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BY EMAIL

January 30, 2013

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

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Algoma Power Inc.
2013 IRM3 Distribution Rate Application
Board Staff Submission
Board File No. EB-2012-0104

In accordance with the Notice of Application and Written Hearing, please find attached the Board Staff Submission in the above proceeding.

As a reminder, Algoma Power Inc.'s Reply Submission is due by February 13, 2013.

Yours truly,

Original Signed By

Martha McOuat
Project Advisor
Electricity Rates Applications

Encl.

Ontario

ONTARIO ENERGY BOARD

STAFF SUBMISSION

2013 ELECTRICITY DISTRIBUTION RATES

Algoma Power Inc.

EB-2012-0104

January 30, 2013

Board Staff Submission
Algoma Power Inc.
2013 IRM3 Rate Application
EB-2012-0104

Introduction

Algoma Power Inc. ("API") filed an application (the "Application") with the Ontario Energy Board (the "Board") on October 22, 2012 under section 78 of the *Ontario Energy Board Act, 1998*, seeking approval for changes to the distribution rates that API charges for electricity distribution, to be effective January 1, 2013. The Application is based on the 2013 3rd Generation Incentive Regulation Mechanism ("IRM") and also includes the impact of the Rural and Remote Rate Protection funding, pursuant to Ontario Regulation 442/01.

The purpose of this document is to provide the Board with the submissions of Board staff based on its review of the evidence submitted by API. Board staff's submission will address the following matters:

- Retail Transmission Service Rates ("RTSR") Adjustments;
- IRM and Rural and Remote Rate Protection ("RRRP") Adjustment Factors;
- Deferral and Variance Accounts ("DVAs");
- Smart Meter Cost Recovery; and
- Effective Date of the Rate Change.

RTSR Adjustments

API has completed the RTSR Workform to calculate its 2013 RTSRs. The Workform has been completed using the Uniform Transmission Rates ("UTRs") applicable to 2012, which were in effect at the time of API's application. Board staff notes that the Board has released its Decision in EB-2012-0031, approving UTRs effective January 1, 2013, as follows:

	As Filed (per kW)	**Approved 2013 UTRs (per kW)**
Network Service Rate	$3.57	$3.63
Line Connection Service Rate	$0.80	$0.75
Transformation Connection Service Rate	$1.86	$1.85

Board staff submits that API has appropriately completed the RTSR Workform, and expects that API will incorporate these updated UTRs as part of the Draft Rate Order process. Board staff asks that API confirm this in its reply submission.

IRM and RRRP Adjustment Factors

API filed its Application on the basis of the Filing Requirements for 3rd Generation IRM, modified to accommodate the requirements of the RRRP as contemplated in O.Reg. 442/01. Electricity Distribution rates for API's R-1 and R-2 rate classes are adjusted in line with the provincial average of rate adjustments for the Residential and General Service < 50kW rate classes approved by the Board in the most recent rate orders for other Ontario electricity distributors. API's Seasonal and Street Lighting rates are adjusted in accordance with the price cap adjustment index established by the Board for third generation IRM applicants. API has used a RRRP adjustment factor of 2.81% for the R-1 and R-2 rate classes, and acknowledges that this factor will be updated for the Draft Rate Order.

For the purposes of adjusting its 2013 revenue requirement, API used an IRM adjustment of 0.88%, consisting of a GDP-IPI of 2.2%, an X-factor of 0.72% and a stretch factor of 0.6%. Board staff notes that the GDP-IPI of 2.2% is consistent with that announced for those distributors under IRM that have a rate year commencing January 1, 2013.The stretch factor is consistent with the Board's letter to Licensed Electricity Distributors dated November 28, 2012. Board staff submits that API has appropriately calculated the adjustment to its revenue requirement for 2013.

Subject to the comments related to API's Smart Meter Cost Recovery below, Board staff submits that API has calculated the rate adjustments for its R-1, R-2, Seasonal and Street Lighting rate classes in accordance with the methodology approved in the EB-2011-0152 proceeding for API's 2012 IRM.

Deferral and Variance Accounts

API proposed to recover a debit balance of $228,285 for its Group 1 DVAs over a twelve-month period.

API initially proposed separate threshold calculations for its Group 1 and Global Adjustment balances. In its EB-2011-0152 Decision, the Board had explicitly reminded API that the EDDVAR report requires that the threshold calculation should apply to all Group 1 Account balances. In response to Board staff interrogatory #3, API submitted an updated threshold calculation, which included all Group 1 accounts and incorporated certain adjustments to the account balances, which are discussed below.

As API did not request disposition of its Global Adjustment Deferral Sub-account in its 2012 IRM rates application, as it was undertaking modifications to its billing system to allow it to separately identify non-RPP customers. The Board directed API to file an application to dispose of its Global Adjustment sub-account balance by June 1, 2012. API had shown 2012 disposition amounts for the Global Adjustment account in its continuity tables as originally filed, which were deducted from the balance for disposition in 2013. API confirmed in response to Board staff interrogatory #3 that it had not filed the application directed by the Board, and revised its continuity tables to reflect that no dispositions had taken place in 2012.

API has included a residual balance for disposition of Account 1590 of ($204,834). The Board approved disposition of several of API’s deferral accounts through its Account 1590 in EB-2007-0744. Rate riders were established in this proceeding to recover the balance over two years, commencing on January 1, 2009 and ending on December 31, 2010.

Board staff notes that the 2008 closing balance (principal and interest) in Account 1590 as shown in the continuity tables is ($899,952). API’s Draft Rate Order in EB-2007-0744 contains a balance as at December 31, 2008 of ($1,007,195). Board staff also notes that API’s continuity tables include a transaction in Account 1590 of $87,359 in 2011, subsequent to the approved recovery period. Board staff requests that API provide a reconciliation of the 2008 balance as filed to the 2008 balance provided in the Draft Rate Order in EB-2007-0744, as well as a clarification of the 2011 transaction in its reply submission.

Board staff notes that the DVA continuity tables in API's IRM model contained certain inconsistencies between the 2011 balances and those provided in its RRR filings. In response to Board staff Interrogatory #6, API responded that the discrepancies relate to the 2011 fixed price and global adjustment true-up calculations submitted in 2012, which were shown in the "Other Adjustments during Q4 2011" column in the model. In the updated continuity tables provided in response to interrogatories, API made additional adjustments to the 1588 Power and Global Adjustment sub-accounts, resulting in an additional net credit difference from the RRR balances of ($31,165). API states that these adjustments relate to "the portion of additional corrections in API's Motion to Vary the Board's Decision on API's 2012 IRM application, that were calculated and remitted to the IESO via former Form 1598 Reporting in Jan 2012".

Board staff notes that the 2010 closing principal balances as submitted in API's original and revised continuity tables are consistent with the 2010 closing balances approved by the Board in API's Motion to Vary the 2012 IRM Decision. The 2010 balances were approved on a final basis. Board staff requests that API clarify what year the additional adjustment of ($31,165) is related to in its reply submission.

Subject to the clarifications requested above, Board staff submits that based on the threshold test calculation of $0.001 per kWh, the threshold for disposition of API's Group 1 DVAs balances has been met and Board staff supports API's request to dispose of these balances over one year.

Smart Meter Cost Recovery

Smart Meter Costs

API has applied to the Board to recover the costs incurred to implement smart meters. API's Smart Meter Cost Recovery application, EB-2012-0285, was submitted on June 15, 2012. On July 17, 2012, API requested, and the Board approved, that the application be held in abeyance and combined with API's 2013 rate application.

API's application, as adjusted in response to interrogatories, requested the recovery of a net deferred revenue requirement to December 31, 2013 of $1,743,027 and a 2013 incremental revenue requirement of $635,123. Board staff identified certain discrepancies in the smart meter model submitted by API. In response to interrogatories, API filed an updated model to correct inputs related to tax rates and rate of return to reflect API's Board-approved parameters for 2007 to 2010, as well as to calculate interest on a monthly, rather than an annual basis. On January 28, 2013, API filed a further update to this model to reflect the Board approved capital structure for 2007 to 2010. The revised total net deferred revenue requirement is $1,752,033. Board staff takes no issue with the inputs as shown in the revised model.

The average costs by rate class and meter type, incorporating actual 2012 and forecast 2013 costs, as well as costs beyond minimum functionality, are summarized as follows[1]:

	1S	*2S*	*3S*	*9S*	*12S*	*16S*	*35S*	***Total***	***Cost Per Meter***
Residential	587	2,482,651	128,330	-	3,009	4,156	-	**2,618,733**	369.10
Seasonal	3,523	1,254,392	32,510	-	-	-	-	**1,290,426**	363.71
GS<50	1,174	225,891	171,106	72,338	6,619	56,110	16,044	**549,282**	578.80
Total	**5,285**	**3,962,934**	**331,946**	**72,338**	**9,628**	**60,266**	**16,044**	**4,458,441**	384.61
	1S	*2S*	*3S*	*9S*	*12S*	*16S*	*35S*	***Total***	***Cost Per Meter***
R1	1,762	2,708,542	299,436	72,338	9,628	60,266	16,044	**3,168,015**	393.84
Seasonal	3,523	1,254,392	32,510	-	-	-	-	**1,290,426**	363.71
Total	**5,285**	**3,962,934**	**331,946**	**72,338**	**9,628**	**60,266**	**16,044**	**4,458,441**	384.61

For comparison purposes, the Board's report, Sector Smart Meter Audit Review Report, dated March 31, 2010, indicates a sector average capital cost of $186.76 per meter (based on 3,053,931 meters with a capital cost of $570,339,200 as from January 1, 2006 to September 30, 2009). The corresponding average total cost per meter (capital and OM&A) is $207.37 from the data in that report.

Board staff notes that the Board followed up on this review on October 26, 2010 and

[1] EB-2012-0104, API Response to VECC IR #6c)

issued a letter to all distributors requiring them to provide information on their smart meter investments on a quarterly basis. The first distributors' quarterly update represented life-to-date investments in smart meter implementation as of September 30, 2010 and, as of this date, the average total cost per meter for reporting Ontario LDCs was $226.92.[2]

Board staff submits that the Board, in its consideration of other applications made by Ontario's electricity distributors, has taken into account the operating, socio-economic, and environmental characteristics of each distributor in assessing the reasonableness of incurred costs[3]. There are distributors for which the per-meter documented costs are closer to API's per meter costs; in these cases, there are characteristics not dissimilar to those of API including distance, low density, topology and vegetation.[4]

Board staff notes that API's per-meter costs are above the average calculated to date; however they are below the average for Hydro One Networks (based on the limited data available).[5] API's smart meter evidence in EB-2012-0285 describes the unique aspects of its service territory, specifically with regard to its expanse of approximately 14,200 square kilometers; its rural and rugged terrain with dense vegetation; and its low customer density of 6.3 customers per kilometer of line, or 0.8 customers per square kilometer. Page 27 of that evidence describes the similarities and differences between API's and Hydro One's smart meter challenges. Board staff notes that API's most significant cost category relates to collectors.

API's smart meter application describes its collaboration with the District 9 ("D9") consortium in the Planning and Procurement stages of the Smart Meter Project. Board staff notes that API participated in the London Hydro RFP process as a member of the D9 consortium, as well as collaborating with its affiliates to share IT development costs.

[2] Monitoring Report Smart Meter Investment – September 2010, March 3, 2011
[3] Decision and Order, EB-2011-0143
[4] e.g. Sioux Lookout Hydro (EB-2012-0245) and Atikokan Hydro (EB-2011-0293).
[5] In Appendix A of the Board's Decision with Reasons EB-2007-0063, issued August 8, 2007, with respect to the combined smart meter proceeding, the Board documented the per meter cost for the 13 applicant utilities then authorized for smart meter deployment. For "urban" distributors for which data was available, the per meter costs ranged from $123.59 to $189.96, while Hydro One Networks' costs were estimated at $479.47. The cost information in the combined smart meter proceeding is informative, but reflects an early stage of smart meter deployment, and so must be used with caution. However, similar patterns and ranges for utilities serving urban areas as those observed in Appendix A of the Decision with Reasons EB-2007-0063 have been observed in more recent cases in which smart meter costs have been considered.

Board staff also notes that the costs submitted by API represent audited costs to December 2011. Actual 2012 and forecast 2013 costs represent approximately 4% of the total capital costs incurred.

Further, it is noted that API has included $131,390 in capital costs beyond minimum functionality for MDMR integration and TOU rate implementation, as well as ODS implementation. Board staff takes no issue with the documented costs related to the "beyond minimum functionality" aspects of its smart meter program.

Board staff submits that API has acted in accordance with the regulations in its processes for the procurement of smart meters and associated equipment and for services to install and operate the smart meters and associated equipment. API has provided adequate explanation for the challenges within its service territory and the impact on overall costs. As such, Board staff considers that the documented historical costs and the forecasted costs are prudent.

Cost Allocation

Through its interrogatory #8, VECC requested that API provide separate revenue requirement models by rate class. API responded that it had provided such a calculation in its original rate application. In that schedule, API allocated Total Return on Capital, Amortization and PILs amounts by class as a proportion of total Smart Meter Costs for all classes. OM&A costs, Smart Meter Funding Adder Revenues and Carrying Charges were allocated based on the number of meters installed by class as a proportion of total meters installed. Board staff notes that smart meter costs should normally be assigned to the different rate classes to reflect the differences in meter cost for each rate class, generally resulting in a higher rate rider for the GS <50kW class than that assigned to the Residential class.

In its response to VECC interrogatory #8e) API states that Residential and GS <50kW customers are both contained within API's R-1 service classification, and that the costs are pooled together to calculate one common disposition rider. Board staff submits that, under these circumstances, the calculation of a separate revenue requirement and resulting rate riders for Residential and GS <50kW customers is not necessary.

Cost Recovery through RRRP

API proposes to allocate the smart meter costs applicable to its R-1 customer class directly to its R-1 revenue requirement for the purposes of calculating RRRP funding. These costs are related to historical smart meter cost recovery net of Smart Meter Funding Adder revenues received ("the SMDR amounts"), as well as the 2013 incremental revenue requirement associated with smart meter implementation ("the SMIRR amounts"). In other words, API proposes not to fully recover these amounts from its R-1 customers through the SMDR and SMIRR rate riders, which has been the practice of smart meter cost recovery approved by the Board for all other LDCs to date, but to recover the total amounts largely from provincial ratepayers.

API states in its evidence that the additional revenue requirement arising from smart meter implementation will have two adverse effects on its customers: first, the distribution rates will increase beyond the average of other utilities' increases in the most recent year; and second, the R-1 class will pay for smart meter implementation twice: once through indexation related to other utilities' rates that have increased their distribution rates to recover their own smart meter costs, and again through a separate smart meter rate rider.

Board staff notes that in its EB-2009-0278 Decision, related to API's 2010 and 2011 cost of service rates proceeding, the Board approved certain changes to the calculation of rate adjustments under RRRP[6]. The Board determined that RRRP rate adjustments would be calculated using changes to other distributors' base rates only (i.e. Monthly fixed charge and Distribution Volumetric rate), and would not include the effect of rate riders or rate adders, regardless of whether any rate riders or adders were intended to recover revenue requirement items. Board staff submits that while the revenue requirement associated with smart meters may be incorporated into certain distributors ' base rates through cost of service applications, it is Board staff's understanding that most distributors are continuing to recover this revenue requirement through SMIRR rate riders, which will remain in effect through the remainder of each such distributor's IRM term. Further, the impacts of the SMDRs are not reflected in the provincial average. Under these circumstances, the provincial average rate impact is lower than it

[6] EB-2009-0278 Decision, page 5

would have been otherwise (i.e. API's customers would not be paying for the average of most other distributors smart meter costs through their RRRP-adjusted rates).

That said, Board staff submits that in the spirit of O. Reg. 442/01, it may be appropriate for the Board to consider socializing a portion of these smart metering costs. Board staff notes that the smart meter program is a mandated provincial initiative, which has resulted in significant costs to API. As noted above, due to the unique circumstances in API's service territory, the costs incurred to implement smart meters are well above the provincial average and would produce significant rate increases for API's customers. Board staff submits that allowing partial recovery of API's smart meter costs through RRRP funding would allow its customers to benefit from the implementation of this provincial program at comparable costs to those of other provincial ratepayers.

Board staff submits that, in the event the Board decides to allow API to recover some of its smart meter costs through RRRP funding, it would be appropriate to revise the calculation of the RRRP adjustment to incorporate the average for provincial utilities <u>including</u> smart meter cost recovery. As noted above, the RRRP adjustment is based on the percentage change of other distributors' base rates only, and does not include rate riders. In this case, the calculation of the provincial average increase applicable to API's 2013 rates should incorporate SMDR and SMIRR rate riders applicable to other distributors in addition to base rates, to ensure that the rates paid by API's customers are more comparable to those of other provincial ratepayers. This treatment would also be consistent with the manner in which the costs of other distribution assets and operating expenses are borne by API's R-1 and R-2 rate classes.

Alternatively, the Board could adopt the proposal set forth by API.

Board staff also notes that API adjusted its 2013 revenue requirement to include the total SMDR and SMIRR proposed amounts. Board staff submits that this treatment is appropriate for the SMIRR since this rate rider is an annual incremental adjustment to the revenue requirement. However, API proposes to recover its total SMDR amount of approximately $1.7 million through the RRRP from provincial ratepayers in one year. Board staff notes that API has calculated its rate riders for its Seasonal rate class to recover its SMDR over 4 years, and suggests that similar mitigation measures should be considered for provincial ratepayers. Board staff suggests that it would be appropriate for the Board to consider recovery of the portion of the SMDR amount applied to the RRRP over a two-year period until API's next cost of service proceeding.

Effective Date of the Rate Change

Board staff notes that API filed its 2013 IRM application on October 22, 2012 while Chapter 3 of the filing requirements indicates that distributors that are seeking rate adjustments effective January 1, 2013 were required to file their IRM application by August 3, 2012. Board staff also notes that API did not provide any reasons for their inability to meet the deadline. As a result, notwithstanding the fact that API's existing rates were declared interim as of January 1, 2013, Board staff submits that the effective date of the rate change should be the 1st of the month following the issuance of the Board's Decision in this proceeding.

- All of which is respectfully submitted –