Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2011-0293

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 Atikokan Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2012.

BEFORE: Paul Sommerville
Presiding Member

Marika Hare
Member

DECISION AND ORDER
June 18, 2012

Introduction

Atikokan Hydro Inc. ("Atikokan") filed an application (the "Application") with the Ontario Energy Board (the "Board") on September 30, 2011 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 Atikokan charges for electricity distribution, to be effective May 1, 2012. The Board assigned the Application file number EB-2011-0293.

On October 24, 2011, the Board issued a letter to Atikokan identifying certain additional evidence that needed to be filed before the Board would consider the Application. Atikokan filed the requested additional evidence on December 14, 2011.

The Board issued a Notice of Application and Hearing dated December 22, 2011. The

Vulnerable Energy Consumers Coalition ("VECC") applied for intervenor status and cost eligibility. No objections were received. The Board determined that VECC would be granted intervenor status and is eligible to apply for an award of costs under the Board's *Practice and Direction on Cost Awards*.

In its Notice of Application and Hearing, the Board indicated its intention to consider the Application by way of a written hearing. The Board issued Procedural Order No. 1 on January 13, 2012. In Procedural Order No. 1, the Board allowed for an initial round of discovery through written interrogatories.

Board staff filed its interrogatories on January 31, 2012, and VECC filed its interrogatories on February 3, 2012. On February 23, 2012 Atikokan filed a letter requesting a six day extension for filing its interrogatory responses. The Board responded by way of a letter issued on February 24, 2012 granting an extension to February 29, 2012. Atikokan filed its interrogatory responses on March 2, 2012.

On March 16, 2012, the Board issued Procedural Order No. 2. In Procedural Order No. 2, the Board allowed for a supplementary round of interrogatories and responses, to be followed by submissions from parties.

In accordance with Procedural Order No. 2, Board staff and VECC filed supplementary interrogatories on March 28, 2012. Atikokan filed its responses on April 11, 2012.

Atikokan filed its Argument-in-Chief ("AIC") on April 20, 2012. Board staff and VECC filed submissions on May 4 and May 9, 2012, respectively. Atikokan Hydro filed its Reply Submission on May 24, 2012.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Effective Date for New Rates;
- Rate Base and Capital Expenditures;
- Operating Revenues and Load Forecast;
- Operating Expenses;
- Cost of Capital;
- Cost Allocation;

- Rate Design;
- Deferral and Variance Accounts;
- Smart Meters;
- Rate Mitigation;
- Other Matters; and
- Implementation.

Effective Date for New Rates

In its Application, Atikokan requested an effective date for rates of May 1, 2012. In Procedural Order No. 2, issued March 16, 2012, the Board made Atikokan's current approved rates interim pending a determination in this proceeding.

While Atikokan filed its Application at the end of September 2011, there was a delay in the commencement of the proceeding as the Application was incomplete, specifically with respect to the proposed disposition of Accounts 1562 and 1592. Atikokan filed additional evidence in mid-December, 2011. A further delay arose as Atikokan requested, and was granted an extension to respond to the first round of interrogatories and a supplementary round of interrogatories was necessary to complete the record.

Neither Board staff nor VECC opposed Atikokan's proposed effective date of May 1, 2012. Recognizing that it would not have the Board's final Rate Order in time for May 1st implementation, Atikokan submitted that it would prepare an appropriate rider that will enable it to recover the incremental revenue requirement for the period commencing May 1st and concluding on the date preceding the implementation date of the new Rate Order, as part of its draft Rate Order to be filed following the issuance of this Decision.

Board Findings

The Board is concerned that some applicants do not consider seriously the timelines prescribed by the Board for filing applications. The Board's letter of March 1, 2011 clearly indicated that distributors must file no later than August 26, 2011 for rates to become effective on May 1, 2012. Atikokan filed more than a month late and filed an application with key information missing. This resulted in a further delay before the Application could be considered. As a result, the Board has determined that Atikokan's new rates will become effective the closest month following the issuance of this Decision; that is, July 1, 2012.

Rate Base and Capital Expenditures

In its Application, Atikokan Hydro proposed a 2012 test year rate base of $2,913,786. Through interrogatories, Atikokan Hydro revised the rate base to $3,041,625. The increase of $127,838 is a result of the following:

- An increase in the net book value of fixed assets of $34,914 due to restatement of the 2011 bridge year according to MIFRS instead of CGAAP;
- An increase of $6,784 in the working capital allowance, due to recognition of $45,229 of OMERS expenses omitted in the initial Application; and
- Reclassification of certain smart meter-related assets from computer hardware to meters as a result of a review of smart meter costs, increasing the net fixed assets by $86,140.[1]

The following table, provided in VECC's submission, summarizes Atikokan's rate base for historical, bridge and test years:

Description	2008 OEB-Approved	2008 Actual	2009 Actual	2010 Actual	2011 (CGAAP)	2012 (CGAAP)	2012 (MIFRS)
Gross Fixed Assets	5,032,491	4,621,076	4,804,897	5,169,638	5,239,138	5,750,922	5,750,922
Accumulated Depreciation	2,483,926	2,691,084	2,830,723	2,936,882	3,117,804	3,319,549	3,250,890
Net Book Value	2,548,565	1,929,992	1,974,174	2,232,756	2,121,334	2,431,373	2,500,032
Average Net Book Value	2,363,115	1,941,283	1,952,083	2,103,465	2,177,045	2,477,949	2,529,279
Working Capital Base	2,512,539	2,635,828	2,705,895	2,913,853	3,172,906	3,415,637	3,415,637
Working Capital Allowance	376,881	395,374	405,884	437,078	475,936	512,346	512,346
Rate Base	2,739,996	2,336,658	2,357,967	2,540,543	2,652,981	2,990,294	3,041,625

Atikokan filed evidence in support of its capital expenditures, including an Asset Management Plan, for historical, bridge and test years, in accordance with the Board's filing requirements.

In its submission, Board staff observed that Atikokan shows volatility in its capital spending from year to year. Board staff submitted that volatility can be expected, particularly for a small utility, due to the "lumpiness" of spending on major assets, like a bucket truck. However, Board staff took no issue with Atikokan Hydro's 2012 test year rate base, as revised.

In contrast, VECC submitted that the rate base be reduced by an amount ranging from $8,000 to $30,000. VECC noted that Atikokan's major capital expenditures were on

[1] Atikokan Hydro, AIC, April 20, 2012, pp. 6-7

vehicles and buildings. VECC also noted that Atikokan's customer base has seen no growth while experiencing a significant loss of load. While Atikokan can derive revenues from non-distribution work (i.e. contracting out), the revenue forecast for non-distribution revenues is declining.

VECC submitted that Atikokan's 2012 forecast for Account 1940 – Tools and Garage Equipment is three times previous annual amounts, and questioned the capital expenditure of $8,500 for Account 1908 – Buildings and Fixtures. VECC also submitted that about $20,000 of customer hardware and software expenditures were questionable based on Atikokan's response to VECC IR # 4.

In reply, Atikokan accepted VECC's submission with respect to the reduction of $8,500 for Account 1980 – Buildings and Fixtures. While stating that the roof of the administrative building is in need of repair, Atikokan has agreed with its affiliate, Atikokan Enercom, with whom it shares the building, that Atikokan Enercom will incur the expenditure.

Atikokan submitted that its historical expenditures on vehicles and buildings were necessary, and that it has been attempting to prolong the useful life of assets; however there comes a time when expenditures are necessary. Atikokan noted that the new garage was necessitated as the existing garage could not accommodate the size of the new bucket truck. Atikokan submitted that the $20,000 of computer hardware and software for 2012 are related to the security audit, and that existing computer equipment is over six years old and a failure would result in the loss of essential data supporting customer service.

Board Findings

The Board accepts the rate base of $3,033,125 - that being the requested amount of $3,041,625 minus the $8,500 reduction agreed to by Atikokan in its reply submission, subject to any adjustments to the Working Capital Allowance necessitated by the Board's determinations on the approved operating expenses elsewhere in this Decision. The Board finds that this amount is reasonable and that the Asset Management Plan supports its planned capital expenditures.

The Board, however, agrees with the concerns expressed by VECC that Atikokan is spending a large amount on buildings, furniture and trucks compared to the distribution plant spend. Given the declining customer base it is the Board's view that Atikokan must be more efficient in prioritizing and utilizing its capital resources. The volatility in spending identified by Board staff is also a concern to the Board. The Board expects Atikokan to identify ways to mitigate this volatility. For example, Atikokan may wish to consider pursuing sharing opportunities with other utilities with respect to equipment which may not be necessary on an on-going basis.

Working Capital Allowance

Atikokan Hydro has used the default 15% formula, whereby the Working Capital Allowance ("WCA") is calculated as 15% of the sum of the cost of power plus controllable expenses. In response to interrogatories, Atikokan Hydro updated the WCA to reflect the HOEP and RPP commodity rates documented in the Board's October 17, 2011 *Regulated Price Plan* Report as well as that change in OM&A for OMERS expense increases, as documented above.

Both Board staff and VECC submitted that one option would be to reduce the WCA factor to 13%, which the Board has announced as being the default, in the absence of a lead-lag study or other evidence, for rates applications for the 2013 test year. In support of its proposal, Board staff noted that Atikokan already bills all customers on a monthly basis, and as such has an average service lag shorter than that for most other distributors and that would support a lower factor.

Atikokan opposed the submissions of Board staff and VECC. Atikokan reiterated that it had followed the Board's Filing Requirements in making its Application. It also submitted that there was no evidence that the 13% WCA factor would be appropriate and that applying the new default of 13%, applicable to applications for 2013 rates going forward, would be arbitrary and inappropriate.

Board Findings

The Board notes that, in the absence of a lead-lag study, the default for Working Capital Allowance for 2012 cost of service applicants is 15%. While this may be generous for Atikokan due to its monthly billing cycle, there is no evidence to suggest any other percentage other than the Board default of 15%. The Board will therefore approve a WCA factor of 15%, as identified in the 2012 Filing Guidelines.

Operating Revenues and Load Forecast

Load Forecast

Atikokan Hydro used a 2012 test year forecast of 25,592,783 purchased system kWh and 23,593,125 billed kWh. Atikokan proposed no changes in its load forecast or its customer/connection forecast during the course of the proceeding. The customer/connection forecast was based on historical information. For the load forecast, Atikokan used a regression-based approach that is common in the Ontario sector. This approach relates demand/load to key determinants such as population, economic activity, weather-related variables, and conservation and demand management factors. The relationship is estimated through statistical regression techniques, and the forecast is derived from the estimated model for the test year period. Finally, Atikokan made external adjustments to the 2011 bridge and 2012 test year forecasts to reflect the phase-in of the CDM targets that Atikokan is required to achieve by 2014 as a condition of its distribution licence.

Board staff noted that Atikokan's approach is a standard one which the Board has accepted in the past. However, Board staff noted one anomaly with the results arising from the fact that Atikokan's proposed model had to take into account the permanent loss of an Intermediate class customer in 2008. Ignoring the historical load of that customer, Atikokan's system consumption has been flat, ignoring the impacts of weather. Board staff submitted that an alternative model, based on a response to VECC IR # 8 c), which removed the historical load for the departed Intermediate customer, may be more reasonable. In response to Board staff IR # 59, this alternative model would give a purchased system forecast of 25,003,092 kWh and a billed forecast of 23,276,163 kWh, a difference of (1.34%).

Board staff submitted that this load forecast may be more realistic as it is based on Atikokan's customer mix now and expected into the foreseeable. Board staff also noted that, while the slightly lower load forecast would have an upward impact on rates, the lower forecast from the VECC model would be more conservative, in posing a lower risk of over-forecasting and affecting the utility's cash situation, while the lower volumetric allocation from Atikokan's fixed/variable split (addressed later in this Decision) would constrain the impacts of slightly higher volumetric rates. VECC disagreed with Board staff's submission, noting that the loss of the Intermediate customer was dealt with through a "class flag". VECC submitted that Atikokan's model, which accounted for the loss of the Intermediate customer via a binary variable, was a better predictor based on an *ex post* comparison for actuals and forecasts.

Board staff noted that Atikokan has documented a trend for lower average annual consumption per streetlighting connection. As streetlighting is an unmetered service, the average consumption is estimated based on a sample of temporarily metered devices and equipment profiles. Board staff submitted that Atikokan's responses to interrogatories on this estimated trend were confusing were unclear and anomalous, as there has been no reduction in the number of streetlights and unclear evidence on what if any energy efficiency initiatives have been undertaken for streetlights. Board staff submitted that Atikokan needs improved data and analysis with respect to streetlighting consumption for its next cost of service application.

VECC raised a concern with respect to Atikokan's estimate of 0.2 GWh of CDM savings in 2012, noting that Atikokan documented no savings in 2011, and about 0.1 GWh of 2012 is supposed to represent the persistence from 2011 CDM programs. However, VECC did not propose any adjustment on the condition that Atikokan establish an LRAM variance account as required by the Board's recently issued *Guidelines for Electricity Distributor Conservation and Demand Management* [EB-2012-0003], issued April 26, 2012.

Atikokan agreed with VECC's submission regarding the higher R-squared and forecasting ability of its original model, and submitted that this should be approved notwithstanding that it produced a higher forecast. Atikokan agreed to comply with the CDM guidelines as proposed by VECC.

Board Findings

The Board finds that the lower forecast submitted in response to VECC IR # 8 c) and Board staff IR # 59 results in a more accurate result, given the loss of the Intermediate customer and little prospect of new customer load. The Board therefore finds a load forecast of 25,003,092 purchased system kWh and 23,276,163 billed kWh as being reasonable. The Board also accepts the customer forecast and the CDM adjustment. It should be noted that Atikokan did not find that it had a material amount of CDM up to and including 2011. The CDM reductions that relate to its CDM license conditions have been reflected in the approved load forecast.

Atikokan will implement a LRAM variance account as set out in the Guidelines.

With respect to the analysis and documentation of the street lighting load, the Board agrees with Board staff's suggestion that improved data is required with the next cost of service application.

Other Revenues

In its Application, Atikokan forecasted Other Operating Revenues of $125,235 for the 2012 test year.[2] In response to various interrogatories, Atikokan explained the volatilities and the drivers on year-over-year differences.

Board staff took no issue with Atikokan's estimate for Other Operating Revenues. VECC submitted that Other Operating Revenues should be increased by $550 for anticipated revenues from MicroFIT service charges. In reply, Atikokan accepted VECC's submission to revise Other Operating Revenues to $125,785.

Board Findings

The Board accepts as reasonable the projected revenue offsets of $125,235 which is the forecast proposed by Atikokan in its Application. The adjustment suggested by VECC due to MicroFit revenues is considered by the Board to fall well below the materiality threshold, and accordingly the Board will not recognize or adopt it.

Operating Expenses

Atikokan forecasted $1,175,151 for Operations, Maintenance and Administration ("OM&A") expenses for the test year. This represents a 45.25% increase over its 2008 Board-approved OM&A of $809,045. Atikokan's OM&A over time is documented below:

Year	2008 Board approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge year forecast	2011 unaudited Actual (VECC IR # 15)	2012 Test Year forecast	2012 Test Year forecast (revised)
OM&A	$809,045	$845,024	$881,683	$1,000,713	$974,277	$948,775	$1,175,151	$1,220,380

Source: Exhibit 4/Tab 1/Schedule 1/page 1/Table 4.1, VECC IR # 15 and AIC/pages 8-10

[2] Exhibit 3/Tab 1/Schedule 2/page 2/Table 3-1

Atikokan revised the OM&A amounts during the discovery phase, with the major difference being an increase in OM&A of $45,229 related to OMERS expense increases. Board staff and VECC submitted that this adjustment was appropriate.

Atikokan explained that the major drivers for the remaining increases in OM&A for 2012 are:

- Change in capitalization policy to be consistent with MIFRS, implemented in 2010;
- Increased expenses due to smart meter and TOU implementation;
- Staffing changes, to hire a lineman apprentice to replace a retiring lineman;
- Regulatory costs, an increase of $50,000 representing ¼ of expected incremental costs associated with the current Application; and
- General and Administrative Salaries and Management Salaries and Expenses.

Board staff acknowledged that these are generally necessary and reasonable increases, but noted that the utility is faced with the real situation that there is no growth in customers or demand. In fact, in 2008, Atikokan lost its Intermediate customer, representing 40% of its demand. Board staff noted that Atikokan already has higher OM&A costs per customer compared to peer utilities, and that its proposed OM&A would increase this further. In Board staff's view, Atikokan's OM&A should be reduced to about $1.1 million, or approximately 10% from that requested, which would allow for recovery of the costs such as the increases in OMERS pension expenses, and ¼ of regulatory expenses; however, Atikokan's management would be incented to seek productivity improvements to manage its costs in line with no growth in customers or demand and the high OM&A costs per customer.

VECC submitted that it had similar concerns as those expressed by Board staff. VECC noted that Atikokan's OM&A per customer was $434 in 2010, proposed to increase to $531, while the average for its cohort was $381. VECC submitted that a 2012 OM&A in the range of $1.025 to $1.065 million should be sufficient.

In reply, Atikokan disagreed with the submissions of Board staff and VECC. Atikokan noted that:

> Throughout the Application and particularly in the deficiency descriptions, Atikokan had indicated that it faces significant challenges to operate at existing rate levels. Preliminary work on its audited 2011 financial statements showed a significantly greater loss than forecast in the current Application ($85,000).

> Revenue in both the Residential and GS<50 kW classes was down in both fixed and volumetric service charges, and revenue for these classes as compared to 2010 would be down by $102,992. … Atikokan will need to increase its rates or decrease its costs to continue to be viable. … Atikokan is faced with rising costs for many items including operating the smart meters, with the same or fewer customers to bear those costs.[3]

Noting that its completed 2011 Audited Financial Statements showed billing costs of $132,193 rather than the preliminary number of $156,366, Atikokan submitted that a revised 2012 OM&A of $1,209,149 is necessary, and that the increase in the OM&A over historical expenses is needed to operate the utility going forward.

Board Findings

The Board notes that Atikokan's 2011 Audited Financial Statements are not on the record in this proceeding, although the unaudited information is. The Board will therefore not take into account the reduction proposed by Atikokan.

The Board agrees with the concerns expressed by VECC and Board staff with respect to the increase and the total amount of Atikokan's proposed OM&A budget. As shown in the evidence, on a per customer basis Atikokan's spend is significantly higher (almost 40%) than other distributors in its cohort. Coupled with a declining customer base and load, this is of great concern to the Board with respect to the resulting rates. Atikokan must increase its efforts to look for efficiency improvements and reduce its OM&A spending. The Board will not micromanage the distributor's business by identifying where reductions should be made, whether in employee complement and compensation, regulatory costs or elsewhere. On an envelope basis the Board approves an OM&A budget approximately 15% lower than proposed, being $1,030,000. This represents approximately a 3% increase over 2011 expenditures.

Depreciation Expense

Atikokan has estimated a depreciation expense of $168,793 for the 2012 Test Year, as submitted in response to Board staff interrogatory #70.

[3] Reply Submission, pages 16-17, May 24, 2012

Board staff noted in its submission that Atikokan has followed the *Accounting for Municipal Electric Utilities in Ontario* and the *2006 Electricity Distribution Rate Handbook*, and has adjusted the depreciation rates for various classes of assets in accordance with the change to IFRS. Board staff took no issue with the proposed depreciation expense, but noted that it may need to be updated as a result of this Decision should the Board make any findings on depreciation expense that deviate from Atikokan's proposals. Board staff submitted that Atikokan should provide adequate documentation in its draft Rate Order filing to support any update to the depreciation expense resulting from this Decision.

VECC took issue with the values for the useful lives of assets used by Atikokan in the Application, and submitted that Atikokan should be required to use the typical useful lives found in the Kinectrics Study.

In reply, Atikokan submitted that adopting the typical useful lives from the Kinectrics Study would result in increased depreciation expense, as the economic lives of transformers would shorten without offsetting increases in other asset categories. Atikokan submitted that the useful lives proposed in the Application are reflective of the actual useful lives of assets in Atikokan's service territory.

Board Findings

The Board accepts the depreciation expense of $82,116 as being reasonable. While greater explanation for the departure from the values suggested in the Kinectrics Study would have been helpful, the Board notes the immaterial difference in depreciation between what Atikokan has proposed and the results had the Kinectrics Study been used. The Board sees no need for an updated Capital Asset Continuity Schedule given its decision on rate base and capital expenditures.

VECC's submission is based on the following analysis:

Account	Description	Average UsefulLifeofIndividualComponentsassumedin theApplication	Depreciation Expense	Average TypicalUsefulLifeofIndividual Components (Kinetrics)	Depreciation UsingKinetrics TypicalUseful Lives	Difference
1820	DistributionStation Equipment<50kV	45	$14,660	50	$14,353	($307)
1830	Poles,Towers& Fixtures	45	$62,485	45	$62,485	$0
1850	LineTransformers	45	$4,971	40	$6,789	$1,818
	Total		$82,116		$83,627	$1,511

As can be seen, there is no difference for Account 1830. For the other accounts, the differences are partially offsetting. In both cases, the 45 years assumed by Atikokan is well within the ranges between the minimum and maximum useful lives from the Kinectrics Study, which covers 91% of the observed data from their study – in other words, assuming a normal distribution curve, 91% of the time, the useful life of that category of assets would be between the minimum and maximum. The Kinectrics Study is not formatted by account, but rather to reflect an even more detailed representation of specific capital components of a category. Thus, DS equipment will have the steel grid structure, cabinet boxes, reclosers, transformers, grounding equipment, relays, etc., all with their own life distributions and typical useful lives. The 45 years proposed by Atikokan is well within the range in the Kinectrics Study. There is no statistical evidence to differentiate between what Atikokan has proposed and the typical useful lives in the Kinectrics Study. VECC's submission is that Atikokan has got it wrong, but they have not provided any empirical evidence to support that position. On the Board's analysis any statistical test would not show a significant difference based on the data documented in the Kinectrics Report. In accepting Atikokan's approach in the particular circumstances of this case the Board should not be seen as modifying in any degree its direction respecting the importance of the Kinectrics study as an integral element in the reflection of a utility's plant.

Low-income Energy Assistance Plan (LEAP)

Atikokan proposed that an expense amount for LEAP equal to $2,000 (as the greater of $2,000 or 0.12% of 2012 distribution revenues dependent on the Board's Decision), should be incorporated in the proposed OM&A. Board staff submitted that Atikokan Hydro's proposal is compliant with Board policy.

Board Findings

The proposed expense of $2,000 for LEAP is consistent with Board policy and is included in the envelope amount of $1,030,000 for OM&A approved earlier in this Decision.

Taxes/PILs

In its Application, Atikokan proposed a grossed-up PILs expense allowance of $17,914. This amount is subject to adjustment for the updated cost of capital, in addition to changes in capital and operating expenses, and possibly other factors, as determined by the Board. In the updated RRWF filed in response to Board staff supplemental IR # 78, Atikokan Hydro documented an updated grossed-up PILs expense of $14,087.

Board staff took no issue with the methodology, as amended through discovery, and submits that Atikokan should use this approach in its draft Rate Order to calculate any updated allowance for taxes/PILs to reflect the Board's Decision. Atikokan concurred with this in its reply submission.

Board Findings

The Board approves a PILs proxy of $14, 087 subject to updating at the time of the draft Rate Order and based on the methodology Atikokan has used to calculate its tax/PILs allowance for 2012.

Green Energy Plan

Atikokan submitted a basic Green Energy Act Plan ("GEA Plan") as part of its Application and proposed no expenditures under its GEA Plan.

Atikokan's basic GEA Plan notes upstream constraints in the transmission system in northwestern Ontario which would limit connection of additional generation. Within Atikokan's own distribution system, the utility has noted design constraints that would limit connections of microFIT generation with capacities of 5 to 10 kW; redesign and rebuilding of the distribution network would be required to overcome these constraints.[4] The utility has noted that there is limited uptake of microFIT within its network.[5]

The review letter from the OPA on Atikokan's GEA Plan, provided as an attachment to the GEA Plan, expressed no concerns with Atikokan's GEA Plan.

Board staff took no issue with Atikokan Hydro's proposed GEA Plan.

Board Findings

The Board has reviewed Atikokan's proposed GEA Plan, and has no issues with it in light of the circumstances and explanations provided.

Cost of Capital

As originally filed, Atikokan used an estimated Cost of Capital of 6.49%, based on a deemed capital structure of 60% debt (56% long-term debt and 4% short-term debt) and 40% equity. It used the then-current Return on Equity ("ROE") of 9.58% and deemed short-term debt rate of 2.08%, which were the Cost of Capital parameters for 2011 applications with May 1, 2011 effective dates as announced in the Board's letter of March 2, 2011. Atikokan acknowledged that these parameters would be updated with data three months in advance of the proposed effective date of May 1, 2012 for its new rates, in accordance with the methodology documented in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009 (the "Cost of Capital Report").

On March 2, 2012, the Board issued a letter documenting updated Cost of Capital parameters for rates effective May 1, 2012. The updated Cost of Capital parameters are:

Cost of Capital Parameter	**Rate**
Return on Equity	9.12%
Deemed Short-term Debt	2.08%
Deemed Long-Term Debt	4.41%

With its update to Board staff supplemental IR # 78 filed on April 11, 2012, Atikokan reflected the updated Cost of Capital parameters in calculating its revenue requirement.

[4] Response to Board staff IR # 4
[5] Response to VECC IR # 8 a)

With the ROE and short-term debt rates, and a change in the weighted average long-term debt rate addressed below, the weighted average cost of capital became 6.09% versus 6.49% as originally applied for.

Board staff submitted that Atikokan's proposal for its Cost of Capital complies with the Cost of Capital Report and with Board policy and practice, but noted that Atikokan, in its Argument-in-Chief, provided an updated and lower weighted average cost of long-term debt to that filed in its original Application, and requested that Atikokan explain the lowered average debt rate in its reply submission. VECC supported Board staff's submission.

In reply, Atikokan documented that it had updated the debt rate applicable to the long term debt with the Town of Atikokan to correspond with the deemed rate of 4.41%.

Board Findings

The Board finds that Atikokan's proposal for the cost of capital, as amended, complies with the Board's policy and practice. Accordingly, the cost of capital parameters applicable to Atikokan's 2012 revenue requirement shall be:

Parameter	**% Capitalization (Deemed)**	**Rate (%)**
Long-term Debt (Weighted Average)	56%	4.22%
Deemed Short-term Debt	4%	2.08%
Return on Equity	40%	9.12%
Weighted Average Cost of Capital	100%	6.09%

Cost Allocation

As part of its Application, Atikokan conducted an updated Cost Allocation study between all customer classes with the following results:[6]

Revenue-to-Cost Ratios - 2010 IRM and 2012 Proposed

Customer Class	Low	High	2010 IRM	2012 Cost Allocation	2012 Proposed	2012 Cost Allocation (revised per VECC IR # 5 a) and c)	2012 Proposed (revised per VECC IR # 5 a) and c)
Residential	85.0%	115.0%	101.0%	97.6%	98.1%	97.3%	97.3%
General Service < 50 kW	80.0%	120.0%	100.0%	134.8%	120.0%	128.8%	120.0%
General Service > 50 kW	80.0%	180.0%	80.0%	82.3%	82.3%	89.0%	90.6%
Streetlighting	70.0%	120.0%	70.0%	75.0%	98.1%	75.8%	90.6%
Sentinel Lighting	70.0%	120.0%	70.0%				
Unmetered Scattered Load	80.0%	120.0%	80.0%				

In its response to VECC interrogatory # 5, Atikokan revised its originally proposed revenue to cost ratios for 2012 and proposed to:

- Decrease the GS<50 kW ratio to 120%, as originally proposed;
- Increase both the GS>50 kW and Street Lighting ratios to 90.6% (in order to maintain the same overall revenues as a result of the first change above); and
- Hold the Residential ratio unchanged at 97.3%

In the subsequent years (2013 and 2014), Atikokan proposed to maintain the same values for each customer class' revenue to cost ratio.

VECC and Atikokan submitted that Atikokan's proposed cost allocation, as revised in response to the interrogatory from VECC, was consistent with the Board's policy and practice, and should be approved.

Board Findings

The Board accepts Atikokan's proposed cost allocation ratios for 2012, as amended in response to VECC's interrogatories, that being:

Customer Class	2012 Revenue-to-Cost Ratios
Residential	97.3%
GS < 50 kW	120.0%
GS > 50 kW	90.6%
Streetlighting	90.6%

[6] Exhibit 7/Tab 1/Schedule 2/page 3/Table 7-3

Rate Design

Elimination of Unmetered Scattered Load ("USL") and Sentinel Lighting Classes

Atikokan proposed to eliminate the USL and Sentinel Lighting Classes on the basis that it no longer has any customers in these classes and has no forecast of any new customers in the foreseeable future. The proposed elimination of these two customer classes is reflected in the load forecast and cost allocation of the proposed revenue requirement and rates.

No parties opposed Atikokan's proposal, but Board staff submitted that, should Atikokan serve any new USL customers in the future, these customers would be included in the GS < 50 kW class. Atikokan agreed with Board staff's submission in its reply submission.

Board Findings

The Board approves the elimination of two rate classes, the unmetered scattered load class and the Sentinel Lighting class, on the basis that these are no longer necessary, with no customers in either class. Should any new USL customers become customers of Atikokan, these customers are to be treated as customers in the GS < 50 kW class.

Fixed/Variable Splits

Atikokan proposed to retain the existing fixed/variable split for all remaining customer classes, as documented in Table 8-3 of its Application. Board staff observed that Atikokan's current split is approximately 80% fixed and 20% variable for each class, and that this split results in higher bills for lower consumption customers but more rate stability for the utility. As such, Board staff took no issue with Atikokan's proposal.

VECC submitted that, where Atikokan's existing Monthly Service Charge ("MSC") was above the ceiling, the MSC should be maintained at the current level. VECC noted that the MSC for the GS < 50 kW and GS > 50 kW classes are currently above their respective ceilings, and will likely remain so as a result of the Board's Decision. VECC submitted that Atikokan's proposal to increase the MSC proportionally to the fixed/variable split even where the existing MSC was above the ceiling was contrary to the Board's policy as stated in the November 2007 *Report of the Board – Application of Cost Allocation for Electricity Distributors* (EB-2007-0667):

> The Board does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC. Distributors that are currently above this value are not required to make changes to their current MSC to bring it to or below this value at this time.[7]

In reply, Atikokan rejected VECC's submission, referencing the Board's decision with respect to Hydro One Brampton Networks Inc.'s 2011 cost of service application:

> The Board accepts HOBNI's proposed MSC which maintains the current fixed/variable proportions. The Board notes that this is consistent with other decisions in which it has approved applications to increase MSC that were already above the cost allocation ceiling, provided that the increase would not result in a higher revenue from the fixed charge relative to the volumetric charge.[8]

Board Findings

The Board approves maintaining the existing percentage split between fixed and variable rates of about 80/20 on the grounds that, for a utility the size of Atikokan, this protects the utility from significant variability in revenues. As noted in Atikokan's reply submission, this is consistent with previous decisions of the Board where the current fixed/variable proportions were maintained.

Retail Transmission Service Rates ("RTSRs")

Atikokan proposed to update its RTSRs consistent with Board-approved Uniform Transmission Rates ("UTRs"). In response to an interrogatory from VECC,[9] Atikokan proposed revised RTSRs reflecting the Board-issued RTSR model and 2012 UTRs approved by the Board in January 2012.

[7] *Report of the Board: Application of Cost Allocation for Electricity Distributors* [EB-2007-0667], November 28, 2007, pages 12-13
[8] Decision and Order [EB-2010-0132], April 4, 2011, page 38
[9] Response to VECC interrogatory # 22

No parties opposed Atikokan's revised RTSRs.

Board Findings

The Board approves Atikokan's proposed 2012 RTSRs as amended in response to VECC's interrogatory. The revised proposal is consistent with Board policy and practice.

Transformer Ownership Allowance ("TOA") Credit

In its Application, Atikokan proposed a TOA credit of $0.17/kW. In response to an interrogatory from Board staff,[10] Atikokan revised its proposal to a credit of $0.24/kW, representing a credit equal to 10% of the proposed volumetric rate for the GS > 50 kW class, in compliance with the Board's decision with respect to Atikokan's 2006 rates application (RP-2005-0020/EB-2005-0335). In response to a supplementary interrogatory from VECC,[11] Atikokan submitted that the credit of $0.24/kW was its preference, but submitted that the TOA credit of $0.31/kW, corresponding to the avoided cost from its cost allocation study, was preferable.

Board staff concurred with Atikokan's revised proposal of the $0.31/kW credit. VECC concurred with Atikokan's proposal to base the TOA credit on the results of the cost allocation study, but submitted that the cost allocation study updated through discovery would result in a TOA credit of $0.29/kW. VECC submitted that the TOA credit should be based on the cost allocation model that reflects the revenue requirement and load forecast as determined by the Board in this Decision. Atikokan agreed with VECC's submission.

Board Findings

The Board approves a TOA credit of $0.29/kW as a fixed rate and agrees that this more closely corresponds to the avoided cost.

[10] Response to Board staff interrogatory # 21
[11] Response to VECC supplemental interrogatory # 6

Loss Factors

In its Application, Atikokan proposed updated to its loss factors as follows:

Description	Loss Adjustment Factor
Supply Facility Loss Factor	1.0045
Distribution Loss Factors	
Secondary Metered Customer < 5000 kW	1.0730
Secondary Metered Customer > 5000 kW	1.0623
Primary Metered Customer < 5000 kW	1.0778
Primary Metered Customer > 5000 kW	1.0671

For a Secondary Metered Customer with demand < 5000 kW, the current Board-approved Total Loss Factor is 1.0753.

Both VECC and Board staff submitted that Atikokan's proposed loss factors should be approved, but also expressed concern with the level of the loss factors. VECC expressed concern about the historical increase in loss factors and submitted that Atikokan be "put on notice" that the loss factor issue will be followed-up on in the utility's next cost of service application.

Board staff acknowledged Atikokan's response to an interrogatory regarding factors that contribute to its increased loss factors, but also submitted that there is no empirical data supporting the assumed 3% loss on Atikokan's 44 kV lines running from Hydro One Networks Inc.'s Moose Lake Transformer Station. Noting that Atikokan's staff will have more available time since they are no longer engaged in most meter reading with the implementation of smart meters, Board staff submitted that Atikokan's staff should be directed to investigate and implement cost-effective methods of reducing losses within the utility's distribution system. Board staff submitted that Atikokan "be directed to file a report on capital and operations and maintenance activities undertaken to address line losses and to conduct a review of non-technical losses, and the results of these, in the utility's next cost of service application."

In its reply submission, Atikokan reiterated that the methodology used to update its loss factors complies with Board policy and practice. However, in consideration of the submissions of Board staff and VECC, Atikokan stated its willingness to file a report on capital and operations and maintenance activities which will address line losses and to review non-technical losses in its next cost of service application.

Board Findings

The Board accepts the proposed Total Loss Factors (e.g. 7.78% for a secondary metered customer < 5,000 kW), but is concerned about these high loss factors. The Board's policy on the level of losses required applicants to file a plan on reducing losses if the distribution loss factor is at or above 5%. Atikokan's proposed distribution loss factor for a secondary metered customer < 5,000 kW is 7.3%. The Board directs Atikokan to investigate measures to reduce losses and to have empirical data available in its next cost of service filing to explain the level of losses and what has been done to reduce losses. The Board notes that Atikokan, in its reply submission, indicated agreement to conduct such a review and provide the results in the next cost of service application.

Deferral and Variance Accounts

Disposition of Group 1 and Group 2 DVA balances

In its Application dated September 30, 2011, Atikokan filed the Deferral and Variance Continuity Schedule for the deferral and variance accounts ("DVA") balances as at December 31, 2010. During the proceeding, Atikokan provided updated DVA balances in responses to interrogatories.

In its submission Board staff documented the current DVA balances in the table below. Accounts 1555 and 1556 are excluded from the table as the disposition of smart meters costs and funding adder revenues is dealt with separately.

Atikokan Group 1 and Group 2 DVA Balances

Group 1 DVA Accounts

Account Description	Account Number	Principal ($)	Interest ($)	Total Claim ($)
RSVA – Wholesale Market Service Charges	1580	- 36,935	14,276	- 22,659
RSVA – Retail Transmission Network Charge	1584	8,273	765	9,038
RSVA – Retail Transmission Connection Charge	1586	34,957	13,411	48,368
RSVA – Power (Excluding Global Adjustment)	1588	- 5,710	8,256	2,546
RSVA – Power (Global Adjustment Sub-account)	1588	9,626	59	9,685
Recovery of Regulatory Asset Balances	1590	1,274	- 640	634
Group 1 DVA Total		**11,485**	**36,127**	**47,612**

Group 2 DVA Accounts

Account Description	Account Number	Principal ($)	Interest ($)	Total Claim ($)
Other Regulatory Assets - OEB Cost Assessments	1508	9,061	924	9,985
Other Regulatory Assets - Pension Contribution	1508	137,278	11,776	149,054
Retail Cost Variance Account - Retail	1518	6,879	157	7,036
Retail Cost Variance Account - STR	1548	20,293	601	20,894
Input Tax Credit	1592	15,210	221	15,431
Group 2 DVA Total		**188,721**	**13,679**	**202,400**
Special Purpose Charge	1521	1,592	138	1,730
Total of Group 1 and Group 2 DVAs, including Account 1521		201,798	49,944	251,742

As part of the rate mitigation plan in its Application, Atikokan proposed to defer the disposition of all Group 1 and Group 2 DVA, except for Smart Meter accounts 1555 and 1556, until it files an IRM application for the 2013 rate year.

Board staff submitted that Atikokan's 2013 IRM rate application proceeding would not be an appropriate forum for the Board to review the Group 2 DVA balances, since they require a review for prudence, and may require closer examination that would lengthen the review of the IRM application as a whole. Board staff also noted "that there is a concern with Atikokan's financial viability if the DVA balances are not disposed in this proceeding … given the [material] debit balance. The recovery for the amounts related to Atikokan's 2010 DVA balances may help enhance Atikokan Hydro's cash flow given the debit balance of the Group 1 and Group 2 accounts."

In reply, Atikokan submitted that this matter is more related to Atikokan's proposed rate mitigation approach.

Board Findings

The Board will not defer clearing of the Group 1 and Group 2 DVA balances. According to the Board's policies, these are appropriately reviewed in a cost of service application. In order to mitigate the rate impact, collection of these accounts shall be over a 46 month period, ending on April 30, 2016.

In subsequent issues dealt with in this Decision, the Board has made findings that will alter the balances of the DVAs which are being approved for disposition. In its draft Rate Order Filing, Atikokan should propose, with adequate documentation, rate riders to dispose of the Group 1 and Group 2 DVA balances, as revised in this Decision.

Disposition of 2008 and 2009 Group 1 DVA balances

In its Decision EB-2010-0064 regarding Atikokan Hydro's 2011 IRM rates application, the Board accepted Atikokan Hydro's proposal to address the disposition of the 2008 and 2009 Group 1 Deferral and Variance Account balances. Despite the Board's direction that no new rate riders would be required to recover the 2009 Group 1 account balances and that Atikokan Hydro should track the 2009 account balances at the account level, Atikokan Hydro incorrectly transferred the 2009 Group 1 account balances to Account 1595 – Disposition and Recovery of Regulatory balance sub-account.[12]

Through interrogatories, Board staff asked Atikokan to confirm if it had tracked the residual balance (i.e. the difference between the 2008 interim balances versus the 2008 final balances, and the 2009 account balances) at the account level per the Board Decision EB-2010-0064. Board staff also asked Atikokan to update its DVA continuity schedule to reflect the Board's direction in its EB-2010-0064 Decision. In response to Board staff interrogatories, Atikokan stated that it misinterpreted the Board's Decision (EB-2010-0064) regarding the treatment of 2008 and 2009 account balances. Atikokan subsequently updated the continuity schedule on April 11, 2012.

Board staff submitted that the revised DVA continuity schedule filed on April 11, 2012 correctly reflects the Board Decision in EB-2010-0064. Board staff further submitted that any variances between the reported RRR and December 31, 2010 DVA balances are immaterial. In its Reply Submission, Atikokan agreed with Board staff's submission.

[12] Atikokan's Deferral and Variance (DVA) continuity schedule, September 30, 2011

Board Findings

The Board confirms that the Group 1 DVA balances for 2008 and 2009 as revised in the response to the Board staff interrogatory filed on April 11, 2012 correctly reflect the Board's prior decision, and are final for the purposes of disposition.

Account 1508 – OEB cost assessments and OMERs

Atikokan recorded a debit principal balance of $9,985 for the OEB cost assessments in Account 1508 sub-account Other Regulatory Assets Cost Assessment for the period of 2006 to 2009. Atikokan also recorded a debit principal balance of $149,054 for pension costs contributions to OMERS in Account 1508 sub-account OMERS for the period of 2006 to 2011, for an aggregate total of $159,039. Atikokan confirmed that the costs for OEB cost assessments and pension costs contributions to OMERS were not included in Atikokan's 2008 Cost of Service rate application, as would have been the normal treatment, and therefore were not recovered in the 2008 rates.

In response to interrogatories, Atikokan has confirmed that it has now included the 2012 OEB Cost Assessment and the OMERS cost in its 2012 operating expenses to be recovered through its 2012 distribution rates.

The submissions of Board staff and VECC both dealt with the issue of the recovery of the prior year amounts given the accounting error treatment of these prior period amounts. Board staff submitted that the Board has options of disallowing the recovery, as these were for prior period amounts, or of allowing the recovery, considering the impact on Atikokan's financial situation.

VECC submitted that both the utility and the Board were partially accountable for the error, stating that the regulatory accounting rules can be onerous and confusing for small utilities and that the Board is resourced with staff to monitor the accounting reporting of utilities and should have identified the accounting errors prior to this Application. VECC suggested that one option would be to allow partial recovery. Atikokan should be allowed to recover amounts except for amounts that would have been allocated to GS > 50 kW and the single Intermediate customers which have departed Atikokan's service territory.

In its reply submission, Atikokan submitted that it should be allowed to recover the full amounts. In the alternative, Atikokan submitted that VECC's proposal may be reasonable.

Board Findings

The Board denies the request for OMERS contributions for the period 2006 to 2011 and OEB cost assessments for the period 2006 to 2009 as being out of period. The Board categorically rejects VECC's submission that the Board is partially responsible for this omission because its accounting rules are unduly onerous and confusing for small utilities. The Board notes that the inclusion of these expenses as distribution expenses was dealt with as far back as the 2006 EDR process, where Tier 1 adjustments moved the historical 2004 test year data to a more typical year for the purposes of setting rates for 2006. If a utility availed itself of Tier 1 adjustments, then all such adjustments had to be made. The Tier 1 adjustments included adjustments for OEB cost assessments and other regulatory agency fees, and for OMERS pension contributions.[13] The Board notes that Atikokan made use of certain Tier 1 adjustments in its 2006 EDR application [RP-2005-0020/EB-2005-0335], and these were approved by the Board.

Regulatory costs were also dealt with in the Board's decision with respect to Atikokan's 2008 rates application. The Board's decision states:

> **Account 1508**
>
> Board staff noted that the Applicant had requested disposition of a debit balance of $70,091 in account 1508 in its original application, but subsequently withdrew this request. This amount represents the balances in sub-account OEB Cost Assessments and sub-account OMERS Pension Contributions for the period up to April 30, 2006. Board staff noted that this account was closed after the 2006 EDR proceeding.[14]

The Board notes that there have been interactions between Atikokan and the Board's Regulatory Accounting and Audit staff to assist the utility's staff on accounting matters.

The Board finally notes that, while regulatory accounting can be a complicated process, accounting errors and revisions are rarely as extensive with other utilities, even those of

[13] RP-2004-0188: Report of the Board, page 11-12, and *2006 Electricity Distribution Rate Handbook*, page 10, both May 11, 2005
[14] Decision and Order [EB-2008-0014], page 20, August 21, 2008

similar size to Atikokan. In the end, Atikokan's management must take responsibility for understanding and adhering to the rules and guidelines of operating in this regulated sector.

***Account 1592 – Sub-account HST/OVAT Input Tax Credit*s**

Atikokan has documented $15,431 in Account 1592 Sub-account HST / OVAT Input Tax Credits (ITCs) as of December 31, 2010. Of this amount, 50% or $7,716 is refundable to Atikokan's ratepayers.

Board staff submitted that Atikokan had not reflected the credit balance refundable to ratepayers of $7,716 in the DVA continuity schedule, but should do so. In reply, Atikokan agreed with Board staff's submission. Atikokan filed an updated DVA continuity schedule reflecting this in its Reply Submission.

Board Findings

The Board approves the incorporation of the Account 1592 Sub-account HST/OVAT Input Tax Credits balance of December 31, 2010 of a credit of $7,716 in the DVA account balances being considered for disposition in this proceeding.

Account 1562 – Deferred PILs

The current proceeding is the Board's first prudence review of Atikokan's evidence related to the disposition of its account 1562 deferred payments in lieu of taxes ("PILs"). The PILs evidence filed by Atikokan in this proceeding included tax returns, financial statements, Excel models from prior applications, calculations of amounts recovered from customers, SIMPIL Excel worksheets and continuity schedules that show the principal and interest amounts in the account 1562 deferred PILs balance.

In pre-filed evidence, Atikokan applied to recover from customers a debit balance of $20,141 consisting of a principal amount of $15,001 plus related carrying charges of $5,140. In response to interrogatories, Atikokan filed amended evidence that reflected a recovery of $29,597 consisting of a principal amount of $21,696 plus related carrying charges of $7,901. Atikokan submitted that it had revised its Account 1562 PILs Continuity Schedule to reflect the collection of Board-approved PILs beginning May 1, 2002.

Noting that Atikokan's unbundled distribution rates did not come into effect until market opening on May 1, 2002, Board staff queried Atikokan for regulatory references to support starting the PILs entitlements earlier than May 1, 2002, and asked whether Atikokan had considered that its entitlement to the 2001 and 2002 PILs proxy should not begin before May 1, 2002 given the delay caused by filing a revised 2002 application.

In response to Board staff IR # 76, Atikokan provided a revised Account 1562 PILs Continuity Schedule, which assumed that collection of the approved PILs began May 1, 2002 and explained why its proposed treatment was appropriate.

In its submission, Board staff stated that Atikokan voluntarily chose to implement unbundled rates including the first and second tranches of MARR, and PILs tax expense, on May 1, 2002 and, as such, Board staff submitted that Atikokan should pro-rate its PILs tax proxy entitlements in the same time period as it billed its customers for the changed unbundled rates. Board staff also observed that Atikokan did not pay any PILs to the Government for the period 2001 through 2006 as evidenced by Ministry of Finance Notices of Assessment filed in this proceeding. Board staff provided its derivation of the amount and estimated that the principal amount to be recovered from Atikokan's ratepayers to be $8,222, plus carrying charges to April 30, 2012 of $2,260, for a total amount of $10,482.

Atikokan replied that it did not agree with Board staff's submission, but that it was aware of the Board's decisions in other recent applications accepting Board staff's proposal. Concurring that it did not actually pay PILs for the period from 2001 Q3 to 2006, Atikokan stated its acceptance of the proposed amount of $10,482 (principal plus interest).

Board Findings

The Board accepts that the principal balance of Account 1562 – deferred PILs to be disposed shall be $8,222, plus interest to April 30, 2012 of $2,260. Atikokan should include this amount in the Group 1 and Group 2 DVA balances to be recovered through rate riders resulting from this Decision.

Smart Meters

In its Application, Atikokan sought disposition and recovery of costs incurred with full deployment of smart meters to all of its Residential and GS < 50 kW customers. Atikokan proposed a uniform SMDR of $3.54/metered customer/month for 36 months.

Board staff noted that Atikokan used its own model originally. Board staff requested that Atikokan review its costs and use the Smart Meter Model Version 2.17 issued by the Board along with Guideline G-2011-0001: *Smart Meter Funding and Cost Recovery – Final Disposition,* issued on December 15, 2011. In its response to Board Staff Interrogatory #38, Atikokan filed a revised version of the Board's Smart Meter Model that indicated the uniform SMDR should be $3.78/metered customer/month for 36 months. As part of its response, Atikokan revised its evidence. In particular, capital costs were changed, mostly with reclassification of some costs from computer hardware to meters. More significantly, the deferred OM&A expenses increased from about $150K to $225K. Explanations were provided in responses to Board staff interrogatories.[15]

Board staff noted that the Board's Guideline states that applicants should address the cost allocation of smart meter costs and whether class-specific smart meter rate riders are warranted. In response to Board staff IR # 42, Atikokan calculated class-specific SMDRs as follows:

- Residential: $3.66/customer/month for 36 months;
- GS < 50 kW: $4.17/customer/month for 36 months; and
- GS > 50 kW: $7.29/customer/month for 36 months.

In its reply submission, Atikokan submitted that these class-specific SMDRs were preferable to a uniform SMDR.

Board staff stated that Atikokan's claimed costs were higher than the Board has seen to date, with the exception of Hydro One Networks Inc. However, Board staff noted that per meter costs can be higher for smaller utilities, that may not be able to realize economies of scale and may face topographical and forestation factors that may increase costs for reliable smart meter communication and operation. Board staff expressed more concern with Atikokan's OM&A costs for smart meters, noting that the

[15] See responses to Board staff IR # 39 and supplementary IR # 66

claimed cost recovery would amount to $45.27 per year, or about $3.75 per month solely for recovery of deferred OM&A costs, and that this is higher than what the Board has seen to date.

While there were two rounds of discovery, the OM&A costs were increased by 50% in the initial interrogatory responses. Board staff submitted that there was “insufficient support on the record about the nature of the products and services for the requested cost levels”[16] claimed by Atikokan, and suggested a disallowance of 20%, to bring costs close to about $350 per meter (the maximum that the Board has seen to date) could be considered.

VECC concurred with Board staff regarding the high level of Atikokan’s capital and operating costs for smart meters. However, VECC submitted that Board staff’s 20% reduction proposal was arbitrary, and suggested that Atikokan’s costs be set at the average of the costs for its cohort. Noting that these costs are not known at this time, as an alternative VECC suggested an allowance of 50% of the proposed costs, with the remainder being dependent on the review of smart meter costs of the cohort utilities or an audit of the costs of Atikokan’s smart meter program.

In its reply, Atikokan noted the concerns expressed by Board staff and VECC. It reassessed its incremental OM&A costs. Atikokan noted that there is a cost of $2,100 per month to Thunder Bay Hydro for CIS/billing services, necessitated by a new billing system to support smart meters and TOU pricing. Atikokan submitted that this cost could be argued as being more appropriately billing costs rather than smart meter costs, and Atikokan stated that it was willing to forego recovery of these costs from 2009 to 2011. This would reduce the incremental OM&A for the SMDR calculations from $224,107 to $148,607, and would give the resulting class-specific SMDRs:

- Residential: $2.39/customer/month for 36 months;
- GS < 50 kW: $2.81/customer/month for 36 months; and
- GS > 50 kW: $5.38/customer/month for 36 months.

Board Findings

The Board agrees with the concerns raised by Board staff and VECC in their submissions. The significant increases in the smart meter costs identified in responses

[16] Board staff submission [EB-2011-0293], page 38, May 4, 2012

to interrogatories is concerning. Considering that Atikokan's smart meter costs were reviewed, albeit not in the context of a detailed review of the prudence of all costs, in the context of an application for an increased Smart Meter Funding Adder in mid-2010 [EB-2010-0185], the Board expected more detailed evidence on smart meter costs in this Application.

The Board will accept VECC's proposal and allow for recovery of 50% of the requested smart meter costs at this time. The Board will direct the Regulatory Accounting and Audit branch of the Board to conduct an audit of Atikokan's smart meter costs. The results of the audit will be considered by the Board with respect to the final amounts to be authorized for recovery in a future application to be filed by Atikokan no later than 6 months from the completion of the subject audit.

Stranded Meters

Atikokan proposed a Stranded Meter Rate Rider ("SMRR") of $0.39 per month, to be effective for a period of three years, to recover the net book value of $23,375 for conventional meters stranded through replacement by smart meters.

Board staff took no issue with the amount which Atikokan was proposing to recover nor with Atikokan's proposal that the SMRR would be uniform for all applicable customer classes. However, Board staff noted that the SMRR is recoverable solely from those classes, typically Residential and GS < 50 kW, for which conventional meters became stranded as a result of replacement by smart meters, and requested that Atikokan confirm the applicable classes in its Reply Submission.

Atikokan confirmed that smart meters were also deployed to the GS > 50 kW class, and submitted that the SMRR should be recoverable from all metered customers as proposed.

Board Findings

The Board approves the SMRR of $0.39 per month, to be collected from Residential, GS < 50 kW and GS > 50 kW customers over a period of 36 months, as proposed. The recovery period will be from July 1, 2012 to June 30, 2015.

Other Matters

Transition from CGAAP to MIFRS

As documented in Board staff's submission, Atikokan stated that the balance for closing net Property, Plant and Equipment ("PP&E") between CGAAP and MIFRS is a credit balance of $34,002. Atikokan proposed to amortize the balance over a four year period. As a result, the annual amortization amount is a credit balance of $8,500 (i.e. $34,002/4). Atikokan calculated the return on the rate base using the average of the opening and closing balance of the PP&E account in 2012 (i.e. ($34,002+$25,501)/2 * 6.49%). Atikokan updated the weighted average return on rate base from 6.49% to 6.09% in its AIC.

Board staff took no issue with the credit balance of $34,002 or the 4-year amortization period, but submitted that Atikokan erred in calculating the return on the average balance of the PP&E amount in 2012, rather than on the closing balance of $34,002. Board staff submitted that Atikokan should update the calculation and document it in the draft Rate Order filing.

In reply, Atikokan reiterated that calculating the return on the average of the opening and closing balance is consistent with the principle of calculating return on the average rate base. However, noting that the difference is an immaterial amount of $260, Atikokan stated that it was willing to accept Board staff's approach.

Board Findings

The Board notes that the PP&E deferral account is a unique account, which is "cleared" through a one-time adjustment to rate base and is designed to capture PP&E differences arising only as a result of the accounting policy changes caused by the transition from CGAAP to MIFRS.

The Board has examined all of the evidence and submissions from Atikokan and the submission of Board staff, and notes Atikokan's acceptance of Board staff's submission. The Board directs Atikokan to provide an updated calculation of the return on the rate base for the PP&E adjustment and submit an updated RRWF when it files its draft Rate Order. That amount, once established as part of the Draft Rate Order process, will be subject to a 46 month amortization period for the PP&E deferral account.

Rate Mitigation

In its Application, Atikokan proposed to mitigate the impacts to customers resulting from its proposed rates. Atikokan proposed to limit bill increases to no more than 10% for a typical Residential customer consuming 800kWh per month through the following:

- Deferral of the disposition of all Group 1 and Group 2 DVAs, except for Smart Meter accounts 1555 and 1556, until 2013; and
- Approval for a credit rate rider to reduce the bill impact based on a consumption of 800 kWh per month to no more than 10%. The amount of the credit would be tracked in a DVA for which Atikokan was seeking approval, with the balance to be disposed of in a subsequent rate application.

In response to a Board staff interrogatory, Atikokan documented that its typical Residential consumption was less that the 800 kWh/month used as the industry norm. Instead, the average consumption per Residential customer in Atikokan is about 581 kWh and only 33% of Residential customers consume at least 800 kWh per month. Thus, Atikokan's rate mitigation proposal would still have meant that most residential customers would have faced bill impacts exceeding 10%. Atikokan proposed to alter its rate mitigation proposal so that the credit rate rider would reduce the bill impact, after taxes and the Ontario Clean Energy Benefit, to no more than 10%.

VECC submitted that Atikokan's rate mitigation plan is reasonable, consistent with previous Board Decisions and thus should be accepted by the Board.

Board staff noted that Atikokan's proposed rate mitigation would reduce the immediate impacts that the utility's ratepayers would face as a result of the rates resulting from the Board's Decision in this Application. Board staff also noted that deferring disposition of the DVA balances would not aid the financial picture of Atikokan since the DVA balances are in a net debit amount of about $250,000. Deferring the DVA disposition until Atikokan's 2013 application would mean that the matter would be considered as part of an IRM rates application. While Group 1 DVA balances are routinely disposed in both IRM and cost of service applications, Group 2 DVA balances are disposed only in cost of service applications. Atikokan's proposal is inconsistent with the Board's EDVARR Report and would result in a lengthier and more involved proceeding than is the intent of the IRM process. Board staff also submitted that deferment to Atikokan's next scheduled cost of service would not be appropriate due to the passage of time and issues of data quality. Board staff submitted that increases in OM&A and smart meter cost recovery were significant drivers of the need for mitigation, and suggested that other approaches, such as extending the period for DVA rate riders, might help address rate impacts to more manageable levels.

Atikokan replied that, depending on the revenue requirement and other determinations by the Board in this Decision, it may still be necessary to mitigate the resulting rate impacts. The utility submitted that it had considered options and that a mitigation plan is appropriate to protect the interests of the customer. Atikokan submitted that its proposed approach is both reasonable and appropriate, and should be approved by the Board in the event that the Board approves a revenue requirement that generates bill impacts of over 10% for that customer profile.

Board Findings

The Board has made a number of changes to Atikokan's proposed revenue requirement and other costs in this Decision, particularly with respect to operating expenses and to the smart meter costs to be recovered. While the Board is also directing recovery of DVA balances, this will be over an extended period to help mitigate the impacts on Atikokan's ratepayers. It is not clear that Atikokan's proposed rate mitigation, or any rate mitigation, will be necessary as a result of this Decision.

Given concerns raised about Atikokan's financial situation, rate mitigation may also not be in the public interest if it has a deleterious impact on Atikokan's cash flow. The Board also notes that the 10% bill impact threshold for rate mitigation is a guideline and not an absolute. Its application may not be warranted in some situations, as the Board believes may apply here.

Nonetheless, while the Board will not approve Atikokan's proposed rate mitigation at this point, should Atikokan determine that rate impacts in its draft Rate Order would significantly exceed the 10% total bill threshold for typical customers in any class, Atikokan should document this and propose a reasonable plan to address any such situation.

Implementation

The Board has made findings in this Decision which change the 2012 revenue requirement and therefore change the distribution rates from those proposed by Atikokan. In filing its draft Rate Order, the Board expects Atikokan to file detailed supporting material, including all relevant calculations showing the impact of the implementation of this Decision on its proposed revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates and all approved rate riders, including bill impacts. Supporting documentation shall include, but not be limited to, the filing of a completed version of the Revenue Requirement Work Form Excel spreadsheet which can be found on the Board's website.

A Rate Order will be issued after the steps set out below are completed.

THE BOARD ORDERS THAT:

1. Atikokan Hydro Inc. shall file with the Board, and shall also forward to the Vulnerable Energy Consumers Coalition, a draft Rate Order attaching a proposed Tariff of Rates and Charges and other filings reflecting the Board's findings in this Decision and Order within 14 days of the date of this Decision and Order.

2. The Vulnerable Energy Consumers Coalition and Board staff shall file any comments on the draft Rate Order with the Board and forward to Atikokan Hydro Inc. within 7 days of the date that Atikokan Hydro Inc. files the draft Rate Order.

3. Atikokan Hydro Inc. shall file with the Board and forward to the Vulnerable Energy Consumers Coalition responses to any comments on its draft Rate Order within 4 days of the date of receipt of Board staff and intervenor comments.

Cost Awards

The Board will issue a separate decision on cost awards once the following steps are completed:

1. The Vulnerable Energy Consumers Coalition shall submit its cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. Atikokan Hydro Inc. shall file with the Board and forward to the Vulnerable Energy Consumers Coalition any objections to the claimed costs within **14 days** from the date of issuance of the final Rate Order.

3. The Vulnerable Energy Consumers Coalition shall file with the Board and forward to Atikokan Hydro Inc. any responses to any objections for cost claims within **21 days** from the date of issuance of the final Rate Order.

4. Atikokan Hydro Inc. shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2011-0293,** be made through the Board's web portal at, www.errr.ontarioenergyboard.ca and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, June 18, 2012

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary