EB-2014-0055

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Algoma Power Inc. for an order approving or just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015.

VULNERABLE ENERGY CONSUMERS COALITION
(“VECC”)
CROSS-EXAMINATION COMPENDIUM

OCTOBER 20, 2014

ALGOMA POWER INC.

2015 RATE APPLICATION (EB-2014-0055)

VECC COMPENDIUM

TAB 1

File Number:	0
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-P
Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential - R1	$ 12,066,293	63.75%	$ 15,148,651	65.00%
Residential - R2	$ 4,569,290	24.14%	$ 3,735,935	16.03%
Seasonal	$ 1,995,675	10.54%	$ 3,722,892	15.97%
Street Lighting	$ 296,807	1.57%	$ 697,035	2.99%
Total	$ 18,928,065	100.00%	$ 23,304,513	100.00%

Notes

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E
	Load Forecast (LF) X current approved equivalent rates	L.F. X current approved equivalent rates X (1 + d)	LF X proposed equivalent rates	Miscellaneous Revenue
Residential - R1	$ 14,900,660	$ 16,617,169	$ 16,617,169	$ 292,845
Residential - R2	$ 3,674,441	$ 4,097,725	$ 4,097,725	$ 75,827
Seasonal	$ 1,763,879	$ 1,967,072	$ 1,967,072	$ 79,308
Street Lighting	$ 139,697	$ 155,789	$ 155,789	$ 18,778
Total	$ 20,478,677	$ 22,837,755	$ 22,837,755	$ 466,758

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate riders.

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2011	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential - R1	114.10	111.63	111.63	85 - 115
Residential - R2	59.80	111.71	111.71	80 - 120
Seasonal	115.00	54.97	54.97	80 - 115
Street Lighting	43.00	25.04	25.04	70 - 120

Notes

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants whose most recent rebasing year is 2006, the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2015	2016	2017	
	%	%	%	%
Residential - R1	111.63	111.63	111.63	85 - 115
Residential - R2	111.71	111.71	111.71	80 - 120
Seasonal	54.97	54.97	54.97	80 - 115
Street Lighting	25.04	25.04	25.04	70 - 120

Note

1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2013 that is outside the Board’s policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2013. In 2014 Table (d), enter the planned ratios for the classes that will be ‘Change’ and ‘No Change’ in 2014 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 ‘Decision – Cost Revenue Adjustment’, column d), and enter TBD for class(es) that will be entered as ‘Rebalance’.

TAB 2

Table 1: Rate-Setting Overview - Elements of Three Methods

	4th Generation IR	Custom IR	Annual IR Index
Setting of Rates			
"Going in" Rates	Determined in single forward test-year cost of service review	Determined in multi-year application review	No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism
Form	Price Cap Index	Custom Index	Price Cap Index
Coverage	Comprehensive (i.e., Capital and OM&A)		
Annual Adjustment Mechanism – **Inflation**	Composite Index	Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts	Composite Index
Annual Adjustment Mechanism – **Productivity**	Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor		Based on 4th Generation IR X-factors
Role of Benchmarking	To assess reasonableness of distributor cost forecasts and to assign stretch factor		n/a
Sharing of Benefits	Productivity factor		
	Stretch factor	Case-by-case	Highest 4th Generation IR stretch factor
Term	5 years (rebasing plus 4 years).	Minimum term of 5 years.	No fixed term.
Incremental Capital Module	On application	N/A	N/A
Treatment of Unforeseen Events	The Board's policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, will continue under all three menu options.		
Deferral and Variance	Status quo	Status quo, plus as needed to track capital spending against plan	Disposition limited to Group 1 Separate application for Group 2
Performance Reporting and Monitoring	A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.		

TAB 3

Appendix 2-V
Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential - R1	Customers	8,432.00	8,559.00	8,495.50	105,791,701		$ 23.34	$ 0.0328		$ 5,849,387.43	$ 16,617,169		$ 16,617,169	$ 10,767,782
Residential - R2	Customers	50.00	50.00	50.00	83,288,188	198,901	$ 596.12		$ 3.1273	$ 979,695.10	$ 4,097,725		$ 4,097,725	$ 3,118,030
Seasonal	Customers	3,191.00	3,084.00	3,137.50	7,731,414		$ 26.75	$ 0.1241		$ 1,966,605.98	$ 1,967,072		$ 1,967,072	$ 466
Street Lighting	Connections	1,018.00	1,018.00	1,018.00	804,705	2,380	$ 0.98	$ 0.1787		$ 155,772.46	$ 155,789		$ 155,789	$ 17
RRRP Funding (Net of Stranded Meter Allocation and Transformer Ownership Credit)										$ 13,889,944.00	$ -		$ -	-$ 13,889,944
Sub-Total A										$ 22,841,404.97	$ 22,837,755		$ 22,837,755	-$ 3,650
Residential - R1 Stranded Meter Allocation										$ -	$ -		$ -	$ -
Residential - R2 Transformer Ownership Credit										$ 74,096.00		$ 74,096	$ 74,096	$ -
Total		12,691.00	12,711.00	12,701.00	197,616,008	201,281				$ 22,915,500.97	$ 22,837,755	$ 74,096	$ 22,911,851	-$ 3,650

TAB 4

API's proposal to maintain status quo revenue to cost ratios is discussed in a following section; Proposed Revenue to Cost Ratios.

microFIT Classification

Consistent with Board policy, API has not included the microFIT customer class as a separate customer class in the Cost Allocation Study. API's current Tariff of Rates and Charges, EB-2013-0110, specifies a monthly service charge for the microFIT Generator Service Classification. API will follow the Board's direction related to the microFIT Generator Service Classification.

Proposed Revenue to Cost Ratios

API gave consideration to many factors related to the results of the 2015 Cost Allocation Study prior to arriving at its proposal to maintain Status Quo[1] revenue to cost ratios. The most salient of the factors considered are listed below and are discussed individually. These factors include:

- Functionality of the Cost Allocation Model
- The Board's Policy Range for the Revenue to Cost Ratios
- Consumer Centric Regulation / Listening to Our Customers
- The Customer's Ability to Pay / Sustainability of the Customer Classification

<u>Functionality of the Cost Allocation Model</u>

As a forward to this discussion, API is not questioning the appropriateness or effectiveness of the Board's Cost Allocation Model; API is supportive of the cost allocation model. The purpose of this discussion is to explain API's interpretation of the model's functionality and outputs, the applicability of the outputs to API's unique circumstances and how these factors contribute to API's proposal to maintain the Status Quo revenue to cost ratios.

[1] Status Quo revenue to costs ratios are the ratios determined on Output Sheet O1 of the 2015 Cost Allocation Study included with this Application

The general purpose of cost allocation in an electricity distribution business in Ontario is to reasonably allocate cost related to the distribution assets connecting an end use customer classification to the IESO controlled grid and to reasonably assign the business' operating costs to each customer classification. Generally there are three primary types of allocators in play with the Cost Allocation Model, these are:

- Demand related allocators
- Density related allocators
- Customer related allocators

Of concern for API is the relationship of the demand and density allocators for API. In the Cost Allocation Model, on Tab I5.1 Miscellaneous Data, at Cell D15, Structure KM (kMs of Roads in Service Area that have distribution line), the Applicant has to enter the kilometres of distribution as a metric to determine the customer density of the Applicant's service territory.

API is a very low density distributor and other than Hydro One Distribution, no other distributor in the province has a customer density profile that approaches API's.

The Cost Allocation Model asks the Applicant to provide the structure circuit length along highways as the input. The layout of API's distribution system and spatial distribution of its customers in very rural and remote areas means that much of API's distribution system is located off-road. In the previous cost of service review this input was left blank. In this Application, API has approximated the input required by the model by using its total length of line. The resultant of this, which is a reasonably an accurate depiction by the Cost Allocation Model, is that API's assets are heavily weighted to density and less so to demand. Though the Model may be responding as it was designed, its weighting of allocators to density may be creating an unintentional outcome in this circumstance.

The weighting of the density allocator has contributed to the re-distribution of costs among the customer classes as compared to the 2011 results. For instance, the Residential – R2 class has moved from a revenue to cost ratio of 59.8% in 2011 to 112.2% for 2015 while the Seasonal class has moved from a revenue to cost ratio of 115% in 2011 to 55.03%.

In reality, API's customers in all classes are very widely distributed throughout its service territory. Generally speaking, API industrial and commercial customers, represented by the Residential – R2 class, are as widely distributed as the Seasonal class customers. The same is true for the Residential – R1 and Street Lighting class customers. Understanding this spatial distribution, where all of API's customers in all classes are utilizing the same assets, particularly the long runs of conductors and numerous poles, equally weighting of allocators ought to be more responsive to demand.

Located in northern Ontario, API is a predominantly winter peaking LDC; on average 41.5% of API's annual demand is realized in the four months from December to March. This peak demand is driven primarily by its Residential – R1 class, which relies primarily on electricity as it heating fuel, and the Residential – R2 customer class. Street Lighting also contributes to the winter peak as lights are normally illuminated co-incident with peak demand. The Seasonal customer class, however, does not contribute to the system peak as the demand associated with this customer class normally appears on the system during off peak period in the summer months.

Understanding the spatial distribution of its customers, the layout of its distribution system and the usage patterns of its customers, API has concluded that, based on the inputs to the Cost Allocation Model, the density weighting of the model may not appropriately reflect the reality of distribution costs apportioned at API.

The Board's Policy Range for the Revenue to Cost Ratios

In the "Report of the Board Review of Electricity Distribution Cost Allocation Policy", dated March 31, 2011, EB-2010-0219, the Board provided the following revenue to cost ratio ranges to be implemented through cost of service applications starting in 2012.

SERVICE CLASS	RANGE
Residential	85 to 115%
General Service < 50 kW	80 to 120%
General Service 50 to 4,999 kW	80 to 120%
Large User	85 to 115%
Unmetered Scattered Load	80 to 120%
Street Lighting	70 to 120%
Sentinel Lighting	80 to 120%

API has interpreted the Board's direction and based on its interpretation applied the Board's Policy Range to its customer classes. API's Residential – R1 customer class is a mix of Residential, General Service < 50 kW and Unmetered Scattered Load customers; API has assumed a Board Policy Range of 85 to 115% for Residential – R1. API's Residential – R2 customer class is basically the General Service 50 to 4,999 kW service class and API has assumed a Board Policy Range of 80 to 120% for Residential – R2. API's Street Lighting class is similar to the Street Lighting service class described in the Board Policy Range; 70 to 120%. There is no Board Policy Range equivalent for the API Seasonal class; by default API has assumed the same Board Policy Range as the Residential – R1 class; 85 to 115%.

Given the seasonal nature, low volume usage and lack of homogeneity of API's Seasonal class as compared with the Residential – R1 class, this assumption may or may not be valid.

Consumer Centric Regulation / Listening to Our Customers

The Board is introducing consumer centric regulation and asking distributors to improve their communications with their customers. This renewed regulatory approach recognizes the need for significant investment in the sector while acknowledging that concerns over bill increases are leading to a sharper focus on the total cost to consumers[2].

[2] OEB Website, A Renewed Regulatory Framework for Electricity

Over the past decade, API has undertaken a program of distribution system renewal with an emphasis on improved customer service and system reliability. The nature of these programs, vegetation and right of way management, high risk conductor replacement and pole replacement, is impactive on all customer classes equally. These investments in the distribution system contribute to upward pressure on electricity distribution rates.

In API, the Seasonal customer classification is a customer class that is by default, defined by regulation. Ontario Regulation 445/07 exempts certain customer classification from the residential classification; Street Lighting and Seasonal. Seasonal has been defined by an occupancy limitation of less than eight months in a twelve month period and as such does not benefit from the RRRP funding.

Rising energy costs, particularly in the Seasonal customer classification, have given rise to customers expressing concerns related to energy costs and actively seeking ways to reduce their energy costs. This includes converting energy sources such as propane powered refrigeration, heating and lighting and in some extreme instances disconnecting from the grid.

Further complicating the issue and fuelling the customer's expressed confusion over this matter is the fact that often neighbours, residing adjacent to each other and utilizing the same distribution system assets are in different customer classifications. With one customer being classified a Residential – R1 and the other a Seasonal customer there is a two-to-one ratio of all in cost of electricity[3]. The Seasonal classified customer consuming 800 kWh will have a total monthly bill that is approximately double the neighbour who is a Residential – R1 class customer.

API's approach to its Cost Allocation Study and its proposed revenue to cost ratios is an attempt to both listen and respond to its customers' expressed concerns, uncertain whether

[3] All in cost of electricity for purposes of this discussion is the total bill expressed in terms of $ per kWh

or not the Cost Allocation Study has appropriately allocated costs to its customer classes. As a result, API has chosen to propose status quo revenue to cost ratios in this Application.

<u>The Customer's Ability to Pay / Sustainability of the Customer Classification</u>

Over the past number of years, API has experienced a continued migration of customers from the Seasonal class to the Residential – R1 class. Customers are expressing their awareness of the price differential existing between these two customer classes. Based on the 2015 Test Year proposed electricity distribution rates, the all in cost of electricity for the Seasonal and Residential – R1 customer consuming 800 kWh is,

- Seasonal Class 0.3119 $/kWh
- Residential – R1 0.1697 $/kWh

Continued and increasing disparity in rates will, in API's understanding of customer concerns, eventually create an unsustainable customer classification for Seasonal customers.

Street Lighting

The very rural nature of the API service territory is indicative of the ratio of 1.24 Street Light devices to the number of connections to the distribution system. This very low density has contributed to the low revenue to cost ratio for the Street Lighting customer class. For the same reasons as discussed previously, API is proposing to maintain the status quo revenue to cost ratio.

The ability to raise the revenue to cost ratio for the Street Lighting customer class is hampered by the proposed total bill impact of this customer class at the status quo revenue to cost ratio.

TAB 5

> be adjusted in line with the average, as calculated by the Board, of any adjustment to rates approved by the Board for other distributors for the same rate year. O. Reg. 335/07, s. 1 (2)."

Under this provision, forecasted consumer revenue for a year is based upon the current rates adjusted for the average increase or decrease in rates approved by the Board for the same rate year. This average adjustment reflects the ratepayers contribution to recovery of any revenue deficiency.

The appropriate method of calculating the average rate adjustments of other distributors in order to calculate the rate increase for the customers of API, and the remaining amount that is payable under RRRP was decided in the Board's Decision and Order, EB-2009-0279, dated November 11, 2010.It is referred to as the RRRP Adjustment factor.

RRRP Payment

Paragraph 5 of Section 2 of the RRRP Regulation sets out the eligibility criteria applicable to API for rural rate protection. This paragraph provides that:

> "5. Consumers,
>
> (i) who are treated as residential-rate class consumers under Ontario Regulation 445/07 (Reclassifying Certain Classes of Consumers as Residential-Rate Class Customers: Section 78 of the Act) made under the Act, or
>
> (ii) who occupy residential premises in an area served by a distributor where,
>
> A. the distributor is licensed to serve the consumers,
> B. the area is not less than 10,000 kilometres in size, and
> C. the average customer density for the distributor is less than seven customers per kilometre of distribution line."

Based on this provision and paragraph 3 of subsection 4(4) of the RRRP Regulation, all of API's re-classified Residential customers are eligible for rural rate protection. This protection does not currently extend to Seasonal and Street Lighting customers. Paragraph 3 of subsection 4(4) of the RRRP Regulation states as follows:

TAB 6

32. 7Staff32 – Seasonal Class and Street Lighting Class

- Ref: Exhibit 7/Tab 1/Sch. 2/p. 9
- Ref: Exhibit 7/Tab 1/Sch. 3/p. 2 - 3

API is proposing RC ratios of 55.03% and 24.66% respectively for the Seasonal and Street Lighting Class.

API states that as there is no Board policy range equivalent of the revenue-to cost (“RC”) ratio for API’s Seasonal class, by default API has assumed the same Board policy range as the Residential – R1 class, i.e. 85% to 115%.

Board staff notes in the tables pertaining to re-balancing RC ratios and Proposed RC ratios, the policy range indicated for the Seasonal class is 80% to 115%.

Board staff also notes that the Board’s policy range for the Street Lighting Class is 70% to 120%.

a) Please provide the rationale for proposing ratios outside the Board’s policy range for these two classes; and

b) Please confirm if the 80% to 115% range pertaining to the Seasonal class is an oversight.

RESPONSE:

a) API’s rationale for proposing ratios outside the Board’s Policy Range for these two classes remains consistent with the evidence submitted in Exhibit 7, Tab 1, Schedule 2 of the Application. API gave consideration to many factors related to the results of the 2015 Cost Allocation Study prior to arriving at its proposal to maintain Status Quo[1] revenue to cost ratios. The most salient of

[1] Status Quo revenue to costs ratios are the ratios determined on Output Sheet O1 of the 2015 Cost Allocation Study included with this Application

the factors considered are listed below and were discussed individually in the Application. These factors include:

- Functionality of the Cost Allocation Model
- The Board's Policy Range for the Revenue to Cost Ratios
- Consumer Centric Regulation / Listening to Our Customers
- The Customer's Ability to Pay / Sustainability of the Customer Classification

As stated in the Application, API is not questioning the appropriateness or effectiveness of the Board's Cost Allocation Model; API is supportive of the cost allocation model. The purpose of the discussion was to explain API's interpretation of the model's functionality and outputs, the applicability of the outputs to API's unique circumstances and how these factors contribute to API's proposal to maintain the Status Quo revenue to cost ratios. In API's last cost of service, EB-2009-0278, the cost allocation study yielded a revenue to cost ratio of 149.94% and the final value accepted in the settlement Agreement was 115%. With no material change to API's distribution system, the 2015 Cost Allocation Study has yielded a revenue to cost ratio of 55.03%. API has questioned whether or not the Cost Allocation Model is responsive of API's unique circumstances of customer density and the system configuration described in Exhibit 2, Tab 1, Schedule 1 and described pictorially on page 2 of this reference.

Further, the Board is introducing consumer centric regulation and asking distributors to improve their communications with their customers. Rising energy costs, particularly in the Seasonal customer classification, have given rise to customers expressing concerns related to energy costs and actively seeking ways to reduce their energy costs. This includes converting to energy sources such as propane powered refrigeration, heating and lighting and in some extreme instances disconnecting from the grid completely. API's approach to its Cost Allocation Study and its proposed revenue to cost ratios is an attempt to both listen and respond to its customers' expressed concerns, regardless of whether or not the Cost Allocation Study has appropriately allocated costs to its customer classes. Further complicating the issue and fuelling the customer's expressed confusion over this matter is the fact that often neighbours, residing adjacent to each other and utilizing the same distribution system assets are in different customer classifications. With one customer being classified a Residential – R1 and the other a Seasonal customer. As a result, API has chosen to propose status quo revenue to cost ratios in this Application.

The customer's ability to pay and the sustainability of the Seasonal and Street Lighting Customer Classification is also a consideration. The Seasonal and Street Lighting Customer Classifications are not subject to RRRP funding. Over the past number of years, API has experienced a continued migration of customers from the Seasonal class to the Residential – R1 class. Customers are expressing their awareness of the price differential existing between these two customer classes. As evidenced by the nature of the interrogatories from the Algoma Power Coalition, Street Lighting costs are also a concern for customers.

For all of these reasons, API is proposing ratios outside the Board's Policy Range for these two classes.

b) API confirms that the reference in Exhibit 7, Tab 1, Schedule 3, pages 2 and 3 to a Policy Range of 80% – 115% is an oversight. The intent is to assume a Policy Range of 85% – 115% similar to that selected for the Residential – R1 classification.

TAB 7

33. 7Staff33 – Density Allocator

- Ref: Exhibit 7/Tab 1/Sch. 2/p. 7 - 8

API states: "the weighting of the density allocator has contributed to the re-distribution of costs among the customer classes as compared to the 2011 results."

API also states: "the density weighting of the model may not appropriately reflect the reality of distribution costs apportioned at API".

a) Please reconcile these two statements;

b) Please provide information and further details supporting the 2nd statement, i.e. density weighting of the model does not reflect reality of distribution costs; and

c) With respect to the cost allocation methodology, please explain what changes, if any, API has investigated to result in a more "realistic" allocation.

RESPONSE:

a) See the explanations in parts b & c.

b) API is inferring that the configuration of its electricity distribution system may not fit with the intended density allocation of the model. As described in Exhibit 2, Tab 1, Schedule 1, in the pictorial on page 2, API's electricity distribution system is comprised of many smaller distribution systems widely dispersed over a large geographic area; it is not a singularly contained system like many of the LDCs in Ontario. This type of dispersed subdistribution systems means that portions of the distribution system behave like a “sub-transmission”.

c) No, API has not investigated a “more” realistic allocation.

TAB 8

34. 7Staff34 – Cost Allocation Model Input

- Ref: Exhibit 7/Tab 1/Sch. 2/p. 7

API states: "The Cost Allocation Model asks the Applicant to provide the structure circuit length along highways as the input. The layout of API's distribution system and spatial distribution of its customers in very rural and remote areas means that much of API's distribution system is located off-road. In the previous cost of service review this input was left blank. In this Application, API has approximated the input required by the model by using its total length of line".

a) Why has API input density information in the cost allocation model associated with this application but left it blank the last time?

b) Please provide a run of the cost allocation model for the 2015 test year that leaves the density information blank as in the previous cost of service review.

c) How does API estimate its total length of line?

RESPONSE:

a) API is uncertain as to why the input density information in the previous cost allocation was omitted.

b) A cost allocation model leaving the density information blank accompanies these responses.

c) API determines its total length of line from a geographical based mapping system.

2014 Cost Allocation Model

EB-2013-0055

Sheet O1 Revenue to Cost Summary Worksheet - Final Run

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	7	12
Rate Base Assets		**Total**	**R1**	**R2**	**Street Light**	**Seasonal**
crev	Distribution Revenue at Existing Rates	$20,356,651	$14,784,364	$3,674,373	$139,694	$1,758,220
mi	Miscellaneous Revenue (mi)	$436,758	$260,772	$112,101	$11,175	$52,709
		Miscellaneous Revenue Input equals Output				
	Total Revenue at Existing Rates	**$20,793,409**	**$15,045,136**	**$3,786,474**	**$150,870**	**$1,810,929**
	Factor required to recover deficiency (1 + D)	1.1508				
	Distribution Revenue at Status Quo Rates	$23,426,431	$17,013,843	$4,228,468	$160,760	$2,023,360
	Miscellaneous Revenue (mi)	$436,758	$260,772	$112,101	$11,175	$52,709
	Total Revenue at Status Quo Rates	**$23,863,188**	**$17,274,616**	**$4,340,569**	**$171,935**	**$2,076,069**
	Expenses					
di	Distribution Costs (di)	$6,195,694	$3,732,055	$1,810,512	$110,358	$542,769
cu	Customer Related Costs (cu)	$2,036,392	$1,507,778	$36,644	$9,141	$482,829
ad	General and Administration (ad)	$4,580,592	$2,911,635	$1,036,457	$66,921	$565,579
dep	Depreciation and Amortization (dep)	$3,947,009	$2,442,785	$1,044,752	$65,114	$394,358
INPUT	PILs (INPUT)	$440,336	$268,929	$123,490	$7,610	$40,307
INT	Interest	$2,946,627	$1,799,611	$826,369	$50,925	$269,722
	Total Expenses	**$20,146,650**	**$12,662,793**	**$4,878,223**	**$310,070**	**$2,295,565**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$3,716,538	$2,269,823	$1,042,287	$64,231	$340,197
	Revenue Requirement (includes NI)	$23,863,188	$14,932,616	$5,920,510	$374,301	$2,635,762
		Revenue Requirement Input equals Output				
	Rate Base Calculation					
	Net Assets					
dp	Distribution Plant - Gross	$123,195,078	$75,722,757	$33,681,113	$2,140,616	$11,650,593
gp	General Plant - Gross	$39,045,691	$23,850,326	$10,942,861	$675,356	$3,577,147
accum dep	Accumulated Depreciation	($67,100,611)	($41,458,506)	($17,960,199)	($1,170,374)	($6,511,532)
co	Capital Contribution	($521,234)	($325,247)	($132,567)	($10,027)	($53,394)
	Total Net Plant	**$94,618,925**	**$57,789,331**	**$26,531,208**	**$1,635,571**	**$8,662,814**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$22,937,890	$12,254,244	$9,663,378	$100,840	$919,429
	OM&A Expenses	$12,812,679	$8,151,468	$2,883,612	$186,421	$1,591,177
	Directly Allocated Expenses	$0	$0	$0	$0	$0
	Subtotal	***$35,750,569***	***$20,405,712***	***$12,546,990***	***$287,261***	***$2,510,606***
	Working Capital	$4,647,574	**$2,652,743**	**$1,631,109**	**$37,344**	**$326,379**

2014 Cost Allocation Model

EB-2013-0055

Sheet O1 Revenue to Cost Summary Worksheet - Final Run

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	7	12
Rate Base Assets		Total	R1	R2	Street Light	Seasonal
	Total Rate Base	$99,266,498	$60,442,073	$28,162,317	$1,672,915	$8,989,193
		Rate Base Input equals Output				
	Equity Component of Rate Base	$39,706,599	$24,176,829	$11,264,927	$669,166	$3,595,677
	Net Income on Allocated Assets	$3,451,399	$4,611,823	($537,654)	($138,135)	($484,635)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0
	Net Income	$3,451,399	$4,611,823	($537,654)	($138,135)	($484,635)
	RATIOS ANALYSIS					
	REVENUE TO EXPENSES STATUS QUO%	100.00%	115.68%	73.31%	45.94%	78.77%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($3,069,780)	$112,520	($2,134,036)	($223,432)	($824,832)
		Deficiency Input equals Output				
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	$2,342,000	($1,579,941)	($202,366)	($559,693)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.69%	19.08%	-4.77%	-20.64%	-13.48%

TAB 9

2014 Cost Allocation Model

EB-2013-0055

Sheet O1 Revenue to Cost Summary Worksheet - Final Run

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	7	12
Rate Base Assets		**Total**	**R1**	**R2**	**Street Light**	**Seasonal**
crev	Distribution Revenue at Existing Rates	$20,478,676	$14,900,660	$3,674,441	$139,697	$1,763,879
mi	Miscellaneous Revenue (mi)	$466,758	$292,845	$75,827	$18,778	$79,308
		Miscellaneous Revenue Input equals Output				
	Total Revenue at Existing Rates	$20,945,434	$15,193,505	$3,750,267	$158,475	$1,843,187
	Factor required to recover deficiency (1 + D)	1.1152				
	Distribution Revenue at Status Quo Rates	$22,837,756	$16,617,169	$4,097,725	$155,789	$1,967,072
	Miscellaneous Revenue (mi)	$466,758	$292,845	$75,827	$18,778	$79,308
	Total Revenue at Status Quo Rates	$23,304,513	$16,910,014	$4,173,551	$174,567	$2,046,380
	Expenses					
di	Distribution Costs (di)	$5,795,694	$3,667,982	$1,069,577	$204,323	$853,813
cu	Customer Related Costs (cu)	$2,036,392	$1,507,778	$36,644	$9,141	$482,829
ad	General and Administration (ad)	$4,580,592	$3,023,163	$653,756	$125,799	$777,874
dep	Depreciation and Amortization (dep)	$3,899,209	$2,504,649	$680,360	$123,962	$590,238
INPUT	PILs (INPUT)	$409,653	$260,409	$75,901	$13,697	$59,646
INT	Interest	$2,911,164	$1,850,571	$539,382	$97,340	$423,870
	Total Expenses	$19,632,704	$12,814,552	$3,055,620	$574,262	$3,188,271
	Direct Allocation	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$3,671,809	$2,334,099	$680,315	$122,773	$534,622
	Revenue Requirement (includes NI)	$23,304,513	$15,148,651	$3,735,935	$697,035	$3,722,892
		Revenue Requirement Input equals Output				
	Rate Base Calculation					
	Net Assets					
dp	Distribution Plant - Gross	$122,555,751	$78,199,286	$22,170,419	$4,091,600	$18,094,446
gp	General Plant - Gross	$39,239,754	$24,948,139	$7,260,204	$1,313,178	$5,718,233
accum dep	Accumulated Depreciation	($66,750,600)	($42,719,078)	($11,845,258)	($2,224,052)	($9,962,213)
co	Capital Contribution	($521,234)	($339,031)	($77,846)	($19,514)	($84,842)
	Total Net Plant	$94,523,671	$60,089,316	$17,507,520	$3,161,211	$13,765,624
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$23,068,924	$12,366,017	$9,676,700	$100,839	$925,368
	OM&A Expenses	$12,412,679	$8,198,923	$1,759,976	$339,264	$2,114,516
	Directly Allocated Expenses	$0	$0	$0	$0	$0
	Subtotal	*$35,481,603*	*$20,564,939*	*$11,436,676*	*$440,103*	*$3,039,885*
	Working Capital	$3,548,160	$2,056,494	$1,143,668	$44,010	$303,988
	Total Rate Base	$98,071,831	$62,145,810	$18,651,187	$3,205,222	$14,069,612
		Rate Base Input equals Output				
	Equity Component of Rate Base	$39,228,732	$24,858,324	$7,460,475	$1,282,089	$5,627,845
	Net Income on Allocated Assets	$3,468,616	$4,095,462	$1,117,932	($399,695)	($1,345,084)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0
	Net Income	$3,468,616	$4,095,462	$1,117,932	($399,695)	($1,345,084)
	RATIOS ANALYSIS					
	REVENUE TO EXPENSES STATUS QUO%	100.00%	111.63%	111.71%	25.04%	54.97%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($2,359,080)	$44,854	$14,333	($538,561)	($1,879,705)
		Deficiency Input Does Not Equal Output				
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$1,761,363	$437,617	($522,468)	($1,676,512)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.84%	16.48%	14.98%	-31.18%	-23.90%

2014 Cost Allocation Model

EB-2013-0055

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Final Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	7	12
	R1	R2	Street Light	Seasonal
Customer Unit Cost per month - Avoided Cost	$13.48	$18.77	$0.42	$12.59
Customer Unit Cost per month - Directly Related	$20.59	$50.01	$0.89	$19.19
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$60.80	$344.53	$39.90	$91.03
Existing Approved Fixed Charge	$20.96	$612.10	$0.00	$24.64

TAB 10

Table 3 Summary of Total Bill Impacts

Summary of Bill Impacts						
Customer Class	**Type**	**Usage kWh**	**Demand kW**	**Total Bill**		
				Includes OCEB (if applicable)		
				Current	Proposed	%
Residential - R1	**RPP-TOU**	**250**		63.04	61.55	-2.38%
		800		147.58	138.19	-6.36%
		1,500		255.18	235.76	-7.61%
		2,000		332.03	305.43	-8.01%
		5,000		793.16	723.52	-8.78%
		10,000		1,561.71	1,420.33	-9.05%
		15,000		2,330.26	2,117.16	-9.15%
Residential - R2	**Non-RPP**	**30,000**	**50**	4,694.57	4,858.65	3.49%
		81,000	**160**	11,753.29	12,269.77	4.39%
		90,000	**225**	13,406.62	14,119.30	5.32%
		4,100,000	**6,000**	542,714.15	562,688.13	3.68%
R2, Interval	**Non-RPP**	**90,000**	**225**	13,502.27	14,119.30	4.57%
Seasonal	**RPP-TOU**	**287**		110.14	109.78	-0.33%
		1,000		292.68	297.47	1.63%
Street Lighting	**Non-RPP**	**150**	**1**	50.17	54.75	9.12%
		19,056	**62**	6,364.05	6,937.78	9.02%

The billing parameters for a Street Lighting customer i.e., 19,056 kWh and 62 kW are changed from the evidence presented in the original Application. This change is intended make the example illustrative of an actual API Street Lighting customer as was discussed during the review stage of the Application.

Table 4 below provides a more detailed bill impact assessment.

TAB 11

Results flowing from the updated cost allocation model may show some ratios being outside of the Board-approved ranges. In these cases, distributors must ensure that their cost allocation proposals include adjustments to bring them into the Board-approved ranges. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rate burden of any particular class or classes is significant.

If the distributor proposes to continue re-balancing after the test year, the ratios proposed for subsequent year(s) must be provided. The fourth table in Appendix 2-P provides a format for presentation. In particular, if the proposed ratios are outside the Board's policy range in the test year, the distributor must show the proposed ratios in subsequent years that would move the ratios into the policy range.

If using a cost allocation model other than the Board model, the distributor must ensure that costs exclude LV costs and deferral and variance accounts such as Smart Meter costs and that revenues exclude rate riders, rate adders and the Smart Metering Entity charge. The distributor must also ensure that information relevant to microFIT unit costs and revenue is consistent with the output from the Board's model.

2.11 Exhibit 8: Rate Design

The following areas are discussed in this exhibit:

1) Fixed/Variable Proportion;
2) Rate Design Policy Consultation
3) Retail Transmission Service Rates (RTSRs);
4) Retail Service Charges;
5) Wholesale Market Service Rate;
6) Smart Metering Charge;
7) Specific Service Charges;
8) Low Voltage Service Rates (where applicable);
9) Loss Adjustment Factors;
10) Tariff of Rates and Charges;
11) Revenue Reconciliation;
12) Bill Impact Information; and
13) Rate Mitigation (where applicable).

Please note that monthly fixed charges must be shown to two decimal places while variable charges must be shown to four places. Distributors wishing to depart from this approach must provide a full explanation as to why they believe it is necessary.

TAB 12

Determination of Residential R1 & R2 2015 Electricity Distribution Rates and RRRP Funding

2015 Distribution Base Rate Determination											
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		13.6%	86.4%	22.24	0.1356	2,267,699	14,349,470	16,617,169
Residential - R2	kW	50		198,901	12.0%	88.0%	820.21	18.1276	492,124	3,605,601	4,097,725
									2,759,823	**17,955,071**	**20,714,894**

2015 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 2015 using the 2014 Board Approved RRRP Adjustment Factor											0.79%
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%	23.34	0.0328	2,379,862	3,465,392	5,845,254
Residential - R2	kW	50		198,901	36.8%	63.2%	600.83	3.1131	360,498	619,199	979,696
Hold Residential - R2 Fixed Charge at $596.12					36.5%	63.5%	596.12	3.1273	357,672	622,024	979,696
Transformer Ownership Allowance - Allocated to the Residential - R2 class										74,096	74,096
									2,737,534	**4,087,417**	**6,824,951**
The Rural and Remote Rate Protection Amount Required for 2015											**$ 13,964,040**

Balanced ? YES

Determination of Seasonal and Street Lighting Distribution Rates

2014 Distribution Base Rate Determination											
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		43.8%	56.2%	22.86	0.1431	860,719	1,106,353	1,967,072
Seasonal (adj.)					51.2%	48.8%	26.75	0.1241	1,007,298	959,774	1,967,072
Street Lighting	kWh	1018	804,705		0.0%	100.0%	-	0.1936	-	155,789	155,789
Street Lighting (adj.)					7.7%	92.3%	0.98	0.1787	11,972	143,818	155,789
									1,019,270	**1,103,592**	**2,122,862**

Balanced ? YES

TAB 13

The portion of revenue requirement allocated to the Residential – R1 and Residential – R2 customer classes that is not recovered from the 2015 electricity distribution rates and 2015 forecasted customers and volumes is recovered through RRRP funding. Under this proposal the 2015 RRRP funding has been calculated at $14,515,412.

Table 8.2.1.5 details the calculation of electricity distribution rates for the Seasonal and Street Lighting customer classes. These customer classes are not subject to RRRP funding; rates are developed to recover the full amount of the revenue requirement allocated to these classes.

Table 8.2.1.5 Determination of Seasonal and Street Lighting Proposed 2015 Rates

2014 Distribution Base Rate Determination											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Seasonal	kWh	3138	7,680,066		43.8%	56.2%	23.51	0.1482	885,349	1,138,011	2,023,360
Seasonal (adj.)					49.8%	50.2%	26.75	0.1323	1,007,298	1,016,062	2,023,360
Street Lighting	kWh	1018	804,690		0.0%	100.0%	-	0.1998	-	160,760	160,760
Street Lighting (adj.)					7.4%	92.6%	0.98	0.1849	11,972	148,788	160,760
									1,019,270	**1,164,850**	**2,184,120**

Initially, the fixed and variable proportions are held at those developed for equivalent rates. The fixed portion is then adjusted to maintain continuity with existing approved rate structures, which were agreed to in EB-2009-0278, API's last cost of service proceeding.

The fixed monthly charges are consistent with those agreed to in the last cost of service review, EB-2009-0278.

The final step is a reconciliation of the revenue recovered from the proposed electricity distribution rates plus the proposed RRRP funding to the revenue requirement adjusted for the transformer ownership credit and the stranded meter cost allocated to the Residential – R1 class. This is detailed in Table 8.2.1.6.

TAB 14

2007 Board Approved Tariff, EB-2007-0744				Proposed		
Delivery Charges				Delivery Charges		
Monthly Rates and Charges	Metric	Effective September 2007		Proposed July 1, 2010		Proposed December 1, 2010
Residential - R1						
Monthly Service Charge	$	20.41		N/A		20.82
Distribution Volumetric Rate	$/kWh	0.0287		N/A		0.0293
Residential - R2						
Monthly Service Charge	$	596.12		N/A		596.12
Distribution Volumetric Rate	$/kW	2.4549		N/A		2.5492
Seasonal						
Monthly Service Charge	$	24.00		N/A		26.07
Distribution Volumetric Rate	$/kWh	0.0700		N/A		0.1001
Street Lighting						
Monthly Service Charge[1]	$	-		N/A		0.96
Distribution Volumetric Rate	$/kWh	0.0496		N/A		0.1537
Rural and Remote Rate Protection	$	8,861,800		N/A		11,440,605

Note 1: Sheet O2 of the Cost Allocation Model determines the minimum fixed charge as $ 0.96
The resulting variable charge with this minimum charge is $ 0.1537

TAB 15

RRRP 2002 – 2007 FUNDING VARIANCE

In its last cost of service application, EB-2009-0278, specifically Exhibit 9, Tab 1, Schedule 6, API sought relief of a funding variance in its RRRP funding account for the period of 2002 to 2007. However, the matter was not raised as part of the Settlement Agreement in the matter of EB-2009-0278. In this Application, API is requesting specific relief of the amount of $173,543 associated with the 2002 to 2007 variance.

In 2003, the government announced plans to extend the RRRP funding to all of Great Lakes Power's (API's predecessor) customers. The relief was in the form of RRRP payments from Hydro One and was determined to be $2,333,808 annually ($194,484 per month). This amount was equated to a monthly credit of $28.50 per residential customer; 6,824 customer times $28.50 per customer per month equals $2,333,808 per annum.

The variance recorded by API relates to a billing system allocation of the monthly $28.50 credit per customer that existed for RRRP funding in that same time frame. The billing system allocated the monthly credit on a 30 day basis, which left the utility short since more funding was credited to the customer than what was received by API (or GLP at the time). Therefore, for a 31 day billing period the billing system would allocate a benefit of $29.45 per customer (31/30 * $28.50 = $29.45). Over a year for 6,824 customers this is a shortfall of approximately $30,000 per year.

Additionally, the funding regime did address the variability in customer counts. As the number of eligible customers changed from 6,824 in 2002 to 6,797 in 2007, the RRRP funding did not keep pace.

API had an accrued balance of $235,653 related to this account at the end of 2008, but determined through an accounting review and comparison to OEB Rate Order Decision EB-2007-0744, that this variability in funding was satisfied as a result of that Decision. Therefore, API is seeking $173,534 according to the following schedule.

Table 9.8.1.1 below summarizes the calculation of the RRRP funding adjustment that is required to address the variance.

Table 9.8.1.1

	Days	RRRP Payments from HONI		Days	# Cust	RRRP Credits to Customers	Variance
2002	245	$1,555,872		245	6,845	$1,593,145	$37,273
2003	365	$2,333,808		365	6,866	$2,380,612	$46,804
2004	366	$2,333,808		366	6,820	$2,371,430	$37,622
2005	365	$2,333,808		365	6,789	$2,354,144	$20,336
2006	365	$2,333,808		365	6,784	$2,352,208	$18,400
2007	243	$1,555,872		243	6,797	$1,568,972	$13,100
		$12,446,976				**$12,620,510**	**$173,534**

API has included the original rate order describing the $28.50 per customer and the annual filings as an Appendix A to this Schedule.

API had been funded previously through a RRRP regime from 2002 – September 2007. The current RRRP regime was implemented in February 2009. There was a variance of $173,534 that related to the 2002-2007 funding which has been recorded as a receivable on the balance sheet of API and should be relieved through an additional payment from the RRRP funding pool administered by Hydro One.

TAB 16

41. 9Staff41 – Funding Variance

- Ref: Exhibit 9/Tab 8/Sch. 1 (including Appendix A)

API's predecessor GLPL collected annually, $2,333,808 from the RRRP pool of funds for 2002 to 2007 as per the Board's Rate Order RP-2003-0149. API is seeking $173,534 which it accrued as an accounts receivable for the difference between what GLPL collected from Hydro One for RRRP and what GLPL credited its customers from 2002 to 2007.

GLPL appealed the Board's decision, EB-2007-0744, dated October 30, 2008. The Board's decision was upheld at Divisional Court, Court of Appeal for Ontario and further appeal was dismissed by the Supreme Court of Canada.

Fortis bought GLPL's distribution business on October 9, 2009. API's cost of service rates were set by the Board on a final basis effective December 1, 2010. API has had its rates set on a final basis by IRM for 2012 and 2013. The Board issued a decision on February 20, 2014 which approved rates on a final basis.

In its Decision on API's 2012 IRM (EB-2011-0152), the Board enhanced the approved methodology to calculate the RRRP funding for the R-1 and R-2 rate classes during IRM years. The rates for all other customer classes not eligible for RRRP would be adjusted by the price cap adjustment index.

a) Table 9.8.1.1 of the evidence shows that API received the exact RRRP in accordance with the Board's Rate Order. As this was part of the revenue requirement, which is not subject to true-up, what is API's justification for this proposal?

b) Please comment on API's proposal for recovery of amounts that pre-date its purchase of the distribution business from GLPL given the impermissibility of retroactive ratemaking.

c) Please explain why any amounts arising from the period prior to API's first rate order in 2010 should be considered by the Board given that rates are set on a final basis by the Board

d) Did API seek the Board's approval for a deferral account to record these amounts for recovery from the rate payers?

e) Why did API not seek the Board's approval to address this issue in its previous Cost of Service application?

RESPONSE:

a) The rates set out in the Board's rate order effective May 1, 2002 (at Exhibit 9, Tab 8, Schedule 1, Appendix A) reflected a discount of $28.50/month for customers eligible under the RRRP program. API does not propose to adjust the historic discounts received by its customers, since to do so would amount to retroactive rate making. Rather, API is seeking to recover the appropriate compensation for the RRRP discounts it provided to its customers during the period from 2002 - September, 2007 through an additional compensation payment from the RRRP funding pool administered by Hydro One. At all relevant times, subsection 79(3) of the OEB Act provided that a distributor is entitled to be compensated for lost revenue resulting from rate reductions under the RRRP program. Therefore, the compensation from HONI for which API is seeking Board confirmation is an entitlement prescribed by legislation.

b) Please refer to API's response to (a) above. Again, API is not proposing to retroactively adjust rates.

c) Please refer to API's response to (a) above.

d) API is not seeking to recover its RRRP underfunding from its rate payers, as suggested by the interrogatory. API is seeking an order from the Board confirming the amount of additional compensation that API is entitled to recover from HONI pursuant to subsection 79(3) of the OEB Act. A deferral account is not required for API to recover this prescribed compensation.

e) API raised this issue in its last cost of service application, but the issue did not form part of the settlement agreement in that proceeding.

TAB 17

9.0-VECC- 43

Reference: E9/T8/S1/pg.8

a) Please confirm that API is seeking to recover amounts which was over-refunded to customers. Please confirm that API (or its predecessor) was only to refund to eligible customers the fixed amount of $2,333,808 on an annual (pro-rated) basis. Did API (or its predecessor) err in providing a larger refund than was contemplated under the RRRP funding model?

b) Please explain why API is only now seeking to recover a variance that originates in 2002 and ended in 2007?

c) Please provide the Board variance account order which authorized the recording of this variance.

RESPONSE:

a) API does not confirm this assertion as API's customers were not over-refunded. The $28.50/month RRRP discount provided to eligible customers was correct. Rather, the funding from the Hydro One administered pool to compensate API for the $28.50/month discount was insufficient.

b) As set out in the evidence, this issue was raised in API's last cost of service application.

c) Please refer to API's response to Board staff interrogatory 41(d).

TAB 18

Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2014-0055**

VOLUME: **Technical Conference**

DATE: **August 20, 2014**

because they seem to be embedded in one of the costs that are listed in that table, but it's not specified in so many words.

MR. LAVOIE: Yes, that in Table 4.1.1.2 of Exhibit 4, tab 1, schedule 1, it is in the lines program category.

MR. ADVANI: That is the third item from the top?

MR. LAVOIE: That is correct.

MR. ADVANI: All right, thank you very much.

MS. DJURDJEVIC: Okay, was Board Staff the last party on that issue?

MR. ADVANI: I believe so, let me just confirm that. Yes, Board Staff had only one question on Exhibit 4.

MS. DJURDJEVIC: Now, as I understand, the parties had skipped issue number 3 and now we are going to go back to that one? Or we are going to 9 next?

MR. ADVANI: We are going to issue 9 now, and we will go to the rest of them after that.

MS. DJURDJEVIC: All right. So let's move on to issue number 9 and -- any preference in who is going first?

MR. GARNER: I was going to ask to go first. It was my request to go to 9, because it was the last issue I was going to cover. And my colleague, Mr. Harper, is going to cover the remainder of the issues.

So if I might, we didn't ask a question on this. But as I indicated during the break, we are left confused with what API is proposing with respect to the funding variance of 173,534 that you are seeking to recover. And we are left even more perplexed after reading the response you had to -- I think it's 49.1-STAFF-41 funding variance, where you indicated the amount you were seeking wasn't retroactive rate making.

I am wondering, since I have you here in person, if you can help us through the history of this with GLPL, the predecessor you purchased the company from, and just explain to us how this arose, and why it isn't retroactive ratemaking and why the concerns raised by Board Staff that, as I understand from their –– the insinuation in their question is that the matter was dealt with and is now behind the company.

Can you help me with that?

MR. TAYLOR: So I think that we can provide background on the issue to help you understand it better, but as far as explaining why it's not retroactive ratemaking, to me that's a legal issue and I don't think this is the appropriate forum to deal with legal argument.

We will be making, presumably later in the proceeding, legal submissions, at which time we will make it abundantly clear as to our position on the legal issue as -- with regard to retroactive ratemaking.

You know, typically in that situation we would file a brief of authorities, we would talk about the law, because retroactive ratemaking is a legal concept.

So in the context of this technical conference, we are not prepared to argue the law today, but we can certainly help you understand the issue better.

MR. GARNER: Well, thank you. And I certainly understand your concern. I am not looking for a detailed justification about the law.

Mr. Taylor, where I was really going to was the interrogatory itself responds by saying API does not propose to adjust the historic discounts. So to your point, I think maybe if you explain why that is, maybe that's where I am losing the train of logic that you have. And I think that's where I'm really going.

MR. TAYLOR: The historic discounts were -- you are talking about the $28.50 per kilowatt-hour -- sorry, per customer per month, we are not proposing to change that.

The rural and remote rate protection subsidy that was provided to API's customers, we don't dispute that that amount was incorrect. We think that the 28.50 was correct, and that is why we are not proposing to change that rate in any way whatsoever.

MR. GARNER: So maybe now, if you have no objection, to let API respond.

MR. TAYLOR: Okay.

MR. LAVOIE: So if I were -- the triple-R regime that was first announced in 2003 and applicable to the API distribution utility, Great Lakes Lower at the time, was determined on a formula that is used in Hydro One rural scenarios, situations, which is, as Mr. Taylor mentioned, $28.50 per month. And it was derived using the $28.50 per month multiplied by -- our average customer count at the time was 6,824, over the course of a year, which equated to a fixed sum of 2,333,808.

Now, implied within the calculation is inherent variability; there are customers that Algoma Power had taken on from the period 2003 to 2007 when the relief of subsidy changed, the formula changed, and in that period of time there was no true-up to what the actual customer count was, and those credits that were appropriately given to the customers over that period of time. So there is a variability with respect to customers.

And the second variance that existed was how the credit was applied. And Algoma Power had a bimonthly billing system that it applied to its residential customers, and inherent in a 28.50 per month -- it sounds simple, but the months don't have the same number of days. And therefore over a bimonthly period, you have to make a billing assumption within that calculation.

And we had done so very similar -- identical, actually, to the fixed monthly charges that are applied as part of our rate structure, applied on a 30-day month basis.

So those two variances that occurred over a period -- actually 2002 to 2007, had accumulated within an account that we are now seeking to recover.

So we feel that this type of variability has to be occurring within the Hydro One system and would be trued up at some periodic basis. You could never be trued up on that number.

So we believe we are asking for the mechanical -- the relief of that mechanical nature of the relief mechanism that was in place at the time.

MR. GARNER: Okay. Thank you. And also that helps me understand what Mr. Taylor was indicating about the 28.50.

Is there a way for you to allocate or distinguish between the amounts of the two variabilities? You said basically there is customer numbers and there is the billing problem, so that 173,000 is a combination of those two variances; is that correct?

And I guess the next question is: Can you break those out?

MR. LAVOIE: We provided a table of the payments and credits in table 9.8.1.1, but we don't have that --

MR. GARNER: I'm not at this stage, but what dawns on me when we review this is there may be an argument for one part of that and not the other part. And therefore would you be able to create -- or know that difference?

I am not going to say I am going to make that argument; it just dawns on me it could be...

MR. LAVOIE: I am not 100 percent certain that we have it in the format that you are asking for, but we do have a calculation for the number, so --

MR. GARNER: Could you undertake to provide that number?

MR. LAVOIE: Yeah. Yes, we will do that.

MS. DJURDJEVIC: Okay. That will be undertaking J1.4, and can we just get that stated on the record?

UNDERTAKING NO. J1.4: TO PROVIDE A MORE DETAILED CALCULATION ON THE VARIANCE, SHOWING THE VARIABILITY

WITH RESPECT TO CUSTOMER NUMBERS AND THE AMOUNT DUE TO THE BIMONTHLY BILLING ISSUE.

MR. GARNER: Well, maybe I will let the parties say what they think the undertaking is, is the best way to...

MR. LAVOIE: API will seek to provide a more detailed calculation on the variance.

MR. GARNER: Which shows the two parts? One, the variability with respect to customer numbers, and, two, the amount due to the bimonthly billing issue?

MR. LAVOIE: Right.

MR. GARNER: Thank you.

My next question is -- you said this variance was occurring between 2002 and 2007, and you had booked it into an account. Did this account have the Board's prior approval?

MR. LAVOIE: We implemented the mechanism through a Board order. We did not seek any particular approval on this account.

I think we felt that it was inherent in the way the application of the subsidy worked that there would be a mechanical remainder, so we do not have a specific approval for this account.

MR. GARNER: And when you say "we," the -- API took over the GLPL at what point in time in this exercise?

MR. LAVOIE: October of 2009.

MR. GARNER: So when you say "we" --

MR. LAVOIE: I guess I am speaking as the --

MR. GARNER: -- who is that?

MR. LAVOIE: -- the licenced distributor. So Great Lakes Power, at the time, did not seek any specific approval on this particular account, if we were to term it as a deferral account of sorts.

MR. GARNER: Okay. Why I ask is that I wonder whether -- how the people at the company at that time understood the Board to know that a variance would occur. How would the Board understand that there was going to be a variance to be collected if it wasn't notified by the utility?

MR. LAVOIE: I don't think that there was specific discussion that we had -- certainly in the last rate application that API had, we did notify the Board of the existence of this issue. So that was the previous application to this one.

2009-0278 was the proceeding, so we have noted the issue in that proceeding.

MR. GARNER: That is when you raised it with the Board the first time?

MR. LAVOIE: We raised it with the Board, yes.

MR. GARNER: Sorry, what was the Board's response to you raising it? Was there any response?

MR. LAVOIE: The Board was silent on the issue.

MR. GARNER: Okay. I think those are all my questions on that.

MS. DJURDJEVIC: Okay, thank you Mr. Garner. Mr. Aiken, do you want to go next on issue 9?

MR. AIKEN: I would, but I don't have any questions.

MS. DJURDJEVIC: Okay.

TAB 19

UNDERTAKING NO. J1.4: TO PROVIDE A MORE DETAILED CALCULATION ON THE VARIANCE, SHOWING THE VARIABILITY WITH RESPECT TO CUSTOMER NUMBERS AND THE AMOUNT DUE TO THE BIMONTHLY BILLING ISSUE.

RESPONSE:

A Live Excel file, Undertaking_No_J1_4_20140821.xslx, accompanies these responses to the Undertakings arising from the Technical Conference.

This file details the derivation of the variability with respect to the customer numbers and the amount due to the bi-monthly billing issue.

	Days	RRRP Payments from HONI	Days	# Cust	RRRP Credits to Customers	Variance	Initial # Cust	RRRP Credits to Customers	Days Pro-rated Variance	Change in # Cust	Customer Count Variance
2002	245	$1,555,872	245	6,845	$1,593,145	$37,273	6,824	1,588,286	32,414	21	4,859
2003	365	$2,333,808	365	6,866	$2,380,612	$46,804	6,824	2,366,222	32,414	42	14,390
2004	366	$2,333,808	366	6,820	$2,371,430	$37,622	6,824	2,372,705	38,897	(4)	(1,275)
2005	365	$2,333,808	365	6,789	$2,354,144	$20,336	6,824	2,366,222	32,414	(35)	(12,078)
2006	365	$2,333,808	365	6,784	$2,352,208	$18,400	6,824	2,366,222	32,414	(40)	(14,014)
2007	243	$1,555,872	243	6,797	$1,568,972	$13,100	6,824	1,575,320	19,448	(28)	(6,348)
		$12,446,976			**$12,620,510**	**$173,534**			**$188,001**		**($14,467)**