November 26, 2015

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700, P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: 2016 4th Generation Incentive Rate-setting Application by Algoma Power Inc. ("API") to Adjust Electricity Distribution Rates & Rural and Remote Rate Protection Funding, Effective January 1, 2016; EB-2015-0051
API Reply Submission

Please find accompanying this letter two (2) copies of API's Reply Submission in the matter of EB-2015-0051.

A PDF version of the reply Submission will, coincidently with this written submission, be filed via the Board's Regulatory Electronic Submission System.

If you have any questions in connection with the above matter, please do not hesitate to contact the undersigned at (905) 994-3634.

Yours truly,

Original Signed by

Douglas Bradbury
Director Regulatory Affairs

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An Application
By
Algoma Power Inc.
To Adjust
Electricity Distribution Rates
&
Rural and Remote Rate Protection Funding
Effective January 1, 2016

Reply Submission

EB-2015-0051

Submitted: November 26, 2015

Preamble

Algoma Power Inc. ("API") filed an application (the Application) with the Ontario Energy Board (the "Board") on August 14, 2015, seeking approval for changes to the rates that API charges for electricity distribution, to be effective January 1, 2016. The Application is based on the Price Cap IR option of the 2016 Incentive Regulation Mechanism ("IRM"). The Board has assigned file No. EB-2015-0051 to the Application.

There were two requests for intervenor status in the Application; the Vulnerable Energy Consumers Coalition ("VECC") and the Algoma Coalition. Both parties were granted intervenor status with costs[1] in relation to API's proposal for applying a change to the rate design for only customers in the R1 class.

Submissions were received on November 16, 2015 from the Board staff, VECC and the Algoma Coalition. This Reply Submission will be limited to the specific issues raised in the Submissions of Board staff and the Intervenors. The specific issues raised generally related to:

- API's proposal to apply the first stage of transition to fully fixed rates for residential customers in its Residential – R1 class,
- the description of generic residential customers in API's proposed Tariff of Rates and Charges,
- rate design for the Seasonal class,
- total bill impacts
- total bill impact mitigation, and
- the Algoma Coalition.

For the purposes of providing a more complete and accurate rate design and total bill impacts, API has updated its rate design proposal to include the Board's determination of the 2015 Inflation Factor, 2.10%, to be used in 2016 IRM applications and the RRRP Adjustment Factor, 1.80%, which was appended to the Board staff's Submission. These values were not known at the date of the Application. Details of the updated rate design are provided with this Reply Submission.

[1] The Algoma Coalition were granted costs in Decision and Procedural Order No. 3, EB-2015-0051, November 9, 2015

Following the presentation of the updated rate design and revenue decoupling, API will address the specific issues raised in the Submissions.

Updated Rate Design & Revenue Decoupling

Updated Annual Price Cap Index Adjustment and 2016 Rate Design

Prior to discussing the specifics of the matters raised by Board staff and VECC in their respective Submissions, API has updated its rate design to acknowledge the Board's determination of the Inflation Factor, 2.10%[2], and the Board staff calculation of the RRRP Adjustment Factor for 2016 electricity distribution rates in API, 1.80%[3].

The following series of tables showing the calculation of electricity distribution rates and RRRP funding for 2016 are reproductions of the tables presented in the Application but for the updated Inflation Factor and RRRP Adjustment Factors, both referenced above. These tables are contained in the rate design model, API_2016_RateDesign_ReplySub_20151117.xlsx, accompanying this Reply Submission.

Table 1 shows the calculated price cap for 2016 electricity distribution rates being used by API in this Reply Submission.

[2] http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Applications%20Before%20the%20Board/Electricity%20Distribution%20Rates/2016%20Electricity%20Distribution%20Rate%20Applications, September 17, 2015

[3] Board Staff Submission, EB-2015-0051, November 16, 2015, Schedule A

Table 1

EB-2015-0051 Final Price Cap for 2016 Electricity Distribution Rates

Price Cap Metric	Status	Value
Inflation Factor	Final	2.10%
Productivity Factor	Final	0.00%
Stretch Factor	Assigned	0.60%
Price Index	Calculated	1.50%

Table 2 outlines the application of the 2016 estimated price cap index to the class revenue shares following adjustments to the revenue to cost ratios. This step allows determination of the overall revenue requirement for 2016 and will facilitate the calculation of the RRRP funding requirement for 2016.

Table 2

IRM Indexed Revenue Requirement for 2016 Using the Actual 2016 Price Cap Excluding Transformer Ownership Allowance			
Customer Class	Revenues		
	Fixed	Variable	Total Revenue
Residential - R1	2,250,815	14,242,634	16,493,449
Residential - R2	487,959	3,575,086	4,063,045
Seasonal	1,055,125	1,356,239	2,411,363
Street Lighting	-	190,566	190,566
	3,793,899	**19,364,524**	**23,158,423**

Note that the Class revenues are indexed using the Price Cap following the changes to the Revenue to Cost Ratios. This step is necessary to determine the overall revenue requirement for 2016 before the RRRP Adjustment Factor is applied.

In the following exhibit, Table 3, the approved electricity distribution rates for the Residential – R1 and Residential – R2 customers classes have been indexed by the actual RRRP Adjustment Factor for 2015; 1.80%. This is consistent with O. Reg. 442/01 and past Board decisions in this matter. The 2016 calculated revenue based on API's last cost of service, EB-2014-0055 is then compared with the revenue requirement allocated to these two classes following the revenue to cost ratio adjustment and the application of the 2016 price cap index, the difference is the RRRP funding required for 2016. The revenue allocated to these two classes is $20,556,494; the sum of $16,493,449 and $4,063,045 from Table 2. The revenue recoverable through rates is derived using the current approved rates indexed by the RRRP Adjustment factor. The difference is compensated in the RRRP funding amount.

Table 3

Determination of Residential R1 & R2 2016 Electricity Distribution Rates and RRRP Funding

Indexed Revenues Allocated to the Residential R1 & R2 Classes for 2016 — $ 20,556,494

2016 Application of Rate Indexing Methodology												
Delivery Charges Indexed by Simple Average of Other LDC Increases in Current Year												
Simple Average Increase in Delivery Charge for 2016 using the 2015 Board Calculated RRRP Adjustment Factor												1.80%
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues			
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue	
Residential - R1	kWh	8496	105,791,701		40.7%	59.3%	23.76	0.0334	2,422,392	3,532,427	5,954,819	
Residential - R2	kW	50		198,901	36.8%	63.2%	611.64	3.1691	366,987	630,344	997,331	
Transformer Ownership Allowance - Allocated to the Residential - R2 class										74,096	74,096	
The Rural and Remote Rate Protection Amount Required for 2016											$ 13,678,440	

The RRRP funding being requested by API for the 2016 rate year is $13,678,440.

The following exhibit, Table 4, provides the calculation of the Seasonal and Street Lighting class electricity distribution rates for 2016 following the revenue to cost ratio adjustment and the application of the 2016 price cap index using the customer and load information accepted in EB-2014-0055.

Table 4

Determination of Seasonal and Street Lighting Distribution Rates

2016 Distribution Base Rate Determination for Non-RRRP Rate Classes											
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Seasonal	kWh	3138	7,731,414		47.5%	52.5%	30.42	0.1637	1,145,398	1,265,966	2,411,363
Street Lighting	kWh	1018	804,705		8.6%	91.4%	1.34	0.2164	16,389	174,178	190,566
									1,161,786	**1,440,143**	**2,601,930**

Updated Decoupling for a Generic Residential Subpopulation of Residential – R1

On April 2, 2015, the Board issued the Board Policy, "A New Residential Rate Design for Residential Electricity Customers"; EB-2012-0410. Under this policy, electricity distributors are to structure residential rates so that all the costs for distribution service are collected through a fixed monthly charge. Due to manner in which the Residential customer class is structured at API specific measures were taken in the Application in order to comply with this policy.

In order to comply with the Board Policy and after discussion with Board staff, the agreed approach to decoupling of residential, non-seasonal customer's electricity distribution rates at API is to create a sub-class of generic residential customers within API's Residential – R1 customer class. This proposal was generally accepted in the Board staff and VECC Submissions. The evidence presented in the Application is updated here to reflect the Board's determination of the Inflation Factor, 2.10%, and the Board staff calculation of the RRRP Adjustment Factor for 2016 electricity distribution rates in API, 1.80%.

API's Residential – R1 customer class is comprised of customers that fit the generic descriptors of Residential, General Service less than 50 kW and Unmetered Scattered Load customers. In Table 5, following, in the first section shows the data associated with the complete Residential – R1 customer class discussed earlier. In the second section of Table 5, the quantities for the Residential – R1 customer class have been allocated between those customers fitting the generic Residential class and those customers that fit the generic General Service less than 50 kW and Unmetered Scattered Load classes as was presented in the Application.

This will result in the segregation of the Residential – R1 class into two subclasses in order to accommodate revenue decoupling for generic residential customers. API will maintain the complete Residential – R1 class for the purposes of rate design and revenue to cost allocations.

Table 5

Revenue Decoupling for the Residential Rate Class - 1st Increment
EB-2015-0051

Rate Class	Customers/ Connections		Test Year Consumption		Proposed Rates			Proposed Revenues			Existing Split	
		Average number of Customers	kWh	kW	Monthly Service Charge	Volumetric		Fixed	Variable	Total	Fixed	Variable
						kWh	kW	$	$	$		
Residential - R1	Customers	8,496	105,791,701		$ 23.76	$ 0.0334		2,422,392	3,532,427	5,954,819	40.7%	59.3%

Rate Class	Customers/ Connections		Test Year Consumption		Proposed Rates			Proposed Revenues			Existing Split	
		Average number of Customers	kWh (Calculated)	kW	Monthly Service Charge	Volumetric		Fixed	Variable	Total	Fixed	Variable
						kWh	kW	$	$	$		
Residential	Customers	7,531	78,889,035		$ 23.76	$ 0.0334		2,147,250	2,634,136	4,781,386	44.9%	55.1%
Non - Residential	Customers	965	25,133,296		$ 23.76	$ 0.0334		275,142	839,211	1,114,353	24.7%	75.3%
Total Residential - R1	Customers	8,496						2,422,392	3,473,347	5,895,739		

Residential Decoupling

Current Monthly Service Charge (post IRM adjustment)	$	23.76
Monthly Service Charge to Achieve 100% Recovery	$	52.91
Four Year Annual Increment Required	$	7.29
Cap Applied to the Annual Increment	$	4.00
First Incremental Monthly Service Charge	$	27.76

Decoupled Residential Rates

Rate Class	Customers/ Connections		Test Year Consumption		Proposed Rates			Proposed Revenues			Existing Split	
		Average number of Customers	kWh	kW	Monthly Service Charge	Volumetric		Fixed	Variable	Total	Fixed	Variable
						kWh	kW	$	$	$		
Residential	Customers	7,531	78,889,035		$ 27.76	$ 0.0288		2,508,738	2,272,648	4,781,386	52.5%	47.5%

The section of Table 5 described as Residential Decoupling, follows the guidelines related to the Board's Policy and determines that in order to fully decouple rates in four years would require an annual change in the fixed component of $7.35; API has proposed to cap the change at $4.00 for 2016. The resultant rate design of the generic residential subclass of API's Residential – R1 customer class is shown in the lower section of Table 11.

API has determined, based on 2014 data, that 10% of its residential customers consume 320 KWh or less on a monthly basis.

Updated Decoupling for Seasonal Class

In both the Board staff and VECC Submissions, a position was presented to extend revenue decoupling to the Seasonal class. The following exhibits provide an update to API's response to Board staff's Interrogatory No. 3 resulting from the updates to the Inflation Factor and the RRRP Adjustment Factor.

Revenue Decoupling for the Seasonal Rate Class - 1st Increment
EB-2015-0051

Rate Class	Customers/ Connections		Test Year Consumption		Proposed Rates			Proposed Revenues			Existing Split	
		Average Customers	kWh	kW	Monthly Service Charge	Volumetric		Fixed	Variable	Total	Fixed	Variable
						kWh	kW	$	$	$		
Seasonal	Customers	3,138	7,731,414		$ 30.27	$ 0.1629		1,139,755	1,259,730	2,399,485	47.5%	52.5%

Residential Decoupling

	2016	2017	2018	2019	2020	2021	2022	2023	2024
Current Monthly Service Charge (post IRM adjustment)	$30.27	$ 34.27	$ 38.27	$42.27	$ 46.27	$ 50.27	$ 54.27	$58.27	$ 62.27
Monthly Service Charge to Achieve 100% Recovery	$63.72								
Four Year Annual Increment Required	$ 8.36								
Cap Applied to the Annual Increment	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 4.00	$ 1.45
First Incremental Monthly Service Charge	$34.27	$ 38.27	$ 42.27	$46.27	$ 50.27	$ 54.27	$ 58.27	$62.27	$ 63.72

Decoupled Residential Rates

Rate Class	Customers/ Connections		Test Year Consumption		Proposed Rates			Proposed Revenues			Existing Split	
		Average Customers	kWh	kW	Monthly Service Charge	Volumetric		Fixed	Variable	Total	Fixed	Variable
						kWh	kW	$	$	$		
Seasonal	Customers	3,138	7,731,414		$ 34.27	$ 0.1435		1,290,379	1,109,106	2,399,485	53.8%	46.2%

Note that the updated inflation factor was used by API to respond to the Board staff interrogatory.

API has determined, based on 2014 data, that 10% of its seasonal customers consume 15 KWh or less on a monthly basis.

API accepts and acknowledges both the Board staff's and VECC's position that Chapter 3 of the Filing Requirements states that "distributors with a seasonal residential class must propose identical rate design treatment for such a class."

API remains concerned that since 2007 its Seasonal customer class has been described as non-residential for the purposes of rate design and RRRP funding eligibility. In acknowledging the position of Board staff and VECC and accepting the intent of the Board's Filing requirements, API remains concerned regarding the consistency rate design for its Seasonal customers. API's customer services group are continually responding to queries from Seasonal customers regarding their eligibility for residential classification and, by default, RRRP funding. API, in response, has consistently applied the eligibility criteria as outlined in its Tariff of Rates and Charges. To now apply the rate design principles established for residential "type" customers to API's Seasonal class, in API's view, will further blur the line for its customers.

For purposes of completeness and clarity, API has, in this Reply Submission, presented a complete rate design and revenue decoupling plan for its Seasonal customer class together with a discussion of total bill impacts.

API's Responses to the Issues Raised

API's Proposal to Apply the First Stage of Transition to Fully Fixed Rates for Residential Customers in its Residential – R1 Class

In their respective submissions, both Board staff and VECC support API's proposal of creating two subpopulations of customers within its Residential – R1 class in order to implement the Board's new rate design policy. Other than its request that the Board specifically approve this proposal in the context of Ontario Regulation 445/07, API has no further submissions in this matter.

The Algoma Coalition did not submit on this specific issue.

The Description of Generic Residential Customers in API's Proposed Tariff of Rates and Charges

On page 6 of their Submission, Board staff proposed rate descriptors for API's Tariff of Rates and Charges specific to the Residential – R1 class which relate to the two criteria in the description of the Residential – R1 class. API submits that the Board staff proposal in this matter is a good one which brings clarity to the proposal.

Neither VECC nor the Algoma Coalition has raised an issued in this matter.

Rate Design for the Seasonal Class

Both Board staff and VECC have correctly stated that Chapter 3 of the Filing Requirements states that "distributors with a seasonal residential class must propose identical rate design treatment for such a class." Further, both parties have submitted that API ought to have extended the revenue decoupling rate design treatment to its Seasonal customer class.

As stated earlier in this reply Submission, API accepts and acknowledges both the Board staff's and VECC's position that Chapter 3 of the Filing Requirements states that "distributors with a seasonal residential class must propose identical rate design treatment for such a class."

However, API's position remains that API has a unique customer class structure among Ontario's rate regulated electricity distribution companies. This structure has been established out of necessity and was done so to effectively manage Ontario Regulation 445/07.

It may be also extrapolated that the Board's guideline, provided in Chapter 3 of the Filing Requirements, is more appropriately associated with the generic Seasonal customer classes found in many other rate regulated electricity distribution companies' Tariff of Rates and Charges.

For completeness and to allow for a full discussion of the issues, API has included a complete rate design for the Seasonal class as contemplated by Board staff and VECC.

Total Bill Impacts

The table shown below summarizes the total bill impacts arising from the methodology used in this Application and the Reply Submission. The total bill impacts for the Seasonal class are post revenue decoupling rate design.

Selected Delivery Charge and Bill Impacts Per Reply Submission
Algoma Power Inc. 2016

Customer Classification and Billing Type	Energy kWh	Demand kW	Monthly Delivery Charge			
			Current	Per Application	Change $	Change %
Residential - R1	800		$ 58.10	$ 68.13	$ 10.03	17.3%
Residential - R1	320		$ 38.95	$ 44.38	$ 5.43	13.9%
Residential - R1 GS	2,000		$ 105.99	$ 132.70	$ 26.71	25.2%
Residential - R2	90,000	225	$ 3,866.81	$ 3,117.53	-$ 749.28	-19.4%
Seasonal	800		$ 198.58	$ 194.53	-$ 4.05	-2.0%
Seasonal	205		$ 76.19	$ 78.58	$ 2.39	3.1%
Seasonal	15		$ 37.11	$ 41.55	$ 4.45	12.0%
Street Lighting	19,056	62	$ 4,356.10	$ 5,015.08	$ 658.97	15.1%

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current	Per Application	Change $	Change %
Residential - R1	800		$ 149.14	$ 176.22	$ 27.09	18.2%
Residential - R1	320		$ 75.78	$ 90.02	$ 14.23	18.8%
Residential - R1 GS	2,000		$ 332.52	$ 397.62	$ 65.10	19.6%
Residential - R2	90,000	225	$ 15,593.66	$ 14,655.45	-$ 938.22	-6.0%
Seasonal	800		$ 292.01	$ 319.06	$ 27.05	9.3%
Seasonal	205		$ 100.75	$ 114.43	$ 13.68	13.6%
Seasonal	15		$ 39.67	$ 49.09	$ 9.42	23.7%
Street Lighting	19,056	62	$ 7,299.15	$ 8,024.41	$ 725.26	9.9%

These total bill impacts are generated by the 2016 Bill Impact Model, API_2016IRM_Bill_Impact _ReplySub_20151118.xlsx, accompanying this Reply Submission.

Total Bill Impact Mitigation

Customer Class: **Residential - R1 [RPP]**

TOU / non-TOU: TOU

Consumption 800 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 23.3400	1	$ 23.34	$ 27.7600	1	$ 27.76	$ 4.42	18.94%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0328	800	$ 26.24	$ 0.0288	800	$ 23.04	-$ 3.20	-12.20%
Smart Meter Disposition Rider	Monthly	$ 2.0500	1	$ 2.05		800	$ -	-$ 2.05	-100.00%
Rate Rider for the Recovery of Lost Revenue Adjustment (LRAM) - effective until December 31, 2015	per kWh	$ 0.0002	800	$ 0.16	$ -	800	$ -	-$ 0.16	-100.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Rate Rider for the Disposition of Account 1575 & 1576 - effective until December 31, 2019	per kWh	-$ 0.0019	800	-$ 1.52	-$ 0.0019	800	-$ 1.52	$ -	0.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A (excluding pass through)				$ 50.27			$ 49.28	**-$ 0.99**	**-1.97%**
Rate Rider for the Disposition of Deferral/Variance Accounts (2014) - effective until December 31, 2015	per kWh	-$ 0.0141	800	-$ 11.28	$ -	800	$ -	$ 11.28	-100.00%
Rate Rider for the Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2015	per kWh	$ 0.0219	0	$ -	$ -	0	$ -	$ -	
Rate Rider for the Disposition of Deferral/Variance Accounts (2016) - effective until December 31, 2016	per kWh		800	$ -	$ -	800	$ -	$ -	
Rate Rider for the Disposition of Global Adjustment Sub-Account (2016) - effective until December 31, 2016	per kWh			$ -	$ -		$ -	$ -	
Low Voltage Service Charge			800	$ -		800	$ -	$ -	
Line Losses on Cost of Power	per kWh	$ 0.1021	73.36	$ 7.49	$ 0.1021	73.36	$ 7.49	$ -	0.00%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 47.27**			**$ 57.56**	**$ 10.29**	**21.77%**
RTSR - Network	per kWh	$ 0.0071	873	$ 6.20	$ 0.0070	873	$ 6.11	-$ 0.09	-1.41%
RTSR - Line and Transformation Connection	per kWh	$ 0.0053	873	$ 4.63	$ 0.0051	873	$ 4.45	-$ 0.17	-3.77%
Sub-Total C - Delivery (including Sub-Total B)				**$ 58.10**			**$ 68.13**	**$ 10.03**	**17.26%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	873	$ 3.84	$ 0.0044	873	$ 3.84	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	873	$ 1.14	$ 0.0013	873	$ 1.14	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0020	800	$ 1.60	$ -	800	$ -	-$ 1.60	-100.00%
OESP Charge	per kWh				$ 0.0011	800	$ 0.88	$ 0.88	
TOU - Off Peak	per kWh	$ 0.0800	512	$ 40.96	$ 0.0800	512	$ 40.96	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1220	144	$ 17.57	$ 0.1220	144	$ 17.57	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1610	144	$ 23.18	$ 0.1610	144	$ 23.18	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 146.64**			**$ 155.95**	**$ 9.31**	**6.35%**
HST		13%		$ 19.06	13%		$ 20.27	$ 1.21	6.35%
Total Bill (including HST)				$ 165.71			$ 176.22	$ 10.52	6.35%
Ontario Clean Energy Benefit [1]				-$ 16.57			$ -	$ 16.57	-100.00%
Total Bill on TOU (including OCEB)				**$ 149.14**			**$ 176.22**	**$ 27.09**	**18.16%**

Shown here is the total bill impact for a Residential – R1, generic residential customer, with electricity distribution rates designed for the first round of revenue decoupling and consuming 800 kWh. This customer will experience a total bill impact 18.18% or $27.09.

Revenue decoupling and application of the RRRP Adjustment Factor, 1.8%, combine for a net increase of $1.22 to the total bill before HST ($4.42 - $3.20 = $1.22). Other factors influencing the total bill include the sunsets related to smart meter rate riders, foregone revenue rate riders and deferral account rate riders; these have a net impact of $9.07 ($11.28 - $2.05 - $0.16 = $9.07).

The major influences on the total bill impact are policy driven. The removal of the Ontario Clean Energy Benefit and the introduction of the Ontario Electricity Support Program account for $17.45. Since API's customers paid a reduced Debt retirement Charge of $0.002 versus $0.007 there is minimal offset occurring to minimize the impact of these changes.

In summary, the total bill impact arising from the indexation of electricity distribution rates combined with the impact of the revenue decoupling initiative account for only 5% of the $27.09 increase in the consumer's total bill. In the absence of the removal of the Ontario Clean Energy Benefit and the introduction of the Ontario Electricity Support Program the total bill impact would be 5.75%; primarily driven by the sunset of the deferral and variance account rate rider.

Given that API has no control of the significant contributing changes to the total bill, a meaningful mitigation is not achievable through normal practices such as cost deferral techniques.

The same basic principles apply to a Residential – R1, generic residential customer, with electricity distribution rates designed for the first round of revenue decoupling and consuming 320 kWh; the consumption attributable to a consumer at the tenth percentile. The results shown on the next page indicate that this consumer will realized a total bill impact of 18.78% or $14.23. In the absence of the removal of the Ontario Clean Energy Benefit and the introduction of the Ontario Electricity Support Program the total bill impact would be 6.43%; primarily driven by the sunset of the deferral and variance account rate rider.

Customer Class: **Residential - R1 [RPP]**

TOU / non-TOU: TOU

Consumption **320** **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 23.3400	1	$ 23.34	$ 27.7600	1	$ 27.76	$ 4.42	18.94%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0328	320	$ 10.50	$ 0.0288	320	$ 9.22	-$ 1.28	-12.20%
Smart Meter Disposition Rider	Monthly	$ 2.0500	1	$ 2.05		320	$ -	-$ 2.05	-100.00%
Rate Rider for the Recovery of Lost Revenue Adjustment (LRAM) - effective until December 31, 2015	per kWh	$ 0.0002	320	$ 0.06	$ -	320	$ -	-$ 0.06	-100.00%
			320	$ -		320	$ -	$ -	
			320	$ -		320	$ -	$ -	
			320	$ -		320	$ -	$ -	
Rate Rider for the Disposition of Account 1575 & 1576 - effective until December 31, 2019	per kWh	-$ 0.0019	320	-$ 0.61	-$ 0.0019	320	-$ 0.61	$ -	0.00%
			320	$ -		320	$ -	$ -	
			320	$ -		320	$ -	$ -	
			320	$ -		320	$ -	$ -	
			320	$ -		320	$ -	$ -	
Sub-Total A (excluding pass through)				$ 35.34			$ 36.37	**$ 1.03**	**2.90%**
Rate Rider for the Disposition of Deferral/Variance Accounts (2014) - effective until December 31, 2015	per kWh	-$ 0.0141	320	-$ 4.51	$ -	320	$ -	$ 4.51	-100.00%
Rate Rider for the Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2015	per kWh	$ 0.0219	0	$ -	$ -	0	$ -	$ -	
Rate Rider for the Disposition of Deferral/Variance Accounts (2016) - effective until December 31, 2016	per kWh		320	$ -	$ -	320	$ -	$ -	
Rate Rider for the Disposition of Global Adjustment Sub-Account (2016) - effective until December 31, 2016	per kWh			$ -	$ -		$ -	$ -	
Low Voltage Service Charge			320	$ -		320	$ -	$ -	
Line Losses on Cost of Power	per kWh	$ 0.1021	29.344	$ 3.00	$ 0.1021	29.344	$ 3.00	$ -	0.00%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 34.62**			**$ 40.16**	**$ 5.54**	**16.00%**
RTSR - Network	per kWh	$ 0.0071	349	$ 2.48	$ 0.0070	349	$ 2.45	-$ 0.03	-1.41%
RTSR - Line and Transformation Connection	per kWh	$ 0.0053	349	$ 1.85	$ 0.0051	349	$ 1.78	-$ 0.07	-3.77%
Sub-Total C - Delivery (including Sub-Total B)				**$ 38.95**			**$ 44.38**	**$ 5.43**	**13.95%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	349	$ 1.54	$ 0.0044	349	$ 1.54	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	349	$ 0.45	$ 0.0013	349	$ 0.45	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0020	320	$ 0.64	$ -	320	$ -	-$ 0.64	-100.00%
OESP Charge	per kWh				$ 0.0011	320	$ 0.35	$ 0.35	
TOU - Off Peak	per kWh	$ 0.0800	205	$ 16.38	$ 0.0800	205	$ 16.38	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1220	58	$ 7.03	$ 0.1220	58	$ 7.03	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1610	58	$ 9.27	$ 0.1610	58	$ 9.27	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 74.52**			**$ 79.66**	**$ 5.15**	**6.90%**
HST		13%		$ 9.69	13%		$ 10.36	$ 0.67	6.90%
Total Bill (including HST)				$ 84.20			$ 90.02	$ 5.81	6.90%
Ontario Clean Energy Benefit [1]				-$ 8.42			$ -	$ 8.42	-100.00%
Total Bill on TOU (including OCEB)				**$ 75.78**			**$ 90.02**	**$ 14.23**	**18.78%**

The average Seasonal customer consumes 205 kWh per month; such a customer will experience a total bill impact of 13.58%, assuming revenue decoupling as presented in this Reply Submission.

Appendix 2-W
Bill Impacts

Customer Class: Seasonal [RPP]

TOU / non-TOU: TOU

Consumption 205 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 27.1500	1	$ 27.15	$ 34.2700	1	$ 34.27	$ 7.12	26.22%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
SME - Net Deferred Revenue Requirement, effective until December 31, 2016	Monthly	$ 3.5700	1	$ 3.57	$ 3.5700	1	$ 3.57	$ -	0.00%
				$ -			$ -	$ -	
Rate Rider for Recovery of Stranded Meter Assets (2014) - effective until December 31, 2015	Monthly	$ 2.5100	1	$ 2.51	$ -	1	$ -	-$ 2.51	-100.00%
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.1462	205	$ 29.97	$ 0.1435	205	$ 29.42	-$ 0.55	-1.85%
Smart Meter Disposition Rider			205	$ -		205	$ -	$ -	
LRAM & SSM Rate Rider			205	$ -		205	$ -	$ -	
	per kWh	$ -	205	$ -	$ -	205	$ -	$ -	
	per kWh	$ -	205	$ -	$ -	205	$ -	$ -	
Foregone Revenue Recovery (2015) - effective until December 31, 2015 (2015)	per kWh	$ 0.0041			$ -	205	$ -	$ -	
	per kWh	$ -	205	$ -	$ -	205	$ -	$ -	
Deferral/Variance Account Disposition - effective until June 30, 2019	per kWh	$ 0.0307	205	$ 6.29	$ 0.0307	205	$ 6.29	$ -	0.00%
Rate Rider for the Disposition of Account 1575 & 1576 - effective until December 31, 2019	per kWh	-$ 0.0019	205	-$ 0.39	-$ 0.0019	205	-$ 0.39	$ -	0.00%
			205	$ -		205	$ -	$ -	
			205	$ -		205	$ -	$ -	
			205	$ -		205	$ -	$ -	
Sub-Total A (excluding pass through)				$ 69.11			$ 73.16	**$ 4.06**	**5.87%**
Rate Rider for the Disposition of Deferral/Variance Accounts (2014) - effective until December 31, 2015	per kWh	-$ 0.0141	205	-$ 2.89	$ -	205	$ -	$ 2.89	-100.00%
Rate Rider for the Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2015	per kWh	$ 0.0219	205	$ 4.49	$ -	205	$ -	-$ 4.49	-100.00%
Rate Rider for the Disposition of Deferral/Variance Accounts (2016) - effective until December 31, 2016	per kWh	$ -	205	$ -	$ -	205	$ -	$ -	
Rate Rider for the Disposition of Global Adjustment Sub-Account (2016) - effective until December 31, 2016	per kWh	$ -	205	$ -	$ -	205	$ -	$ -	
Low Voltage Service Charge			205	$ -		205	$ -	$ -	
Line Losses on Cost of Power	per kWh	$ 0.1021	18.7985	$ 1.92	$ 0.1021	18.7985	$ 1.92	$ -	0.00%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 73.41**			**$ 75.87**	**$ 2.46**	**3.35%**
RTSR - Network	per kWh	$ 0.0071	224	$ 1.59	$ 0.0070	224	$ 1.57	-$ 0.02	-1.41%
RTSR - Line and Transformation Connection	per kWh	$ 0.0053	224	$ 1.19	$ 0.0051	224	$ 1.14	-$ 0.04	-3.77%
Sub-Total C - Delivery (including Sub-Total B)				**$ 76.19**			**$ 78.58**	**$ 2.39**	**3.14%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	224	$ 0.98	$ 0.0044	224	$ 0.98	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	224	$ 0.29	$ 0.0013	224	$ 0.29	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0020	205	$ 0.41	$ -	205	$ -	-$ 0.41	-100.00%
OESP Charge	per kWh				$ 0.0011	205	$ 0.23	$ 0.23	
TOU - Off Peak	per kWh	$ 0.0800	131	$ 10.50	$ 0.0800	131	$ 10.50	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1220	37	$ 4.50	$ 0.1220	37	$ 4.50	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1610	37	$ 5.94	$ 0.1610	37	$ 5.94	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 99.06**			**$ 101.27**	**$ 2.21**	**2.23%**
HST		13%		$ 12.88	13%		$ 13.17	$ 0.29	2.23%
Total Bill (including HST)				$ 111.94			$ 114.43	$ 2.49	2.23%
Ontario Clean Energy Benefit [1]				-$ 11.19			$ -	$ 11.19	-100.00%
Total Bill on TOU (including OCEB)				**$ 100.75**			**$ 114.43**	**$ 13.68**	**13.58%**

As with the Residential – R1 customer, the increase is primarily driven by the Ontario Clean Energy Benefit. In the absence of this initiative the total bill impact is 2.23%; inclusive of revenue decoupling.

API has performed analysis of its 2014 customer statistics and determined that 10% of its seasonal customers consume 15 KWh or less on a monthly basis. This low level of consumption shows the extreme seasonal nature of the Seasonal class in general. For a customer consuming 15 kWh the total bill impact is 23.75%. In the absence of Ontario Clean Energy Benefit initiative, the total bill impact is 11.37%; inclusive of revenue decoupling. An exhibit detailing the total bill impact is provided on the following page.

Given the diversity found in the consumption by customers in the Seasonal class together with the assertion that the associated premises are not primary residences than API questions whether or not a test for low volume consumption ought to apply.

As with the Residential – R1 customer class, API has no control of the significant contributing changes to the total bill, a meaningful mitigation is not achievable through normal practices such as cost deferral techniques.

Appendix 2-W
Bill Impacts

Customer Class: Seasonal [RPP]

TOU / non-TOU: TOU

Consumption 15 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 27.1500	1	$ 27.15	$ 34.2700	1	$ 34.27	$ 7.12	26.22%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
SME - Net Deferred Revenue Requirement, effective until December 31, 2016	Monthly	$ 3.5700	1	$ 3.57	$ 3.5700	1	$ 3.57	$ -	0.00%
				$ -			$ -	$ -	
Rate Rider for Recovery of Stranded Meter Assets (2014) - effective until December 31, 2015	Monthly	$ 2.5100	1	$ 2.51	$ -	1	$ -	-$ 2.51	-100.00%
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.1462	15	$ 2.19	$ 0.1435	15	$ 2.15	-$ 0.04	-1.85%
Smart Meter Disposition Rider			15	$ -		15	$ -	$ -	
LRAM & SSM Rate Rider			15	$ -		15	$ -	$ -	
	per kWh	$ -	15	$ -	$ -	15	$ -	$ -	
	per kWh	$ -	15	$ -	$ -	15	$ -	$ -	
Foregone Revenue Recovery (2015) - effective until December 31, 2015 (2015)	per kWh	$ 0.0041			$ -	15	$ -	$ -	
	per kWh	$ -	15	$ -	$ -	15	$ -	$ -	
Deferral/Variance Account Disposition - effective until June 30, 2019	per kWh	$ 0.0307	15	$ 0.46	$ 0.0307	15	$ 0.46	$ -	0.00%
Rate Rider for the Disposition of Account 1575 & 1576 - effective until December 31, 2019	per kWh	-$ 0.0019	15	-$ 0.03	-$ 0.0019	15	-$ 0.03	$ -	0.00%
			15	$ -		15	$ -	$ -	
			15	$ -		15	$ -	$ -	
			15	$ -		15	$ -	$ -	
Sub-Total A (excluding pass through)				$ 35.86			$ 40.42	**$ 4.57**	**12.74%**
Rate Rider for the Disposition of Deferral/Variance Accounts (2014) - effective until December 31, 2015	per kWh	-$ 0.0141	15	-$ 0.21	$ -	15	$ -	$ 0.21	-100.00%
Rate Rider for the Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2015	per kWh	$ 0.0219	15	$ 0.33	$ -	15	$ -	-$ 0.33	-100.00%
Rate Rider for the Disposition of Deferral/Variance Accounts (2016) - effective until December 31, 2016	per kWh	$ -	15	$ -	$ -	15	$ -	$ -	
Rate Rider for the Disposition of Global Adjustment Sub-Account (2016) - effective until December 31, 2016	per kWh	$ -	15	$ -	$ -	15	$ -	$ -	
Low Voltage Service Charge			15	$ -		15	$ -	$ -	
Line Losses on Cost of Power	per kWh	$ 0.1021	1.3755	$ 0.14	$ 0.1021	1.3755	$ 0.14	$ -	0.00%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 36.90**			**$ 41.35**	**$ 4.45**	**12.07%**
RTSR - Network	per kWh	$ 0.0071	16	$ 0.12	$ 0.0070	16	$ 0.11	-$ 0.00	-1.41%
RTSR - Line and Transformation Connection	per kWh	$ 0.0053	16	$ 0.09	$ 0.0051	16	$ 0.08	-$ 0.00	-3.77%
Sub-Total C - Delivery (including Sub-Total B)				**$ 37.11**			**$ 41.55**	**$ 4.45**	**11.99%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	16	$ 0.07	$ 0.0044	16	$ 0.07	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	16	$ 0.02	$ 0.0013	16	$ 0.02	$ -	0.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0020	15	$ 0.03	$ -	15	$ -	-$ 0.03	-100.00%
OESP Charge	per kWh				$ 0.0011	15	$ 0.02	$ 0.02	
TOU - Off Peak	per kWh	$ 0.0800	10	$ 0.77	$ 0.0800	10	$ 0.77	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1220	3	$ 0.33	$ 0.1220	3	$ 0.33	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1610	3	$ 0.43	$ 0.1610	3	$ 0.43	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 39.01**			**$ 43.45**	**$ 4.43**	**11.37%**
HST		13%		$ 5.07	13%		$ 5.65	$ 0.58	11.37%
Total Bill (including HST)				$ 44.08			$ 49.09	$ 5.01	11.37%
Ontario Clean Energy Benefit [1]				-$ 4.41			$ -	$ 4.41	-100.00%
Total Bill on TOU (including OCEB)				**$ 39.67**			**$ 49.09**	**$ 9.42**	**23.75%**

The Algoma Coalition

The Algoma Coalition, on page 5, stated;

> "Not only has API failed to take any effort whatsoever to consult with the Algoma Coalition per the terms of the Board approved settlement agreement in EB-2014-0055…"

and,

> "The Algoma Coalition requests that the Board remind API of their commitment to create a stakeholder process for the purpose laid out in the settlement agreement from proceeding EB-2014-0055 and assign a timeline of 60 days following the resolution of this proceeding for the first meeting to be called."

The Algoma Coalition is making reference to Schedule G of the Settlement Agreement in the matter of EB-2014-0055; API's Cost of Service proceeding. A copy of Schedule G of the Settlement Agreement is attached hereto.

On page 1 of Schedule G of the Settlement Agreement, it is clear that the parties had agreed that the first meeting was set for 2016 as it outlines the "Topics of Discussion for 2016 Meeting".

Also on page 1 of Schedule G of the Settlement Agreement under the heading "Attendees", reference is made to "Note 1". Note 1 reads,

a) Algoma Coalition will provide API by October 17, 2014 a list of its current members who are customers of API, and will update and share that list with API prior to each annual meeting.
b) Algoma Coalition will use its best efforts to maximize attendance by those of its members serviced by API at each annual meeting.

As per Note 1 part a), the Algoma Coalition will provide API with a list of its current members who are customers of API prior to a meeting in 2016.

Finally, Note 3 of Schedule G of the Settlement Agreement reads,

> "For clarity, API will prepare for the sessions, provide adequate location and staff to make presentations, however, Algoma Coalition members and

> representatives will be responsible for their own costs to prepare for and attend the annual sessions."

It is API's expectation that the first meeting will occur in 2016 as agreed upon and filed with the Board and that the Algoma Coalition and will update and share a list of its current members who are customers of API, with API prior to this meeting.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

Attachment

Schedule “G”

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ALGOMA POWER INC. / ALGOMA COALITION STAKEHOLDER SESSIONS

Purpose: To provide meaningful input and feedback for Algoma Power Inc. (API's) planning processes that focuses on value for money and measurable outcomes. The spirit of the stakeholder session is to ensure participation, transparency and meaningful discussions between API and Algoma Coalition municipal customers. Note the customer engagement framework described herein is in no way intended to derogate from API's ability to have regular/other meetings with its municipal customers. For greater clarity, what is being proposed is a high-level annual consultation focused particularly on the topics identified below as opposed to the day-to-day concerns API municipal customers may have (ie. outages etc.), which it is believed are more effectively dealt with through individual meetings therewith.

Frequency: Annually – meetings are generally to be structured in two parts:

1. Providing an update in respect to progress in meeting prior year plans;
2. Providing an overview of anticipated changes with respect to the topics of discussion below.

Location: Algoma Power Inc.
2 Sackville Road, Suite A
Sault Ste. Marie, ON
P6B 6J6
(or other location as determined prior to setting annual meeting agenda)

Attendees: Algoma Coalition on behalf of API municipal customers and/or all API municipal customers (See **Note 1**)

Topics of Discussion for 2016 meeting (See Note 2):

1. Distribution System Plans
    a) Local Infrastructure planning
    b) Capital Planning
    c) Major Maintenance Planning
    d) Reliability Statistics and Performance
    e) Quality of Service Statistics and Performance
    f) O&M savings from Capital spending
2. Regional Infrastructure Planning
3. Smart Grid
4. Energy Conservation & Demand Management
5. Regulatory Applications
    a) Rate Applications
    b) Other Regulatory Filings
    c) RRRP Implementation / Modification

Note 1:

a) Algoma Coalition will provide API by October 17, 2014 a list of its current members who are customers of API, and will update and share that list with API prior to each annual meeting.

b) Algoma Coalition will use its best efforts to maximize attendance by those of its members serviced by API at each annual meeting.

Note 2:
As mentioned above, the foregoing is not a definitive list of topics and may vary from meeting to meeting. It is anticipated that API will provide such information about anticipated yearly changes with respect to the above-noted topics to enable attendees to help shape such changes to minimize any detrimental result on them therefrom.

Note 3:
For clarity, API will prepare for the sessions, provide adequate location and staff to make presentations, however, Algoma Coalition members and representatives will be responsible for their own costs to prepare for and attend the annual sessions.