Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2010-0135

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 Kenora Hydro Electric Corporation Ltd. for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2011.

BEFORE: Karen Taylor
Presiding Member

Paul Sommerville
Member

DECISION AND ORDER

BACKGROUND

Kenora Hydro Electric Corporation Ltd. ("Kenora Hydro" or the "Applicant" or "Kenora") filed an application with the Ontario Energy Board (the "Board") on November 1, 2010, under section 78 of the *Ontario Energy Board Act, 1998*, S.O 1998, c. 15 (Schedule B), seeking approval of its proposed distribution rates and other charges, effective May 1, 2011. Kenora Hydro is a licensed electricity distributor serving approximately 6,087 customers in the City of Kenora.

Kenora Hydro is one of 80 electricity distributors in Ontario whose rates are regulated by the Board. In an effort to assist distributors in preparing their applications, the Board issued the *Filing Requirements for Transmission and Distribution Applications* on November 14, 2006. Chapter 2 of that document, as amended on June 28, 2010, outlines the filing requirements for cost of service rate applications, based on a forward test year, by electricity distributors.

On March 5, 2009, the Board informed Kenora Hydro that it would be one of the electricity distributors to have its rates rebased for the 2011 rate year. This was confirmed in the Board's letter of April 20, 2010. On August 24, 2010 Kenora Hydro notified the Board that it while it would not be able to file its 2011 COS application by the August 31, 2010 deadline, it would try to file the application at the earliest possible opportunity. Kenora Hydro filed a cost of service application based on 2011 as the forward test year on November 1, 2010.

The Board assigned the application file number EB-2010-0135 and issued a Notice of Application and Hearing dated November 23, 2010. The Board approved the Vulnerable Energy Consumers Coalition ("VECC") as an intervenor. No letters of comment following the publication of the Notice were received by the Board or the Applicant.[1]

In Procedural Order No.1 issued on December 20, 2010, the Board established a schedule for the delivery of interrogatories and responses.

In Procedural Order No. 2 and Order for Interim Rates, issued on February 24, 2011, the Board declared Kenora Hydro's existing rates interim, effective May 1, 2011, confirmed that the hearing would be in written form and established a schedule for a second round of interrogatories and for the filling of submissions. In total, Kenora Hydro filed responses to 47 VECC and 50 Board staff interrogatories. Board staff and VECC filed their submissions on March 29, 2011 and April 5, 2011 respectively. Kenora Hydro filed is its reply submission on April 19, 2011.

Revenue Requirement

Kenora Hydro originally sought approval for a base revenue requirement of $2,850,945 for its 2011 test year to be recovered through new rates effective May 1, 2011. The revenue deficiency at current rates associated with this revenue requirement is $909,070

[1] Response to Board staff interrogatory No.4

2011 Revenue Requirement Components	
OM&A	$ 2,062,785
Amtz/Depreciation	$ 468,960
Property Taxes	$ 13,260
Capital Taxes	$ -
Income Taxes (grossed up)	$ 20,812
Other Expenses	$ -
Return - interest	$ 236,259
Return- ROE	$ 406,115
Service Revenue Requirement	$ 3,208,191
Revenue Offsets	$ 357,246
Base Revenue Requirement	$ 2,850,945

Residential customers consuming 800kWh per month would experience a 32.9% increase in their delivery charges, or $9.45 per month on their total bill, if the Board were to approve the application as filed. The corresponding increase for a General Service < 50kW customer consuming 2,000kWh per month would be 31.7% and $15.39.

During the interrogatory process Kenora Hydro had identified a number of adjustments, listed in the table below, that it wished to make to its pre-filed evidence[2].

Table 1

Adjustments Proposed by Kenora Hydro	OM&A	Amtz/ Depr'n	Capital	Cost of Capital
OM&A Expenses				
PST savings	($13,096)			
LEAP Program	$3,850			
OMERS	$1,167			
Allocated costs from City of Kenora	($40,434)			
Regulatory costs	($21,053)			
Interest Expense on Longe Term Debt				($74,776)
Capital Expenditures				
Overhead conductors		($400)	($20,000)	
Line Transformers (capital contribution)		($680)	($34,000)	
Office Equipment		($750)	($15,000)	
Tool, Shop and Equipment		($125)	($2,500)	
Miscellaneous Equipment		($100)	($2,000)	
Smart Meter Amortization		($500)		
Total	($69,566)	($2,555)	($73,500)	($74,776)

[2] Response to VECC interrogatory No. 47

In its reply submission Kenora Hydro proposed further adjustments in response to matters raised by Board staff and VECC in their submissions. The Board addresses these adjustments later in the Decision.

The full record for this proceeding is available at the Board's offices. The Board has chosen to summarize the record to the extent necessary to provide context to its findings.

THE ISSUES

The following issues were raised in the submissions of the intervenor and Board staff, and are addressed in this Decision.

- Capital Expenditures and Rate Base
- Customer/Load Forecast and Revenues;
- Operating, Maintenance & Administrative Expenses;
- Payments in Lieu of Taxes and Depreciation;
- Retail Transmission Service Rates;
- Cost of Capital;
- Cost Allocation and Rate Design;
- Deferral and Variance Accounts;
- Smart Meters;
- Effective Date and Implementation;

CAPITAL EXPENDITURES AND RATE BASE

Capital Expenditures

Kenora Hydro originally proposed capital expenditures totaling $1,284,500 for 2011. This is about 21% higher than forecasted 2010 expenditures and 13% lower than actual expenditures in 2009. Kenora Hydro indicated that it prepared its 2011 capital budget net of HST. Table 2 summarizes Kenora's historical and proposed capital expenditures as presented in the pre-filed evidence.

Table 2

Capital Expenditures	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
Transformer Station Equip >50 kV (note	$ 47,250	$ 819,137	$ 351,639	$ 1,059,614	$ 280,000	$ 605,000
Poles, Towers & Fixtures	146,380	101,207	131,453	35,886	67,000	60,000
O/H Conductors & Devices	69,718	77,375	92,308	98,347	75,000	100,000
Underground Conduit	-	383			62,000	18,000
U/G Conductors & Devices	4,092	53,107	5,040		90,000	40,000
Line Transformers	32,498	26,796	32,311	31,459	97,000	119,000
Services	63,205	50,173	26,568	33,914	33,000	35,000
Meters	6,645	37,648	537	469	3,000	3,500
Buidling & Fixtures	1,859				365,000	155,000
Office Furniture and Equipment	2,911	2,147	509	7,284	1,000	16,000
Computer Equipment - Hardware	9,176	1,855	538	2,194	6,000	2,000
Computer Equipment- Software	-		3,192	12,094	2,000	2,000
Transportation	-	25,556		247,161		150,000
Tools, Shop & Garage	3,040	1,408	4,442	2,861	5,000	5,000
Measure & Test Equip	3,738		377		2,000	2,000
Communication Equipment			378			
Miscellaneous Equipment	-	13,484			2,000	2,000
Capital Contribution	-46,120	-55,504	-24,196	-54,891	-30,000	-30,000
TOTAL	$ 344,392	$ 1,154,772	$ 625,096	$ 1,476,392	$ 1,060,000	$ 1,284,500

note 1: Transformer Station expenditure in 2007 includes T3 replacement due to lightning strike. Insurance claim posted in 2008 for $422,303 and in 2009 for $163,210

Board staff submitted that Kenora Hydro had provided an adequate explanation of the capital expenditures incurred between 2006 and 2009. In response to VECC interrogatories No. 9 and No. 37, Kenora Hydro indicated that the preliminary actuals for 2010 total $860,138, excluding accruals. In this regard, Board staff submitted that the amount for 2010 should continue to be the number as filed, absent a proper examination of any revisions to this amount. VECC submitted that Kenora's 2010 planned capital spending is reasonable and should be reflected in its 2011 rate base.

There are four projects or items which account for the inter-year volatility in annual capital expenditures: the Transformer Station rebuild program, a double bucket truck replacement in 2009, building repair and replacement in 2010 and 2011 and a single bucket truck replacement in 2011.

The most significant of these is the rebuild/replace program affecting Kenora Hydro's three Transformers (> 50kV).

The key events from the transformer station history and plan presented in evidence includes:

- Transformer T2: struck by lightning in 2007 and replaced with a used unit from the U.S.;
- Transformer T3: failed in 2009 and has been replaced with the rebuilt T2;
- Transformer T1: will be replaced in June 2011 with the rebuilt T3;
- Spare: the replaced T1 will be rebuilt in 2011 and serve as a spare.

Board staff noted that the projected future capital expenditures, at $848,888 for 2012, $429,000 for 2013, and $329,000 for 2014 are significantly less than 2010 and 2011 levels.[3] Board staff submitted that Kenora Hydro should consider deferring the inclusion of the re-build costs of the spare transformer into rate base. This would limit the significant growth in 2011 rate base and help mitigate the bill impact of the new rates on customers. Kenora Hydro responded that that the re-winding of T1 will now take place in 2012. Accordingly the capital expenditures planned for 2011 should be reduced by $302,500 with a corresponding increase in 2012.

VECC noted that Kenora Hydro has reviewed the priority and need for each of its planned 2011 capital projects and has concluded that some $39,500 in spending was not required and that $34,000 in capital contributions had been overlooked.[4] Given this $73,500 adjustment proposed by Kenora Hydro, VECC submitted that Kenora Hydro's proposed capital spending for 2011 is reasonable and should be reflected in the Applicant's 2011 rate base. Board staff also submitted that the Board should accept the $73,500 decrease to its 2011 capital expenditures indentified by Kenora Hydro.

VECC pointed out that the Asset Management Plan (the "Plan") filed by Kenora is not really an Asset Management Plan because it does not contain any details regarding the condition of the Applicant's assets, any resulting inventory of required work nor any prioritization of that work which would lead to the proposed capital budget. Nevertheless VECC commended Kenora Hydro for initiating the processes needed to develop Asset Management and anticipates that a comprehensive plan will be available to support its next cost of service filing.

BOARD FINDINGS

The Board finds Kenora's 2006 to 2009 capital expenditures to be prudent and that they should be included in the 2011 rate base.

[3] Exhibit 2-3-2 Table 18.
[4] Response to Board staff interrogatory No.13.

The Board also accepts the 2010 Bridge Year capital expenditures budget as filed, given the close relationship between the 2010 Bridge Year number of $1,060,000 and the preliminary actuals for 2010 of $860,000, excluding accruals.

Kenora Hydro initially proposed a 2011 Test Year capital budget of $1,284,500 which it revised during the course of the proceeding to $908,500 to reflect reductions totaling $376,000. The Board accepts Kenora's updated 2011 Test Year capital budget of $908,500.

The Board is concerned with the volatility and overall increase in Kenora's capital budget over the 2006 to 2011 period, inclusively. The Board directs Kenora to file a proper Asset Management Plan in its next cost of service application.

Rate Base

Kenora Hydro originally proposed a rate base for 2011 in the amount of $10,307,488. This is about 63% higher than the rate base approved in 2006. Between 2006 and 2009 actual year-on year increases have averaged between 7% and 9% while the 2010 bridge year is 11.9% higher than 2009 actual and 2011 test year is 18% higher than the 2010 budget. Excluding the Working Capital Allowance ("WCA"), the increase over 2010 is 21.7%. The historical and forecasted rate bases are summarized in the table 3.

Table 3

Rate Base	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
Fixed Assets/ Average Book Value	$ 5,081,318	$ 4,968,823	$ 5,287,981	$ 5,757,413	$ 6,363,567	$ 7,127,660	$ 8,672,540
Working Capital Allowance (WCA)	$ 1,244,609	$ 1,262,232	$ 1,382,208	$ 1,382,534	$ 1,439,587	$ 1,604,945	$ 1,634,948
Rate Base	$ 6,325,927	$ 6,231,055	$ 6,670,189	$ 7,139,947	$ 7,803,153	$ 8,732,605	$ 10,307,488
rate base year-on year inc.	na	-1.5%	7.0%	7.0%	9.3%	11.9%	18.0%

The significant increase in 2011 over the historical average is largely due to the inclusion of Smart Meter costs of $894,178 (gross plant of $1,024,635 less accumulated depreciation of $130,457).[5] To the end of 2010, this amount was recorded in the Smart Meter variance account. The Board will address the impact of Smart Meters on rate base later in this Decision.

[5] Exhibit 9-2-3 p.2 table10

VECC and Board staff took no issue with Kenora Hydro's methodology which was based on 15% of the forecast cost of power and controllable expenses for calculating the WCA. In response to VECC's and Board staff's submissions that the most up-to-date information should be used to quantify the WCA component, Kenora Hydro agreed to update the WCA to reflect any changes in controllable expenses and load forecasts as directed in the Board's Decision as well as the most current Regulated Rate Price and Uniform Transmission Rates.

Kenora Hydro did not respond to Board staff's submission, which VECC supported, that the aforementioned updated information should include sufficient details and explanations to aid the understanding of the updated numbers and their derivation.

BOARD FINDINGS

The Board accepts the originally proposed 2011 rate base, as adjusted by (i) the net reduction of $376,000 in 2011 capital expenditures; and (ii) the updated WCA that would accompany the draft Rate Order.

The Board accepts Kenora's agreement to file an updated Working Capital Allowance and directs Kenora to include in the draft rate order sufficient detail to support the calculations.

OPERATING REVENUE

The following issues are addressed in this section:

- Load Forecast
- Customer Forecast
- Other Distribution Revenue

<u>Load Forecast</u>

Kenora Hydro's load forecast methodology consists of the following steps:

First, a total system-wide weather normalized purchased energy forecast is developed using a multifactor regression model that includes historical load, economic and weather related variables. Second, the energy forecast is adjusted by the proposed loss factor to derive the system-wide billed energy forecast. Third, the forecast of the number of customers by rate class is derived by using a geometric mean analysis for the years 2002-2009. Fourth, a non-weather normalized forecast of billed energy by rate class is developed using forecast customer counts and trends in average use per customer. Fifth, the forecasts for weather sensitive customer classes (Residential, GS<50 and

GS>50), are adjusted so that the total derived in the second step is matched. Finally, the resulting forecast by class is then adjusted for the anticipated 2011 load reductions associated with the CDM targets set by the Board for Kenora Hydro.[6]

Kenora Hydro's proposed load forecast for 2011 by rate class as compared to 2009 actual and 2010 forecast is presented in table 4. The 2011 load forecasts for the residential and GS < 50kW classes are 2.4% and 3%, less than forecasted for 2010, respectively, and 4.3% and 5.4% less than 2009 actual. Of the 2.4% decrease for the residential class and the 3% decrease for the GS < 50kW class about 1.1% reflects Kenora Hydro's estimate of the 2011 impact of the CDM targets.

Table 4

(in kWh)

Rate Classes	2009 Actual	2010 Bridge Year	2011 Test Year	2011 vs 2009 [% inc./(dec)]
Residential	39,909,017	39,135,578	38,188,928	
year-on-year %inc./ (dec.)		-1.9%	-2.4%	-4.3%
GS< 50 kW	23,638,260	23,046,528	22,359,418	
year-on-year %inc./ (dec.)		-2.5%	-3.0%	-5.4%
GS >50 kW	43,454,274	44,508,715	45,342,066	
year-on-year %inc./ (dec.)		2.4%	1.9%	4.3%
Street lighting	1,690,689	1,758,282	1,807,975	
year-on-year %inc./ (dec.)		4.0%	2.8%	6.9%
Unmetered Scattered Load	157,460	151,793	144,681	
year-on-year %inc./ (dec.)		-3.6%	-4.7%	-8.1%
TOTAL	108,849,700	108,600,896	107,843,068	
year-on-year %inc./ (dec.)		-0.2%	-0.7%	-0.9%

VECC and Board staff did not take issue with the methodology utilized by Kenora Hydro to prepare its load forecast. VECC noted that the model has a high Adjusted R-Squared value and all the proposed explanatory variables are both statistically significant and have intuitively correct coefficients. However, Board staff did take issue with the customer forecast and the calculation of the CDM adjustment. VECC also disputed the loss factor Kenora Hydro used to convert forecast purchased energy to billed energy.

[6] Exhibit 3-2-1

Customer Forecast

Kenora Hydro is forecasting a decline in residential and GS < 50kW customer numbers for 2010 and 2011 as compared to 2009, and an increase in GS > 50 kW customers. Street lighting connections remain constant and unmetered scattered load connections increase from 28 to 30. Kenora used a geometric mean analysis, based on 2002-2009 actuals, to forecast the 2010 and 2011 residential and general service customer levels. The historical and forecast customer levels since the last rebasing year are set out in table 5.

Table 5

CUSTOMERS & CONNECTIONS	2006 Board approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
Residential	4,980	5,029	5,012	4,781	4,783	4,728	4,674
GS <50kW	793	782	794	732	713	708	703
GS>50kW	58	61	66	66	70	72	75
TOTAL	5,831	5,872	5,872	5,579	5,566	5,508	5,452
Street Lighting	550	550	550	550	550	550	550
Unmetered Scattered Load	3	28	28	28	28	29	30
Grand Total	6,384	6,450	6,450	6,157	6,144	6,087	6,032

In response to VECC interrogatory No. 13, Kenora Hydro provided the actual customer levels for 2010. These are presented in table 6.

Table 6

CUSTOMERS	2009 Actual	2010 Bridge Year	2010 Actual	2011 Test Year
Residential	4,783	4,728	4,770	4,674
GS <50kW	713	708	744	703
GS>50kW	70	72	69	75
TOTAL	5,566	5,508	5,583	5,452

Board staff noted the under-forecasting in 2010 for the Residential and GS < 50kW customer classes and asserted that the forecast for 2011 should be re-calculated taking the 2010 actuals into account, thereby improving the currency and accuracy of the result. Board staff submitted a forecast, utilizing Kenora Hydro’s geometric mean analysis, including 2010 actuals. As compared to the forecast in the pre-filed evidence, Board staff’s forecast for Residential customers at 4,731, is1.2% higher, for GS < 50 kW at 736, is 5.1% higher and for GS > 50 kW at 70, is 6.7% lower. VECC submitted that 2011 should be updated to reflect the 2010 actuals and accepted Board staff's approach as a reasonable way of achieving it.

Kenora Hydro agreed with Board staff's revised forecast and confirmed that it would use the following customer numbers in the final rate model.

Class	2011 Test Year Count
Residential	4,731
GS < 50 kW	736
GS > 50kW	70
TOTAL	**5,537**

BOARD FINDINGS

The Board accepts the revised 2011 test year customer count. In the Board's view, using actual 2010 results improves the accuracy and currency of the geometric mean analysis used to forecast 2011 customer counts by class.

<u>CDM adjustment</u>

The 2011 load forecast incorporates a CDM adjustment totaling 1.23 GWh. This adjustment reflects Kenora Hydro's interpretation of the 2011-14 Net Cumulative Energy Savings Target of 5.220 GWh and the 2014 Annual Peak Demand Saving Target of 0.860 MW set by the Board in its EB-2010-0215/0216 Decision and Order, dated November 12, 2010. For Kenora Hydro, the CDM savings to be realized in 2011 equates to ¼ of the savings that are targeted for realization in 2014.

VECC and Board staff disagreed with Kenora Hydro's interpretation that viewed the 5.220 GWh target as the reduction target for 2014, and not as the accumulated decreases in consumption over the 2011 to the 2014 period. When questioned by VECC and Board staff about the rationale for this interpretation, Kenora Hydro claimed that the 5.220 GWh target cannot be the accumulated amount since this would result in a 28% load factor, which is not the case for Kenora Hydro. In this regard, VECC noted that the various CDM programs offered by the OPA have different impacts on energy consumption versus peak load and pointed to Kenora Hydro's experience in the OPA's program for 2008 and 2009 whose results translate to a 15.8% load factor.

Board staff submitted that the CDM target adjustment that should be included in the

2011 load forecast is 522,000 kWh. This assumes a 10% achievement, in the first year, of the accumulated GWh target of 5.220 GWh. On this basis the load forecast presented in the pre-filed evidence would be increased by 708,000 kWh.[7] Board staff viewed 2011 as a start-up year for Kenora and noted that the expected hiring date for a new Manager of CDM and Engineering was mid-February of 2011. VECC described Board staff's 10% assumption as "aggressive" since it assumed an equivalent level of program savings each year such that savings in the first year of implementation are equivalent to the annual savings persisting in future years. VECC pointed to the fact that the Manager of CDM and Engineering would not be in place at the beginning of 2011 and the introduction of programs would be phased in during 2011. VECC also noted that the CDM target for 2011 contained in Kenora Hydro's CDM strategy filed with the Board, EB-2010-0215, indicates a 2011 target of 365,000 kWh, and cumulative target of 5,000,000 kWh. VECC concluded that the CDM adjustment should be no more than 400,000 kWh as this corresponds to the aforementioned target and adjusted for the increase in the cumulative target.

Kenora Hydro in its reply submission indicated its agreement with Board staff's submission and concurred that the CDM target reduction in 2011 should be 522,000 kWh, representing 10% of the total target savings. Kenora Hydro also noted that the Board in its recent Brampton Decision, EB-2010-0132, found the 10% calculation for the test year appropriate.

BOARD FINDINGS

The Board accepts the CDM target of 522,000 kWh for 2011 as proposed by Board staff and agreed to by Kenora Hydro. The Board notes that the proposed treatment is consistent with the Board's approach in other applications for 2011 rates.

Total Loss Factor

Kenora Hydro is proposing to maintain its loss factor at the currently approved level of 1.043 or 4.30%. Pursuant to the Board's filing requirements, Kenora Hydro provided a total loss factor calculation which takes into account the actual losses (distribution) between 2005 and 2009 while holding the supply loss constant at 1.0045. The results are summarized in table 7.

[7] Calculation: 2011 CDM target in the prefiled evidence of 1.23GWh less Board staff's target of .522GWh equals 708,000 kWh.

Table 7

TOTAL LOSS FACTOR	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	Average
Distributon Loss Factor	1.0537	1.0352	1.0366	1.0393	1.0192	1.0368
Supply Faciltiy Loss Factor at 1.0045	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
TOTAL	1.0582	1.0397	1.0411	1.0438	1.0237	1.0413

While the calculation results in a total loss factor of 1.0413[8] Kenora Hydro proposed to stay with the existing loss factor of 1.043. Kenora Hydro noted that it did not see the need for an explanation supporting this proposal since the filing requirements only require a justification if the proposed total loss factor rate is 1.05 or greater.

In interrogatory No.34 Board staff noted that the 2009 actual Distribution Loss factor, at 1.0192 was significantly lower than prior years experience. Kenora responded that the 2009 result was likely due to a calculation anomaly because of the unbilled kWh at year end. Kenora Hydro provided factors based on billed consumption matched to IESO purchases. Board staff accepted Kenora's Hydro's explanation and submitted that it had no concerns with the proposed loss factor.

VECC submitted that since 1.0414 was the average loss factor over the historical period in the multi-factor regression model, the same factor should also be used to convert the purchased energy forecast into the billed energy forecast. Kenora Hydro had used its proposed total loss factor of 1.043 in the conversion calculation. In its reply submission, Kenora Hydro noted that that Board staff did not comment on Kenora Hydro's proposed loss factor and that it would follow the Board's direction in this regard.

BOARD FINDINGS

The Board finds that it is appropriate to use the existing loss factor of 1.043 to adjust the estimated total system-wide weather normalized purchased energy forecast to derive the system-wide billed energy forecast. The Board does not believe that it is appropriate to use the average historical loss factor proposed by VECC, as this historical average may not be representative of future losses and that the variability in the observed distribution loss factors over the 2005 to 2009 period has not been fully explained. Moreover, no analysis was filed that would give the Board sufficient

[8] For the Total Loss Factor- Secondary Metered Customer < 5,000 kW. The proposed factor for Primary Metered Customer < 5,000kW is 1.0325

confidence that the average historical loss factor would be more accurate than the current loss factor. For these reasons, the Board does not agree that because an average loss factor of 4.14% was experienced during the historical period utilized in the multi-factor regression that this factor must also be used to convert the purchased energy forecast into the billed energy forecast.

Finally, the Board notes that the proposed total loss factor of 1.043 is less than 1.05, the threshold above which the Board's filing requirements state that a forecast loss factor must be justified. The Board accepts Kenora Power's proposal to maintain the total loss factor at the currently approved level.

Other Distribution Revenue

Kenora Hydro's Other Distribution Revenue includes revenues from service charges, late payment charges, net income related to providing street lighting maintenance services to the city of Kenora (the "city") and sewer and water billing services for the city, interest on variance & deferral account balances, investment interest, electric property rental, retail services and gains on asset sales.

Historical and proposed Other Distribution Revenues, and the amount that serves as an offset to Kenora Hydro's Service Revenue Requirement, are set out in table 8.

Table 8

Other Distribution Revenue	2006 Board approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
Specific Service Charges	$ 73,608	$ 38,232	$ 37,393	$ 36,650	$ 37,040	$ 37,000	$ 37,000
Late Payment charges	$ 22,142	$ 23,524	$ 30,609	$ 31,710	$ 42,618	$ 43,000	$ 43,000
Other Distributing Revenues	$ 130,446	$ 124,147	$ 110,598	$ 112,040	$ 116,333	$ 159,790	$ 161,040
Other Income and Expenses	$ 141,393	$ 123,757	$ 169,313	$ 146,012	$ 109,021	$ 78,375	$ 112,166
TOTAL	$ 367,589	$ 309,660	$ 347,913	$ 326,412	$ 305,012	$ 318,165	$ 353,206
year-on-year % change		-15.8%	12.4%	-6.2%	-6.6%	4.3%	11.0%
Adjustmentment for 2011 Rev. Req.Offset							
-less 1/2 of $20k gain on sale of bucket truck							-$ 10,000
- plus $0.25 Retailer Administration Fee							$ 14,040
Revenue Requirement Offset							**$ 357,246**

VECC and Board staff expressed concern with the proposed 50-50% sharing between the shareholder and the ratepayer of the anticipated gain of $20,000 stemming from the intended sale of the existing bucket truck. They submitted that the full amount of the gain should be recorded as a revenue offset. Kenora Hydro viewed its treatment as consistent with the guidelines contained in the 2006 Rate Handbook. In response to

Board staff supplemental interrogatory No. 5, Kenora Hydro agreed that the rate setting exercise set out in the 2006 Handbook focused on actual results for 2004 and 2005 and not on the proposed budget for the test year.

Board staff doubted whether there was a sound reason for ratepayers to share the gain on a planned sale of an existing truck while solely the ratepayer bears the $150,000 costs of the replacement truck. Board staff submitted that the 50-50% gain sharing treatment contained in the 2006 Handbook does not necessarily apply in this situation since the replacement, and corresponding sale, is part of the Applicant's capital expenditure proposals for the prospective test year. The truck to be sold cannot be considered surplus because it is being replaced with another.

VECC concurred with Board staff's submission adding that an alternative way of viewing the gains on the disposal is as a "trade-in" accompanying the purchase of the new truck. In this scenario, 100% of the $20,000 would accrue to ratepayers through reduced capital spending. VECC further noted that the 50/50 sharing approach set out in p. 28 of the 2006 Rate Handbook applies specifically to capital gains and losses on non-depreciable assets and therefore is not applicable to assets such as trucks.

Kenora Hydro in its reply submission indicated that it was willing to update the model to attribute 100% ($20,000 in total) of the gain on the sale of the bucket truck to benefit customers. However, since this gain is a one-time event, not expected to re-occur over the next 4 years, Kenora Hydro submitted that the gain from the sale should be accorded the same treatment as other one-time events in this rate application. On this basis only ¼ of the gain, or $5,000, should be included in the Revenue Offset in the test year.

VECC also had a concern with the inclusion of $7,500 in the Revenue Offset that was related to interest income on deferral and variance accounts balances. VECC submitted that this amount should be excluded as it is also recorded in the deferral/variance accounts and credited to customers through that mechanism. Kenora Hydro in its reply submission indicated that it would, upon direction from the Board, remove this amount from its revenue offset for 2011.

Kenora Hydro proposed to add a specific service charge, "Service Disconnection Fee - if requested by customer" to the standard Schedule of Rates and Tariffs.[9] This service

[9] Response to Board staff interrogatory No. 4

is identified in Kenora Hydro's Conditions of Service and the associated revenues have been included in the other distribution revenues presented in the evidence at Exhibit 3 Table 21. The fee for this service would be the same as the standard disconnect / reconnect rates for non-payment set out in Kenora Hydro's schedule of rates and tariffs.

Board staff indicated that it had no concerns with this proposal.

BOARD FINDINGS

The Board believes that it is appropriate to record 100% of the gain on the sale of the bucket truck as a revenue offset in 2011, and should be booked for accounting purposes as Other Revenue. The Board believes that the bucket truck cannot be viewed as being surplus to utility operations as it is being replaced, with the cost of the replacement bucket truck reflected in Kenora's distribution rates.

As indicated above, the Board believes that it is appropriate to record 100% of the gain on sale in 2011 for rate making purposes. While the Board agrees that this is a one-time event and not currently expected to be repeated over the IRM period, the Board believes that recognizing 100% of the gain in 2011 for the purposes of setting rates will provide an additional opportunity for rate mitigation in the context of the current application.

The Board is also of the view that the Revenue Offset should be reduced by the amount forecasted for interest earnings on deferral and variance account credit balances to prevent double-crediting the customer.

The Board finds that the Service Disconnection Fee should be included in the Schedule of Rates and Tariffs and notes that no parties had concerns with this proposal.

OPERATING COSTS

Kenora's Hydro operating costs include Operating, Maintenance and Administration ("OM&A), Depreciation and Federal and Provincial ("PILS") taxes. The historical, bridge year and test year amounts for these expenses are set out in the table below.

Table 9

OPERATING EXPENSES	2006 Board approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
OM&A	$ 1,414,783	$ 1,278,734	$ 1,387,191	$ 1,633,819	$ 1,701,608	$ 1,800,457	$ 2,062,785
Amtz/Depreciation	$ 349,626	$ 367,748	$ 394,996	$ 379,434	$ 436,107	$ 480,640	$ 468,960
Property Taxes	$ 12,668	$ 12,668	$ 12,397	$ 12,684	$ 12,478	$ 13,000	$ 13,260
Federal/Provincial Taxes	$ 1,917	$ 7,561	$ 11,203	$ 2,808	$ 2,269	$ -	$ 20,812
TOTAL	$ 1,778,994	$ 1,666,711	$ 1,805,787	$ 2,028,745	$ 2,152,462	$ 2,294,097	$ 2,565,817

Operating, Maintenance and Administration

Kenora Hydro initially proposed a Test Year budget of $2,062,785 which represented a 14.6% increase over 2010 and a 45.8%, or a 7.8% per annum increase over 2006 Board approved. Through the interrogatory process, and as confirmed in its reply submission, Kenora Hydro reduced its proposed OM&A for 2011 by $69,566.[10] On this basis, the increase as compared to 2010 is 10.7% and the annual increase since 2007 Board approved is 7.1%. The historical and proposed OM&A expenditures are presented in Table 10.

Table 10

Operating. Maintenance & Administration	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year	Updated 2011 Test Year
Operation	$ 117,762	$ 119,291	$ 132,133	$ 139,373	$ 172,747	$ 172,173	$ 198,090	na
Maintenance	$ 427,306	$ 269,662	$ 245,439	$ 303,518	$ 373,025	$ 365,813	$ 400,649	na
Billing & Collection	$ 375,827	$ 354,924	$ 387,712	$ 411,372	$ 490,429	$ 560,760	$ 576,943	na
Community Relations	$ 1,370	$ 972	$ 4,432	$ 98,291	$ 2,261	$ -	$ -	na
Administrative & General *	$ 492,518	$ 533,885	$ 617,475	$ 681,265	$ 663,146	$ 701,711	$ 887,103	na
Total	**$ 1,414,783**	**$ 1,278,734**	**$ 1,387,191**	**$ 1,633,819**	**$ 1,701,608**	**$ 1,800,457**	**$ 2,062,785**	**$ 1,993,219**
Year on Year % Increase		**-9.6%**	**8.5%**	**17.8%**	**4.1%**	**5.8%**	**14.6%**	**10.7%**
2011 vs 2006 Brd Approved							**45.8%**	**40.9%**
Annual increase 2011 vs 2006 Board Approved							**7.83%**	**7.10%**
Annual Increase 2009 actual vs 2006 actual					**9.99%**			
Annual Increase 2009 actaul vs 2006 Board Approved					**6.35%**			

Kenora Hydro provided explanations for the yearly variances over the 2006 to 2009 period. Kenora Hydro noted that the inflation rates for 2006, 2007, 2008, and 2009 were 1.8%, 1.8%, 2.3% and 0.4% respectively and that the forecast inflation rate reflected in 2010 and 2011 is 2.0% annually.[11] Kenora Hydro sourced its 2% inflation forecast from

[10] The $69,566 decrease reflects a reduction of $40,434 to correct the amount charged by city of Kenora for services, reduced costs of $21,053 for the 2011 CoS application, $13,096 for the elimination of PST provision, an increase of $3,850 for LEAP and an increase of $1,167 for additional OMERS pension costs.

[11] Exhibit 4-1-1 p.2 Table 1

the Ontario Ministry of Finance's *Ontario Economic Outlook* dated November 2010. [12]

Board staff noted in its submission that significant increases in OM&A expenditures, as compared to 2006 Board approved, started in 2007. Board staff included a table which listed items (or drivers), that Board staff derived from the evidence, which account for the increase between 2007 actual and 2011 proposed.[13] Board staff asked Kenora Hydro to comment on the accuracy of the listing. The listing and Kenora Hydro's changes are shown in the table below.

Table 11

Items: increase between 2007 and 2011 (in $K)	Per Board Staff Submission	Per Kenora Hydro Reply Submission
Inflation @ 6.8%	$140	$140
Full year cost of apprentice linesman hired in 2007	$40	$40
Regulatory ($150k for 2011 case amortized over 4 yrs.)	$37	$37
Asset Managemnt Plan Development & Completion*	$37	$37
Smart Metering expensed to OM&A	$60	$60
Engineer in 2010 (CDM/GEA/Smart Grid) - Kenora share	$40	$62
Two (2) new office staff in 2009	$110	$110
One (1) new management staff in 2010	$100	-
Overhead- Oper., Mntce, Conductors & Transformers	$75	$148
Miscl.	$37	$42
TOTAL	$676	$676
*note: $150k over 4 years		

With respect to the increase between 2007 actual and the 2011 Test Year (updated), VECC noted that Kenora Hydro's actual OM&A[14] costs increased by 22% between 2007 actual and 2009 actual and are projected to increase by a further 17% between 2009 actual and 2011. VECC indicated that even after allowing for the one-time costs associated with the Rate Application, the Asset Management Plan, new LEAP costs , and Smart Meter costs, the OM&A costs proposed for 2011 are 10.25% higher than 2009. VECC attributed most of this increase to staff additions over the two year period.

<u>Increase in OM&A between 2010 and 2011</u>

Kenora Hydro's updated 2011 OM&A is 10.7% higher than the 2010 Bridge Year. A listing of the major reasons for the increase between 2010 and 2011, as presented in Board staff's submission and reflecting Kenora Hydro's updated numbers for 2011 appears in the table below.

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[12] Response to Board staff interrogatory No. 20.
[13] Calculation: $2,062,785 (2011 per pre-filed evidence) less $1,387,191(2007 Actual)
[14] VECC included property taxes costs in its OM&A amounts.

Table 12

Reasons for the increase in OM&A Between 2010 and 2011	2011 original	2011 updated
Full year compensation for employee who returned to work in August 2010	$ 63,000	$ 63,000
3% increase in wages and salaries	$ 31,600	$ 31,600
Full year compensation, Kenora share, of MGR (Engineer)of CDM/Conservation hired in late 2010	$ 31,000	$ 31,000
General non-compensation inflation @ 2% (approximate)	$ 15,000	$ 15,000
2011 COS Application Regulatory Costs (1/4 of $150,000)	$ 37,500	$ 16,447
Asset Management Plan Development and Completion (1/4 of $150,000)	$ 37,500	$ 37,500
OM&A Contra Account -5695 (2010 Smart Meters charged to D/V account)	$ 60,000	$ 60,000
Net Miscl decreases & increases	($13,272)	($61,785)
TOTAL	$ 262,328	$ 192,762

The specific changes to the updated 2011 Test Year OM&A submitted by VECC and Board staff were in the following areas.

Inflation and Compensation

Board staff noted the proposed 2011 OM&A includes about $32,000 for unionized and management salary and wage increases of 3%. The last year of the existing union contract, April 1, 2010 to March 31, 2011, provides a 3% increase. Kenora Hydro had assumed a 3% increase for the future contracts. Board staff submitted that salary and wage increases for all employees in the current economic environment should be limited to no more than 1.3% which is the price escalator the Board is using in the 2011 IRM proceedings.

VECC also questioned the overall 2% inflation adjustment used by Kenora Hydro when it prepared the 2011 proposed budget in light of the price escalator of 1.3% approved by the Board for the 2011 IRM applications. VECC pointed out that, even when allowing for onetime costs, 2011 is 10.25% or $175,000 higher than 2009 actual. VECC submitted that the 2011 OM&A should be reduced by $12,000 to reflect 1.3% increase for inflation.[15] VECC noted that its calculation results in a lower reduction than that proposed by Board staff, which VECC estimated to be in the $18,000 range.[16]

Kenora Hydro disagreed with Board Staff's submission that increases in compensation

[15] Calculation in VECC's submission assumes that 3% of the 10.25% ($175,000) increment between 2010 and 2011 is the provision for inflation. An inflation forecast of 1.3% (IRM escalator) reduces the provision in 2011 for inflation by $12,000, from $51,200 to $39,200.
[16] Calculation in VECC's submission takes the $31,000 provision in the 2011 proposed OM&A for salary and wage increases (originally costed at 3%) down to 1.3% (IRM escalator).

should be limited to the 1.3% escalator applied in the 2nd and 3rd generation IRM applications. Kenora Hydro asserted that its recent wage settlement is consistent with other utilities across the province. To support this position, Kenora Hydro included, in its reply submission, a document (the “document”) prepared by the Municipal Electric Association Reciprocal Insurance Exchange (“MEARIE”) which detailed wage settlements for 69 utilities in Ontario. Kenora Hydro noted that of the 35 utilities presenting 2012 information, the average increase was 2.9%, with a high of 3.8% increase in North Bay and with the majority of the 2012 at 3%. Kenora Hydro views these contract settlements as setting precedent across the province, with a direct impact on Kenora Hydro’s settlements. Kenora Hydro also pointed to the settlement proposal for Waterloo-North, dated March 31, 2011. Although it called for a reduction in non-wage expenses from 2% to 1.3%, it did not reduce the 3% provision for salary and wage increases. Kenora Hydro submitted that, since the imposition of a 1.3% limit on the increase on wages at this stage is neither acceptable nor reasonable, the 3% annual payroll increase should remain as budgeted and proposed in the application.

BOARD FINDINGS

The Board is not convinced that the information in the document relating to wage settlements is determinative with respect to whether Kenora’s base wages and salaries and the applied-for increases are appropriate. Importantly, the document is not a comprehensive compensation survey and it is not indicative of whether Kenora’s compensation levels are appropriate.

The Board will place little weight on the Waterloo-North settlement proposal; to place significant weight on the settlement proposal in the context of this application could result in selective benchmarking. Further, the Board notes that a settlement proposal usually reflects a number of trade-offs negotiated between the parties and one particular item cannot be taken in isolation, out of context of the remainder of the proposed settlement. The Waterloo-North settlement proposal is therefore of limited use in the context of this application.

The Board believes that the 3% general increase in wages and salaries is excessive and higher than the 2% inflation forecast from the Ontario Ministry of Finance’s *Ontario Economic Outlook* dated November 2010.   The Board believes that a 2% inflation factor is appropriate for wages and salaries. Accordingly, the Board finds that the 2011 Test Year OM&A should be reduced by $10,000.

The Board agrees that it is appropriate to use a 1.3% inflation factor for non-salary items, consistent with that approved by the Board for the 2011 IRM applications. Accordingly, the Board finds that the 2011 Test Year OM&A should be reduced by $5,000.

OMERS

Kenora Hydro indicated that it did not include the impact of the increase in contribution rates recently announced by OMERS for 2011, 2012, and 2013.[17] Kenora calculated the amount to be $1,167.00 for 2011. Board staff agreed that this amount should be included in the approved revenue requirement.

VECC submitted that, since the proposed increase in OMERS costs is in effect for only three years (2011-2013), the amount included in 2011 should be the aggregate amount for the three years amortized over four years. On this basis the provision to be added to 2011 would be $875 rather than $1,167.

BOARD FINDINGS

The Board will increase 2011 OM&A by $1,167 to reflect higher OMERS costs. While the Board acknowledges that the proposed increase in OMERS costs will be in effect for three years, the difference between the approach adopted by the Board and that submitted by VECC is relatively small and not material.

Regulatory Cost

Kenora Hydro originally forecast that it would incur $150,000 related to the 2011 COS application and proposed to amortize $37,500 annually over 4 years commencing in 2011. Through the interrogatory responses and in its reply submission, Kenora Hydro agreed to reduce the amount provided in its 2011 OM&A for costs associated with the 2011 cost of service proceeding from $37,500 to $9,447. A breakout of the costs is presented in table 13.

[17] Response to Board staff supplemental interrogatory No. 22

Table 13

2011 Cost of Service Application Projected Costs			
	As Filed	IR response**	Reply Submission
OEB Assessment for Hearing (intervenor costs)	$ 38,000	$ 12,000	$ 12,000
OEB Section 30 Costs	$ 1,000	$ 30,000	$ 2,000
Expert Witness	$ 6,000		
Legal Costs (2010)*	$ 3,000		
Legal Costs*	$ 15,000		
Consultant Costs (2010)	$ 32,000	$ 8,787	$ 8,787
Consultant Costs	$ 55,000	$ 15,000	$ 15,000
Total	$ 150,000	$ 65,787	$ 37,787
annual amortized amount	**$ 37,500**	**$ 16,447**	**$ 9,447**

Notes:
* In "IR Response" and "Reply Submission columns" assumes legal costs included in Consultant Costs.
** VECC interrogatory No. 20

BOARD FINDINGS

The Board finds that the proposed changes are acceptable and approves the amortization of the revised projected cost of the 2011 cost of service application over a four year period.

Low Income Energy Assistance Program

In response to Board staff interrogatory No. 21, Kenora confirmed that its original application did not include a provision for Low Income Energy Assistance Programs (“LEAP”) or for legacy programs such as winter warmth. Kenora calculated that the costs of LEAP, based on 0.12% of the proposed total distribution revenue for 2011 ($3,208,191) would total $3,849.83. This calculation is consistent with the Board’s guidance found in its letter on LEAP Emergency Financial Assistance dated October 20, 2010.

VECC and Board staff submitted that Kenora should update this calculation in accordance with the approved revenue requirement as approved by the Board in this proceeding. Kenora Hydro replied that it would so.

BOARD FINDINGS

The Board directs Kenora Hydro to reflect a re-calculated LEAP, based on the findings in this Decision and Order, in its revenue requirement at the time the draft Rate Order is prepared.

Affiliate Charges

The City of Kenora provides Finance and Billing/Collections services to Kenora Hydro. For 2011 Kenora Hydro indicated in its prefilled evidence that it would be charged for $24,744 for the Finance services and $239,800 for Billing/Collections for a total of $264,544. In its response to Board staff interrogatory No. 24, Kenora Hydro proposed to reduce the Billing/Collections charge by $40,434 to correct for an overstatement of projected costs.

Kenora Hydro provides water meter readings, billing/accounting and street lighting maintenance services to the city. For 2011 Kenora Hydro will charge the city $50,156, $44,250 and $73,750 respectively for these services.[18]

Board staff submitted that it had no concerns on the costs and revenues associated with the transactions between Kenora Hydro and the city, given the correction identified by Kenora in its response to Board staff interrogatory No. 24. Board staff also noted that it was not commenting on whether these activities are compliant with Section 71 of the *Ontario Energy Board Act.* VECC did not make a submission on affiliate charges other than noting and accepting the aforementioned $40,434 correction.

BOARD FINDINGS

The Board accepts the adjusted forecasted charges and revenues between Kenora Hydro and the city.

OM&A Summary

Kenora Hydro originally filed OM&A expenses for the 2011 Test Year in the amount of $2,062,785. Through the interrogatory process and confirmed in its reply submission, Kenora has proposed to reduce this amount by $76,566. The Board has accepted this reduction.

The Board has also reduced the 2011 OM&A by a further $15,000 related to the provision for inflation and salary and wage increases.

After making these adjustments, the increase, excluding the costs associated with the Rate Application, the Asset Management Plan, new LEAP costs, OMERS, and Smart Meter costs, between 2009 actual and 2011 Test year is about 9.3% or about 4.5% per annum.

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[18] Source: Exhibit 4-4-5 p2 table 8

Although the Board is approving no additional general reductions in 2011 OM&A, the Board views the year-over-year incremental growth rate in OM&A expenses to be unsustainable and unsupported by Kenora Hydro's load and customer growth rates. The Board encourages Kenora Hydro to explore more innovative shared services models with its shareholder and other utilities, in order to increase cost efficiency and slow the overall growth rate in OM&A.

The Board expects Kenora Hydro to demonstrate enhanced OM&A cost control over the forthcoming IRM period and notes that the annual growth in OM&A expenses between actual 2009 and 2006 Board approved was 6.35%, well in excess of inflation over a similar period of approximately 1.6% per annum.

The continued growth of OM&A expenses at rates in excess of inflation may not be viewed as prudent by the Board in future cost of service rates proceedings.

PAYMENTS IN LIEU OF TAXES ("PILs")

Kenora Hydro's provision for PILs totals $20,812. Board staff raised no issues regarding the tax calculation as filed. VECC questioned $500 in depreciation associated with 2011 smart meter additions in the tax calculation which Kenora Hydro agreed to remove in the final revenue requirement calculation.

BOARD FINDINGS

The Board accepts the provision of $20,812 for PILs, subject to removing $500 related to depreciation associated with the 2011 smart meter additions that Kenora has agreed to remove in its final revenue requirement calculation.

The Board directs Kenora Hydro to re-calculate, as warranted, the level of PILs on the basis of the Board's findings in this Decision, and to include sufficient details of the calculations to ensure the accuracy of the PILs calculation.

DEPRECIATION

Kenora Hydro's 2011 provision for depreciation and amortization expenses, as originally filed totaled $468,960. In light of the reductions of $73,500 to the 2011 Capital Expenditures, Kenora Hydro proposed to reduce this amount by $2,555.

BOARD FINDINGS

The Board notes that Kenora filed this application on a CGAAP basis. Accordingly, Kenora maintained its current depreciation rates. The Board approves Kenora's provision of deprecation and amortization expenses subject to Kenora updating and revising its proposed provision to reflect reductions of $376,000 to the approved 2011 Capital Expenditures.

COST OF CAPITAL

Kenora Hydro's original application proposed a deemed capital structure which was consistent with the Board's guidelines. The cost rate for Short Term Debt and the Return on Equity as shown in table 14 were the same rates the Board specified for 2010 in its *Cost of Capital Parameters for 2010* issued on February 24, 2010. Kenora Hydro indicated its intention to update the Board's Return on Equity and deemed debt rates for 2011 pursuant to the cost of capital parameters issued by the Board on March 3. 2011.[19]

Table 14

2011 Test Year Cost of Capital					
	Amount (Rate Base)	Weight	Cost Rate	Weighted Cost	Return
Long Term Debt	$ 5,772,193	56%	3.95%	2.21%	$ 228,002
Short Term Debt	$ 412,300	4%	2.07%	0.08%	$ 8,535
Total Debt	$ 6,184,493	60%		2.29%	$ 236,536
Common Equity	$ 4,122,995	40%	9.85%	3.94%	$ 406,115
TOTAL	$ 10,307,488	100%		6.23%	$ 642,651

Source: Exhibit 5-1-2 table 1

Kenora Hydro derived the long term debt rate of 3.95% using existing and anticipated loans and other financial instruments between Kenora Hydro and the city and Infrastructure Ontario. As indicated in table 15, these instruments total $5,197,479 and carry interest costs of about $205,000.

[19] Response to Board staff interrogatory No. 27 and Reply Submission p.7

Table 15

Cost of Debt	Amount	Issue Date	Rate	Interest
City of Kenora Loan	**$ 3,069,279**	1-Jan-00	**2.77%**	**$ 85,019**
Infrastructure Ontario Loans				
Substation re-build	$ 700,000	1-Sep-10	5.80%	$ 40,600
Smart Meter	$ 1,128,200	Sept 09/Sept /10	5.50%	$ 62,051
Substation re-build	$ 300,000	1-Jan-11	5.80%	$ 17,400
Sub-total	**$ 2,128,200**			**$ 120,051**
Grand Total	**$ 5,197,479**		**3.95%**	**$ 205,070**

Source: Exhibit 5-1-2-p.2 table 2

Board staff in its submission pointed out that that specific instruments used to calculate the 3.95% debt rate totaled $5,197,479 while the 2011 rate base capitalized by long term debt totals $5,772,193. Board staff supported Kenora Hydro's choice to apply its embedded debt rate to the amount deemed capitalized by long term debt, as opposed to using a forecast or the Board's deemed debt rate, since this approach was consistent with prior Board decisions where there is no debt forecast to be issued.

In response to VECC interrogatories No. 21 and No. 46, Kenora Hydro updated interest carrying costs to reflect the current status, of the anticipated conversion, from loan to debenture, of the borrowings from Infrastructure Ontario, and confirmed that the new weighted effective cost of long term debt would be 2.72%, being $130,275 divided by $4,797,479 (the total face value of the loans and debentures as shown in table 16 below).

Table 16

Substation Rebuild L	Infrastructure Ontario	N	October 1, 2010	400,000	40	1.50%	2011	6,000
Smart Meter Loan	Infrastructure Ontario	N	Dec/09	900,000	15	3.50%	2011	31,500
Shareholder Loan	City of Kenora	Y	January 1, 2000	3,069,279	40	2.77%	2011	85,000
Smart Meter Loan	Infrastructure Ontario	N	June 1, 2011	228,200	40	5.50%	2011	6,275
Substation Rebuild L	Infrastructure Ontario	N	June 1, 2011	200,000	40	1.50%	2011	1,500
						TOTAL		$130,275

VECC submitted that the weighted long term debt rate of 2.72% may be understated since the calculation did not take the impact of the conversion delays on principal (debt) into account. Kenora Hydro agreed with VECC's observation and provided calculation details to support a weighted long term debt rate of 2.82%.

Board staff had also noted that the financial instruments shown in the table 16 total $4,797,000 which is $400,000 less than total amount of loans and debentures that underpinned the weighted long term debt rate of 3.95 % as originally filed (see table 15). Board staff asked that Kenora Hydro indentify what other debt instruments would be required to make up this difference. Kenora Hydro replied that projected working capital levels for 2011 are such that it no longer needs the $400,000 in 2011 to meet its obligations.

<u>City of Kenora Loan</u>

Kenora Hydro borrowed $3,069,278 in 1999 from the city of Kenora in the form of a debenture. The terms of the debenture were amended, by way of by-law, in February 2003. The amendment to the original by-law is re-produced below. [20]

> 5. Section 7 shall be amended to read as follows:
>
> On December 31, 1999, the Company shall borrow $3,069,278.85 by way of debenture from the City. This debenture shall be repayable based on demand, and shall bear interest at a rate equal to the City's appointed bank's prime rate for that month as used for calculating interest payments on the City's accounts.

Board staff expressed concern with the variability risk for Kenora Hydro inherent in the terms of this debenture. For example, the debenture could be recalled at any time and carrying costs could increase significantly in times of increasing short term interest rates. Board staff questioned the appropriateness of the existing terms and conditions and the impact they could have on Kenora Hydro's asset management and operating plans. Board staff submitted that Kenora should develop plans in the near future that would mitigate any financial distress that could potentially ensue. Kenora Hydro responded that it agreed that the variable rate of interest currently charged by the city can create deviations from budgeted interest rates, and from the Board's approved interest rate in rate applications. Kenora Hydro indicated that it would make an effort to renegotiate the terms of the interest rate with the city.

BOARD FINDINGS

The Board accepts the deemed capital structure of 40% equity, 4% short-term debt and 56% long-term debt, as it is consistent with the Board's guidelines.

[20] Exhibit 5-1-2- appendix A.

The Board directs Kenora Hydro to update its cost of capital for ROE and short-term debt rate based on the parameters issued by the Board in its letter of March 3, 2011.

The Board shares the concerns of Board staff and VECC with respect to the recalculated weighted long term debt rate of 2.82%. The Board is not convinced that the recalculated rate addresses the potential increase in Kenora's weighted long term debt rate when existing loans with Infrastructure Ontario are converted to debentures, and as such, may underestimate the cost of long term debt during the IRM term. However, the Board is of the view that it is the responsibility of management to appropriately quantify and estimate its cost of long term debt, particularly long term debt with non-affiliated parties. Accordingly, the Board will accept the recalculated weighted long term debt rate of 2.82%.

The Board also shares Staff's concern that the terms of Kenora Hydro's debenture with the city may not be appropriate. The variable rate and demand nature of the debenture may adversely affect Kenora Hydro's financial performance and overall corporate liquidity, potentially adversely affecting the financial integrity of the utility. The Board directs Kenora Hydro to develop a contingency plan that would mitigate any financial distress arising from higher short term interest rates and/or the unanticipated repayment of the debenture. This contingency plan is to be filed with the Board no later than, or in conjunction with, Kenora's next IRM rates application in 2012. Kenora Hydro is also encouraged, on a best efforts basis, to renegotiate the terms of the debenture with the city.

COST ALLOCATION AND RATE DESIGN

The following issues are addressed in this section:

- Revenue-to-Cost Ratios
- Monthly Service Charges ("MSC")
- Transformer Ownership Allowance
- Retail Transmission Service Rates ("RTSR")

Revenue-to-Cost Ratios

Kenora Hydro indicated that it used the Board-approved Cost Allocation model (CA model) as well as followed the Board's guidelines and instructions to calculate the allocated costs and revenues by class. In response to VECC interrogatory No. 21, Kenora Hydro provided revised class revenue amounts to correct for mismatched figures which were reflected in Exhibit 7-1-2 Table 2. The Revenue to Cost Ratios per the CA Model and the Proposed Revenue to Cost Ratios for 2011 are shown in table 17.

Table 17

2011 Revenue to Cost Ratios

RATE CLASSES	Revenues *	Allocated Costs (per CA model)	Revenue to Cost Ratio (per CA model)	Proposed Revenue to Cost Ratio	Policy Range (%)
Residential	$ 1,887,941	$ 1,875,272	100.68%	100.67%	85-115
GS< 50 kW	$ 523,774	$ 683,802	76.60%	80.00%	80-120
GS >50 kW	$ 729,147	$ 567,693	128.44%	124.52%	80-180
Street lighting	$ 59,086	$ 76,164	77.58%	77.66%	70-120
Unmetered Scattered Load	$ 8,243	$ 5,260	156.71%	138.00%	80-120
Total	$ 3,208,191	$ 3,208,191	100.00%		

Note: '* Base Revenues increased in same proportion as exisitng rates plus offset revenue as allocated in CA model.

Source: Response to VECC interrogatory No. 22

Kenora Hydro indicated that for 2011 it adjusted the ratios for GS<50 kW and Unmetered Scattered Load to bring them within the Board’s policy range. However, with respect to Unmetered Scattered Load, Kenora Hydro would phase-in the adjustment over three years: to 138% in 2011, to 129% in 2012 and to 120% in 2013. Kenora Hydro also adjusted the ratio for GS> 50kW from 128.44% to 124.52% to bring it closer to 100% so as to reduce the amount of inter class subsidization. Kenora Hydro compared this adjustment as similar to that of moving a ratio to within the Board’s policy range, with the purpose of reducing inter-class subsidization.

VECC submitted that Kenora Hydro had properly applied the Board’s cost allocation methodology and the CA model-generated revenue to cost ratios were a good place to start.

Both VECC and Board staff noted that although Kenora Hydro was adjusting the revenue to cost ratio downward for Unmetered Scattered Load class in 2012 and 2013, there were no offsetting ratio changes in the other classes. VECC submitted that subject to a clarification from Kenora Hydro that it intended to also change the GS> 50kW ratios it had no concerns regarding Kenora’s proposed revenue to cost ratio adjustments for either 2011 or for the years 2012 and 2013. In this regard, Kenora Hydro submitted new ratios to correct for this oversight. Table 18 sets out the revised ratios for 2012 and 2013 proposed by Kenora Hydro.

Table 18

2011-2013 Revenue to Cost Ratios

RATE CLASS	2011	2012	2013	policy range
Residential	100.67%	100.67%	100.67%	85-115
GS< 50 kW	80.00%	80.00%	80.00%	80-120
GS >50 kW	124.52%	124.61%	124.70%	80-180
Street lighting	77.66%	77.66%	77.66%	70-120
Unmetered Scattered Load	138.00%	129.00%	120.00%	80-120

VECC also observed that the pattern of year over year changes for the GS>50 ratio is unique. The current cost to revenue ratio of 128.44% drops to 124.52 in 2011 and then increases marginally in 2012 and 2013. VECC submitted that this is acceptable since the material reduction in 2011 helps to offset the significant increase in overall distribution rates.

BOARD FINDINGS

The Board finds that the proposed revenue to cost ratios are acceptable and consistent with the Board's revenue to cost ratio policy.

The Board directs that the accepted revenue to cost ratios for 2012 and 2013 are to be reflected in Kenora's 2012 and 2013 IRM.

Monthly Fixed Charges and Variable Distribution Rates

Kenora Hydro described its proposed fixed monthly rates as consistent with the Board's guidance found in the *Board Report on the Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), dated November 28, 2007. The current and proposed fixed monthly and variable distribution rates are presented in table 19.

Table 19

Change in Rates				
	Fixed Monthly		Variable	
	Current	Proposed	Current	Proposed
Residential	$ 13.53	$ 19.86	$ 0.0099	$ 0.0145
GS < 50kW	$ 25.77	$ 39.79	$ 0.0040	$ 0.0062
GS > 50kW	$ 372.26	$ 528.38	$ 1.2372	$ 1.6794
Streetlighting (kW)	$ 3.54	$ 5.20	$ 2.3277	$ 3.4214
Unmetered Scattered Load	$ 13.00	$ 16.65	$ 0.0041	$ 0.0053

Kenora Hydro indicated that the proposed fixed monthly rates are above the floor amount, with the floor amount calculated as avoided costs and noted that all changes in the Monthly Service Charge ("MSC") are due solely to changes in the total base revenue requirement attributable to each customer class. Kenora Hydro considered it appropriate for the purposes of setting rates in this application to maintain the current and fixed and variable proportions of its rates. Kenora Hydro's understanding of the current regulatory status is that distributors are not presently required to change their fixed monthly rate even though it may exceed the ceiling. Kenora provided a history of the Board's activity concerning the question of fixed/variable split and the Board's communication, in October 2010, to halt the Review of Distribution Revenue Decoupling Mechanisms. In light of this, Kenora concluded that it would be imprudent to make adjustments to the fixed/variable split prior to the resolution of the fixed/variable split issue.[21]

VECC disagreed with Kenora Hydro's approach that maintains the fixed/variable split proportions for each customer class.

VECC viewed Kenora Hydro's approach as inconsistent with the November 2007 Report. In that report the Board noted that the Cost Allocation methodology "set a ceiling for the MSC (Monthly Service Charge)" and stated that it considered it to be inappropriate to make significant changes to that ceiling (as had been proposed by Board Staff) and concluded that "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

[21] Response to VECC interrogatory No. 24.

required to make changes to their current MSC to bring it to or below this value at this time".

VECC submitted that the direction of the Board in its November 2007 Report was clear: that in cases where the current MSC is below the ceiling set by the Cost Allocation methodology the distributor was not to make any changes such that the resulting MSC would exceed the ceiling. VECC prepared the following table to set out Kenora Hydro's 2010 MSC by class, its proposed 2011 MSC values and the MSC ceiling based on the 2011 Cost Allocation. [22]

Class	Current MSC (2010)	Proposed MSC (2011)	Board's MSC Ceiling
Residential	$13.53	$19.86	$18.69
GS<50	$25.77	$39.79	$30.85
GS>50	$372.26	$528.38	$81.69
Street Lights	$3.54	$5.20	$6.40
USL	$13.00	$16.65	$9.71

Sources: Exhibit 8/Tab 1/Schedule 1, pages 3-4

VECC stated the table illustrates that for the Residential and GS<50 classes, the current MSC is below the ceiling value established by the Cost Allocation methodology and adopted by the Board. VECC submitted that, in order to conform with the Board's EB-2007-0667 Report, the 2011 MSC for these classes should be no greater than the ceiling for the respective class: $18.69 in the case of Residential and $30.85 in the case of GS<50. VECC also noted that in the case of the Residential class the bill impacts (prior to taxes) are significantly higher for low volume customers (e.g. 20.21% for 250 kWh/month and 13.73% for 500 kWh per month) than for high volume customers (e.g. 6.56% for 1,500 kWh per month and 6.88% for 2,000 kWh per month). VECC included a table in its submission which demonstrated, if an MSC value of $18.69 were to be adopted, the bill impacts would be not as divergent.

[22] VECC submission p.5

	Monthly Residential Bill impact (before taxes)	
Monthly Use	Kenora's Proposed $19.86 MSC	VECC's Proposed $18.69 MSC
250 kWh	20.21%	18.47%
500 kWh	13.73%	13.33%
750 kWh	10.52%	10.72%
1,000 kWh	8.59%	9.12%
1,500 kWh	6.58%	7.44%

Sources: Exhibit 8/Tab 1/Schedule 5, Appendix C, pages 1-3
VECC #25 c)

VECC also noted that in the case of the GS>50 and USL classes, the MSC is already above the ceiling adopted by the Board. VECC submitted, while the Board's Report does not require the value to reduced, in keeping with the spirit of the Report, the value should not be increased further in 2011.

Board staff did not have any concerns with Kenora Hydro's proposed fixed monthly rates.

In its reply submission, Kenora Hydro did not respond to VECC's submissions on the matter.

BOARD FINDINGS

The Board accepts Kenora Hydro's proposed MSC which maintain the current fixed/variable proportions. The Board believes that the proposed MSC are consistent with the Board's guidelines and previous decisions of the Board.

RETAIL TRANSMISSION SERVICE RATES

Kenora Hydro proposed new Retail Transmission Service Rates ("RTSR") which were prepared pursuant to the Board's guidelines for electricity distribution Retail Transmission Service rates (G-2008-0001) Revision 2.0 dated July 8, 2010. The resulting rates were between 6.3% and 7.3 % lower than the current RTSR rates. Kenora Hydro acknowledged, however, in the likely event that new Uniform Transmission Rates ("UTR") were issued during the proceeding, it was prepared to update its proposed RTSR for 2011 as necessary. VECC and Board staff agreed that the RTSR rates should be updated if new UTRs were issued during the proceeding.

On January 18, 2011 the Board issued its Rate Order for Hydro One Transmission (EB-2010-0002) which adjusted the UTRs effective January 1, 2011 as indicated in the table below.

Table 20

Uniform Transmission Rates	kW Monthly Rates		Change
	Jan 1, 2010	Jan 1, 2011	
Network Service Rate	$2.97	$3.22	+8.4%
Connection Service Rates			
Line Connection Service Rate	$0.73	$0.79	
Transformation Connection Service Rate	$1.71	$1.77	
			+4.9%

Kenora Hydro included in its reply submission updated RTSRs, along with the supporting RTSR Adjustment model, reflecting the UTR effective January 1, 2011. The updated proposed RTSRs are shown below.

Retail Transmission Service Rates Proposed for 2011

RATE CLASS	Network Charges			Connection Charges		
	Current	Proposed	% change	Current	Proposed	% change
Residential (per kWh)	$ 0.0059	$ 0.0059	0.0000%	$ 0.0016	$ 0.0016	0.0000%
GS< 50 kW (per kWh)	$ 0.0052	$ 0.0052	0.0000%	$ 0.0014	$ 0.0014	0.0000%
GS >50 kW (per kW)	$ 2.1686	$ 2.1657	-0.1337%	$ 0.5417	$ 0.5434	0.3138%
Street lighting (per kW)	$ 1.6355	$ 1.6330	-0.1529%	$ 0.4187	$ 0.4200	0.3105%
Unmetered Scattered Load (per kW)	$ 0.0052	$ 0.0052	0.0000%	$ 0.0014	$ 0.0014	0.0000%

As compared to the current charges, only the GS > 50kW and Street lighting classes indicate a change, and these are less than a 0.5% reduction.

BOARD FINDINGS

The Board accepts the updated retail transmission rates proposed for 2011.

DEFERRAL AND VARIANCE ACCOUNTS

Kenora Hydro listed in its pre-filed evidence the deferral and variance accounts currently in use and the associated balances, including interest, as of December 31, 2009.[23] The net balance for all these accounts is a debit of $153,032. The net balance is comprised of accounts which Kenora Hydro seeks to dispose by way of rate rider, the

[23] Exhibit 9-1-1 table 1 and table 2

Smart Meter account balances and the remaining accounts which would stay on the books for future consideration.

Kenora Hydro seeks disposition of the account balances, shown in table 21, totaling a credit of $518,855, by way of rate rider over a period of four years commencing in 2011.[24]

Table 21

DEFERRAL AND VARIANCE ACCOUNTS - Proposed for dispostion-		
(balances, including interest, as of 31-12-2009 **Balances for Dispostion**	Account Number	Amount
RSVA - Wholesale Market Service	1580	-$ 331,676
RSVA - RT Network Service	1584	-$ 6,836
RSVA - RT- Connection	1586	-$ 507,032
RSVA - Power including global adjustment	1588	$ 246,112
Sub-total RSVA accounts		-$ 599,432
Other Regulatory Assets *	1508 & 1525	$ 80,577
Total **		-$ 518,855

note: * OEB cost assessments & OMERS
** totals $521,517 including interest to April 30, 2011

The total for all accounts listed in table 21, but excluding the global adjustment sub-account, is a $674,716 credit. The global adjustment sub-account balance is a $155,561 debit. Kenora Hydro has calculated rate riders that allow for the disposition of the global adjustment sub-account debit only to non-RPP customers.

The remaining deferral and variance account balances total $671,887 and are comprised of the accounts listed in table 22. Kenora Hydro is not requesting disposition and recovery of these account balances, except for the two Smart Meter accounts. The Board will consider the Smart Meter accounts later in this Decision.

[24] In response to Board staff interrogatory No. 31, Kenora Hydro confirmed that the account balances set out in Exhibit 9-1-1-p.1 table 1 are consistent with the balances reported under RRR 2.1.7 for the year ended December 31, 2009. The disposition amount ($521,517) for the purposes of generating the applicable rate riders includes forecasted interest to April 30, 2011.

Table 22

DEFFERAL AND VARIANCE ACCOUNTS	Balances not cleared by rate rider
(balances, including interest, as of 31-12-2009)	
	Amount
IFRS Transition	$ 3,734
Renewable Generation	$ 12,438
Smart Grid	$ 1,847
Smart Meters - Revenue and Capital	$ 869,938
Smart Meters - Expenses	$ 138,217
Regulatory Asset Recovery	$ 1,367
PILs account 1562	$ 6,535
Future Income Tax Accrual	-$ 362,189
Total	**$ 671,887**

Kenora Hydro, while noting the default term for the disposition of Group 1 balances is usually one year, proposed to recover the credit balance of $521,517 over a four year period. Kenora Hydro was concerned that a disposition period of one year would result in a significant rate impact commencing May 1, 2012 when the credit rate rider would lapse. Kenora Hydro viewed a four year term as a means of mitigating the resulting rate shock associated with a one year disposition.

In response to Board staff interrogatory No. 33, Kenora Hydro provided residential bill impacts, holding all other variables constant, associated with a one, two and three year rate riders. Board staff submitted, based on this evidence, that a one year disposition results in significant mitigation by reducing the year-on-year delivery, and total bill impacts for 2011 by 60% and 40% respectively. With a one year recovery, the 2011 bill impact is 19.7% (delivery) and 6.1% (total bill). Under this scenario, in 2012 with the termination of the credit, the delivery and total bill impacts would be 14.75% and 4.9 % respectively. Assuming an IRM increment of about 1.5%, this would have rates in 2012 increase by less that the delivery increase, and slightly more than the total bill increase experienced in 2011, all else being equal. VECC also saw no reason to depart from the default one-year recovery period.

Also referring to the response to Board staff interrogatory No. 33, VECC submitted that when the rate increases for 2011 are taken into account along with the impact when the rate rider is discontinued, a one-year recovery period produces a more stable and acceptable outlook for year over year rate increases.

Kenora Hydro argued that the period of disposition should be based on the time it took to accumulate the balance and must consider the magnitude of the amount to be re-paid. Kenora Hydro requested that a four year disposition be allowed, describing the one year period for disposition as unreasonable since the balances were accumulated over several years.

> Not only will customers experience a very confusing increase in rates in 2012, but Kenora Hydro will be in a position to payback this accumulated balance over a 12 month period. From a cash flow perspective, as well as the customer impacts, the one year disposal is not a logical approach to this disposal.[25]

Kenora Hydro pointed to the Waterloo North decision, EB-2009-0210, where a three year disposition was allowed. Kenora Hydro argued that it is facing the same cash flow disadvantages as Waterloo North, given the sizeable amount to be re-funded.

PILs Accounts 1562 and 1592 and 1592 sub-account HST/OVT

Account 1562 (Deferred Payments in Lieu of Taxes) shows a debit balance a $6,535. Kenora Hydro indicated that it is not seeking disposition of the account balance in this application and that it would wait until the outcome of the combined PILs (EB-2008-0381) proceeding before initiating a review of the account.

Board staff noted, and Kenora confirmed, that Kenora has not recorded any balances in account 1592 (PILS and Tax Variances for 2006 and Subsequent Years). Kenora Hydro explained that since Kenora Hydro is not subject to the federal Large Corporation Tax ("LCT") a change in legislation to repeal the LCT did not impact it. Kenora Hydro noted that this, and the fact that the LCT was not used in the 2006 rate application, was discussed at a meeting with Board staff held on October 26, 2006.

Kenora Hydro confirmed that it was unable to record incremental Input Tax Credits ("ITC") in deferral account 1592 (PILs and Tax Variances, Sub-account HST / OVAT Input Tax Credits) as directed by the Board in its 2010 IRM decision[26], dated April 16, 2010. Kenora Hydro explained that the necessary guidance from the Board became available only on December 23, 2010 and noted that while it should have the ITC

[25] Reply Submission p. 16.

[26] Excerpt from the Board's Decision and Order EB-2009-0200 p.6 "The Board therefore directs that, beginning July 1, 2010, Kenora Hydro shall record in deferral account 1592 (PILs and Tax Variances, Sub-account HST / OVAT Input Tax Credits (ITCs)) the incremental ITC it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST. Tracking of these amounts will continue in the deferral account until the effective date of Kenora Hydro's next cost of service rate order. 50 % of the confirmed balances in the account shall be returnable to the ratepayers."

amount ready by March 28, 2011, it would only file this information in this proceeding if formally requested. [27]

Board staff accepted Kenora Hydro's explanation and submitted that for practical reasons, such as the advanced stage of this proceeding and the need for audited numbers, the Board's consideration of amounts recorded in the sub-account should take place in a subsequent proceeding.

Staff submitted that the Board may wish to direct Kenora Hydro to bring forward this sub-account, for disposition in the next rate proceeding for Kenora Hydro which would be the 2012 IRM application. Board staff noted that while a review and disposition of account 1592 would not be typically within the scope of an IRM proceeding, waiting until Kenora Hydro's next rebasing application, anticipated for 2015, would result in an unreasonably long delay in providing customers with the benefit of the ITCs. Staff also noted that the timing question is a generic issue that would apply to all applicants that have a deferral account for ITCs and whose next applications are within the IRM framework.

BOARD FINDINGS

The Board finds that the account balances for rate rider disposition are acceptable and that they be disposed of on a final basis as of December 31, 2009.

The Board finds that it is appropriate to dispose of the GA sub-account by means of a separate rate rider applicable to non-RPP customers that is included in the delivery component of the bill. The Board notes that this approach is the prevalent practice amongst distributors and was the approach used by the Board in the 2011 IRM applications.

The Board finds the rate rider charge determinants to be appropriate.

In general, the Board finds that a one year disposition period is appropriate. The Board is not persuaded that there is sufficient reason to depart from the default one-year recovery period and believes that a one-year disposition will result in a significant opportunity for rate mitigation in the context of this application. However, as noted by the Board later in this Decision and Order, the effective date for final rates arising from this proceeding is a matter to be determined by the Board. In order to avoid multiple

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[27] Response to Board staff interrogatory No. 6

changes in rates over the 2011 rate year, the disposition period will begin with the effective date for final rates and end April 30, 2012.

The Board acknowledges that Kenora Hydro has indicated that it will wait for the outcome of the combined PILs (EB-2008-0381) proceeding before initiating a review of the account 1562.

The Board directs Kenora Hydro to bring forward sub-account 1592 for disposition in its next rate proceeding, being the 2012 IRM application. The Board believes that waiting to dispose of this account until Kenora's next cost of service rates application in 2015 results in an unreasonably long delay in providing customers with the benefit of the ITCs.

New Variance Account

Kenora is requesting Board approval for the establishment of a new variance account to track future charges from the IESO for smart meter entity and MDMR costs. In response to Board staff interrogatory No. 37 Kenora confirmed that its 2010 and 2011 OM&A expenses do not have a provision for these anticipated costs.

Board staff submitted, and VECC concurred, that the Board should deny this request. Board staff pointed to the PowerStream decision, EB-2010-0209, at page 9 where, regarding a similar request, the Board concluded that "In terms of tracking the MDM/R costs it is open to the Applicant to do so should these costs arise in advance of PowerStream's next rate application, but the Board will not establish a formal deferral account at this time." Board staff indicated that it was unaware of any additional certainty subsequent to the PowerStream decision regarding the timing and magnitude of Smart Meter entity charges for both the historical and future periods.

Kenora Hydro did not respond concerning this matter in its reply submission.

BOARD FINDINGS

The Board denies Kenora Hydro's request for an MDMR variance account. The Board believes that this request is premature and that Kenora has made no provision in its 2011 OM&A expenses for anticipated MDMR costs. Furthermore, the Board notes that has not been any additional certainty regarding the timing and magnitude of these costs since the date of the PowerStream decision.

Late Payment Penalty Recovery

In its initial evidence Kenora Hydro sought recovery of a one-time expense of $16,378 for the Late Payment Penalty Costs. This is the amount Kenora Hydro would pay on June 30, 2011 pursuant to the terms of the settlement of the LPP Class Action as approved by the Honourable Mr. Justice Cumming of the Ontario Superior Court on July 22, 2010. Pending further Board action on the matter, Kenora Hydro proposed a one year rate rider to recover said amount from ratepayers and the establishment of a variance account to record any difference between the costs paid and the amount collected from customers.

On February 22, 2011 the Board issued its generic decision and order, file EB-2010-0295, regarding the recovery from ratepayers of the costs and damages incurred in the Late Payment Penalty Class Action. On March 4, 2011 Kenora filed its proposed rate riders allowing for the recovery of $16,378 as directed by the Board in its February 22, 2011 Decision and Order.

Except for the total amount to be recovered, Board staff had no issues with the rate rider calculations. The February 22, 2011 Decision and Order indentified the recoverable amount for Kenora to be $16,296.32 while the rate rider calculation is based on $16,378. In its reply submission, Kenora Hydro recognized this oversight and provided revised riders as shown in table 23. Kenora Hydro also confirmed Board staff's assumption that given the Board's Decision and Order dated February 22, 2011 Kenora Hydro is no longer seeking the establishment of a variance account.

Table 23

Kenora Hydro Electric Corporation Ltd.
Late Payment Settlement Recovery Rate Rider
REVISED MARCH 31, 2011
Board File EB-2010-0295

Class	2009 2.1.5 RRR Distribution Rev	Revenue Proportion	Recovery $ 16,296	2009 2.1.5 Data # Customers	2009 2.1.5 Data # Connections	Annual Charge Per Cust/Conn	Monthly Fixed Rate Rider	Monthly Fixed Rounded 2 dec.	Check Monthly RR
Residential	1,189,684.68	59.85%	$ 9,753.37	4,777		$ 2.04	$ 0.1701	$ 0.17	$ 9,750.81
GS < 50 kW	327,549.58	16.48%	$ 2,685.34	733		$ 3.66	$ 0.3053	$ 0.31	$ 2,685.42
GS > 50 kW	434,648.78	21.87%	$ 3,563.37	69		$ 51.64	$ 4.3036	$ 4.30	$ 3,563.38
Streetlights	35,890.38	1.81%	$ 294.24		532	$ 0.55	$ 0.0461	$ 0.05	$ 294.30
TOTALS	1,987,773.42	100.00%	$ 16,296.32						$ 16,293.91

BOARD FINDINGS

The Board notes that Kenora Hydro is no longer asking for a Late Payment Penalty deferral account. The Board finds the total amount to be recoverable, the charge determinants, the revised rate rider, and the one-year disposition period are appropriate and consistent with the Board's generic decision and order, file EB-2010-0295 dated February 22, 2011. However, consistent with the Board's finding in this decision with respect to the effective date of final rates and to avoid multiple changes in rates over the 2011 rate year, the disposition period will begin with the effective date for final rates and end April 30, 2012.

Harmonized Sales Tax

In response to Board staff interrogatory No. 6, Kenora stated that the preparation of the 2011 Capital Budget did not include the HST and so no adjustments would be necessary. With respect to the operating budget Kenora noted that the 2011 OM&A budget included about $13,096 of HST and confirmed that that its 2011 test year OM&A should be reduced by $13,096.[28]

Board staff had no issues with the adjustment of OM&A proposed by Kenora Hydro.

BOARD FINDINGS

The Board accepts the $13,096 reduction in 2011 OM&A.

SMART METERS

Kenora Hydro in its original application sought a number of approvals regarding its smart meter program, including:

- A cost recovery rate rider of $2.09 per metered customer per month for the period May 1, 2011 to April 30, 2012 which would collect the difference between the smart meter adder collected from May 1, 2006 to December 31, 2009 and the 2009 and 2010 revenue requirement related to smart meters deployed as of December 31, 2009;

- Inclusion of smart meter capital deployed as of December 31, 2009 in the 2011 rate base, in the amount of $894,178;

- Inclusion of smart meter operation and maintenance expenses of $59,000 in the 2011 revenue requirement associated with smart meters deployed as of December 31, 2009; and

- Reducing the smart meter funding adder, from $1.00 to $0.09 per month per metered

[28] Source: Response to Board staff interrogatory No. 9.

customer, to fund remaining smart meter capital expenditures for 2010 and 2011 to complete the Smart Meter capital program.

Kenora Hydro in its pre-filed evidence indicated that the total residential and small commercial installations were 92% completed as of the end of 2009 and 100% are expected to be installed by the end of 2010. During the interrogatory process Kenora Hydro advised that that as of December 31, 2010 and as reported to the Board on January 11, 2011, 100% of the residential and 97.9% of the GS< 50kW installations are completed and 16 meters remained to be installed.[29]

Kenora Hydro also stated in its pre-filed evidence that its smart meter costs were audited as part of the 2009 financial statement audit. Board staff submitted that Kenora Hydro's evidence included the background information, pursuant to the Board's Smart Meter Guidelines, that should accompany a request for the recovery of smart meter costs. Board staff also noted that the Board, in its 2010 IRM Decision and Order for Kenora, EB-2009-0200, confirmed that Kenora is authorized to conduct smart meter activities.

Kenora Hydro indicated that it has been a member of the North West Utilities Smart Meter Initiatives Group for this project and belongs to the Smart Meter Consortium to share knowledge and access favourable group pricing. In this regard, Kenora Hydro filed a copy of a letter from the Fairness Commissioner attesting to the fairness of the selection of the two highest ranked vendors. Kenora Hydro did not file the actual procurement contract citing a non-discloser agreement with the vendor.

Rate Rider - Recovery of Smart Meter Costs

Kenora Hydro originally sought a rate rider of $2.09 per metered customer per month for the period May 1, 2011 to April 30, 2012. The rate rider would collect the difference between the smart meter adder collected from May 1, 2006 to December 31, 2009 and the 2009 and 2010 revenue requirement related to smart meters deployed as of December 31, 2009.

Board staff did not have a concern with the per unit costs, shown below, incurred to 2009 for smart meters and collectors since they fell within an acceptable historical range.[30]

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[29] In response to VECC interrogatory No. 31.
[30] Exhibit 9-2-2 p.1 table 6

Smart Meter Per Unit Costs

Ex 9 - Table 6 - Smart Meter Per Unit Costs

Advanced Metering Collection Device - Residential and GS<50		Cost Per Meter
Costs	2009	
Total Capital Cost Installed Meter	$902,185	
Number of Meters Installed	5,097	$177

OM&A Costs		Cost Per Meter
Costs	2009	
Incremental OM&A Costs -2009 Actual	$119,548	$23
OM&A Costs		Cost Per Meter
Costs	2010	
Incremental OM&A Costs - 2010 Projected	$60,000	$12

However, Board staff pointed out that the calculation of the proposed rate rider included a forecast of costs for 2010 while the Smart Meter guidelines state that the recovery by way of rate rider should only consider "actuals" that have been audited. [31] Kenora Hydro viewed the recovery of 2010 forecasted costs as beneficial for the ratepayer since this would result in interest payment savings by the utility because of improved cash flows.[32] Board staff, in principle, questioned Kenora's claim of ratepayer benefit, and absent further elaboration and evidence, submitted that the Board should put little weight on this assertion in its findings.

Board staff was also concerned with the accuracy of the results from the smart meter revenue requirement model utilized by Kenora Hydro to quantify the costs for recovery through the rate rider. Board staff noted that Kenora Hydro (i) had used the 2011 Cost of Capital for all years - going back to 2006 instead of the costs of capital that was explicitly or implicitly in rates in each year (ii) did not use the half year rule in 2009 for new additions ($62K instead of $68k/2) and (iii) did not calculate and include the 2010 revenue requirement for the meters installed in 2009 and (vi) had recorded all the smart meter capital expenditures as Meter or Meter Installation asset types; the expectation being that under Generally Accepted Accounting Principles the expectation some of the expenditures be recorded as Computer Hardware or Computer Software or Tools and Equipment.

VECC noted that Kenora Hydro had excluded the cost incurred for capabilities beyond

[31] Smart Meter Funding and Cost Recovery G-2008-0002 (dated October 22, 2008) guideline pages 11-12, utilities seeking smart meter cost recovery must base their request on costs already expensed (not forecast).
[32] Source: Response to Board staff IR No. 39.

minimum functionality. While stating that it had no concerns regarding Kenora Hydro's proposed treatment of smart meter capital costs incurred up to December 31, 2009, VECC submitted that it shared Board Staff's concerns regarding Kenora Hydro's calculation of the 2009 and 2010 revenue requirements associated with the smart meters installed as of December 31, 2009.

In its reply submission, Kenora Hydro included a revised rate rider calculation ("Rate Rider Model") to address staff's concerns and to reflect the latest Board-approved cost of capital rates for 2011.[33] The revised rate rider proposed by Kenora was $2.99.

Kenora Hydro stated that the Rate Rider Model was updated to reflect/correct the following:

- The cost of capital has been updated back to 2006, to reflect rates explicit or implicit in each year;
- The 2009 software costs of $56,296 have been transferred to the Software category.
- Calculations for the ½ year amortization were corrected for 2009; and
- The 2010 revenue requirement column was updated to include the 2009 capital.

Kenora Hydro also noted that a revision to smart meter 2009 capital expenditures was required. Upon review, and in light of the Frequently Asked Questions released by the Board in December 2010, Kenora Hydro determined that $34,932 for internal labour and equipment time for smart meter installations had been inappropriately charged to the smart meter deferral account 1555. Kenora Hydro concluded that these costs should not have been included since they were not incremental to its operations. Kenora Hydro confirmed that the revised Rate Rider Model corrects for this. While acknowledging that parties would not have had an opportunity to comment on this correction, Kenora Hydro noted the amount is immaterial in comparison to the total being adjusted and that the correction benefits rate-payers.

<u>Rate Adder</u>

Kenora proposed to reduce the current smart meter funding adder, from $1.00 to $0.09 per month per metered customer, to fund remaining smart meter operating and capital expenditures for 2010 and 2011. Kenora Hydro indicated that the adder reflected annual maintenance expenses of $1,000 and installation costs in 2011 of $15,000.

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[33] See Board letter dated March 3, 2011 re: Cost of Capital Parameters for 2011 Cost of Service Applications for Rates Effective May 1, 2011.

Board staff asked Kenora Hydro to confirm whether the installation costs pertain to the installation of meters that were purchased but not installed in 2010. Board staff also submitted that, given the relatively small magnitude of the number of meters left to be deployed, the Board should consider approving the inclusion of the aforementioned costs in rate base on a final basis. This treatment would simplify the presentation of Smart Meter cost recovery on the bill and would provide finality to the smart meter review process for Kenora Hydro. In this regard, Board staff asked that Kenora Hydro indicate what the capital cost per unit for the remaining installations in 2011 will be as compared to the audited costs for meters already deployed.

VECC disagreed with Board's staff's suggestion regarding the rate base treatment of 2010 and 2011 forecasted expenditures. While recognizing that the remaining spending is small relative to the total program costs, VECC noted that the Board's practice to-date has been to only permit audited smart meter spending to be included in rate base. VECC expressed concern about the precedent that may be set if the Board adopts Board staff's suggestion. In the event that Board adopts Staff's suggestion, VECC noted that the weighted costs of meters by customer class as used in the Cost Allocation study would need to be updated.

Kenora Hydro in its reply submission included an updated run of the Rate Adder Model which reduced the proposed original Rate Adder from $0.09 to $0.04. Kenora Hydro indicated that the original run had included non-incremental costs which it now excluded from the updated run of the model. The updated Rate Adder would generate $2,436 in funds in 2011 as compared to $5,911 with the original Rate Adder. Given the small amount involved and the administrative burden associated with implementing and tracking a new rate adder, Kenora Hydro submitted that that it wished to withdraw its request for a Rate Adder.

<u>Stranded Meters</u>

As presented in the pre-filed evidence, the costs of the conventional, and now stranded meters, continued to be recovered in the revenue requirement since the stranded meter assets remained in rate base. Kenora Hydro referenced the Board's EB-2007-0063 decision dated August 8, 2007 to support this treatment. Kenora also confirmed that it would continue to record stranded meter costs at their original cost in account 1860-Meters and amortize them at a 25 year rate until directed otherwise by the Board. [34] Kenora stated that net book value of all conventional meters was $174,069, for

[34] Response to Board staff interrogatory No. 38

purchases up to December 31, 2005; that the conventional meters purchased from 2006 to 2008 had a net book value of $40,999 and these amounts are all included in rate base.[35] [36]

Board staff pointed to a discrepancy between the aforementioned amounts and the amount of $172,284 indentified in the summary of stranded meter costs in part vii) of the response to Board staff interrogatory No. 38.

Given that Kenora Hydro had almost completed its smart meter installation program and most of its smart meters will be included in rate base, Board staff submitted that this application should also address an appropriate recovery mechanism for recovering the stranded costs.

Board staff also noted the Smart Meter Funding and Cost Recovery Guideline (G-2008-0002), dated October 22, 2008, instructed distributors to report the stranded meter costs in a new sub-account: Smart Meter Capital and Recovery Offset Variance Account 1555, sub-account Stranded Meter costs. Disposition of said accounts would be determined by the Board in a future proceeding.

Board staff stated that the Board's combined decision, EB-2007-0063, referenced by Kenora Hydro for continued rate base treatment, was issued several years ago at a time when the deployment of smart meters was only at an early stage and the full impacts of the stranded meter costs were largely unknown. In the current situation, as the distributor will be receiving rate base treatment on most of its smart meters that have replaced its "stranded" meters, Board staff asserted that that it may no longer be appropriate for the distributor to receive a concurrent rate base treatment for stranded meters that are no longer used and useful.

Board staff submitted that at this time, a simpler and more appropriate approach from an accounting perspective for recovery of stranded meters may be to allow recovery of the estimated residual net book value of the overall stranded meters. The estimated amount would comprise the pooled residual net book value of the removed from service meters, less any sale proceeds and contributed capital, to the time when smart meters would have been fully deployed (e.g., as of December 31, 2011). The total estimated stranded costs of $175,000 as of December 31, 2011 could then be recovered through a separate rate rider. In the event the Board adopted this approach, Board staff noted

[35] Exhibit 9-2-1 p.2. ln 10-15
[36] Response to Board staff interrogatory No. 38 part (i)

that Kenora Hydro should revise this estimate to the end of 2011 to reflect the derivation of the amount discussed above and to reflect information that is more current.

Board staff also submitted that the estimated total costs related to the stranded meters in rate base, on approval for recovery, should be removed from rate base (and Account 1860, Meters) and tracked in “Sub-account Stranded Meter Costs” of Account 1555. The associated recoveries from the separate rate rider would also be recorded in this sub-account to draw down the balance in the sub-account. The approved estimate of stranded meter costs would be trued-up to actual costs, recorded in the sub-account, and submitted for review in the distributor’s next cost of service application. A final disposition of the sub-account balance (comprised of the final stranded meter costs as of December 31, 2011 net of the rate rider recoveries) would be addressed in that proceeding.

Board staff invited parties to comment on the recovery methodology for the stranded meter costs, the proposed recovery period, and the associated bill impacts. VECC did not comment on this proposal in its submission.

Kenora Hydro agreed with the proposal to dispose stranded meter assets by way of a rate rider, with a true-up in the next COS rate application. Kenora Hydro suggested a “per meter” based rate with a four year term to mitigate further rate increase.

Kenora Hydro also provided updated figures as to the net book value of the stranded meters that that would remain on its books as of December 31, 2011. The net book value of conventional meters procured prior to 2006 is $117,712 and the net book value of conventional meters procured after 2006 is $36,181 for a total net book value of $153,893. Kenora Hydro also sought clarification whether the amount to be transferred to a sub-account of account 1555 would include meters purchased after the 2005 cut-off as well as those purchased prior to 2006.

BOARD FINDINGS

The Board believes that it is appropriate to close smart meter capital deployed as at December 31, 2009 of $894,178 to rate base. The Board notes that this amount was audited as part of the 2009 financial statement audit and that Kenora Hydro provided the requisite background information pursuant to Board’s Smart Meter Guidelines. The Board has also previously confirmed, in EB-2009-0200, that Kenora Hydro is authorized to conduct smart meter activities.

The Board notes that the approved 2011 OM&A includes expenses associated with smart meters.

The Board finds that the revised Rate Rider Model, as amended, is appropriate. However, as set out below in the section that discusses the effective date for rates, the Board finds the appropriate term of the rate rider is July 1, 2011 to April 30, 2012.

The Board accepts the withdrawal of Kenora Hydro's application for a Smart Meter Funding Adder and the non-recovery of approximately of $2,436 in 2011.

The Board accepts the treatment of Stranded Meters suggested by staff. Stranded Meter costs are to be removed from rate base as of the opening balance for January 1, 2011. Kenora Hydro is directed to confirm the opening net book value of these assets as of January 1, 2011. Kenora Hydro is directed to update its revenue requirement calculation to reflect the removal of these assets from rate base. The Board reminds Kenora Hydro that one of the updates to its revenue requirement calculation arising from the removal of Stranded Meters from rate base is a reduction in test year depreciation. The Board also approves a rate rider, effective July 1, 2011 to April 30, 2012, to be charged on a per meter basis to recover the Stranded Meter costs.

EFFECTIVE DATE

Kenora Hydro in its application filed on November 1, 2011 requested that the Board make its new rates effective May 1, 2011. Subsequently, Kenora Hydro by way of letter dated January 5, 2011 requested that the Board declare Kenora Hydro's current rates interim, effective May 1, 2011, in the event that the Board's Rate Order for this proceeding would not be issued by May 1, 2011. In Procedural Order No. 2 and Order for Interim Rates issued on February 24, 2011, the Board declared Kenora Hydro's current rates interim and emphasized that the order for interim rates should not be construed as predictive, in any way whatsoever, of the final determination of the Application.

Board staff in its submission stated that a November 1, 2010 filing is about 2 months later than expected for a May 1 effective date and noted that Kenora Hydro indicated that it " does not have the expectation that potential under-recovered revenues between the period May 1, 2011 and the time new rates are implemented will be recouped". [37]

[37] Response to Board staff supplemental interrogatory No.1

Board staff also noted that while Kenora Hydro delayed the filing of responses to the first round of interrogatories by 10 days, it made a significant effort to respond to all interrogatories and to update its application accordingly. Given the current timing and circumstances, Board staff submitted, and VECC agreed, that the Board may wish to approve a July 1, 2011 effective date and that the rates can be implemented on this same date barring any further delays in this proceeding. Board staff is of the view that a further delay in the effective date beyond the two months noted above for the filing of the initial application is not warranted.

BOARD FINDINGS

The Board finds July 1, 2011 to be a fair and reasonable date for rates to be declared effective, given the late filing of the application.

<u>Draft Rate Order</u>

The Board has made findings in this Decision which change the 2011 revenue requirement and therefore change the distribution rates from those originally proposed by Kenora Hydro. In filing its draft Rate Order, it is the Board's expectation that Kenora Hydro will not use a calculation of the revised revenue sufficiency to reconcile the new distribution rates with the Board's findings in this Decision. Rather, the Board expects Kenora Hydro to file detailed supporting material, including all relevant calculations showing the impact of this Decision on Kenora Hydro's revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates. Supporting documentation shall include, but not be limited to, filing 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.

1. Kenora Hydro shall file with the Board, and shall also forward to intervenors, a draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision within **14 days** of the date of the issuance of this Decision. The draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates including the Revenue Requirement Work Form in Microsoft Excel format.

2. Intervenors shall file any comments on the draft Rate Order with the Board and forward to Kenora Hydro within **7 days** of the date of filing of the draft Rate Order.

3. Kenora Hydro shall file with the Board and forward to intervenors responses to any comments on its draft Rate Order within **4 days** of the date of receipt of intervenor comments.

COST AWARDS

The Board may grant cost awards to eligible stakeholders pursuant to its power under section 30 of the *Ontario Energy Board Act, 1998*. The Board will determine eligibility for costs in accordance with its *Practice Direction on Cost Awards*. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board's *Practice Direction on Cost Awards*. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

1. Intervenors shall file with the Board and forward to Kenora Hydro their respective cost claims within **7 days** from the date of issuance of the final Rate Order.

2. Kenora Hydro shall file with the Board and forward to intervenors any objections to the claimed costs within **21 days** from the date of issuance of the final Rate Order.

3. Intervenors shall file with the Board and forward to Kenora Hydro any responses to any objections for cost claims within **28 days** of the date of issuance of the final Rate Order.

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

All filings with the Board must quote the file number EB-2010-0135, and 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 be received by the Board by 4:45 p.m. on the stated date. Parties should 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 e-mail their documents to the attention of the Board Secretary at BoardSec@ontarioenergyboard.ca. All other filings not filed via the Board's web portal should be filed in accordance with the Board's *Practice Directions on Cost Awards*.

DATED at Toronto**,** May 25, 2011
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary