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 just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015.

EB-2014-0055

Algoma Power Inc.

Settlement Proposal

October 10, 2014

This settlement proposal (the "Settlement Proposal") is for the consideration of the Ontario Energy Board (the "Board") in its determination of the rate application by Algoma Power Inc. ("Algoma Power" or "API") for 2015 electricity distribution rates.

INTRODUCTION

Algoma Power filed an application with the Board on May 12, 2014 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B), seeking approval for changes to the rates that Algoma Power charges for electricity distribution, to be effective January 1, 2015 (the "Application"). The Board assigned the Application File Number EB-2014-0055.

Three parties requested and were granted intervenor status: Energy Probe Research Foundation ("Energy Probe" or "EP"); the Vulnerable Energy Consumers Coalition ("VECC"); and the Algoma Coalition (the "Coalition" or "Algoma Coalition"). These parties are referred to collectively as the "Intervenors".

In Procedural Order No. 1, issued on June30, 2014, the Board approved the Intervenors in this proceeding and made its determination regarding the cost eligibility of the Intervenors.

In Procedural Order No. 2, issued on July 10, 2014, the Board set out dates for interrogatories (July 21 and 22, 2014), interrogatory responses (August 7, 2014), a Technical Conference (August 20, 2014), and a Settlement Conference (September 8-9, 2014).

Subsequent to the Technical Conference, parties conferred on and agreed to a proposed issues list for the Board’s consideration. On August 28, 2014, the Board issued a decision in which it approved the proposed issues list (the "Issues List"), which is at Attachment "A" to this Settlement Proposal.

The Settlement Conference was duly convened in accordance with Procedural Order No.2 with Ms. Gail Morrison as facilitator. The Settlement Conference lasted longer than the Board's prescribed dates and concluded on October 8, 2014.

Algoma Power and the following Intervenors participated in the Settlement Conference (collectively the “Parties”):

- the Coalition
- Energy Probe
- VECC

The role adopted by Board Staff in the Settlement Conference is set out on page 5 of the Board’s Settlement Conference Guidelines (the “Guidelines”). Although Board Staff is not a party to this Proposal, as noted in the Guidelines, the Board Staff who did participate in the Settlement Conference are bound by the same confidentiality standards that apply to the Parties to the proceeding.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Guidelines. The Parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the proposed settlement of each issue during the Settlement Conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this settlement proposal.

SETTLEMENT PROPOSAL

This Settlement Proposal represents a partial settlement of the issues, in that some cases have been completely settled, while three issues remain unsettled. It is acknowledged and agreed that none of the Parties will withdraw from this Settlement Proposal under any circumstances, except as provided under Rule 32.05 of the Board's Rules of Practice and Procedure.

The Parties explicitly request that the Board consider and accept this Settlement Proposal as a package. None of the matters in respect of which a settlement has been reached is severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this comprehensive Settlement Proposal. The distinct issues addressed in this proposal are intricately interrelated, and reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this Settlement Proposal which may be unacceptable to one or more of the Parties. If the Board does not accept the Settlement Proposal in its entirety, then there is no settlement unless the Parties agree in writing that those portions of the Settlement Proposal that the Board does accept may continue as a valid settlement, subject to any revisions that may be agreed upon by the Parties.

In the event that the Board directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties must agree with any revised Settlement Proposal prior to its resubmission to the Board for its review and consideration as a basis for making a decision.

Unless otherwise expressly stated in this Settlement Proposal, the agreement by the Parties to the settlement of each issue shall be interpreted as being for the purpose of settlement only and not a statement of principle applicable in any other situation. Where, if at all, the Parties have agreed that a particular principle should be applicable generally, this Settlement Proposal so states expressly. This is consistent with Board policy, under which settlements and their approval by the Board are considered to be specific to the facts of the particular case, and not precedents unless clearly so stated.

It is also agreed that this Settlement Proposal is without prejudice to any of the Parties re-examining these issues in any subsequent proceeding and taking positions inconsistent with the resolution of these issues in this Settlement Proposal. However, none of the Parties will in any subsequent proceeding take the position that the resolution therein of any issue settled in this Settlement Proposal, if contrary to the terms of this Settlement Proposal, should be applicable for all or any part of the 2015 Test Year.

The Parties agree that the following unsettled issues will be addressed by way of a hearing for determination by the Board:

- Is the applicant's proposal to recover the RRRP funding variance from the 2002 to 2007 period appropriate?
- Are the proposed revenue-to-cost ratios appropriate?
- Are the proposed fixed/variable splits appropriate?

The Parties believe that an oral hearing is the most appropriate forum to address these unsettled issues because the Board will be privy to discussions made during witness examination, and an oral hearing will give the Board the opportunity to ask API's witnesses and the intervenors questions should any arise.

The Settlement Proposal provides a description of each of the settled issues, together with references to the evidence before the Board. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the responses to Interrogatories and Technical Conference Questions and Undertakings, and all other components of the record up to and including the date hereof, including additional information included by the Parties in this Settlement Proposal, and the Attachments to this document.

References to the evidence supporting this Settlement Proposal on each issue are set out in each section of this Settlement Proposal. The Attachments were prepared by the Applicant. The Intervenors are relying on the accuracy and completeness of the Attachments in entering into this Settlement Proposal.

The revenue requirement and rate adjustments arising from this Settlement Proposal will allow Algoma Power to make the necessary investments to serve customers, maintain the integrity of the distribution system, to maintain and improve the quality of its service, and to meet all compliance requirements during 2015.

Algoma Power has filed budgets for the Test Year that are illustrative of how it would achieve these goals, however, the actual decisions as to how to allocate resources and in what areas to spend the agreed- upon capital and OM&A are ones that must be made by the utility during the course of the year. This is typical of all forward test year cost of service applications, and such decisions are subject to the Board's normal review in subsequent proceedings. Furthermore, Algoma Power submits that the reduced amounts of capital and OM&A that were agreed on through settlement, may not allow Algoma Power to sufficiently complete all projects/plans as they were originally contemplated in the Application.As noted above this will not compromise its ability to maintain the integrity of its distribution system and its service quality.

ORGANIZATION AND SUMMARY OF THE SETTLEMENT PROPOSAL

The following Attachments accompany this Proposal:

"A" – The Issues List Decision dated August 28, 2014

"B" – Updated Chapter 2 Appendices (*from the Filing Requirements for Electricity Distribution Rate Applications*)

The following list identifies those Appendices that have been updated since the original Amended Application datedMay 27, 2014 filing:

2-BA: Fixed Assets Continuity Schedule, December 31, 2014

2-BA: Fixed Assets Continuity Schedule, December 31, 2015

2-H: Other Operating Revenue Offset Table

2-P: Cost Allocation

2-V: Revenue Reconciliation

2-W: Bill Impacts

2-Z: Tariff of Rates and Charges

“C” – Schedule of Cost of Power

“D” – Tax Calculations

“E” – Adjustment to 2015 Load Forecast with CDM Adjustment

“F” – Revenue Requirement Workform

"G" - API/Algoma Coalition Stakeholder Sessions

The following electronic models will accompany this Settlement Proposal and will be filed with the Board:

A. Revenue Requirement Workform; API 2015_RRWF_Settlement 20141010.xlsm
B. Rate Design Model; API_Settlement_2015EDR_RateDesign_20141010.xlsx
C. Bill Impact Model;API_2015EDR_Bill_Impact _Model_Settlement_20141010.xlsx
D. Cost Allocation Model;API_ 2015_Cost_Allocation_Model_V3 1 - Settlement_20141010.xlsm
E. Settlement Appendices: Settlement_Appendices_20141010.xlsx

This Settlement Proposal has been organized to follow the Board's approved Issues List. It should be noted that the Issues List was not available to Algoma Power at the time it prepared its pre-filed evidence, nor was it available to the Intervenors at the time they prepared their interrogatories and technical conference questions. As such, although the Parties have organized this Settlement Proposal in accordance with the Issues List, we trust that the Board will appreciate the difficulty of addressing each sub-issue individually, given that none of the evidence in this proceeding was organized in this manner.

OVERVIEW OF THE SETTLEMENT PROPOSAL

The Parties have reached a partial settlement.

In reaching settlement, the Parties have been guided by the Filing Requirements for 2014, and the *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012 ("RRFE").

The agreement among the Parties reduces Algoma Power's applied-for service revenue requirement by $558,675, from $23,863,189 to $23,304,514.

Table 1 below provides the components of Algoma Power's revenue requirement for the 2015 Test Year, incorporating the changes as settled.

Table 1. Contributions to Change to Revenue Requirement

		Applied-for		Settlement		Change	
		%	$	%	$	%	$
1	Rate Base		99,266,498		98,071,831		- 1,194,666
2	Cost of Capital	6.71%		6.71%		-	
3	Return on Rate Base		6,663,164		6,582,973		- 80,192
4	OM&A Expenses		12,812,679		12,412,679		- 400,000
5	Amortization		3,947,009		3,899,209		- 47,800
6	Income Taxes (including other tax credits)		440,336		409,653		- 30,683
7	2015 Service Revenue Requirement		23,863,189		23,304,514		- 558,675
8	Less Miscellaneous Revenue		436,758		466,758		30,000
9	2015 Base Revenue Requirement		23,426,431		22,837,756		- 588,675

Table 2 details the individual contributions of matters arising from the interrogatory process and the settlement to the change in Rate Base.

Table 2 Proposed Settlement Rate Base

RATE BASE

Description	2014 Bridge Year	Stranded Meters	2014 Bridge Year Revised	2015 Test Year	Other Settlement Adjustments	Revised 2015 Test Year
Gross Fixed Assets	157,557,032	(890,528)	156,666,504	165,812,251		165,812,251
Accumulated Depreciation	(65,418,323)	652,221	(64,766,102)	(68,713,111)	47,800	(68,665,311)
Net Book Value	92,138,709	(238,307)	91,900,402	97,099,140		97,146,940
Average Net book Value				94,499,771		94,523,671
Working Capital Requirement				35,750,569		
Proposed Adjustment to OM&A					(400,000)	
Increase in Cost of Power					131,033	
Net change in Working Capital Requirement					(268,967)	35,481,602
Working Capital Allowance				4,647,574	10%	3,548,160
Rate Base				99,147,345		98,071,831
Original Rate Base						99,266,498
Difference						(1,194,667)

The change to the rate base is attributable to several factors, these are:

- Interrogatory 2 – Energy Probe – 8 highlighted a matter associated with the stranded meters in gross assets and accumulated depreciation. In API's response to this interrogatory the rate base for 2015 was re-calculated on the average of opening and closing net book value for 2015 with the opening balance excluding stranded meters. The re-calculation of the 2015 rate base provided with API's interrogatory response is reflected in Table 1.
- For the purpose of settlement, API has reduced its proposed amortization expense in the test year by $47,800.
- API has reduced its proposed working capital requirement by $400,000 reflecting the reduction, for the purpose of settlement, in its 2015 test year proposed OM&A expense.
- API has increased its cost of power by $131,033 to reflect the changes to the load forecast as accepted by the Parties. Details of the determination of the changes to the cost of power were presented in Undertaking JT1.8.
- For the purpose of settlement, API has reduced its working capital allowance from 13% to 10% of the revised working capital requirement.

The accumulated effect of each of these measures reduces API's proposed test year rate base by $1,194,667 from $99,266,498 to $98,071,831.

This reduction of $1,194,667 in the test year rate base has the further effect of reducing API's return on rate base by $80,192 and reducing income tax, both as detailed in Table 1.

The remaining contributors to the reduced 2015 test year revenue requirement are the $400,000 reduction to OM&A expense, the $47,800 decrease in amortization expense, the resultant changes to income tax, including the $7,425 apprenticeship tax credit, and the $30,000 increase in the 2015 test year forecast for other revenue. These accumulated reductions to rate base are partially offset by a $131,033 increase in cost of power. This increase in cost of power is solely attributable to the revised load forecast which adds 1,133,546 kWh of energy throughput. Each of these matters is addressed individually in this Proposed Settlement Agreement.

Table 3below provides bill impacts for a typical customer by rate class for the Proposed Settlement Base Revenue Requirement. These rate impacts have been calculated on the basis of a rate design incorporating the actual 2015 RRRP Adjustment Factor of 0.79% which as issued by the Board on October 3, 2014.

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.

Table 4 Detailed Summary of Bill Impacts

Summary of Bill Impacts															
Customer Class	Type	Usage kWh	Demand kW	Sub-Total A			Sub-Total B			Sub-Total C			Total Bill		
				Excludes Pass Through			Distribution			Delivery			Includes OCEB (if applicable)		
				Current	Proposed	%	Current	Proposed	%	Current	Proposed	%	Current	Proposed	%
Residential - R1	**RPP-TOU**	**250**		31.46	33.00	4.88%	34.17	32.60	-4.60%	37.46	35.98	-3.94%	63.04	61.55	-2.38%
		800		49.72	50.10	0.76%	56.66	47.09	-16.88%	67.17	57.92	-13.77%	147.58	138.19	-6.36%
		1,500		72.96	71.87	-1.49%	85.27	65.54	-23.14%	104.99	85.85	-18.24%	255.18	235.76	-7.61%
		2,000		89.56	87.42	-2.39%	105.72	78.72	-25.54%	132.01	105.79	-19.86%	332.03	305.43	-8.01%
		5,000		189.16	180.72	-4.46%	228.36	157.78	-30.91%	294.09	225.47	-23.33%	793.16	723.52	-8.78%
		10,000		355.16	336.22	-5.33%	432.78	289.55	-33.09%	564.23	424.92	-24.69%	1,561.71	1,420.33	-9.05%
		15,000		521.16	491.72	-5.65%	637.19	421.32	-33.88%	834.37	624.38	-25.17%	2,330.26	2,117.16	-9.15%
Residential - R2	**Non-RPP**	**30,000**	**50**	753.62	713.25	-5.36%	985.58	1,109.82	12.61%	1,223.77	1,368.06	11.79%	4,694.57	4,858.65	3.49%
		81,000	**160**	1,100.12	970.92	-11.74%	1,726.41	2,116.87	22.62%	2,488.61	2,943.23	18.27%	11,753.29	12,269.77	4.39%
		90,000	**225**	1,304.87	1,123.18	-13.92%	2,000.74	2,538.50	26.88%	3,072.59	3,700.56	20.44%	13,406.62	14,119.30	5.32%
		4,100,000	**6,000**	19,496.12	14,651.12	-24.85%	51,197.06	66,343.48	29.58%	79,779.59	97,331.82	22.00%	542,714.15	562,688.13	3.68%
R2, Interval	**Non-RPP**	**90,000**	**225**	1,304.87	1,123.18	-13.92%	2,000.74	2,538.50	26.88%	3,157.24	3,700.56	17.21%	13,502.27	14,119.30	4.57%
Seasonal	**RPP-TOU**	**287**		73.41	76.50	4.21%	76.41	75.93	-0.62%	80.18	79.82	-0.45%	110.14	109.78	-0.33%
		1,000		168.81	185.52	9.90%	177.28	181.56	2.41%	190.43	195.10	2.45%	292.68	297.47	1.63%
Street Lighting	**Non-RPP**	**150**	**1**	24.71	27.50	11.29%	25.87	29.81	15.23%	29.50	33.54	13.71%	50.17	54.75	9.12%
		19,056	**62**	3,397.84	3,752.28	10.43%	3,545.18	4,045.86	14.12%	3,770.21	4,277.37	13.45%	6,364.05	6,937.78	9.02%

In its Application, API had requested RRRP funding of $14,515,412. In this Proposed Settlement Agreement, API is requesting RRRP funding of $13,964,040 a reduction of $551,372. This reduction has two primary drivers; the predominant driver is the reduction in Service Revenue Requirement of $558,675, and the second is API'sremoval of its request to recover $192,509 of stranded meter costs by allocating them to the Residential - R1 class. API will now recover these costs by way of a rate rider specific to the Residential – R1 rate class.These reductions are offset by the actual RRRP Adjustment Factor of 0.79% being significantly less than the assumed RRRP Adjustment factor in the Application of 3.76%. The RRRP Adjustment Factor directly impacts the share of revenue attributable to the Residential – R1 and Residential – R2 rate classes that is either recovered from rate or is allocated to RRRP funding.

In addition, the Parties agree that in the event that that Board is unable to implement Algoma Power's distribution rates by January 1, 2015, the Intervenors support a January 1, 2015 effective date for distribution rates.

PLANNING

a) Capital

Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:

i. customer feedback and preferences;
ii. productivity;
iii. benchmarking of costs;
iv. reliability and service quality;
v. impact on distribution rates;
vi. trade-offs with OM&A spending;
vii. government-mandated obligations; and
viii. the applicant's objectives.

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 2; Interrogatory 2-Energy Probe-8, Interrogatory 2-Staff-8

For the purposes of settlement, the Parties accept that the level of planned capital expenditures is appropriate, as is the rationale for planning and pacing choices, and has been adequately explained giving due consideration to the items listed in i-viii above, subject to the qualifications set out below.

Qualifications:

i) Stranded Meters: For the purpose of settlement, the Parties agree that Algoma Power's opening 2015 rate base should be reduced by $119,153, being one half of the net book value of stranded meters removed from opening rate base, as shown in Table 6 provided in the summary to this section.The evidentiary basis for this change is API's response to interrogatory 2-Energy Probe-8.

ii) Allowance for Working Capital: For the purpose of settlement, the Parties agree that Algoma Power's allowance for working capital will be calculated based on 10% of the sum of cost of power and controllable expenses, instead of 13% as originally proposed by Algoma Power. The effect of decreasing the allowance for working capital has been partially offset by an increase in the cost of power of $131,033. The increase in cost of power is a consequence of the change to the load forecast which is being used in this Proposed Settlement Agreement. The Parties have agreed to use the load forecast defined by Undertaking JT1.8. The impact of the change in load forecast on the elements contributing to the cost of power is shown below in Table 5.

Table 5 The2015 Cost of Power Expense Summary

2015 Cost of Power Expense Summary						
Charge Type	Updated as per Undertakings		As per the Application		Change	
4705 - Cost of Power	$ 19,243,046		$ 19,132,846		$ 110,200	
4708 - Charges - WMS	$ 949,245		$ 943,800		$ 5,445	
4714 - Charges - NW	$ 1,449,453		$ 1,441,452		$ 8,001	
4716 - Charges - CN	$ 1,036,440		$ 1,030,661		$ 5,778	
4730 - Charges - Rural Rate Assistance	$ 280,459		$ 278,850		$ 1,609	
4751 - Charges - IESO SME	$ 110,281		$ 110,281		$ -	
Total	$ 23,068,922		$ 22,937,890		$ 131,033	

This table has been excerpted from API's response to Undertaking JT1.8 filed with the Board on August 22, 2014.

iii) Customer Feedback and Preferences: API will conduct an annual stakeholder session with the Algoma Coalition as described at Attachment "G".

Summary:

As a result of the qualifications set out above, the Parties accept that Algoma Power's 2015 rate base for the purpose of setting 2015 rates is $98,071,831. The Parties accept the following components of Algoma Power's 2015 rate base:

Table 6 Summary of Changes to the 2015 Rate Base

RATE BASE

Description	2015 Test Year Application	2014 Bridge Year	Stranded Meters	2014 Bridge Year Revised	2015 Test Year, IR Response	Other Settlement Adjustments	Proposed Settlement 2015 Test Year
Gross Fixed Assets	165,812,251	157,557,032	(890,528)	156,666,504	165,812,251		165,812,251
Accumulated Depreciation	(68,713,111)	(65,418,323)	652,221	(64,766,102)	(68,713,111)	47,800	(68,665,311)
Net Book Value	97,099,140	92,138,709	(238,307)	91,900,402	97,099,140		97,146,940
Average Net book Value	94,618,924				94,499,771		94,523,671
Working Capital Requirement	35,750,569				35,750,569		
Proposed Adjustment to OM&A						(400,000)	
Increase in Cost of Power						131,033	
Net change in Working Capital Requirement						(268,967)	35,481,602
Working Capital Allowance	4,647,574				4,647,574	10%	3,548,160
Rate Base	99,266,498				99,147,345		98,071,831

b) OM&A

Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to:

i. customer feedback and preferences;
ii. productivity;
iii. benchmarking of costs;
iv. reliability and service quality;
v. impact on distribution rates;
vi. trade-offs with capital spending;
vii. government-mandated obligations; and
viii. the applicant's objectives

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 4; Interrogatory 4-Energy Probe-25, Interrogatory 4-Energy Probe-29, Interrogatory 4-Staff-21

For the purposes of settlement, the Parties accept that the level of planned OM&A expenditures as agreed to is appropriate, as is the rationale for planning choices, and has been adequately explained giving due consideration to the items listed in i-viii above, subject to the qualifications set out below. The parties have given consideration to the matters of productivity and benchmarking of costs and are conscious of the Board's Decision in the matter of API's 2014 incentive rate-setting application; EB-2013-0110. In its Decision, the Board found that the PEG model, although applicable to the vast majority of distributors, may not apply to distributors that are particularly unique.[1] Further in its Decision, the Board indicated that it was providing

[1]Decision and Order, EB-2013-0110 dated February 20, 2014, page 7 & 8

Algoma with sufficient time to decide on the appropriate course of action for future incentive rate setting.[2] API is scheduled to apply for a form of incentive rate-setting in 2015 for rates effective January 1, 2016. In that application API will address productivity and benchmarking of costs.

Qualifications:

i) OM&A:

For the purpose of settlement, the Parties agree that Algoma Power will reduce its proposed 2015 OM&A expense of $12,704,879 by $400,000, resulting in a 2015 OM&A budget of $12,304,879.The Parties agreed on the adjustment based on an "envelope" approach, so that any determination of potential budget reductions to reflect the Board-approved 2015 OM&A will be at the discretion of Algoma Power.

ii) Amortization:

For the purpose of settlement, the Parties agree that Algoma Power will adjust its operating costs for the purpose of setting 2015 rates by reducing its proposed amortization expense in the Test Year by $47,800,representing the difference between the actual amortization expense for capital additions from 2011 through 2013 which was determined based on depreciation being calculated in the month following when an asset was placed in service and the amount that would have been calculated ifthe half-year-rule had been used.The evidentiary basis for the quantum of this reduction is Algoma Power's response to interrogatory 4-Energy Probe-25.

iii) Apprenticeship Tax Credit:

For the purpose of settlement, the Parties agree that Algoma Power will reduce its forecast 2015 income tax expense by $7,425 representing an Ontario apprenticeship training tax credit in the Test Year. The evidentiary basis for the quantum of this reduction is Algoma Power's response to interrogatory 4-Energy Probe-29.This tax credit is included in the determination of the test year income tax amount shown on line 6 of Table 1.

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[2] Decision and Order, EB-2013-0110 dated February 20, 2014, page 8

iv) Customer Feedback and Preferences: API will conduct an annual stakeholder session with the Algoma Coalition as described at Attachment "G".

Summary:

As a result of the qualifications set out above, the Parties accept that Algoma Power's 2015 operating costs for the purpose of setting 2015 rates is as shown below in Table 6.

Table 6. Contributions to Change to 2015 Operating Costs

	Applied-for $	Settlement $	Change $
OM&A Expenses	12,812,679	12,412,679	- 400,000
Amortization	3,947,009	3,899,209	- 47,800
Income Taxes (including other tax credits)	440,336	409,653	- 30,683
Total	17,200,024	16,721,541	- 478,483

REVENUE REQUIREMENT

i. Have all elements of the Base Revenue Requirement been appropriately determined in accordance with Board policies and practices?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 6; Interrogatory 6-Staff-30

For the purposes of settlement, the Parties accept that all elements of the Base Revenue Requirement have been appropriately determined in accordance with Board policies and practicesthat the Parties are aware of including, but not limited to, the Board's Filing Requirements and the RRFE. More specifically, in negotiating this Settlement Proposal the Parties were mindful of achieving the objectives set out in the RRFE, those being: customer focus; operational effectiveness; public policy responsiveness; and financial performance.

Changes to individual components of the revenue requirement have been noted and explained under sections 1a and 1b above.

ii. Has the Base Revenue Requirement been accurately determined based on these elements?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 6; Interrogatory 6-Staff-31

For the purposes of settlement, the Parties accept that all elements of the Base Revenue Requirement has been accurately determined in accordance with Board policies and practices including, but not limited to, the Board's Filing Requirements and the RRFE. As set out above, the Parties agree to Algoma Power's 2015 base revenue requirement in the amount of $22,837,756.

Further, for the purpose of settlement the Parties agree that Algoma Power's 2015 forecast other revenues used to set 2015 rates should be increased by $30,000 from $436,758 to $466,758.

The following table that illustrates the components of Algoma Power's base revenue requirement:

Table 7 Components of Revenue Requirement

	Applied-for		Settlement		Change	
	%	$	%	$	%	$
Rate Base		99,266,498		98,071,831		- 1,194,666
Cost of Capital	6.71%		6.71%		-	
Return on Rate Base		6,663,164		6,582,973		- 80,192
OM&A Expenses		12,812,679		12,412,679		- 400,000
Amortization		3,947,009		3,899,209		- 47,800
Income Taxes (including other tax credits)		440,336		409,653		- 30,683
2015 Service Revenue Requirement		23,863,189		23,304,514		- 558,675
Less Miscellaneous Revenue		436,758		466,758		30,000
2015 Base Revenue Requirement		23,426,431		22,837,756		- 588,675

LOAD FORECAST, COST ALLOCATION AND RATE DESIGN

i. Are the proposed customer classes, load and customer forecast, loss factors, CDM adjustments and resulting billing determinants an appropriate reflection of the energy and demand requirements of the applicant and its customers?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 3; Interrogatory Algoma Coalition #6, Interrogatory 3-Staff-19, Interrogatory 3-Energy Probe-13, Interrogatory 3-Energy Probe-15, Interrogatory 3-VECC-11, Interrogatory 3-VECC-16, Undertaking No. JT1.6, Undertaking No.JT1.7, Undertaking No. JT1.8

For the purposes of settlement, the Parties accept thatAlgoma Power's customer classes, load and customer forecast, CDM adjustments and resulting billing determinants as presented in the Application are an appropriate reflection of the energy and demand requirements of the Applicant and its customers, subject to the following qualifications:

Qualifications:

i) Load Forecast:

For the purposes of settlement, the Parties accept the customer and load forecast as was presented by API in response to undertakings JT1.6, JT1.7 and JT1.8 arising from the Technical Conference, of this proceeding, held on August 20, 2014.

Table 8, below, provides a comparison of the load forecast accepted by the Parties for the Proposed Settlement and that used in the original Application.

Table 8 Revised Test Year Forecast

Algoma Power Inc. Test Year Load Forecast			
	Per Undertakings	**Per Application**	**Change**
Retail kWh	2015 CDM Adjusted Load Forecast	2015 CDM Adjusted Load Forecast	
Residential - R1	105,791,701	104,826,589	965,112
Seasonal	7,731,414	7,680,066	51,348
Residential - R2	83,288,188	83,171,116	117,072
Street Lights	804,705	804,690	15
Total Customer (kWh)	197,616,007	196,482,461	1,133,546
kW	2015 CDM Adjusted Load Forecast	2015 CDM Adjusted Load Forecast	
Residential - R1	-		
Seasonal	-		
Residential - R2	198,901	198,897	4
Street Lights	2,380	2,380	0
Total Customer (kW)	201,281	201,277	4

Table 9 provides a clear definition of the test year forecast with respect of the adjustments made for CDM for each customer classification.

Table 9 Class Specific Adjustments to Load Forecast

Adjustment To Load Forecast
Algoma Power Inc.

Retail kWh	Weather Normalized 2015F (Elenchus)		CDM Load Forecast Adjustment	2015 CDM Adjusted Load Forecast
	A	C = A / B	E = D * C	F = A - E
R1 (kWh)	106,126,288	54%	334,587	105,791,701
Seasonal (kWh)	7,755,866	4%	24,452	7,731,414
R2 (kW)	83,551,603	42%	263,415	83,288,188
Street Lights (kW)	807,250	0%	2,545	804,705
Total Customer (kWh)	198,241,007	100%	625,000	197,616,007
	B		D	

kW	Weather Normalized 2015F (Elenchus)		CDM Load Forecast Adjustment *	2015 CDM Adjusted Load Forecast
	G	I = G / H	J = G / A * E	K = G - J
R1 (kWh)	-	0%		-
Seasonal (kWh)	-	0%		-
R2 (kW)	199,530	99%	629	198,901
Street Lights (kW)	2,388	1%	8	2,380
Total Customer (kW)	201,918	100%	637	201,281

Finally Table 10 is the detailed test year weather normalized customer and load forecast used for the rate design in the Proposed Settlement.

Table 10 Test Year Customer and Load Forecast

2015 Test Year Normalized Customer and Load Forecast Information

Customer Class Name	*2010 Actual*	*2011 Actual*	*2012 Actual*	*2013 Year End*	*2013 Normalized*	*Bridge Year 2014 Normalized*	*Test Year 2015 Normalized*
Customers and Connections							
Residential - R1	*8,031*	*8,082*	*8,166*	*8,306*	*8,306*	*8,432*	*8,559*
Seasonal	*3,538*	*3,453*	*3,405*	*3,298*	*3,298*	*3,191*	*3,084*
Residential - R2	*43*	*46*	*49*	*50*	*50*	*50*	*50*
Street Lighting (# of Connections)	*1,052*	*1,052*	*1,018*	*1,018*	*1,018*	*1,018*	*1,018*
TOTAL	*12,664*	*12,633*	*12,638*	*12,672*	*12,672*	*12,691*	*12,711*
Volumes in kWh							
	2010 Actual	*2011 Actual*	*2012 Actual*	*2013 Year End*	*2013 Normalized*	*Bridge Year 2014 Normalized*	*Test Year 2015 Normalized*
Residential - R1	*98,515,494*	*103,344,412*	*103,512,450*	*106,250,425*	*104,788,841*	*104,839,037*	*105,791,701*
Seasonal	*11,130,245*	*10,087,145*	*10,136,343*	*8,458,860*	*8,342,500*	*8,025,496*	*7,731,414*
Residential - R2	*70,938,155*	*75,394,032*	*79,423,076*	*83,700,857*	*83,416,121*	*83,425,900*	*83,288,188*
Street Lighting	*721,376*	*523,958*	*728,404*	*807,250*	*807,250*	*807,250*	*804,705*
TOTAL	*181,305,270*	*189,349,547*	*193,800,273*	*199,217,392*	*197,354,712*	*197,097,683*	*197,616,008*
Volumes in kW							
	2010 Actual	*2011 Actual*	*2012 Actual*	*2013 Year End*	*2013 Normalized*	*Bridge Year 2014 Normalized*	*Test Year 2015 Normalized*
Residential - R1							
Seasonal							
Residential - R2	*163,570*	*176,514*	*185,948*	*199,530*	*199,530*	*199,530*	*198,901*
Street Lighting	*Note: Street Ligting revenue in API is based on kWh.*						
TOTAL	*163,570*	*176,514*	*185,948*	*199,530*	*199,530*	*199,530*	*198,901*
	N/a	***2011 Actual***	***2012 Actual***	***2013 Actual***		***2014 Actual***	***2015 Board Calculation***
RRRP Adjustment Factor		2.500%	2.810%	3.750%		3.760%	0.790%
Transformer Ownership Allowance							
kW		*115,523*	*118,393*	*123,494*		*123,494*	*123,494*
$		*69,314*	*71,036*	*74,096*		*74,096*	*74,096*

Is the proposed cost allocation methodology including the revenue-to-cost ratios appropriate?

Status: No Settlement

Supporting Parties: N/A

Evidence: Exhibit 7; Interrogatory 7Staff32, Interrogatory 7Staff33, Interrogatory 7Staff34, Interrogatory 7-VECC-31, Interrogatory 7-VECC-33, Interrogatory 7-VECC-34, Interrogatory 7-VECC-35, Undertaking No. JT1.8

The Parties request that this issue be addressed by an oral hearing for the reasons set out above.

Are the Applicant's proposals for rate design appropriate?

Status: No Settlement

Supporting Parties: N/A

Evidence: Exhibit 8; Interrogatory 8-Energy Probe-35, Interrogatory 8-VECC-36, Interrogatory 8-VECC-37, Interrogatory 8-VECC-41

The Parties request that this issue be addressed by an oral hearing for the reasons set out above.

Is the Applicant's proposal for RRRP funding appropriate?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 8, Interrogatory 7-VECC-34, Interrogatory Algoma Coalition #4, Interrogatory Algoma Coalition #5, Interrogatory 8-Energy Probe-35, Interrogatory 8-VECC-36, Undertaking No. JT1.8

For the purposes of settlement, the Parties accept that Algoma Power's proposal for RRRP funding methodology is appropriate.API's electricity distribution rates for Residential Service Classification (both Residential R–1 and Residential R–2) are adjusted in accordance with Ont. Reg. 442/01. The electricity distribution rates for these classes are adjusted in line with the average of rate adjustments of select rate classes of other distributors in the most recent rate year, as calculated by the Board; the RRRP Adjustment Factor. The approved 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-2009-0278, dated November 11, 2010.

Shown below is the RRRP funding determination which has been excerpted from the API Proposed Settlement Rate Design Model accompanying this Proposed Settlement. The RRRP funding being requested in this Proposed Settlement Agreement is $13,964,040. This amount has been calculated using the Board's issued calculation of the 2015 RRRP Adjustment Factor of 0.79%.

Table 11 Calculation of the 2015 RRRP Funding Amount

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

2015 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
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%**
			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
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**

ii. Do the impacts of any rate change require mitigation?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 8, Tab 2, Schedule 12

Table 12 below has been determined on the basis of the rate design accompanying this Proposed Settlement Agreement. There are no total impacts which exceed 10 percent and therefore API is not proposing rate mitigation.

Table 12 Summary of 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%

ACCOUNTING

i. Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 1, Tab 1, Schedule 11

For the purpose of settlement, the Parties accept that all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and the rate-making treatment of each of these impacts is appropriate.

API uses the ASPE accounting standard and has done so since January 1, 2011. Previous to January 1, 2011, API used the CGAAP accounting standard. Pursuant to the Board letter of July 17, 2012, API has applied changes to the depreciation expense and capitalization policies effective January 1, 2013, consistent with the Board's regulatory accounting policy direction in that letter. These changes are reflected in API's 2013 Actuals, 2014 Bridge Year and 2015 Test Year results.

ii. Are the Applicant's proposals for deferral and variance accounts and their disposition appropriate?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 9, Undertaking No. JT1.4

For the purpose of settlement, the Parties accept Algoma Power's proposals for deferral and variance accounts and their disposition including the extension of the sunset date on the rate rider to dispose of the Seasonal Mitigation deferral account.

Algoma Power applied for the recovery of its Group 1 regulatory deferral and variance account ("DVA") balances as at December 31, 2013, with projected interest to December 31, 2014. The total of Group 1 accounts requested for disposition is a credit of $452,421. API also sought recovery of selected Group 2 and other DVA accounts including: a debit of $18,864 for OEB 1568, LRAM Variance Account; a debit of $760,467 for OEB 1574, Deferred Rate Impact Amounts; a credit of $1,850,564 for OEB 1576, Accounting Changes under CGAAP; and a credit of $446,778 for OEB 1592,PILs and Tax Variance for 2006 and Subsequent Years. These amounts, as well as their disposition timeframesare set out in the following table.

This Settlement Proposal will result in the following rate riders:

Residential Service Classification		
Rate Rider for Recovery of Stranded Meter Assets (2014) - effective until December 31, 2015	$	1.8800
Rate Rider for the Disposition of Deferral/Variance Accounts (2014) - effective until December 31, 2015	$/kWh	(0.0129)
Rate Rider for the Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2015	$/kWh	0.0201
Rate Rider for the the Recovery of Lost Revenue Adjustment (LRAM) - effective until December 31, 2015	$/kWh	0.0002
Rate Rider for the Disposition of Account 1575 & 1576 - effective until December 31, 2019	$/kWh	(0.0019)
Residential - R2 Classification		
Rate Rider for the Disposition of Deferral/Variance Accounts (2014) - effective until December 31, 2015	$/kW	(5.4026)
Rate Rider for the Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2015	$/kW	8.4104
Rate Rider for the the Recovery of Lost Revenue Adjustment (LRAM) - effective until December 31, 2015	$/kW	0.0029
Rate Rider for the Disposition of Account 1575 & 1576 - effective until December 31, 2019	$/kW	(0.7877)
Seasonal Customers Classification		
Rate Rider for Deferral/Variance Account Disposition - effective until June 30, 2019	$/kWh	0.0307
Rate Rider for Stranded Meter Assets (2014) - effective until December 31, 2015	$	2.30
Rate Rider for the Disposition of Deferral/Variance Accounts (2014) - effective until December 31, 2015	$/kWh	(0.0129)
Rate Rider for the Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2015	$/kWh	0.0201
Rate Rider for the Disposition of Account 1575 & 1576 - effective until December 31, 2019	$/kWh	(0.0019)
Street Lighting Service Classification		
Rate Rider for Deferral/Variance Account Disposition - effective until June 30, 2019	$/kWh	(0.0129)
Rate Rider for the Disposition of Global Adjustment Sub-Account (2014) - effective until December 31, 2015	$/kWh	0.0201
Rate Rider for the Disposition of Account 1575 & 1576 - effective until December 31, 2019	$/kWh	(0.0019)

OTHER

i Is the Applicant's proposal to seek recovery of the RRRP funding variance from the 2002 to 2007 period appropriate?

Status: No Settlement

Supporting Parties: N/A

Evidence: Exhibit 9, Tab 8; Interrogatory 9Staff41, Interrogatory 9-VECC43

The Parties request that this issue be addressed by oral hearing for the reasons set out above.