs.

RATE SETTING AND RATE RELIEF

Algoma Power's forecasted 2020 costs of approximately $26 million includes operating costs, payments for capital investments that are spread over the life of the assets, the cost of debt and equity to support capital investments, and various taxes.

These total costs are divided between groups of customers (residential, commercial/industrial, seasonal and street lighting), and rates are calculated based on forecasted 2020 load and customer counts.

Revenue from seasonal and street lighting customers in 2015 was less than the costs assigned to them, requiring higher than inflationary rate increases for these customers from 2015 to 2019. Distribution revenues and costs are now in line which will limit 2021 to 2024 rate adjustments to inflationary increases.

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

A number of other rate relief programs under the Fair Hydro Plan (lower time-of-use rates, caps on distribution rates for residential customers and credits for First Nation residential customers) are not affected by the application.

Finally, annual adjustments to transition residential and seasonal customers towards fixed monthly distribution rates continue to be applied.

BILL IMPACTS

For the distribution portion of the bill, API has forecasted increases of $2.33 for a typical residential customer (750 kWh per month) and $7.44 for a typical small commercial customer (2000 kWh per month). These adjustments are the result of the annual RRRP adjustment described above, and changes to rate riders for pass-through costs.

Website Link (For Application, Scorecard and Other Information): www.algomapower.com
Customer Service Email Contact: customerservice@algomapower.com

ALGOMA POWER INC.

BOARD OF DIRECTORS' MEETING
JUNE 5, 2019

RESOLUTION OF THE BOARD OF DIRECTORS
OF ALGOMA POWER INC.
(THE "CORPORATION")

2020 COST OF SERVICE RATE APPLICATION

WHEREAS the board of directors of the Corporation (the "Board") has reviewed and discussed the Corporation's 2020 Cost of Service Rate Application, including, its revenue requirement of $25,937,065, a rate base of $119,873,438, and a total bill impact to an average residential customer of 2.9% and to an average general service customer of 3.3% effective January 1, 2020 (the "Rate Application");

AND WHEREAS the Rate Application was filed with the Ontario Energy Board ("OEB") on May 17, 2019.

AND WHEREAS following deliberation in respect of the Rate Application, the Board has determined that the submission of the Rate Application to the Ontario Energy Board ("OEB") is in the best interest of the Corporation.

NOW THEREFORE BE IT UNANIMOUSLY RESOLVED THAT:

1. The Rate Application and the submission of the Rate Application to the OEB on May 17, 2019, is hereby ratified and confirmed, and the Board further authorizes and approves any necessary applications, notices, or documents submitted to the OEB in connection thereto, and to take any such further steps and do any and all such further acts or things as shall be necessary or desirable in carrying out the Rate Application.

2. The authority and power given in the foregoing resolutions shall be deemed retroactive and any and all acts authorized hereunder performed prior to the passage of these resolutions are in all respects hereby ratified and approved.