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RESS & COURIER

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

Attention: Ms. K. Walli, Board Secretary

Dear Ms. Walli:

Re: Dubreuil Lumber Inc. and Algoma Power Inc. - Application for Leave to Sell Distribution System & Related Matters (EB-2018-0271) – Applicant Interrogatory Responses

We are legal counsel to Algoma Power Inc. (API), which together with Dubreuil Lumber Inc. (DLI) is the applicant in the above-referenced proceeding. On January 3, 2019 the Ontario Energy Board (the "Board") issued Procedural Order #1 in connection with the proceeding. On January 15, 2019 the applicant received interrogatories from Board Staff. Enclosed, please find the applicant's responses to the interrogatories from Board Staff.

Please note that the applicant requests confidential treatment for its response to Board Staff IR #9(a), which contains information relating to API's measures to address the Board's cybersecurity requirements. As such, the response to 9(a) in the version that is being filed electronically on the Board's Regulatory Electronic Submission System is redacted. A hard copy of the response is being provided to the Board in accordance with the Board's Practice Directions on Confidential Filings.

Yours truly,

Jonathan Myers

cc: Mr. Ken Buchanan, DLI
Mr. Greg Beharriell, API
Mr. Craig David, API
Mr. Charles Keizer, Torys LLP

ALGOMA POWER INC./DUBREUIL LUMBER INC.

Responses to Interrogatories from Board Staff

OEB STAFF - 1

Reference: Exhibit B/Tab 1/Schedule 1/Page 4
Exhibit D/Tab 1/Schedule 1/Appendix A – Asset Purchase Agreement
Exhibit E/Tab 2/Schedule 1/Pages 5-6

Preamble: As one of the requested approvals, Algoma Power Inc. (API) and Dubreuil Lumber Inc. (DLI) (collectively, the Applicants) request the following:

d. API requests that the OEB endorse its proposed approach of allocating costs attributable to the DLI service area, at the time of API's next rebasing, primarily to API's R1 and R2 rate classes, which are eligible for Rural or Remote Rate Protection;

Further discussion of this is provided in Exhibit E/Tab 2/Schedule 1 at pages 5-6.

Request:

a) Based on the record, a panel may decide to defer certain matters to another, often subsequent hearing, where they may be more completely or properly considered, but the panel will not make a decision that will bind a panel considering the matter in a future application. Please specify exactly what API is seeking in requesting that the OEB panel deciding this application "endorse its proposed approach of costs attributable to the DLI service area" which will be considered in API's next application to rebase its rates for all of API's customers.

b) API only briefly reiterates this request at the bottom of pages 5 and 6 of Exhibit E/Tab 2/Schedule 1, and without further support.

   i. Please identify if this request is specifically tied to a term or condition of the Asset Purchase Agreement (APA). If so, identify the specific term, condition or clause.

   ii. Please document the necessity of this specific approval as part of this application.

c) Please identify any precedent(s) that API is aware of, for the kind of the "endorsement" that API is seeking.

Response:

a) The Applicants recognize that a decision of a panel in one proceeding cannot bind a panel in a future proceeding. However, the first panel can express general support for a plan or methodology, state its expectations as to a future circumstance, as well as provide guidance to a future panel in connection with matters expected to arise in the future proceeding. It may also want to explain how any such expectations have informed its findings. This is the nature of the Applicants' request that the OEB "endorse" its proposed approach to cost allocation following API's next rebasing proceeding. API therefore requests that the panel in the current proceeding express its general support for API's planned approach to cost allocation and guide the future panel by indicating that the current panel's expectation, in finding the Proposed Transaction meets the 'no harm' test, is that API's future rates will be based on an allocation of the costs attributable to the DLI service area primarily to its R1 and R2 customer classes so as to mitigate potential rate impacts to existing Seasonal and Street Lighting customers.

The foregoing is consistent with the request in the pre-filed evidence. In particular, on pp. 5-6 of Exh E-2-1, the Applicants explain that the rates for API's R1 and R2 customers are determined in accordance with the RRRP regulation and, as such, regardless of any impact of the Proposed Transaction on API's underlying cost structure, there will be no distribution rate impacts for these customer classes. However, API's remaining customers, being Seasonal or Street Lighting customers, are not eligible for RRRP. Therefore, to avoid having the Proposed Transaction adversely and disproportionately impact its Seasonal and Street Lighting customers, API explained its intention to propose, in its next rebasing application, that any costs attributed to the DLI service area be allocated primarily to the R1 and R2 customer classes. Following this explanation, the Applicants state: "<u>To guide a future panel of the OEB in considering that cost allocation model</u>, API asks the OEB to endorse this approach as part of its decision in the present Application." (emphasis added)

Although the Handbook suggests that rate matters will be determined by a separate panel in a future rate application and not in the MAADs proceeding, the Board recently clarified that the cost allocation methodology to be used in setting future rates for a consolidated entity is relevant to the MAAD application. As explained by the Board in its April 12, 2018 Decision and Order in Hydro One's application to acquire the shares of Orillia Power Distribution (EB-2016-0276),

> *The OEB is of the view that it would have been reasonable to see a forecast of costs to service Orillia customers beyond the ten year period and an explanation of the general methodology of how costs would be allocated to Orillia ratepayers after the deferral period . . . The OEB recognizes that any forecast of cost structures and cost allocation 10 years out would include various assumptions and could not be expected to be 100% accurate. However, the OEB has highlighted its concern and its need to better understand the implications of how Orillia customers will be impacted by the consolidation beyond the ten year period. In the absence of information to address that OEB concern, the OEB cannot reach the conclusion that there will be no harm.*

It is therefore the Applicants' understanding that the question of how the costs of serving the acquired customers will be allocated following API's next rebasing application, and the impacts of that allocation methodology on both the acquired customers and API's existing customers, is fundamental to the Board's analysis in applying the "no harm" test in the present proceeding and that it is therefore appropriate for the Board to make findings on that aspect of the application.

b)

i. If the OEB determines that API's request - for the Board to endorse its plans to allocate costs related to the DLI service area in a manner that mitigates bill impacts to API's existing customers - is not appropriate, then API would not have a reasonable expectation of being able to recover its costs in a manner that results in no harm to its existing customers. As such, API's Board of Directors may consider that proceeding with the Proposed Transaction is contrary to the interests of its existing customers, and could therefore decide not to proceed with the Proposed Transaction in accordance with s. 3.5(c) of the APA and the definition of "Successful OEB Decision" thereunder. See also response to Board Staff IR 13.

ii. A unique aspect of the application is that rates for the majority of API's customers would not be affected in any way by the Proposed Transaction, resulting from the application of O. Reg. 445/07 and O. Reg. 442/01 (the "RRRP Regulations"). Irrespective of API's actual revenue requirement, the RRRP Regulations require that the distribution rates charged to API's residential and general service customers (i.e. its R1 and R2 rate classes) are adjusted annually based on the average of distribution rate increases for all other LDC's. None of API's R1 and R2 customers will therefore be harmed by the application from a rates perspective even if API's future revenue requirement increases as a result of the Proposed Transaction. In contrast, customers belonging to API's Seasonal and Street Lighting rate classes do not benefit from the rate stability provided by RRRP.

   Following API's proposed acquisition of DLI's assets and customers, API's revenue requirement will increase due to the incremental cost to serve the DLI service area. However, this incremental cost to serve the DLI service area will not be fully offset by the incremental distribution rate revenue that API will receive from the acquired customers. In the absence of any adjustments to the methodology for API's cost allocation, customers in the Seasonal and Street Lighting rate classes would be allocated additional costs and experience rate increases as a result of the acquisition. In the normal course, this would demonstrate that the proposed consolidation results in harm to customers in the form of rate increases for certain classes of existing customers. In addition to this being an outcome that API wants to avoid, it may also give rise to a determination by the OEB that the transaction should not be approved. However, the circumstances underpinning the application are that DLI is not a financially viable distributor and would be unable to operate independently of API.

Moreover, API has demonstrated in the application and in response to Board Staff IR 11 that consolidation is more efficient than the alternative of stand-alone operation.

In developing its cost allocation proposal, API considered an alternative where it would maintain non-harmonized rates (at least initially) between its existing service area and the DLI service area. In this scenario, all of the existing DLI customers, which are classified as either residential or commercial customers, would become RRRP-eligible customers, and would pay distribution rates identical to those paid by API's other customers, because of the RRRP Regulations. There would be no cost allocation to a Seasonal rate class for the DLI service territory since API is not aware of any seasonal customers in Dubreuilville. This leaves Street Lighting as the only rate class that would require a rate specific to the DLI service area since API will establish an account for the street lights in Dubreuilville at the time of acquiring DLI's customers. In order to establish a justifiable street-lighting rate for a single account with approximately 50 Street Lights in Dubreuilville, API would have to undertake a complete cost allocation exercise for the DLI service area, including a consideration of how to appropriately allocate portions of API's overall administrative and general costs to the DLI service area.

Since residential and commercial customers would comprise approximately 99.8% of the customer accounts, and virtually 100% of the load in the Dubreuilville service area, API allocating substantially all of the costs directly associated with the DLI service territory to its R1 and R2 rate classes and charging the street lighting account the same rates as its existing street lighting customers was determined to be a much more reasonable and cost-efficient approach. API noted at Exh. E-2-1, page 6 that a small number of streetlights are currently unmetered and unbilled, and that it would consider allocating a small portion of the costs related to the Dubreuilville service area to its Street Lighting rate class at the time of its next cost of service application. In API's view, allocating an amount equal to the forecasted distribution revenue from street lights in Dubreuilville would be a reasonable proxy to ensure cost neutrality to API's existing street lighting customers, while avoiding the expense of additional cost allocation and rate design studies to establish separate street lighting rates for a single account (i.e. the Township of Dubreuilville's street lighting account).

c) See response to (a), above.

<u>OEB STAFF - 2</u>

Reference: Exhibit C/Tab 1/Schedule 1/Page 5

Preamble: In Exhibit C/Tab 1/Schedule 1, the Applicants state:

> The combination of an expansive rural service area and very low population density present unique cost challenges with respect to the operation and maintenance of API's distribution system.

Request:

a) What type of impact(s) will the addition of the DLI distribution system have on API's unique cost challenges with respect to the operation and maintenance of API's distribution system?

Response:

API's customer density will remain relatively unchanged as a result of the addition of the DLI distribution system, as illustrated in the table on page 5 of Exh. E-2-1. Further, as illustrated in API's service area maps at Exh. C-1-1, Appendix C, Dubreuilville is embedded within API's existing service area, and is in proximity to distribution system assets that are currently owned, operated and maintained by API.

The cost of investments made and planned during the 2017-2019 period are summarized at F-3-1, page 2, with the associated cost recovery and rate impacts addressed in the application. As explained at Exh. E-2-1, pages 4-5, the acquired assets and customers can be readily integrated into API's existing business processes, and API does not expect a material change to its underlying cost structure in light of the small changes to API's cost drivers (3% increase in customer count, 0.5% increase in circuit km, and a 2.5% increase in customer density).

OEB STAFF - 3

Reference: Exhibit C/Tab 2/Schedule 1/Page 2
DLI Rates

Preamble: API notes that a condition of the Interim Licence Order[1] was for API to:

> 2. Collect revenue from customers within the service area of DLI based on the charges that are currently applied by DLI.

Request:

a) Please provide a table documenting the rates that API has charged to customers of DLI since assuming operation of the DLI distribution system in accordance with the interim licence.

b) Please provide any explanation or documentation necessary to understand the derivation and application of DLI's rates (i.e., what form of rate adjustments, if any, have been applied, consistent with DLI's past practice).

c) Assuming approval of the application by the OEB, please confirm that API will continue to charge customers in Dubreuilville in accordance with DLI's current rates until the closing of the transaction. If there are any proposed or anticipated variances, please explain.

Response:

a) Please see the attached **Schedule 3(a)**.

b) Please see the attached **Schedule 3(a)**.

c) Confirmed. API will continue to charge customers in Dubreuilville according to the rate-setting methodology illustrated in **Schedule 3(a)** until closing of the transaction. After closing of the transaction, these customers would become API customers and would be charged according to API's approved Tariff of Rates and Charges.

[1] EB-2017-0153

OEB STAFF - 4

Reference: Exhibit C/Tab 2/Schedule 1/Pages 7-8

Preamble: In Exhibit C/Tab 2/Schedule 1, the Applicants state:

> All distribution poles were tested in 2017. Based on the test results, 10 poles in poor condition will be replaced before the end of 2018.
> …
> A number of additional installations have been flagged for replacement in 2018 to address general issues of non-compliance with Measurement Canada requirements, or issues related to prevention of tampering.
>
> API plans to replace all electromechanical meters that have expired seals in 2018. In conjunction with this effort, API is also investigating options for cost effectively extending the reach of its AMI network to cover the DLI service area. The meters installed in 2018 will be fully compatible with the AMI network if and when AMI coverage is deployed.

Request:

a) Please provide a status update on the work that was scheduled to be completed in 2018.

b) Please provide additional updates and status reports, including associated cost updates, on any other key developments regarding efforts to bring the DLI distribution system into compliance.

c) Have any timelines been revised with regard to implementing updates and changes to the DLI distribution system? If so, please elaborate.

d) Please provide an estimate of the anticipated reduction in meter reading costs resulting from the extension of the AMI network into the DLI service area once fully implemented.

Response:

a) API completed a number of high-priority projects in 2018, the most significant of which included completion of all load transfers from Substation #1 to Substation #2 and the subsequent decommissioning of Substation #1. API also replaced most electromechanical meters in Dubreuilville with electronic smart meters, and is continuing the process of addressing all outstanding deficiencies with respect to non-compliance with Measurement Canada requirements and meter replacements associated with older style meter bases and/or uncommon meter types. For a small number of deficient metering installations, outage requirements for replacing or upgrading the installations are longer than originally expected and API has postponed this work until spring 2019 in order to avoid prolonged outages during winter weather that arrived earlier than normal in 2018. API had planned to source a spare transformer in 2018 to improve contingency plans for Substation #2. However, after reaching out to a number of other LDC's and a used and surplus equipment vendor, API was unable to procure a suitable spare. As a result, API will explore alternatives for interim contingency response options in 2019 as it advances engineering and design efforts related to the rebuild of Substation #2, which is planned for 2020. Given the significant high-priority work completed in 2017 and 2018, and the associated planned outages necessary to complete this work, API deferred the replacement of 10 poles initially planned for 2018 to 2019 in consideration of the customer impact of planned outages. API also considered that this would allow for more cost-effective mobilization of resources and equipment to replace a total of 20 poles in Dubreuilville 2019.

b) The refurbishment and compliance plan developed by API is outlined at pages 12-14 of the 60-Day report, a copy of which is provided in Exh. C-2-1, Appendix 'C'. Significant activities completed in 2017 and forecasted to be completed in 2018 are summarized at Exh. C-2-1, pages 6-8, with an update on actual completion of 2018 work activities provided in (a) above. 2017 actual and 2018 forecasted costs are summarized in the table at Exh. F-3-1, page 2. API is currently in the process of finalizing 2018 actual costs, but notes that approximately $150k of 2018 forecasted capital costs have been shifted from 2018 to 2019 as a result of deferring certain projects for the reasons described in (a), above. API does not otherwise expect any material variances in the 2018 or 2019 cost forecasts that are provided in the table referenced above.

c) Certain projects planned for 2018 have been deferred to 2019, as described in (a) and (b), above. API's refurbishment and compliance plan for the DLI system, referenced in (b), above, categorized the required updates and changes to the DLI system in either the Short-Term Plan, or the Medium- and Long-Term Plan. Items listed under the Short-Term Plan have either been completed, or are forecasted to be completed in 2019. Items listed in the Medium- and Long-Term Plan that have not already been initiated will be prioritized accordingly in API's 2020-2024 Distribution System Plan.

d) On the assumption that all, or substantially all of the meters located in Dubreuilville would be within reach of planned AMI infrastructure, API anticipates that costs associated with meter reading and manual data entry of meter reads would be reduced by approximately $35k per year. API expects that these savings will be offset by approximately $20k as a result of O&M costs associated with the required AMI infrastructure. Though API expects a relatively small amount of cost savings from AMI implementation, it plans to proceed with this project in order to transition eligible customers to time-of-use pricing in compliance with the Standard Service Supply Code, to provide customers with access to detailed consumption data[2], and to improve operational response to outage events through the analysis of alarms relayed by the AMI network.

[2] Since replacing electromechanical meters in Dubreuilville with smart meters, API has received a number of inquiries from DLI's customers inquiring as to when online access to consumption data will become available.

OEB STAFF - 5

Reference: Exhibit F/Tab 3/Schedule 2/Pages 1-6

Preamble: The application states that the proposed transaction does not present an opportunity to recover transaction and transition costs through a deferred rebasing period. API requests that the Transaction and Integration Costs Deferral Account be given an effective date of April 4, 2017, which coincides with the OEB's Decision and Order requiring API to take possession and control of the DLI distribution system.

API proposes to record all costs associated with the preparation of the Asset Purchase Agreement and this application, as well as all costs related to the OEB's hearing process (including, but not limited to legal fees and intervenor cost awards), and costs related to the closing of the proposed transaction ($168,674 total forecast for 2018 and 2019).

Request:

a) Please state how the Applicants will ensure that the transaction and transition costs will not significantly impact the ratepayer funded revenue requirement.

Response:

API has taken several steps to minimize the impacts on revenue requirement, and ultimately on rates. As described in Exh. F-3-1, a portion of the 2017-2019 costs associated with API's interim operation of DLI's distribution system were included in a rate rider applicable to DLI customers only, in a similar manner as smart meter costs were recovered through rate riders.

Due to the one-time nature of certain costs, API proposed that these costs be recorded in a deferral account and included as one-time costs at the time of its next cost of service application. These costs were forecasted at $551,499 in the application. However, API notes that this forecast included $60,000 in intervenor cost awards. Since no parties registered as intervenors, API hereby reduces its forecast to $491,499. In recovering this amount over API's next 5-year rate setting period, only $98,300 would be added to API's test-year revenue requirement. This amount represents less than 0.5% of the revenue requirement of approximately $23.3 million approved in API's prior cost of service application (EB-2014-0055).

Further, in consideration of the RRRP rate-setting framework applicable to API, and assuming that the OEB endorses API's cost allocation proposal (see response to Board Staff IR 1), the $98,300 would effectively be recovered through RRRP. The OEB's most recent decision on the RRRP charge uses a denominator of 131.7 TWh in calculating the RRRP rate. The impact on the RRRP rate resulting from API's proposal is therefore [$98,300 / (131.7 TWh * 1e+9 kWh/TWh)] = $0.00000075/kWh.

<u>OEB STAFF - 6</u>

Reference: Exhibit C/Tab 2/Schedule 1/Appendix C – 60-Day Status Report

Preamble: The Applicants advised that some DLI customers only speak French. As a result, API noted that they have worked with another FortisOntario utility to translate any communication and messages into French. API has also implemented bilingual messages on the outage information line.

Request:

a) What other steps has API taken to ensure that French-speaking customers of DLI will be able to receive appropriate levels of customer service?

Response:

API's Customer Service department currently has one staff member fluent in French that will be able to respond to inbound calls or emails from French-speaking customers. In the event that this employee is unavailable, API will retain the flexibility to transfer calls to bilingual customer service representatives of its affiliates as required. Further, API staff in API's Engineering department that are fluent in French would assist with communications in respect of customer work requests (new services, service upgrades, etc.).

Additionally, API will continue to translate key communications and messages into French whether these are communicated in writing or verbally. As a recent example, on September 19, 2018, API conducted a town-hall session for residents of Dubreuilville to engage with customers on the current application and received assistance from the Clerk of the Township of Dubreuilville in translating questions and answers received during that presentation.

OEB STAFF - 7

Reference: Exhibit F/Tab 2/Schedule 1/Page 2
Exhibit F/Tab 2/Schedule 1/ Appendix A – Proposed Tariff of Rates and Charges
Exhibit F/Tab 2/Schedule 1/Appendix B – Bill Impact Details

Preamble: In the application, API filed its proposed 2019 Tariff of Rates and Charges under consideration in its 2019 IRM application (EB-2018-0017). Proposed bill impacts on customers in Dubreuilville were filed based on these proposed rates.

The OEB issued its Decision and Rate Order approving a Final Tariff of Rates and Charges for API effective January 1, 2019.

Request:

a) Please file a copy of API's approved 2019 Tariff of Rates and Charges.

b) Please provide a schedule showing updated bill impacts for typical residential and general service customers in Dubreuilville based on the approved 2019 Tariff of Rates and Charges for API (i.e., in the same format as provided in the application and as outlined below).

Rate Class	**Monthly Consumption (kWh)**	**Total Bill – API Interim Operation**	**Total Bill – Proposed Transaction**	**$ Change**	**% Change**
Residential	393				
Residential	750				
Commercial	2,000				

Response:

a) Please see the attached **Schedule 7(a)**.

b) The following table reflects updates to API's approved 2019 rates (as per the tariff provided in (a), above, as well as updates to WMS and RRRP rates, as per the OEB's decision and order in EB-2018-0294, dated December 20, 2018. **Schedule 7(b)**, attached, provides the detailed bill impact calculations[3] in support of the table below.

Rate Class	**Monthly Consumption (kWh)**	**Total Bill – API Interim Operation**	**Total Bill – Proposed Transaction**	**$ Change**	**% Change**
Residential[4]	393	$ 103.22	$ 92.16	-$11.06	-10.7%
Residential[4]	750	$ 147.65	$ 129.30	-$18.35	-12.4%
Commercial	2000	$ 320.40	$ 340.56	$ 20.16	6.3%

[3] The methodology and assumptions underlying the bill impact calculations remains the same as described at Exh. F-2-1 – only API's distribution rates, the WMS rate and the RRRP rate were updated to reflect 2019 rates as approved by the OEB in December 2018. API further notes that the changes to the WMS and RRRP rates are offsetting (the former decreases by $0.0002/kWh while the latter increases by the same amount), however the updated rates are reflected in the detailed calculations for accuracy.

[4] The residential cases remain unchanged from the application, despite a reduction of $0.11 in API's approved 2019 monthly service charge as compared to the application. This is because in both cases, the total distribution charges exceed the cap of $36.86 under the Distribution Rate Protection (DRP) program. While the total bill impact remains unchanged, the $0.11 difference can be seen in comparing the "Effect of DRP" line of the detailed bill impact calculations in Schedule 7b to those provide in Exh. F-2-1, Appendix B of the application.

OEB STAFF - 8

Reference: API 2017 Consolidated Scorecard

Preamble: In reviewing API's 2017 Consolidated Scorecard for the 2013-2017 period, OEB staff observed that API's SAIDI and SAIFI scores have met OEB targets.

Request:

a) Please explain how API will be able to ensure that the "no harm" test is satisfied with respect to reliability for both existing API customers and former DLI customers given that API will be required to devote significant resources and efforts in order to bring the DLI distribution system into compliance.

Response:

API has already completed a number of projects required to bring the DLI distribution system into compliance and to address high-priority issues with respect to safety, environmental protection and reliability. Examples of major projects include voltage conversion, installation of a bypass line, retirement of Substation #1, and replacement of electromechanical meters with smart meters, all of which are summarized on pages 12-13 of the 60-Day Status Report, provided at Exh. C-2-1, Appendix C. In order to ensure that reliability for API's existing customers did not suffer as a result of devoting resources to these and other projects, API used a mix of contracted services and temporary employees. For future large-scale projects in the DLI service area, such as the rebuild of Substation #2 and implementing a pole replacement program, API expects that it would follow a similar approach of using contract and temporary employees where significant resources are required.

From a capital investment planning perspective, API does not anticipate any material changes to the prioritization or pacing of capital investments aimed at improving reliability for its existing customers. System Renewal investments aimed at maintaining reliability by replacing end of life assets will continue to be informed by asset demographics and condition assessments. The same asset condition analysis and distribution system planning process currently applied to API's existing assets will be applied to the acquired assets in pacing and prioritizing investments for 2020 and beyond. All else being equal, API's annual replacement targets for poles, for example, would increase marginally as a result of acquiring DLI's assets. API's System Service investments aimed at improving reliability are generally focused on installation of new SCADA-capable devices, and substation improvements to address reliability and contingency concerns. The rebuild of DLI Substation #2, described above, will be planned as a distinct project within API's Distribution System Plan for asset end-of-life reasons, but the replacement substation will also address reliability risks and allow future SCADA implementation in Dubreuilville. API does not expect that any other material programs will be required in Dubreuilville from a reliability perspective and, as such, does not expect any material adjustments to API's reliability improvement projects will be required as a result of the acquisition.

From an operating perspective, regardless of whether API services the DLI service area, the Power Line Technicians operating from API's Wawa work centre cover a large geographical area from a work center that is relatively central in terms of response time to their coverage area. API's historical approach has been to keep at least one crew relatively close to Wawa during regular business hours (i.e. assigned to service work or other relatively minor planned work in or near Wawa), so that this crew is able to quickly mobilize to respond to outages or emergencies anywhere in their coverage area. Additionally, any work requiring planned outages incorporate customer notification of both planned and alternate dates on which outages may occur, so that API can defer work to the alternate date to increase outage and emergency coverage in the event of actual or forecasted inclement weather. API has continued with its historical approaches to ensuring adequate outage and emergency response since being required to operate DLI's distribution system, and plans to continue doing so in the future.

In responding to after-hours outages or emergencies, in addition to keeping one crew generally available in the Wawa area during business hours, API maintains one crew on-call in the Wawa area at all times outside of regular business hours. Further, in the event of multiple outages or a major event, API is able to request additional on-call coverage from its Wawa-area Power Line Technicians and/or mobilize additional crews from its Sault Ste. Marie and Desbarats work centres as required. API will also proactively reassign crews from Sault Ste. Marie and Desbarats as required where shortages in Wawa-area coverage are anticipated due to vacation, project commitments, or significant inclement weather. The scale of API's service area and the configuration of its transmission supply points is such that major events are unlikely to affect the entire service area simultaneously.

OEB STAFF - 9

Reference: *Ontario Cyber Security Framework*

Request:

a) Please describe the extent to which API has considered the *Ontario Cyber Security Framework*[5] (the Framework) in designing and implementing controls and privacy mechanisms to ensure the continued protection of operational and customer data.

b) Please confirm the current status of API's interim certification for cyber security progress as required by the OEB.

c) Please confirm that API will adhere to the Distribution System Code (DSC) requirement related to the Framework when launching new IT products and abide by the related OEB reporting requirements.

Response:

a) [redacted]

[redacted]

b) API filed an Interim Certification Report with the OEB on May 24, 2018 and concurrently filed an Interim Certification Report on behalf of DLI. API trusts that the OEB has copies of these reports and will maintain the confidentiality of these reports.

c) Confirmed.

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[5] https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf

OEB STAFF - 10

Reference: Exhibit E/Tab 1/Schedule 1/Page 4

Preamble: In Exhibit E/Tab 1/Schedule 1, the Applicants state that:

> … API will implement the necessary investments and operational improvements more efficiently and at a lower cost upon consolidation as compared to having to make those investments and improvements as an interim operator of the DLI system.

Request:

a) Please explain how API would be able to implement investments and operational improvements more efficiently and at a lower cost when it is consolidated compared to as an interim operator of the DLI distribution system. Please identify any assumptions required to produce the comparison and provide financials, where appropriate.

Response:

The statement in the preamble was made by API in the context of suggesting that the OEB's considerations of its statutory objectives under the no harm test should be applied broadly to include reliability and quality of service, among other things, instead of the typical focus on price. API stated that a focus on price would be inappropriate given the OEB's determination that DLI was likely to fail in meeting its obligation to supply electricity, and that certain investments and operational improvements would be required to address these circumstances, irrespective of the Proposed Transaction. In stating that it would be able to implement these investments and improvements more efficiently, API considered the various inefficiencies and associated costs that would result from long-term operation of DLI's distribution system on an interim basis. Examples of these inefficiencies are listed at Exh. E-2-1, pages 1-2, and associated estimates of costs are provided in response to Board Staff IR 11.

OEB STAFF - 11

Reference: Exhibit E/Tab 2/Schedule 1/Pages 1-2

Preamble: In Exhibit E/Tab 2/Schedule 1, the Applicants state:

> In the absence of consolidation, API would incur additional administrative and regulatory costs due to inefficiencies inherent in operating two distinctly licensed LDC's.

The Applicants then provide examples of items that would generate additional administrative and regulatory costs if API were to continue operating the DLI distribution system on an interim basis rather than on a consolidated basis.

Request:

a) Please compare the costs associated with each of the bulleted items listed on pages 1 and 2 of Exhibit E/Tab 2/Schedule 1 on a consolidated basis to the anticipated costs were API and DLI to remain independent of each other. Please explain the differences.

Response:

The bulleted items listed at the above reference represent examples of inefficiencies and costs that API expects in the event that the Proposed Transaction does not proceed, but API continues to be obligated to operate DLI's distribution system through successive extensions to the Interim Licence. As such, there will be little to no costs associated with any of these items on a consolidated basis since DLI customer records have already been migrated to API's CIS/ERP, GIS and outage management systems and API has already implemented cost and revenue tracking associated with DLI's distribution system in its ERP system for the purpose of complying with the Interim Licensing Order. Minimal effort will therefore be required to incorporate the additional customer and cost-related items into the relevant aspects of API's RRR filings and financial reporting. Likewise, on closing of the Proposed Transaction, the acquired assets, maintenance plans and investment plans could easily be incorporated into API's existing processes for asset management, distribution system planning, and compliance with O. Reg. 22/04.

Since API anticipates little to no costs associated with these items on the basis of the Proposed Transaction proceeding, the following table provides estimates of the incremental costs associated with each item in the event that the Proposed Transaction does not proceed. Note that some items from the bulleted list have been combined in the table below, such as regulatory costs associated with stand-alone cost of service applications, and costs associated with other ongoing regulatory requirements such as RRR filings, scorecards and IRM applications.

Activity	**Cost Driver(s)**	**Description of Cost Estimate**	**Incremental One-Time Cost Without the Proposed Transaction**	**Incremental Annual Cost Without the Proposed Transaction**
Changes to ERP system to establish and maintain DLI as a stand-alone entity	Compliance with legal requirements such as tax filings, annual audits and regulatory requirements, such as RRR reporting and maintenance of financial records in compliance with Accounting Procedures Handbook	~0.5 IT FTE (800 hrs) to duplicate, maintain, test and support functionality for accounting, rates and billing, reporting, customer service, etc; One-time, per user, and ongoing licencing fees	$20,000	$52,000
Regulatory: stand-alone cost of service application, RRR filings, scorecards, IRM, etc.	Ensure that rates charged to DLI customers are set by the OEB in consideration of DLI's actual cost of service; recovery of interim net costs recorded in the Interim Licence Deferral Account; ongoing regulatory compliance	Estimate based on review of Appendix 2-M filings from comparable LDC's[6]	Amortized over IRM rate-setting periods[6]	$57,000

[6] While no LDC's in Ontario have customer counts as low as DLI, API reviewed the Appendix 2-M filings of relatively small LDC's (Chapleau PUC, Atikokan Hydro, and Cooperative Hydro Embrun) that have recently filed cost of service applications and determined that approximately $110,000 in one-time costs would be required every five years (i.e. $22,000 amortized over each rate setting period), plus approximately $35,000 annually for ongoing regulatory costs related to RRR filings, scorecards and IRM applications, among other things.

Activity	Cost Driver(s)	Description of Cost Estimate	Incremental One-Time Cost Without the Proposed Transaction	Incremental Annual Cost Without the Proposed Transaction
Finance department: retain auditors and support annual audit, ongoing regulatory accounting, compile data for RRR reporting, rate applications, additional budgeting effort, support administration of service agreement, etc.	Ensure that DLI's owner is provided with accurate stand-alone financial statements; Regulatory compliance	Annual audit fee; ~0.3 FTE (500 hrs) Establish service agreement		$33,000
Establish and administer service agreement	Provide a contractual basis for the provision of services and allocation of costs from API to DLI	Legal and administrative effort to establish agreement	$2,000	Administration of inter-company billing captured under finance activities above
Engineering: GIS/OMS, Asset Management and System Planning, O. Reg. 22/04 processes and audits	Legal compliance; public and worker safety	200 labour hours annually for stand-alone system planning, budgeting, outage reporting, etc.; O. Reg 22/04 process development and audits Software licensing	$1,000	$50,000
Total Estimated Incremental Costs:			**$23,000**	**$192,000**

OEB STAFF - 12

Reference: Exhibit G/Tab 2/Schedule 2/Page 1

Preamble: In Exhibit G/Tab 2/Schedule 2, the Applicants state:

> To support API in its efforts to promptly implement a long term solution for the DLI system, API requests that the OEB add a condition to API's distribution licence which provides that the OEB will refrain from enforcing regulatory requirements that are ***within the OEB's control*** insofar as such requirements relate to circumstances or defects inherited by API through its acquisition of the DLI system, provided however that upon becoming aware of any such circumstances or defects relating to the acquired DLI system API shall take reasonable steps to address those circumstances or defects within a reasonable period. **[emphasis added]**

The Applicants assert that, by API acquiring the DLI distribution system, API is assuming various risks in order to achieve a long-term solution in the public interest, and API is not able to mitigate those risks through indemnities or purchase price reduction as it is acquiring the distribution system for a nominal price from an insolvent company. The Applicants further assert that if API becomes liable for any damages from DLI's legacy ownership and operation of the system, it may need to seek relief from the OEB such as through the establishment of a new deferral account.

Request:

a) Please identify any precedent(s) that API is aware of, for licences granted by the OEB which include a similar condition to provide a licensee with limited relief from regulatory liability.

b) Please identify the specific enforcement requirements within the OEB's control, insofar as such requirements relate to circumstances or defects inherited by API through the acquisition of the DLI distribution system, that API would want the OEB to refrain from enforcing. Please explain and provide rationale.

c) Please confirm that API is requesting this condition for API's distribution licence only in respect of the DLI service area, and only for the period until all deficiencies and potential compliance issues of the DLI distribution system are fully addressed.

d) Please indicate when API estimates it will have addressed all deficiencies and potential compliance issues in the DLI distribution system, and confirm when/how API will request the OEB to amend its licence to remove the condition.

e) Would a "Successful OEB Decision", as referred to in the APA, include the requested licence condition? What would the impact be in the event that:

i. The condition was not included.

ii. The OEB instead allowed a certain limited time period for compliance.

Response:

a) The Applicants are aware of two key precedents for licences granted by the OEB which include a similar condition to provide a licensee with limited relief from regulatory liability. These are the Interim Electricity Distribution Licence issued to Hydro One Networks Inc. (HONI) to take possession and control of the business of Cat Lake Power Utility Inc. (ED-2006-0181) and the Interim Electricity Distribution Licence issued to API to take possession and control of the electricity distribution system in the Township of Dubreuilville (ED-2017-0153), each of which was issued pursuant to s. 59 of the *Ontario Energy Board Act* (the "Act"). As required by ss. 59(3.1) of the Act, each of these licences includes a condition at s. 9 that addresses the liability of the licensee and which states that the licensee is not liable for anything that results from taking possession and control of the relevant business/assets or otherwise exercising or performing the licensee's powers and duties under the Act in relation to the relevant business/assets, the interim licence or any order of the Board, unless liability arises from the licensee's negligence or wilful misconduct.

As neither HONI nor any other person has filed a MAAD application to acquire Cat Lake's business to provide a long-term solution, HONI's interim licence remains in place and has been extended on 45 occasions since 2006. As such, HONI has had the benefit of the liability protection provided in its interim licence for over 12 years. To API's knowledge, API is unique in being the first interim licensee under s. 59 that has filed a MAAD application to acquire the facilities for which it has been appointed interim operator, and is the first to request that the licence for its existing business be amended to include authorization in respect of acquired facilities previously authorized under an interim licence.

In addition, the Applicants are aware of numerous instances where licensees have applied for and received amendments to existing licenses for the purpose of obtaining exemptions from specific regulatory requirements – such as licence or code requirements – that would otherwise apply, the contravention of which would otherwise give rise to a risk of regulatory liability. See response to (b), below.

b) API would want the OEB to refrain from (1) issuing compliance orders under s. 112.3 of the Act, (2) issuing orders suspending or revoking API's licence under s. 112.4 of the Act, (3) issuing orders requiring payment of administrative penalties under s. 112.5 of the Act, and (4) alleging that API or any of its officers or directors have committed an offence under Part IX of the Act. Each of these enforcement powers is within the Board's control and may be exercised by the Board in circumstances where there has been or there is likely to be a contravention of an "enforceable provision", as that term is defined in the Act. As the specific circumstances or defects that API may be inheriting through the proposed acquisition are not and cannot be fully known at this time, API is not in a position to itemize them. However, examples of the types of concerns that API has, which could potentially give rise to regulatory liability, include that it is acquiring a system where a small number of meters remain non-compliant with Measurement Canada requirements, that it has not properly accounted for line losses in its rates and will not have done so until the time of its next cost of service application, that it may not be able to provide evidence of completed electrical safety inspections for service work completed before May 2017, that it may not be able to provide evidence that any maintenance, repairs or replacements completed prior to May 2017 comply with O. Reg. 22/04, and that it will require time following the closing of the transaction to transition to full compliance with all OEB codes and reporting requirements.

c) Confirmed.

d) API is not in a position to estimate when it will have will have addressed all deficiencies and potential compliance issues in the DLI distribution system since, as discussed in (b), above, any specific circumstances or defects that API may be inheriting through the proposed acquisition are not and cannot be fully known at this time. DLI has historically operated under a combination of regulatory exemptions and lack of enforcement action, such that API cannot reasonably be expected to be aware of or address every aspect of non-compliance within a short period of time and it is on this basis that API has requested the licence condition with respect to liability. However, as explained in (e), below, API considers that allowing a limited time period for compliance, subject to the right to request an extension as circumstances may warrant, would be appropriate.

e) API would consider the requested licence condition to be one element of a "Successful OEB Decision" for purposes of the APA. If the condition was not included, API's Board of Directors may consider that due to uncertainty with respect to regulatory compliance and the resulting risk of enforcement actions, proceeding with the Proposed Transaction is contrary to the interests of both its customers and its shareholders. See further discussion in response to Board Staff IR 13.

   If the OEB were to instead allow a specified time period for compliance, then API suggests that it do so by including the requested licence condition, with a stipulation that the condition expires on a certain date, subject to the opportunity for API apply to the OEB to extend the expiry date if needed. API further suggests that an appropriate expiry date would be December 31, 2024, coinciding with the end of API's next 5-year planning cycle and rate-setting term. This would provide API with the opportunity to implement projects that are identified as priorities for the Dubreuilville service area in its next DSP, while also providing the flexibility for reprioritization of projects in the event that issues or circumstances arise that are currently unknown to API. This date would also result in API having seven full years of records relating to the operation and maintenance of distribution system assets in Dubreuilville, which would align with the OEB's requirement that regulatory records be retained for seven years. Finally, if the OEB determines that a limited time period for compliance is appropriate, API requests that the OEB specifically recognize in the licence condition that API may apply for extension of the initial expiry date in the event that compliance issue arising from the inherited business or assets has been identified, which requires additional time to fully resolve. API notes that providing such protection from regulatory liability until December 31, 2024, plus the opportunity to request an extension, is reasonable considering the liability protection that HONI has enjoyed under its interim licence in respect of Cat Lake for the past 12+ years.

A precedent for allowing a time-limited period for compliance, for recognizing that a licence condition applies to certain assets and/or customers only, and for recognizing that circumstances may arise requiring the extension of the initial time-limited period can be found in API's own licence. Specifically, Schedule 3.1 of API's distribution licence (ED-2009-0272) provides that API is exempt from provisions of the Standard Service Supply Code requiring time-of-use pricing for RPP customers. This exemption applies to a specific group of customers only, and expires on December 31, 2019. Moreover, in requesting a five-year exemption, API indicated that it intended to investigate options and costs for achieving future compliance, and intended to consult with customers and other stakeholders on the appropriateness of including such costs in its next rate application. In its decision in granting the requested exemption[7], the OEB turned its mind to the challenges and associated costs of achieving compliance, and encouraged API's approach of customer and stakeholder engagement, leaving open the possibility for API to apply for a future extension of the December 31, 2019 expiry date. API notes that it intends to include a request for extension of this expiry date in its upcoming cost of service application, and that a number of meters in the DLI service area may be included in this request.

[7] EB-2015-0199; Decision and Order; October 5, 2015; pp. 2-3

OEB STAFF - 13

Reference: Exhibit D/Tab 1/Schedule 1/Page 1

Preamble: In Exhibit D/Tab 1/Schedule 1, the Applicants state:

> Closing of the transaction contemplated under the APA is conditional upon, among other things, the parties obtaining from all applicable governmental authorities such authorizations as are required to be obtained to permit the change of ownership of the distribution system assets that are to be sold under the agreement, including approval of the Proposed Transaction by the OEB, amendment of API's distribution licence by the OEB to include the DLI system and service area, and all other related relief sought, in ***a form and substance satisfactory to API,*** **acting reasonably. [emphasis added]**
>
> …
>
> A 'Successful OEB Decision' under the APA refers to one or more decisions or orders of the OEB authorizing the acquisition by API of the DLI distribution system and amending API's licence to include operation of the DLI system, as well as addressing all other relief requested in ***a manner acceptable to API in its sole discretion*** **… [emphasis added]**

Request:

a) Please clarify what the Applicants define as a "form and substance satisfactory to API" and "a manner acceptable to API".

Response:

The references in the preamble are intended to emphasize that, pursuant to the APA, API is not obligated to close on its purchase of the DLI system unless the order of the OEB granting DLI leave to sell its distribution system in its entirety is acceptable to API as the purchaser. API does not have a specific definition as to what will be satisfactory or acceptable to it. Rather, upon receipt of the OEB's decision and order, API's management will review all aspects of the decision and order relative to the various elements of relief requested in the application in order to assess whether the OEB's findings give rise to any potential risks for API's existing customers, the acquired DLI customers and for API's shareholders. API's management will provide its assessment of the decision and order to API's Board of Directors. API's Board of Directors will then determine whether API will complete the transaction, having regard to a broad range of factors that include the OEB's findings in the decision and order, the interests of API's shareholder, the interests of API's existing customers, and the interests of the DLI customers that are to be acquired. In making the decision, API's Board of Directors' will be mindful of its legal duties in respect of supervising and managing API and exercising its powers in the best interests of API. As part of its analysis, it is expected that API's Board of Directors would consider factors that include, but are not limited to, the Board's findings in respect of the request for endorsement of API's approach to the future allocation of DLI costs among API's existing rate classes (which, as discussed in response to Board Staff IR 1, has consequences for certain of API's existing customers) and the Board's findings in respect of the request for limited relief from regulatory liability in connection with the acquisition (which, as discussed in response to Board Staff IR 12, has consequences for API's shareholder).

OEB STAFF - 14

Reference: Exhibit E/Tab 2/Schedule 1/Page 6

Preamble: In Exhibit E/Tab 2/Schedule 1, the Applicants state:

> "Addressing unmetered and incorrectly metered loads has significantly reduced system losses over the past year."

Request:

a) If possible, please provide kWh values for how much API has been able to reduce system losses over the past year. If possible, please also provide the financial value associated with the kWh values.

Response:

API is unable to determine a precise kWh value of system losses since any savings resulting from corrections to metering and billing will be masked by inherent variability in losses with changing consumption (both at an individual customer level and a system-wide level). Further, system changes such as the retirement of substation #1 will also have an impact on reducing system losses. However, API has tracked system losses on a monthly basis (aligned with meter reading dates), and has determined that system losses have been reduced from 26% in 2017 to 15% in 2018. The following table compares approximate delivery volumes (with delivery point metering values adjusted to approximately align with DLI customers meter reading dates) and calculated system losses for 2017 and 2018.

		2017	**2018**
Total kWh Delivered to DLI	A	7,099,124	7,994,177
DLI Customers Total Metered kWh	B	5,616,467	6,939,373
Loss Factor	C = A / B	1.26	1.15
System Losses (kWh)	D = A – B	1,482,657	1,054,804

If the system loss factor had remained at 26% with 2018 delivery volumes, then system losses in 2018 would have been 1,804,237 kWh (6,939,373 * 26%). As a result, API estimates that approximately 750,000 kWh have been saved in 2018 as a result of loss-reduction efforts. Assuming a total cost of power of $0.10/kWh, the resulting savings for 2018 (which are expected to continue for each subsequent year, at a minimum) are approximately $75,000.

OEB STAFF - 15

Reference: Exhibit E/Tab 2/Schedule 1/Page 7

Preamble: In Exhibit E/Tab 2/Schedule 1, the Applicants state:

> API expects that any travel time from Wawa to the Township will be more than offset by the fact that API crews will arrive with the appropriate equipment, trained personnel and spare equipment to efficiently and effectively address any issues. Further, API has the ability to rapidly increase its response efforts during major events by calling in additional crews and/or activating emergency response plans to receive assistance from other LDCs. This improved response would be provided irrespective of the Proposed Transaction. However, additional costs would be incurred to administer service agreements and accurately allocate third-party costs (e.g. call centre costs) between API and DLI in the event that API were to provide this enhanced response capability in its capacity as an interim operator as compared to being the owner and operator of the DLI system as part of a consolidated utility.

Request:

a) If possible, please provide an indication of the additional costs that would be incurred to administer service agreements and accurately allocate third-party costs between API and DLI in the event that API were to provide the enhanced response capability in its capacity as an interim operator.

Response:

Please see response to Board Staff 11. Specifically, the table in that response contains a line item entitled “Establish and administer service agreement”, and provides an explanation of the incremental costs that would be incurred. For clarity, the enhanced response capability has been provided since the OEB issued the Interim Licence in April 2017, and to date the associated direct operational costs (e.g. API internal labour, materials, etc.) of outage and emergency response have been tracked in the Interim Licence Deferral Account. In the event of long-term operation under an Interim Licence, API considers that a service agreement would be required so as to fairly allocate a portion of API’s indirect costs (i.e. general and administrative costs, third-party call centre costs, etc.) to DLI.

OEB STAFF - 16

Reference: Exhibit E/Tab 2/Schedule 1/Page 7

Preamble: In Exhibit E/Tab 2/Schedule 1, the Applicants state that:

> "API will continue to enhance its education and engagement activities with respect to the Acquired Customers, irrespective of the status of the Proposed Transaction."

Request:

a) Please clarify how API will enhance its education and engagement of customers in the DLI service area. Furthermore, does this education and engagement include informing DLI customers about the status of investments being made to bring the DLI distribution system into compliance and subsequent impacts on reliability?

Response:

DLI's existing customers have been incorporated into a number of API's existing customer engagement and education efforts such as newsletters, surveys, and "Your Kilowatt Hour" sessions.[8] API has also taken steps to make DLI's customers aware of Algoma Power's website, social media channels, and outage and emergency contact numbers through the use of direct mailings, bill inserts and town-hall sessions. The Township of Dubreuilville has also been included, and will continue to be included, in API's engagement and education efforts with its municipalities, including annual attendance at council meetings, and an invitation to an annual engagement meeting with all municipalities and First Nations.

Further, on September 19, 2018, API held a meeting with the Council of the Township of Dubreuilville followed by a town-hall session for residents of Dubreuilville so that API could engage with Council and DLI's customers on the current application. The presentation delivered during this meeting, a copy of which is provided in **Schedule 16** attached hereto, described the status of investments completed and planned to address compliance and reliability issues with respect to the DLI distribution system, and also educated customers on various aspects of the current application.

[8] These are sessions in which Customer Service and CDM representatives travel to the communities served by Algoma Power Inc. in order to meet one-on-one with any type of customer (e.g. residential, small business owner, etc.) at pre-arranged times, to answer any questions they might have specific to their account, consumption patterns, opportunities for energy efficiency, or any other questions or concerns of a more general nature.

Schedule 3(a)

DLI Rates Charged by API Under Interim Licence

Calculation of DLI Delivery Rates

		2017									2018
Consumption Month		**Apr**	**May**	**June**	**July**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**
Delivery Charge to DLI	A	13,760.99	12,996.73	10,160.86	9,915.91	10,377.07	10,608.82	14,343.02	18,474.90	23,019.38	- 13,558.12
DRC		-	-	-	-	-	-	-			
Delivery Charge to DLI	A	13,760.99	12,996.73	10,160.86	9,915.91	10,377.07	10,608.82	14,343.02	18,474.90	23,019.38	- 13,558.12
Metered kWh Delivered to DLI	B	587,524.80	524,175.60	415,084.80	403,844.40	397,558.80	420,396.80	544,440.00	735,711.60	968,946.40	985,306.40

		2017								2018	
Consumption Month		**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**
Pass-through Delivery Rate Calculation ($/kWh)	C = A / B	0.0234	0.0248	0.0245	0.0246	0.0261	0.0252	0.0263	0.0251	0.0238	- 0.0138
DLI Additional Rate ($/kWh)	D	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150
Fixed Rate ($/month)	E	23.76	23.76	23.76	23.76	23.76	23.76	23.76	23.76	23.76	23.76
Total Variable Delivery Rate ($/kWh)	F = C + D	0.0384	0.0398	0.0395	0.0396	0.0411	0.0402	0.0413	0.0401	0.0388	0.0012

Notes:

1. For the period of June-Oct 2017, API had not yet implemented process to calculate, update, test and bill a new variable rate on a monthly basis and the actual variable rates billed during this period are the May 2017 rates (i.e. $0.0234/kWh pass-through; $0.0384/kWh total). Monthly updates were initiated beginning in November 2017.

2. The rates and calculations above are representative of the delivery portion of the bill only. Electricity and regulatory charges were billed based on OEB-approved RPP rates and regulatory rates in effect each month, consistent with DLI's prior practice.

3. A loss adjustment factor of 1.0808 was applied to DLI customers, consistent with DLI's prior practice.

Calculation of DLI Delivery Rates (Continued)

		2018									
Consumption Month		**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**
Delivery Charge to DLI	A	- 10,808.74	- 11,830.66	- 9,107.53	- 456.81	- 4,729.58	- 5,393.32	- 4,920.44	- 1,309.58	- 7,142.15	- 9,569.83
DRC											
Delivery Charge to DLI	A	- 10,808.74	- 11,830.66	- 9,107.53	- 456.81	- 4,729.58	- 5,393.32	- 4,920.44	- 1,309.58	- 7,142.15	- 9,569.83
Metered kWh Delivered to DLI	B	853,676.40	809,870.00	679,406.40	485,847.20	414,853.60	414,842.40	401,997.60	434,267.20	628,710.80	779,956.40
		2018									
Consumption Month		**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Pass-through Delivery Rate Calculation ($/kWh)	C = A / B	- 0.0127	- 0.0146	- 0.0134	- 0.0009	- 0.0114	- 0.0130	- 0.0122	- 0.0030	- 0.0114	- 0.0123
DLI Additional Rate ($/kWh)	D	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150
Fixed Rate ($/month)	E	23.76	23.76	23.76	23.76	23.76	23.76	23.76	23.76	23.76	23.76
Total Variable Delivery Rate ($/kWh)	F = C + D	0.0023	0.0004	0.0016	0.0141	0.0036	0.0020	0.0028	0.0120	0.0036	0.0027

Schedule 7(a)

API's 2019 Tariff of Rates and Charges

Schedule A

To Decision and Rate Order

Tariff of Rates and Charges

OEB File No: EB-2018-0017

DATED: December 13, 2018

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2019
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0017

RESIDENTIAL R1 SERVICE CLASSIFICATION

For the purposes of rates and charges, a residential service is defined in two ways:
i) a dwelling occupied as a residence continuously for at least eight months of the year and, where the residential premises is located on a farm, includes other farm premises associated with the residential electricity meter, and
ii) consumers who are treated as residential-rate class customers under Ontario Regulation 445/07 (Reclassifying Certain Classes of Consumers as Residential-Rate Class Customers: Section 78 of the Ontario Energy Board Act, 1998) made under the Ontario Energy Board Act, 1998.

This application refers to a Residential service with a demand of less then, or is forecast to be less than, 50 kilowatts, and which is billed on an energy basis. Class B consumers are defined in accordance with 0. Reg. 429/04. Futher servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge - Applicable only to customers that meet criteria (i) above	$	42.23
Service Charge - Applicable only to customers that meet criteria (ii) above	$	25.64
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate - Applicable only to customers that meet criteria (i) above	$/kWh	0.0172
Distribution Volumetric Rate - Applicable only to customers that meet criteria (ii) above	$/kWh	0.0361
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0078)
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Approved on an Interim Basis	$/kWh	(0.0011)
Rate Rider for Disposition of Accounts 1575 & 1576 - effective until December 31, 2019	$/kWh	(0.0019)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0066
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0060

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Algoma Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2019

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0017

RESIDENTIAL R2 SERVICE CLASSIFICATION

This classification refers to a Residential service with a demand equal to or greater than, or is forecast to be equal to or greater than, 50 kilowatts, and which is billed on a demand basis. Class A and Class B consumers are defined in accordance with 0. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	659.94
Distribution Volumetric Rate	$/kW	3.4194
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0078)
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Approved on an Interim Basis	$/kW	(0.4880)
Rate Rider for Disposition of Accounts 1575 & 1576 - effective until December 31, 2019	$/kW	(0.8010)
Retail Transmission Rate - Network Service Rate	$/kW	2.5066
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2787

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2019
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2018-0017

SEASONAL CUSTOMERS SERVICE CLASSIFICATION

This classification includes all services supplied to single-family dwelling units for domestic purposes, which are occupied on a seasonal/intermittent basis. A service is defined as Seasonal if occupancy is for a period of less than eight months of the year. Class B consumers are defined in accordance with O. Reg. 429. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	54.75
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.1494
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0078)
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Approved on an Interim Basis	$/kWh	(0.0012)
Rate Rider for Disposition of Account 1574 - effective until June 30, 2019	$/kWh	0.0307
Rate Rider for Disposition of Accounts 1575 & 1576 - effective until December 31, 2019	$/kWh	(0.0019)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0066
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0060

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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EB-2018-0017

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting. The consumption for these unmetered accounts will be based on the calculated connection load times the calculated hours of use established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.05
Distribution Volumetric Rate	$/kWh	0.3310
Rate Rider for Disposition of Global Adjustment Account (2019) - effective until December 31, 2019 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0078)
Rate Rider for Disposition of Deferral/Variance Accounts (2019) - effective until December 31, 2019 Approved on an Interim Basis	$/kWh	(0.0011)
Rate Rider for Disposition of Accounts 1575 & 1576 - effective until December 31, 2019	$/kWh	(0.0019)
Retail Transmission Rate - Network Service Rate	$/kW	1.8150
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.6438

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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EB-2018-0017

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

Algoma Power Inc.

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EB-2018-0017

SPECIFIC SERVICE CHARGES

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Customer Administration

Arrears certificate (credit reference)	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection - during regular business hours	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/reconnect at meter - during regular hours	$	65.00
Disconnect/reconnect at meter - after regular hours	$	185.00
Disconnect/reconnect at pole - during regular hours	$	185.00
Disconnect/reconnect at pole - after regular hours	$	415.00
Install/remove load control device - during regular hours	$	65.00
Install/remove load control device - after regular hours	$	185.00

Other

Specific charge for access to the power poles - per pole/year		
(with the exception of wireless attachments)	$	43.63
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00

Algoma Power Inc.

TARIFF OF RATES AND CHARGES

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EB-2018-0017

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

Retail Service Charges refer to services provided by Algoma Power Inc. to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly fixed charge, per retailer	$	20.00
Monthly variable charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer	1.0917
Total Loss Factor - Primary Metered Customer	1.0808

Schedule 7(b)

Detailed Bill Impact Calculations

Customer Class:	RESIDENTIAL R1(i) SERVICE CLASSIFICATION - 10th Percentile
RPP / Non-RPP:	RPP
Consumption	393 kWh
Demand	- kW
Current Loss Factor	1.0917
Proposed/Approved Loss Factor	1.0917

	Stand-Alone 2019			API Rates 2019			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 23.76	1	$ 23.76	$ 42.23	1	$ 42.23	$ 18.47	77.74%
Distribution Volumetric Rate	$ 0.0150	393	$ 5.90	$ 0.0172	393	$ 6.76	$ 0.86	14.67%
Effect of DRP						$ (12.13)	$ (12.13)	
Fixed Rate Riders	$ 27.72	1	$ 27.72	$ 11.16	1	$ 11.16	$ (16.56)	-59.74%
Volumetric Rate Riders	$ -	393	$ -	-$ 0.0019	393	$ (0.75)	$ (0.75)	
Sub-Total A (excluding pass through)			**$ 57.38**			**$ 47.27**	**$ (10.10)**	**-17.61%**
Line Losses on Cost of Power	$ 0.0770	36	$ 2.77	$ 0.0770	36	$ 2.77	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	393	$ -	-$ 0.0011	393	$ (0.43)	$ (0.43)	
CBR Class B Rate Riders	$ -	393	$ -	$ -	393	$ -	$ -	
GA Rate Riders	$ -	393	$ -	$ -	393	$ -	$ -	
Low Voltage Service Charge	$ 0.0152	393	$ 5.97		393	$ -	$ (5.97)	-100.00%
Smart Meter Entity Charge (if applicable) and/or any fixed ($) Deferral/Variance Account Rate Riders	$ -	1	$ -	$ 0.57	1	$ 0.57	$ 0.57	
Additional Volumetric Rate Riders (Sheet 18)		393	$ -	$ -	393	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 66.12**			**$ 50.19**	**$ (15.94)**	**-24.10%**
RTSR - Network	$ -	429	$ -	$ 0.0066	429	$ 2.83	$ 2.83	
RTSR - Connection and/or Line and Transformation Connection	$ -	429	$ -	$ 0.0060	429	$ 2.57	$ 2.57	
Sub-Total C - Delivery (including Sub-Total B)			**$ 66.12**			**$ 55.59**	**$ (10.53)**	**-15.93%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	429	$ 1.46	$ 0.0034	429	$ 1.46	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	429	$ 0.21	$ 0.0005	429	$ 0.21	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
RPP - First Tier	$ 0.0770	393	$ 30.26	$ 0.0770	393	$ 30.26	$ -	0.00%
RPP - Second Tier	$ 0.0890	-	$ -	$ 0.0890	-	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 98.31**			**$ 87.78**	**$ (10.53)**	**-10.71%**
HST	13%		$ 12.78	13%		$ 11.41	$ (1.37)	-10.71%
8% Rebate	8%		$ (7.86)	8%		$ (7.02)	$ 0.84	
Total Bill on TOU			**$ 103.22**			**$ 92.16**	**$ (11.06)**	**-10.71%**

Customer Class:	**RESIDENTIAL R1(i) SERVICE CLASSIFICATION - OEB Typical**
RPP / Non-RPP:	**RPP**
Consumption	**750** kWh
Demand	**-** kW
Current Loss Factor	**1.0917**
Proposed/Approved Loss Factor	**1.0917**

	Stand-Alone 2019			**API Rates 2019**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	**$ 23.76**	1	$ 23.76	$ 42.23	1	$ 42.23	$ 18.47	77.74%
Distribution Volumetric Rate	**$ 0.0150**	750	$ 11.25	$ 0.0172	750	$ 12.90	$ 1.65	14.67%
Effect of DRP						$ (18.27)	$ (18.27)	
Fixed Rate Riders	**$ 27.72**	1	$ 27.72	$ 11.16	1	$ 11.16	$ (16.56)	-59.74%
Volumetric Rate Riders	**$ -**	750	$ -	-$ 0.0019	750	$ (1.43)	$ (1.43)	
Sub-Total A (excluding pass through)			**$ 62.73**			**$ 46.60**	**$ (16.14)**	**-25.72%**
Line Losses on Cost of Power	**$ 0.0770**	69	$ 5.30	**$ 0.0770**	69	$ 5.30	$ -	0.00%
Total Deferral/Variance Account Rate Riders	**$ -**	750	$ -	-$ 0.0011	750	$ (0.83)	$ (0.83)	
CBR Class B Rate Riders	**$ -**	750	$ -	$ -	750	$ -	$ -	
GA Rate Riders	**$ -**	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	**$ 0.0152**	750	$ 11.40		750	$ -	$ (11.40)	-100.00%
Smart Meter Entity Charge (if applicable) and/or any fixed ($) Deferral/Variance Account Rate Riders	**$ -**	1	$ -	$ 0.57	1	$ 0.57	$ 0.57	
Additional Volumetric Rate Riders (Sheet 18)		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 79.43**			**$ 51.64**	**$ (27.79)**	**-34.99%**
RTSR - Network	**$ -**	819	$ -	$ 0.0066	819	$ 5.40	$ 5.40	
RTSR - Connection and/or Line and Transformation Connection	**$ -**	819	$ -	$ 0.0060	819	$ 4.91	$ 4.91	
Sub-Total C - Delivery (including Sub-Total B)			**$ 79.43**			**$ 61.95**	**$ (17.47)**	**-22.00%**
Wholesale Market Service Charge (WMSC)	**$ 0.0034**	819	$ 2.78	$ 0.0034	819	$ 2.78	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	**$ 0.0005**	819	$ 0.41	$ 0.0005	819	$ 0.41	$ -	0.00%
Standard Supply Service Charge	**$ 0.25**	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
RPP - First Tier	**$ 0.0770**	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%
RPP - Second Tier	**$ 0.0890**	-	$ -	$ 0.0890	-	$ -	$ -	
Total Bill on TOU (before Taxes)			**$ 140.62**			**$ 123.15**	**$ (17.47)**	**-12.43%**
HST	13%		$ 18.28	13%		$ 16.01	$ (2.27)	-12.43%
8% Rebate	8%		$ (11.25)	8%		$ (9.85)	$ 1.40	
Total Bill on TOU			**$ 147.65**			**$ 129.30**	**$ (18.35)**	**-12.43%**

Customer Class:	RESIDENTIAL R1(ii) SERVICE CLASSIFICATION - OEB Typical	
RPP / Non-RPP:	RPP	
Consumption	2,000	kWh
Demand	-	kW
Current Loss Factor	1.0917	
Proposed/Approved Loss Factor	1.0917	

	Stand-Alone 2019			API Rates 2019			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 23.76	1	$ 23.76	$ 25.64	1	$ 25.64	$ 1.88	7.91%
Distribution Volumetric Rate	$ 0.0150	2000	$ 30.00	$ 0.0361	2000	$ 72.20	$ 42.20	140.67%
Fixed Rate Riders	$ 27.72	1	$ 27.72	$ 11.16	1	$ 11.16	$ (16.56)	-59.74%
Volumetric Rate Riders	$ -	2000	$ -	-$ 0.0019	2000	$ (3.80)	$ (3.80)	
Sub-Total A (excluding pass through)			**$ 81.48**			**$ 105.20**	**$ 23.72**	**29.11%**
Line Losses on Cost of Power	$ 0.0845	183	$ 15.50	$ 0.0845	183	$ 15.50	$ -	0.00%
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	-$ 0.0011	2,000	$ (2.20)	$ (2.20)	
CBR Class B Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0152	2,000	$ 30.40		2,000	$ -	$ (30.40)	-100.00%
Smart Meter Entity Charge (if applicable) and/or any fixed ($) Deferral/Variance Account Rate Riders	$ -	1	$ -	$ 0.57	1	$ 0.57	$ 0.57	
Additional Volumetric Rate Riders (Sheet 18)		2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 127.38**			**$ 119.07**	**$ (8.31)**	**-6.52%**
RTSR - Network	$ -	2,183	$ -	$ 0.0066	2,183	$ 14.41	$ 14.41	
RTSR - Connection and/or Line and Transformation Connection	$ -	2,183	$ -	$ 0.0060	2,183	$ 13.10	$ 13.10	
Sub-Total C - Delivery (including Sub-Total B)			**$ 127.38**			**$ 146.58**	**$ 19.20**	**15.07%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,183	$ 7.42	$ 0.0034	2,183	$ 7.42	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,183	$ 1.09	$ 0.0005	2,183	$ 1.09	$ -	0.00%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Ontario Electricity Support Program (OESP)								
RPP - First Tier	$ 0.0770	750	$ 57.75	$ 0.0770	750	$ 57.75	$ -	0.00%
RPP - Second Tier	$ 0.0890	1,250	$ 111.25	$ 0.0890	1,250	$ 111.25	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 305.14**			**$ 324.34**	**$ 19.20**	**6.29%**
HST	13%		$ 39.67	13%		$ 42.16	$ 2.50	6.29%
8% Rebate	8%		$ (24.41)	8%		$ (25.95)	$ (1.54)	
Total Bill on TOU			**$ 320.40**			**$ 340.56**	**$ 20.16**	**6.29%**

Schedule 16

Community Information Session Presentation

Wednesday September 19, 2018
Dubreuilville
Information Session

Algoma Power Inc.

A FORTIS ONTARIO Company

Agenda

- **Introduction**

  Jennifer Rose, Regional Manager, Algoma Power Inc. (API)

- **Update on Algoma Power acquisition of Dubreuilville Distribution System**
  - **Update on Commercial discussions with DLI**

    Glen King, Vice President and CFO, FortisOntario
  - **OEB Approval Request - Mergers, Acquisitions, Amalgamations and Divestitures (MAAD) Application**

    Greg Beharriell, Manager Regulatory Affairs, FortisOntario

- **2018 Work Plan Update**
  - **Meter Replacement**
  - **Station 1 Decommissioning**

    Phil Johnston, Supervisor Technical Services, API

- **Customer Service Message**

  Jody Tait, Energy Efficiency and Customer Service Advisor, API

- **Feedback/Questions**

API Operation of DLI System – Status

OEB Appoints API as Interim Operator
- April 2017

API Work to Address Critical Safety, Reliability, Compliance and Customer Service Issues
- 2017-2018

API/DLI Enter into Purchase Agreement
- August 2018

OEB Review and Approval Process
- Target September to December 2018

Integration Process
- Critical items in 2017/2018
- Rate integration in 2019
- Full integration ongoing based on priority

Ontario Energy Board Approval Requirements

- The Ontario Energy Board (OEB) must approve any Mergers, Acquisitions, Amalgamations and Divestures involving licensed utilities
- Commonly referred to as “MAAD Application”
- Specific filing requirements – MAAD Handbook available on OEB website
- OEB review of applications considers a “no harm test”

MAAD Application - Overview

- API plans to submit an application to the OEB before the end of September
- API will propose to acquire the distribution assets of DLI
- There are unique circumstances that the OEB must consider:
  - API has already been appointed as interim operator
  - DLI's rates and billing methods have not previously been approved by the OEB
  - Historical rates and operating practices are not sustainable in terms of safety, reliability, legal and regulatory considerations
  - Most API customers receive Rural and Remote Rate Protection (RRRP) subsidies that provide long-term stability in distribution rates

MAAD Application – OEB Process

Submit Application
- Target September

Review and Notice

Hearing Process

OEB Decision

Closing Date
- Target January 1, 2019

MAAD Application – Key Requests / Themes

- API and DLI will request the following:
  - Approval for DLI to sell its electricity distribution system to API
  - Approval to move DLI customers to API's rate classes
  - Approve rate riders to recover a portion of interim costs
  - Approve an account to record other costs for future recovery
  - License amendments
- Emphasis on the importance of safety, reliability, customer service and compliance

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MAAD Application - Bill Mitigation Efforts

- API will propose the following in the MAAD application to minimize bill impacts:
  - Recover only a portion of the interim costs through new rate riders, over a 6-year period to minimize the monthly amount
  - The remainder of the interim costs and all transaction/integration costs are proposed to be recovered through a future API rate process that would not affect the rates paid by individual customers in Dubreuilville
  - Request to move to API rate structure as of January 1, 2019 to trigger additional rate protection for residential customers

MAAD Application - Summary

	API as Interim Operator	API Acquires DLI Assets
Monthly Rate Rider ($/customer)	$27.72	$11.16
Typical Residential Bill (750 kWh)	$147.65	$129.30
Typical Commercial Bill (2000 kWh)	$320.40	$340.84
Future Cost Structure	New processes, systems, reporting, audits, etc. required – would result in upward pressure on costs	DLI assets and customers can be integrated into existing API processes, reporting and audits
Future Cost Recovery	All costs recovered directly from customers in Dubreuiville – would result in new rates or rate riders	Costs can be integrated into API's planning and rate-setting process
Future Distribution Rates	Annual increases resulting from above cost pressures and investments in DLI system	Annual increases tied to industry inflationary factor (RRRP); Cap on total distribution charges for residential customers

2018 Work Plan Update

Meter Replacement

- Replace all Seal Expired Electrical Meters with new Measurement Canada approved meters in Dubreuilville.
- All electricity meters installed by utilities in Canada have a predetermined expiry period. This period can range from 6 to 12 years (depending on the type of meter)
- Nearly all meters found in service, in Dubreuilville, were seal expired and needed to be replaced.
- Measurement Canada Website Link:
  - https://www.ic.gc.ca/eic/site/mc-mc.nsf/fra/lm04708.html

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2018 Work Plan Update Continued

Station 1 Decommissioning

2018 Work Plan Update

Station 1 Decommissioning

- Sub Station #1 was found to be at end of life and in poor condition
- After exploring the options, it was decided that the best course of action was to retire, decommission and remove the station. This is a benefit for system reliability for the customers.
- There were concerns about oil potentially leaking/seeping from one of the old transformers, API engaged a third party engineering firm to obtain soil samples and advise on the level of remediation required to properly address any issues found.

Please contact us!

- We require accurate, up to date information on all customer accounts

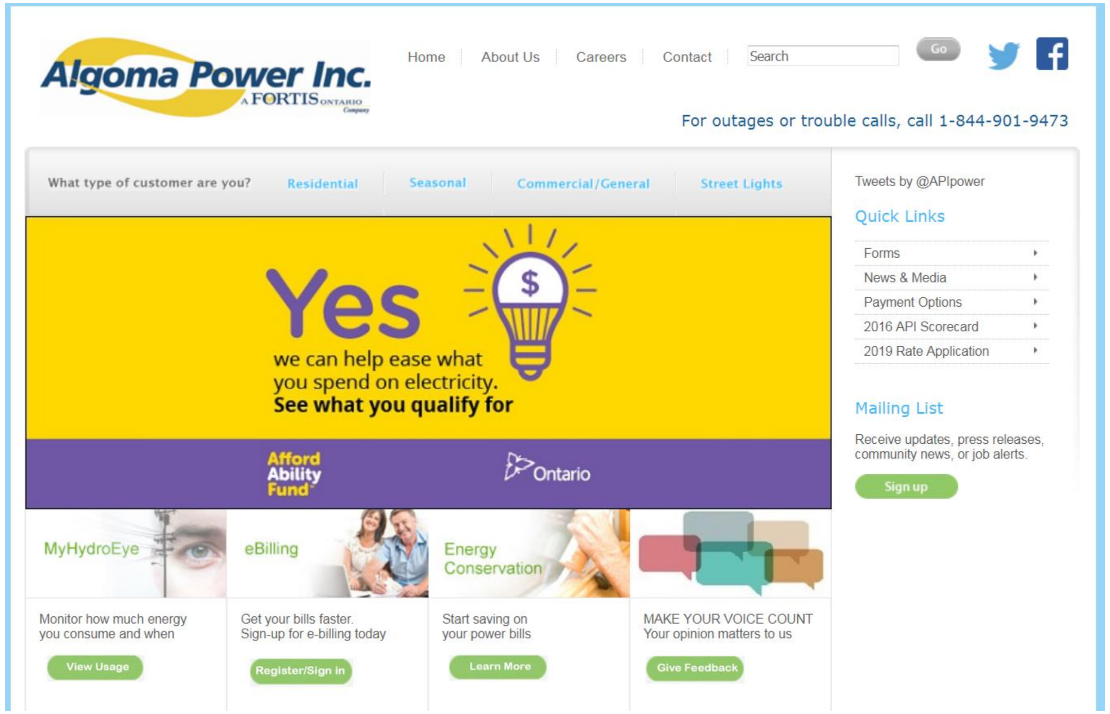
- Information such as:
  - Telephone number
  - Email address
  - Any additional names on account
  - Mailing address
  - Owner or Tenant

AffordAbility Fund Program

- www.affordabilityfund.org
- 1-855-494-3863

Visit our website

- To learn more about API's services, for news about the industry, etc., visit our website at:



- www.algomapower.com

Customer Service

Monday to Friday, 8:00am to 4:30pm.

Telephone 705-256-3850, option 1, option 0

Toll free at 1-877-457-7378, option 1, option 0

Email: customerservice@algomapower.com

*We have French speaking customer service representatives available to communicate with you if preferred.

Mercredi, le 19 septembre, 2018
Dubreuilville
Séance d'information

Agenda

- **Introduction**

  Jennifer Rose, Directrice générale, Algoma Power Inc (API)

- **Mise à jour sur l'acquisition du système de distribution de Dubreuilville par Algoma Power Inc**
  - **Mise à jour des discussions commerciales avec Dubreuil Lumber Inc (DLI)**

    Glen King, Vice président et Chef des finances, FortisOntario
  - **Demande d'approbation de la Commission de l'énergie de l'Ontario (CEO) – Dépôts liés aux acquisitions, aux dessaisissements et aux fusions (portant le nom de MADD)**

    Greg Beharriell, Directeur des affaires réglementaires, FortisOntario

- **2018 Mise à jour du plan de travail**
  - **Remplacement de compteurs**
  - **Démantèlement du Poste de transformation no. 1**

    Phil Johnston, Superviseur des services techniques, API

- **Message du service à la clientèle**

  Jody Tait, Conseillère en efficacité énergétique et service à la clientèle, API

- **Questions et Commentaires**

Statut de l'opération du système DLI par API

CEO nomme API comme l'opérateur intérimaire
- Avril 2017

API travail à adresser la sécurité critique, la fiabilité, la compliance et les problèmes du service à la clientèle
- 2017-2018

API/DLI Conclurent un contrat d'achat
- August 2018

Le processus de révision et d'approbation du CEO
- Objectif de Septembre à Décembre 2018

Procès d'intégration
- Items critiques en 2017/2018
- Intégration de tarifs en 2019
- Intégration complète en cours par base prioritaire

Les exigences pour l’approbation de la Commission de l’énergie de l’Ontario

- CEO doit approuver toutes les requêtes en fusion des distributeurs et des transporteurs d’électricité
- Connu et référé sous le nom de “MAAD Application” puisque ces publications spécialisées ne sont disponibles qu’en anglais
- Exigences spécifiques du procès d’application – Le document « MAAD Handbook » est disponible sur le site web du CEO
- La CEO révise les applications en considérant le «No harm test»

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Application MAAD – Apperçu

- API prévoit soumettre une application au CEO avant la fin de septembre 2018
- API proposera l'acquisition des biens de distribution de DLI
- Il y a des circonstances uniques dont la CEO devra observer:
  - API a déjà été nommé comme opérateur intérimaire
  - Les taux et méthodes de facturation de DLI n'ont jamais été approuvés par la CEO
  - Les taux historiques et les pratiques d'opérations ne sont pas stables en terme de sécurité, fiabilité et considérations légales et réglementaires
  - La plupart des clients de API reçoivent les subvention « Rural and Remote Rate Protection (RRRP) » qui fournissent de la stabilité long-terme pour les taux de distribution

Application MAAD – Procès du CEO

Soumettre l'Application

- Cible September

Révision et Avis

Procès de l'audition

Décision du CEO

Date de fermeture

- Cible Le 1er janvier, 2019

Application MAAD – Demandes clés et Thèmes

- API et DLI feront les demandes suivantes:
  - L'approbation de la vente du système de distribution d'électricité de DLI à API
  - L'approbation du changement du classement de tarifs d'électricité de DLI à ceux de API
  - L'approbation du rajustement tarifaire afin de récupérer une partie des coûts intérimaires
  - L'approbation d'un compte afin de noter les autres coûts impliqués avec la récupération future
  - L'amendement de licences
- L'emphase sur l'importance de la sécurité, la fiabilité, le service à la clientèle et la conformité

Application MAAD – Efforts d'atténuation des factures

- API proposera ce qui suit dans l'application MAAD pour minimiser les impacts des factures:
  - Récupérer qu'une partie des coûts provisoires par le biais de nouveaux avenants tarifaires, sur une période de six ans, afin de minimiser le montant mensuel
  - Le reste des coûts provisoires et tous les coûts de transaction / d'intégration devraient être récupérés dans le cadre d'un futur processus tarifaire API, qui n'affecterait pas les tarifs payés par les clients individuels à Dubreuilville.
  - Demande de passage à la structure tarifaire API à compter du 1er janvier 2019 pour déclencher une protection tarifaire supplémentaire pour les clients résidentiels

Application MAAD - Sommaire

	API en tant qu'opérateur intermédiaire	API acquiert les actifs de DLI
Taux d'avenants mensuels ($ / client)	27,72$	11,16$
Facture résidentielle typique (750 kWh)	147,65$	129,30
Facture commerciale typique(2000 kWh)	320,40$	340,84$
Structure des coûts futurs	De nouveaux processus, systèmes, rapports, vérifications, etc. requis - entraîneraient une pression à la hausse sur les coûts	Les actifs et les clients de DLI peuvent être intégrés aux processus API, aux rapports et aux vérifications existants
Recouvrement des coûts futurs	Tous les coûts récupérés directement auprès des clients à Dubreuilville - entraîneraient de nouveaux tarifs ou avenants tarifaires	Les coûts peuvent être intégrés à la planification de API et au processus de détermination des taux
Taux de distribution futurs	Augmentation annuelle résultant des pressions sur les coûts ci-haut et d'investissements dans le système de DLI	Augmentation annuelle liée au facteur inflationniste de l'industrie (RRRP); Plafonnement des frais de distribution totaux pour les clients résidentiels

2018 Mise à jour du plan de travail

Remplacement des compteurs

- Remplacer tous les compteurs électriques avec des sceaux expirés par des nouveaux compteurs approuvés par Mesure Canada
- Tous les compteurs électriques installés par les services publics au Canada ont une période d'expiration prédéterminée. Cette période peut varier de 6 à 12 années (dépendant du genre de compteur)
- Presque tous les compteurs retrouvés en service ont un sceau expiré et doivent être remplacés.
- Lien au site web de Mesure Canada:
  - https://www.ic.gc.ca/eic/site/mc-mc.nsf/fra/lm04708.html

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2018 Mise à jour du plan de travail
Suite

Démantèlement du Poste de transformation no. 1

2018 Mise à jour du plan de travail

Démantèlement de Poste de transformation no. 1

- Poste de transformation no. 1 à été retrouvé en pauvre condition.
- Suite à l'exploration des options, le meilleur choix déterminé est de retraiter, démanteler et enlever la station. Ceci sera un avantage pour la fiabilité du système pour les clients.
- Il y avait des inquiétudes sur la possibilité de fuites et d'écoulements d'un des vieux transformateurs. API a embauché une entreprise d'ingénierie d'un tiers fournisseur de services afin d'obtenir des échantillons de sol et d'aviser sur le niveau de l'assainissement exigé afin de bien adresser tout problème retrouvé.

SVP contactez-nous!

- Nous exigeons l'information exacte et à jour pour les comptes de tous nos clients

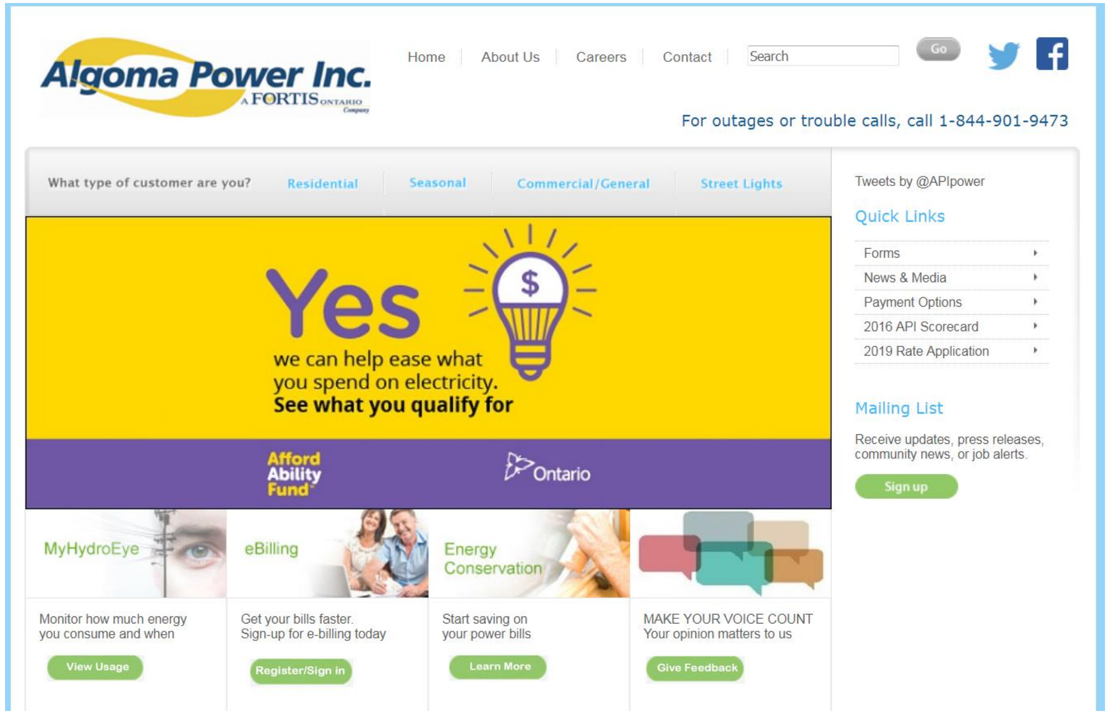
- Informations telles que:
  - Numéro de téléphone
  - Courriel
  - Tout autre nom à rajouter sur le compte
  - Adresse postale
  - Propriétaire ou locataire

Fonds pour des frais abordables

- www.affordabilityfund.org
- 1-855-494-3863

Visitez notre site web

- Pour en savoir plus sur nos services, les nouvelles de l’industrie, etc., visitez notre site web au:
- www.algomapower.com



Service à la clientèle

Lundi au Vendredi, 8h00 à 16h30

Téléphone 705-256-3850, option 1, option 0

Sans frais au 1-877-457-7378, option 1, option 0

Courriel: customerservice@algomapower.com

*Nous avons des représentants du service à la clientèle disponibles pour vous servir en français si c'est votre préférence