2008 Electricity Distribution Rates
Atikokan Hydro Inc.
EB-2008-0014

OM&A EXPENSES

1. General – Regulatory Costs

(i) Please present the breakdown for actual and forecast, where applicable, for the 2006 Board approved, 2006 actual, 2007 bridge year, and 2008 test year regulatory costs as shown in the table below.

(ii) Under "Ongoing or One-time Cost", please identify and state if any of the regulatory costs are "One-time Cost" and not expected to be incurred by the applicant during the impending two year period when the applicant is subject to 3rd Generation IRM process or it is "Ongoing Cost" and will continue throughout the 3rd Generation IRM process.

(iii) Please provide Atikokan Hydro's proposal on how it intends to recover the "One-time" costs as part of its 2008 rate application.

Regulatory Cost Category	Ongoing or One-time Cost?	2006 Board Approved	2006 Actual	2007 (as of Dec 07)	% Change in 2007 vs. 2006	2008 Forecast	% Change in 2008 vs. 2007
OEB Annual Assessment							
OEB Hearing Assessments (applicant initiated)							
OEB Section 30 Costs (OEB initiated)							
Expert Witness cost for regulatory matters							
Legal costs for regulatory matters							
Consultants costs for regulatory matters							
Operating expenses associated with staff resources allocated to regulatory matters							
Operating expenses associated with other resources allocated to regulatory matters (please identify the resources)							
Other regulatory agency fees or assessments							
Any other costs for regulatory matters (please define)							

2. Ref: Exhibit 4/ Tab 1/ Schedule 2/ Page 1

Table 1 below was prepared by Board staff to review Atikokan Hydro's OM&A expenses. Note rounding differences may occur, but are immaterial to the questions below.

Table 1

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
OM&A Expenses				
Operations	258,051	284,184	262,800	311,895
Maintenance	38,224	26,278	79,500	38,800
Billing & Collecting	139,572	152,849	158,550	167,950
Community Relations	-	1,956	-	-
Administrative and General Expenses	284,294	187,469	258,000	277,000
General Advertising Expense	1,714	1,940	2,200	2,400
Total Controllable Expenses	**721,855**	**654,676**	**761,050**	**798,045**
Bad Debt	(466)	1,948	2,500	3,000
Property Insurance	6,345	7,208	7,500	8,000
Taxes other than income	-	-	-	-
Amortization Expense	145,951	155,617	145,996	168,510
Total Distribution Expenses	**873,685**	**819,449**	**917,046**	**977,555**
LCT, OCT & Income Taxes	-	-	-	-
Total Operating Costs	**873,685**	**819,449**	**917,046**	**977,555**

Table 2 below was created by Board staff to review Atikokan Hydro's OM&A forecasted expenses from the evidence provided in the application's Exhibit 4. Note rounding differences may occur, but are immaterial to the following questions.

Table 2

	2006 Board Approved	Variance 2006/2006	2006 Actual	Variance 2007/2006	2007 Bridge	Variance 2008/2007	2008 Test	Variance 2008/2006
OM&A Expenses								
Operations	258,051	**26,133**	284,184	**- 21,384**	262,800	**49,095**	311,895	**27,711**
		3.6%		**-3.3%**		**6.5%**		**4.2%**
Maintenance	38,224	**- 11,946**	26,278	**53,222**	79,500	**- 40,700**	38,800	**12,522**
		-1.7%		**8.1%**		**-5.3%**		**1.9%**
Billing & Collecting	139,572	**13,277**	152,849	**5,701**	158,550	**9,400**	167,950	**15,101**
		1.8%		**0.9%**		**1.2%**		**2.3%**
Community Relations	-	**1,956**	1,956	**- 1,956**	-	**-**	-	**- 1,956**
		0.3%		**-0.3%**		**0.0%**		**-0.3%**
Administrative and General Expenses	284,294	**- 96,825**	187,469	**70,531**	258,000	**19,000**	277,000	**89,531**
		-13.4%		**10.8%**				**13.7%**
General Advertising Expense	1,714	**226**	1,940	**260**	2,200		2,400	**460**
		0.0%		**0.0%**		**2.5%**		**0.1%**
Total Controllable Expenses	**721,855**	**- 67,179**	**654,676**	**106,374**	**761,050**	**36,795**	**798,045**	**143,369**
		-9.3%		**16.2%**		**4.8%**		**21.9%**

a) Please confirm that Atikokan Hydro agrees with the two tables prepared by Board Staff presented above. If Atikokan Hydro does not agree with any of the information in the two tables above please advise why not. If Atikokan Hydro determines that the tables require modification, please provide amended tables with full explanation of changes made.

b) Please provide a table identifying the key cost drivers that are contributing to the overall increase of 21.9% in controllable expenses over 2006 Historical relative to 2008.

3. Ref: Exhibit 4/Tab 2/Schedule 1

OM&A COSTS	2006	2008	Variance	% Change
Operation (Working Capital)				
5020-Overhead Distribution Lines and Feeders -Operation Labour	$ 242,224	$ 264,945	$ 22,721	9.38%
5025-Overhead Distribution Lines & Feeders -Operation Supplies and Expenses	$ 27,132	$ 35,300	$ 8,168	30.10%
Maintenance (Working Capital)				
5135-Overhead Distribution Lines and Feeders - Right of Way	$ 13,808	$ 25,000	$ 11,192	81.05%
Billing and Collections				
5310-Meter Reading Expense	$ 47,198	$ 52,050	$ 4,852	10.28%
5315-Customer Billing	$ 99,261	$ 110,000	$ 10,739	10.82%
5340-Miscellaneous Customer Accounts Expenses	$ 5,745	$ 6,800	$ 1,055	18.36%
Administrative and General Expenses				
5610-Management Salaries and Expenses	$ 9,779	$ 12,500	$ 2,721	27.82%
5615-General Administrative Salaries and Expenses	$ 48,986	$ 62,000	$ 13,014	26.57%
5620-Office supplies and expenses	$ 4,675	$ 7,200	$ 2,525	54.01%
5630-Outside Services and Employed	$ 5,212	$ 65,000	$ 59,788	1147.12%
5665-Miscellaneous General Expenses	$ -	$ 3,200	$ 3,200	N/A

The above table depicts the variances between 2006 and 2008 of certain operating costs. Atikokan Hydro has provided no explanation or justification for the variances.

For each variance, please provide a clear and detailed explanation.

4. Ref: Exhibit 4/Tab 2/Schedule 3/Pages 2 and 3

The schedule presented is described as providing explanations for variances between 2006 actual and 2007 bridge year. However, the figures presented are labeled 2007 bridge and 2008 test year.

For the record, please update Pages 2 and 3 with the correct labels.

5. Ref: Exhibit 4/Tab 2/Schedule 3/Page 2

Please explain the variance of $20,044 in account 5415; what is described as the 2008 test year amount of $22,000 does not appear on the OM&A costs table (Exhibit 4/ Tab 2/ Schedule 1) which shows amounts of zero for both 2007 and 2008.

6. Ref: Exhibit 4/Tab 2/Schedule 3/Page 3

The 2007 Bridge year amount for account 5630 is $60,000. Please provide a breakdown of the costs incurred.

7. Ref: Exhibit 4/Tab 2/Schedule 3/Page 4

The schedule presented intends to provide explanations for some variances between the 2007 bridge and 2008 test year. However, the figures presented are labeled “Board Approved” and “2006 Actual”.

i. Please update page 4 with the correct labels.

ii. For account 5680, Exhibit 4 / Tab 2/ Schedule 1 shows the 2006 actual was $4686 and the 2007 projected is $6000 with $6500 for 2008. Please reconcile these figures with those stated on lines 9 to 10.

8. Ref: Exhibit 4/Tab 2/Schedule 3/Page 4

For account 5705, please provide a more complete explanation for the variance of $22,514. Please provide details of the missing assets and indicate the years for which they are missing.

PURCHASE OF SERVICES OR PRODUCTS

9. Ref: Exhibit 4/ Tab 2/ Schedule 7

(i) In the section “Summary of tendering process/summary of cost approach”, Atikokan Hydro appears to be providing a breakdown of the costs, but not a summary of the tendering process/summary of cost approach.

Please clarify what the “Summary of tendering process/summary of cost approach” section of this schedule represents. For instance for 2006, for Thunder Bay Hydro Utility Services, the information provided states “Wholesale 10475.45 MSP service 18656.00.” If this is intended to represent a breakdown of the total annual expense of $27,301, please explain why the two items total $29,131.45, or make any necessary corrections. If not, please state what these numbers represent. Please provide similar information for each of the purchased services for 2006, 2007 and 2008.

(ii) As required by the Filing Guidelines, please provide a summary of the tendering process/summary of cost approach for each of the services purchased from third parties.

(iii) Please state whether the 2007 information is a full year 2007 forecast, or year-to-date as of the filing date of the application.

(iv) Please explain why the 2008 forecast is the same as for 2007, except for a decrease in Elenchus costs

SHARED SERVICES

10. Ref: Exhibit 4/Tab 2/Schedule 4

Section 2.5 (Exhibit 1 Operating & Maintenance and Other Costs) of the Filing Requirements for Transmission and Distribution Applications, requires certain details of shared services. Please provide the following information for each shared service for the 2006, 2007, and 2008 rate years:

i. type of service
ii. total annual expense by service
iii. rationale and cost allocators used for shared costs for each type of service.

11. Ref: Exhibit 4/Tab 2/Schedule 4

Please provide the following information with respect to the statements made in the shared services evidence:

(i) Please indicate what equipment and office space is shared by Atikokan Hydro and its affiliate Atikokan Enercom
(ii) Please explain the process by which Atikokan Hydro determines the pricing for its employee services to Atikokan Enercom.
(iii) Please clarify the statement that “All financial arrangements are based on commercially aquired amounts [The rent for space is the same per square foot at the mall in the parking lot.”
(iv) Please explain why Atikokan Hydro believes that “There is no opportunity to use knowledge from one company to give advantage to the other.”

EMPLOYEE COMPENSATION

12. Ref: Exhibit 4 / Tab 2 / Schedule 8

On Page 1, Atikokan Hydro provides a breakdown of total compensation for 2006 to 2008. Please confirm that the salary and wages and benefits amounts for the executive have been incorporated with Atikokan Hydro’s unionized employee category.

13. Ref: Exhibit 4 / Tab 2 / Schedule 8

On Page 1, Atikokan Hydro provides a breakdown of total compensation for 2006 to 2008.

(a) Please confirm that the sum of unionized compensation (including benefits) is forecast to increase from $549,796 in 2006 to $557,680 in 2008, and that expressed on a “per FTE” basis the average compensation increases from approximately $61,088 in 2006 to $79,669 in 2008.

(b) In light of (a), please provide a justification for this two-year increase of 30%.

14. Ref: Exhibit 4 / Tab 2 / Schedule 8

On Page 1, Atikokan Hydro provides a breakdown of total benefits from 2006 to 2008. Please provide the 2006 Board Approved amount, or if no amount is available, please explain why.

15. Ref: Exhibit 4 / Tab 2 / Schedule 8

Please indicate whether or not Atikokan Hydro has an employee incentive program and if so, provide a breakdown of amounts paid for 2006, including Historical Board Approved and Historical Actual, 2007 and 2008.

16. Ref: Exhibit 4 / Tab 2 / Schedule 8

Please state whether or not Atikokan Hydro has overtime compensation. If so, please provide a breakdown of overtime amounts for 2006, including Historical Board Approved and Historical Actual, 2007 and 2008 and indicate whether these amounts have been included as part of total salary and wages.

17. Ref: Exhibit 4 / Tab 2 / Schedule 8

Please provide details regarding the status of Atikokan Hydro’s pension fund and all assumptions used in the analysis.

18. Ref: Exhibit 4 / Tab 2 / Schedule 8

Please provide a breakdown of total employee costs charged to OM&A for 2006, including Historical Board Approved and Historical Actual, 2007 and 2008. For

any remaining amounts, please indicate where the costs were charged, i.e. capitalized, for all years.

CORPORATE COST ALLOCATION

19. Ref: Exhibit 4/ Tab 2/ Schedule 6

In its application, Atikokan Hydro has not stated whether there are any shared services between the distribution company and its parent, the Township of Atikokan. Please either confirm that there are no such services, or if there are, please file a detailed description of the assumptions underlying the corporate cost allocation and provide documentation of the overall methodology and policy.

RATE BASE

20. Ref: General

a) For the years 2002 to 2008 inclusive, please provide a table listing the following information (actual dollars where available, or expected, planned or projected dollars, or % where indicated):

   i. Actual Return on the Equity portion of the regulated rate base (%);
   ii. Allowed Return on the Equity portion of the regulated rate base (%);
   iii. Retained Earnings;
   iv. Dividends to Shareholders;
   v. Sustainment Capital Expenditures excluding smart meters;
   vi. Development Capital Expenditures excluding smart meters;
   vii. Operations Capital Expenditures;
   viii. Smart meters Capital Expenditures;
   ix. Other Capital Expenditures (identify);
   x. Total Capital Expenditures including and excluding smart meters;
   xi. Depreciation;
   xii. Construction Work in Progress
   xiii. Number of customer additions by class
   xiv. Rate Base
   xv. Population of service area

b) Please complete the following table:

	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Projected	2008 Projected
1. Net Income (loss)							
2. Total Depreciation & Amortization Expenses							
3. Total Capital Expenditures (including smart meters)							
4. Non-cash working capital balances							
5. Other							
Subtotal (A =1+2+3+4+5)							
Cash, beginning of period (B)							
Cash, end of period (B) + (A)							

21. Ref: Exhibit 2/ Tab 1/ Schedule 2

With reference to page 1 of this Exhibit and the Rate Base Summary Table and Associated Detailed Tables:

For Year 2006: Board-Approved Gross Assets versus Actuals:

(i) Please provide a table reconciling the cost differences and the reasons for the difference between the Board-approved Gross Asset Value totaling $3,194,987 versus an actual of $4,404,157.

(ii) Please reconcile the 2006 opening Gross Plant figure of $3,194,987 on the Rate Base Summary Table with the Continuity Statement Schedule 1 Opening Balance figure of $4,239,674 for 2006 Gross Plant Value.

(iii) Please provide a reconciliation of any audit adjustments made in order to bridge the gap between the Board-Approved figures and the actual figures that have been provided.

22. Ref: Exhibit 2

For the years 2002 to 2006 inclusive, please complete the following table including actual dollars and % where indicated. Please identify the cost drivers, as indicated in the table. Examples of cost drivers are: replacement of aging or low capacity power lines, system expansions, etc. Please identify the type and

amount of any one-time, unusual expenditure that may have been incurred in any particular year and caused a change outside the given threshold, as provided in the table. Please exclude any smart meters from the dollar amount for the capital expenditure figures used in the table.

A	B	$ Change (A-B)	% Change (A/B)	Cost Drivers for the change (increase or decrease) if the % change is either less than zero or more than 10%
2003	2002			
2004	2003			
2005	2004			
2006 Actual	2005			
2006 Actual	2006 Board Approved			
2007 Bridge Year	2006 Actual			
2008 Test Year	2007 Bridge Year			

23. Ref: Exhibit 2/ Tab 2/ Schedule 3/ Page 1

Materiality Analysis on Gross Asset - 2006 Board-Approved vs 2006 Actual

Atikokan Hydro asserts that the distribution assets for 2006 were undervalued by $824,821 because these assets were incorrectly assigned to a non-distribution asset account. Assuming that the Board approves this accounting reallocation to Atikokan Hydro's rate base, what is the effect on the average residential customer's annual bill if this asset is incorporated into rate base? Please provide a comparison between the old rate (with this error) and a new rate with this error corrected. Please show the distribution dollar component of the bill and the total for the bill.

24. Ref: Exhibit 2/ Tab 3/ Schedule 1/ Overview

a) Carry Over Projects and their Costs

(i) Please identify carryover projects where applicable, for the 2006 actual, 2007 bridge year, and 2008 test year. For each carryover project, please provide and present the information as indicated in Table 1 below.

Table 1 – Identification of Carryover Project

Type of the Carryover Project (e.g. power line replacements, pole replacements, smart meters, etc.)	**$ Carryover from 2005 to 2006**	**% Carryover from 2005 to 2006 to total 2006 Capital expenditure**	**$ Carryover from 2006 to 2007**	**% Carryover from 2006 to 2007 to total 2007 Capital expenditure**	**$ Carryover from 2007 to 2008**	**% Carryover from 2007 to 2008 to total 2007 Capital expenditure**
1.						
2.						
3.						
4.						
5.						

(ii) For each carryover project, please provide the reasons for the carryover in the format of Table 2 shown below. Please specify whether the project is a one-time or an ongoing project.

Table 2 – Reasons for the Carryover Projects

Type of the Carryover Project (e.g. Underground cable replacement, smart meters, etc.)	**One-time or ongoing project?**	**Reasons for the Carry Over**
a)		
b)		
c)		
d)		
e)		
f)		

b) Please confirm that Atikokan Hydro has no projects for which a Leave to Construct under section 92 is required.

c) Please provide Atikokan Hydro's most recent long term Capital Project or Asset Management Plan or equivalent which Atikokan Hydro may be using for long term capital planning.

d) Please indicate if Atikokan Hydro has utilized any asset condition study in developing its Asset Management Plan. Please file the study, if any, with the Board.

e) With reference to Exhibit 2/Tab3/Schedule 1/Transportation & Related Equipment, please confirm if all the old transportation equipment will continue in service or if some will be physically disposed. Please describe the physical retirement plans for these old transportation items.

f) Please provide the following information on service reliability indicators recorded and used by Atikokan Hydro:

   a. a listing of all the Service Reliability Indicators maintained and used, and their actual values for each of the years 2002 through 2007;
   b. whether or not Atikokan Hydro has maintained the reliability performance for the three year period 2003 to 2005 in 2006, and if not, why not.
   c. Atikokan's 2008 reliability improvement targets, if any, for the SAIDI, SAIFI and CAIDI.
   d. if Atikokan Hydro has established 2008 service reliability improvement targets, a copy of the plan that identifies programs or projects that Atikokan Hydro will undertake to achieve these targets.

25. Ref: Exhibit 2/ Tab 4/ Schedule 2

The Cost-of-Power has increased from $1,836,713 (2006 actual) to $2,660,684 for test year 2008, a rise of 44.8%. Please explain the reasons for this 44.8% increase and list the electricity unit price increases and the quantity of electrical energy changes.

COST OF CAPITAL

26. Ref: Exhibit 6 /Tab 1/Schedule 2 – Capital Structure

Please provide information on Atikokan Hydro's capital structure according to the following table format, for each of the following years:

a) 2006 Board-approved;
b) 2006 actual;
c) 2007 bridge; and
d) 2008 test.

	Dollars ($)	Ratio (%)	Rate (%)	Rate X Ratio

			/100 (%)
Debt			
Long-term			
Short-term			
Total Debt			
Equity			
Common Equity			
Preference shares			
Total Equity			
Weighted Average Cost of Capital	100%		

27. Ref: Exhibit 6/ Tab 1/ Schedule 2 – Short-term Debt

In the table shown under "Capital Structure", Atikokan Hydro has used a short-term debt rate (under "Cost Rate") of 4.77% for the 2008 Test Year.

The *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, issued December 20, 2006 (the "Board Report") states the following in section 2.2.2:

"**The Board has determined that the deemed short-term debt rate will be calculated as the average of the 3-month bankers' acceptance rate plus a fixed spread of 25 basis points**." This is consistent with the Board's method for accounting interest rates (i.e. short-term carrying cost treatment) for variance and deferral accounts. The Board will use the 3-month bankers' acceptance rate as published on the Bank of Canada's website, for all business days of the same month as used for determining the deemed long-term debt rate and the ROE.

For the purposes of distribution rate-setting, the deemed short-term debt rate will be updated whenever a cost of service rate application is filed. The deemed short-term debt rate will be applied to the deemed short-term debt component of a distributor's rate base. Further, consistent with updating of the ROE and deemed long-term rate, the deemed short-term debt rate will be updated using data available three full months in advance of the effective date of the rates." [Emphasis in original]

a) Please provide the derivation of the 4.77% short-term debt rate estimate showing the calculations, data used and identifying data sources.

b) Please confirm if Atikokan Hydro is proposing that the deemed short-term debt rate would be updated based on January 2008 Consensus Forecasts and Bank of Canada data, in accordance with the methodology documented in section 2.2.2 of Board Report.

c) If Atikokan Hydro is not proposing that the methodology in the Board Report be followed, please provide Atikokan Hydro's reasons for varying from the methodology in the Board Report.

28.Ref: Exhibit 6 /Tab 1/ Schedule 2 – Return on Equity

Atikokan Hydro states that it is requesting a Return on Equity ("ROE") of 8.68% per the Board's formulaic approach as documented in Appendix B of the Board Report based on August 2007 data.

The table shown under "Return on Equity" on page 2 of Exhibit 6/ Tab 1/ Schedule 2 provides a summary of the calculation of the 8.68%.

(i) Please provide the source data used in the calculation and identify the specific data series, data sources and the date(s) of the data used in that table.

(ii) Is Atikokan Hydro proposing that the ROE would be updated using January 2008 data from *Consensus Forecasts* and Bank of Canada / Statistics Canada as documented in Appendix B of the Board Report, or is it proposing that the 8.68% ROE proposed in the application be used as a fixed rate?

(iii) If Atikokan Hydro is not proposing that the methodology in the Board Report be followed, please provide Atikokan Hydro's reasons for deviating from the guidelines in the Board Report.

29. Ref: Exhibit 6/ Tab 1/ Schedule 2 and Exhibit 6/ Tab 1/ Schedule 3 – Long-Term Debt

In the table shown on Pages 1 and 2 summarizing the calculation of the weighted average cost of capital, Atikokan Hydro uses a Cost Rate of 6.00%. However, on the tables shown under "Cost of Debt" on Exhibit 6/ Tab 1/ Schedule 3, Atikokan Hydro shows a rate of 5% for its debt in all years.

a) Please provide a reconciliation between the debt rates shown in Exhibit 6/ Tab 1/ Schedule 2 and Exhibit 6/ Tab 1/ Schedule 3.

b) In the tables provided in Exhibit 6/ Tab 1/ Schedule 3, Atikokan Hydro shows that the amount outstanding ("AmtOS") and debt cost (or interest payable) on the Note Payable to the (municipal) shareholder is increasing each year from 2004 to 2008 (forecast). In its 2006 EDR application (RP-2005-0020 / EB-2005-0335),

Atikokan Hydro stated that it had negotiated a "payment holiday" due to financial constraints it was then facing.

i) Is Atikokan Hydro still under the "payment holiday" on the debt owed to the municipal shareholder?

ii) If it is, please explain why this is still the case. What financial and operational circumstances continue to necessitate Atikokan Hydro not paying even the interest on the debt? When does Atikokan Hydro expect that it will be able to pay, at a minimum, the interest on outstanding debt?

iii) If it is not still under the "payment holiday" on the municipally-owed debt, please explain the reason for the increases in the debt outstanding and interest payable over time.

LOAD FORECASTING

30. Ref: Exhibit 3/ Tab 2/ Schedule 1/ Page 1

The Applicant states that the weather-normalization that was generated was performed by Hydro One.

Please provide the Hydro One report and any spreadsheets containing data supporting the calculations of the normalized historical load.

31. Ref: Exhibit 3/ Tab 2/ Schedule 1/ Pages 1 to 7

On pages 1 to 7, the Applicant explains how it developed its 2008 load forecast. While some details are missing, the essential approach used appears to be that the Applicant:

- determined the 2008 forecasted customer count for each customer class,
- determined the weather-normalized retail energy for each customer class for 2004,
- determined the 2004 retail normalized average use per customer ("retail NAC") for each class by dividing each of the weather-normalized retail energy values by the corresponding number of customers/connections in each class existing in 2004,
- applied the 2004 retail NAC for each class to the 2008 Test Year without modification, and
- determined the 2008 Test Year energy forecast for each customer class by multiplying the applicable 2004 retail NAC value for each class by the 2008 forecasted customer count in that class.

Please:

a) Confirm that the above is the essence of the Applicant's load forecasting methodology,
b) Differentiate the approach used for weather sensitive loads from that used for non-weather sensitive loads, and
c) Correct any errors in the above explanation.

32. Ref: Exhibit 3/ Tab 2/ Schedule 1/ Pages 2/3 and 6/7

On pages 2 and 3, the Applicant develops its customer count forecast. Statements are made that appear to support the reasonableness of using trend analysis for a number of customer classes. One of the classes referenced is the GS 3000-4999 kW class which shows the customer count decreasing from one customer in 2006 to no customer in 2007. However, no further details are presented in this schedule even though on pages 6 and 7 this class – and this customer alone - appears to account for almost half of the Applicant's kWh load.

Please provide details regarding the timing of the loss of this customer including the kW and kWh profile change over time.

33. Ref: Exhibit 3/ Tab 2/ Schedule 1/ page 5

In the first table on page 5, the Applicant shows the calculation of the loss factor for the three customer classes it considers to be weather sensitive. Board staff notes the unusual situation where the values associated with the Weather Actual Retail kWh are greater than the values associated with the Weather Actual Wholesale kWh. Please clarify the methodology and calculations used to derive these values.

For each of the three weather sensitive classes, please:

a) Provide source documents verifying each of the three Weather Actual Wholesale kWh values and each of the three Weather Actual Retail kWh values,
b) Explain the calculation, together with the values used, to determine the respective loss factor values,
c) Re-file the subject table and any other tables in the application as may be necessary to correct any errors or changes associated with the calculation of the loss factors, and
d) Provide any additional information that may enable Board staff to fully understand the calculations made by the Applicant with respect to items a) to c) above.

34. Ref: Exhibit 3/ Tab 2/ Schedule 1/ page 5

In the second table on page 5, the Applicant shows the calculation of the retail NAC for the three customer classes it considers to be weather sensitive. Board staff notes the unusual situation where the Weather *Normal* Wholesale kWh (2004) values in this table are identical to the Weather *Actual* Wholesale kWh values in the first table on page 5. Board staff is unable to replicate the Retail NAC values shown in the second table on page 5.

For each of the three weather sensitive classes, please:

a) Confirm the Weather Normal Wholesale kWh (2004) values in the second table are as intended or show the process - together with values and calculations – used to obtain these values from the Weather Actual Wholesale kWh values
b) Provide the detailed calculation of the “Retail NAC” values shown in the table
c) Re-file the second unnumbered table and any other tables in the application as may be necessary to correct any calculation errors or changes, and
d) Provide any additional information that may enable Board staff to fully understand the calculations made by the Applicant with respect to items a) to c) above.

35. Exhibit 3/ Tab 2/ Schedule 1/ page 6

The Applicant notes on page 6: “Billed kW is estimated based on a load factor calculated using a ratio of historical billed kW to historical retail kWh, by class”.

Please provide:
a) the rationale and detailed description of this process, and
b) supporting source values and calculations.

36. Ref: Exhibit 3/ Tab 2/ Schedule 1/ pages 6 and 7

On pages 6 and 7, the Applicant summarizes the results of its customer and load forecast. Board staff notes that data for General Service 3000-4999 kW class appear twice in the table.

Please clarify this apparent duplication or re-file the summary on which the Applicant will rely for the customer and load forecasts showing the forecast for each of the customer classes and, for greater certainty, the applicable totals for all customer classes.

37. Ref: Exhibit 3/ Tab 2/ Schedule 1/ pages 1 to 7

In pages 1 to 7, the Applicant explains how it determined the 2004 retail normalized average use per customer ("retail NAC") for each class and apparently used this value for other years also. This does not appear to adequately weather-normalize the energy usage in historical years and does not allow for the possible change in energy usage per customer over the 2002 – 2008 period due, for example, to Conservation and Demand Management. The minimal amount of weather normalization and the constant retail energy assumption could potentially lead to forecasting errors.

a) Please file a data table for the historical years 2002 to 2006 that shows:

i. the actual retail energy (kWh) for each customer class in each year,
ii. the weather normalized retail energy (kWh) for each customer class in each year (where, for the customer classes that the Applicant has identified as weather sensitive, the weather normalization process should, as a minimum, involve the direct conversion of the actual load to the weather normalized load using a multiplier factor for that year and not rely on results for any other year),
iii. the values of the weather conversion factors used,
iv. the customer count for each class in each year,
v. the retail normalized average use per customer for each class in each year based on the weather corrected kWh data in item ii. above, and
vi. as a footnote to the table, the source(s) of the weather correction factors.

b) Please file a data table for the 2002 to 2008 period:

i. utilizing the retail normalized average use per customer values for each class in each year obtained in a) v. above for the historical years 2002 to 2006,
ii. including 2007 and 2008 projections for the retail normalized average use per customer values (where, for each of the weather-sensitive classes, this is based on trends in the data) for each class, and
iii. as a footnote to the table, for each of the weather-sensitive classes, describe in detail the trend analysis performed in ii. above.

c) Please file an updated version of the historical/forecast table presented in Exhibit 3,Exhibit 2/Tab2/Schedule1/Pages 6 and 7 utilizing the weather corrected data determined in b) above.

COST ALLOCATION AND RATE DESIGN

Cost Allocation

37.Ref: Exhibit 8/ Tab 1 / Schedule 5 / Worksheet O1 'Revenue to Cost summary Worksheet '– Second Run/ Page 680

Please confirm that the proportion of the total revenue requirement allocated to the respective classes are those shown in the following table (column 2), and that the same proportions applied to the test year revenue requirement would yield the class revenue requirements shown in column 3.

	Class Revenue Requirement - 2006	Proportion of Total	Proportional Class Revenue - 2008
Class	**$**	**%**	**$**
Residential	487,763	54.0	590,386
GS<50 kW	197,094	21.8	238,745
GS > 50 kW	129,041	14.3	156,211
Streetlights	85,231	9.4	103,164
Sentinel Lights	2,215	0.2	2,681
USL	1,735	0.2	2100
Total	903,078	100	1,093,347

Revenue to Cost Ratios

38.Ref: Exhibit 8 / Tab 1 / Schedule 2 / Page 4, and Exhibit 8 / Tab 1 / Schedule 3 / Page 3

Please confirm that the Revenue to Cost Ratios in the first reference are the ones that were filed in the Informational Filing EB-2006-0247, and that the table in the second reference shows ratios from a version of the cost allocation model that has been modified to reflect the absence of any customers in the Intermediate class.

Please provide an appropriate title for the table in the second reference.

39.Ref: Second Exhibit 8 / Tab 1 / Schedule 2, and Exhibit 8 / Tab 1 / Schedule 3 / page 3

Please note that there are two schedules with the same numbering. The reference is the second of these, which has only three pages.

a. Please explain the meaning of “Existing Range” in the table in Schedule 2, and of the phrase “applied for ranges” in the paragraph preceding the table on page 2. In particular, please explain whether the ratios shown in the table are the ratios that result from the proposed rates.

b. Please provide a brief explanation of why the ratios are so different between the two referenced tables for the Residential Class (132% vs 125%), Sentinel Lights (1% vs 12%), and USL (271% vs 15%).

Rate Design

40. Ref: General

Please confirm that Atikokan Hydro does not wish to have a rate approved for the Intermediate class in the event that a customer joins the system or grows to a size above 2500 kW prior to the next rate re-basing.

41. Ref: Exhibit 9 / Tab 1 / Schedules 7 and 8

Please explain what costs are included in the "Total Base Revenue Requirement" in column H of the Reconciliation table (Schedule 8) amounting to $1,747,569, that are not included in the "Base Service Revenue Requirement" in Schedule 7, totalling $1,093,297.

42. Ref: Exhibit 8 / Tab 1 / Schedule 3 / Page 3

The first two data columns in the following table replicate the data in the referenced table in the application. The third and fourth data columns show policy based limits on revenue to cost ratios (column 3) and staff calculations of alternative class revenues that would conform to the policy-based ranges.

	Application		**Board Staff Alternative**	
	Revenue to Cost Ratio (col 1)	Over/(Under) Contribution (col 2)	Policy-based Revenue to Cost Ratio (col 3)	Class Revenue Targets, relative to Total @ $1,093,297 (col 4)
Class	**%**	**$**	**%**	
Residential	125.08	122,215	115	< $678,975
GS<50 kW	107.67	15127	120	< $286,520
GS > 50 kW	22.76	(99,669)	80	> $125,000
Streetlights	22.8	(65,789)	70	> $72220
Sentinel Lights	11.96	(1,950)	70	> $1875
USL	15.33	(1,469)	80	> $1680
Total		0		

a. Please prepare a table showing rates that, together with the forecast loads and customer numbers, would generate revenue equal to the total revenue requirement (net of revenue offsets), and class revenues lower than the those shown in column 4 of the table for the Residential class and GS < 50 kW class, and higher than the amounts in column 4 for the other classes.

b. Please calculate total bill impacts for representative customers in each class corresponding to the rates in part (a).

Monthly Service Charges

43. Ref: Exhibit 9 / Tab 1 / Schedule 1 / tables on second and third pages

The final column of the table on the second page is headed “Grand Total”, and appears to be the proportion of class revenue to total revenue using the current rate structure. The second data column in the table on the third page is headed “Fixed charges as percent of total for customer class”, which is self-explanatory. The columns have the same numerical values.

a. Please confirm that the amounts shown are correct for the table on the second page, and are not correct for the table on the third page.
b. Please confirm that the amounts on the third page were not used to calculate the monthly service charges proposed in the application.

44. Ref: Revised Cost Allocation in Exhibit 9 / Tab 1 / Schedule 5 / worksheet O2 ‘Monthly Fixed Charge Min. & Max worksheet – second run’, and Exhibit 9 / Tab 1 / Schedule1 / table on second page

a. Given that the Minimum System model of customer unit costs (ceiling) for 2006 is $20.09 for the Residential class, and given that the proportion of revenue generated by the fixed charge is nearly 80% of the class total revenue, please provide a justification for the proposed Monthly Fixed Charge of $36.52, or alternatively please propose a lower charge together with a calculation of the corresponding volumetric rate that would compensate for the decreased revenue and the proportions of class revenue that it would generate by the fixed and volumetric rates.

b. Given that the Minimum System model of customer unit costs (ceiling) for 2006 is $38.46 for the General Service < 50 kW class, and given that the proportion of revenue generated by the fixed charge is over 80% of the class total revenue, please provide a justification for the proposed Monthly Fixed Charge of $72.80, or alternatively please propose a lower charge together with a calculation of the

corresponding volumetric rate that would compensate for the decreased revenue and the proportions of class revenue that it would generate by the fixed and volumetric rates.

45. Ref: Exhibit 9 / Tab 1 / Schedule1 / table on third page

a. Please clarify whether the number 7 indicated for the USL class refers to USL connections or the number of customers, or both. Please confirm that the proposed Monthly Service Charge is to be charged on a per customer basis.

b. Please explain why the number of customers with Sentinel Lighting is 1 in the referenced table, but is 16 in the revenue forecast at Exhibit 3 / Tab 1 / Schedule 3 / page 2.

Total Bill Impact Calculations

46. Ref: Exhibit 1 / Tab 1 / Schedule 6 / Page 4 and Exhibit 9 / Tab 1 / Schedule 9

In Exhibits 1 and 9, the bill impact calculation for Unmetered Scattered Load is done with consumption of zero. In Exhibit 9, the impact on Sentinel Lighting is done variously with a monthly service charge and zero consumption or with non-zero consumption but no monthly service charge. Please provide valid impact calculations for these two customer classes.

Retail Transmission Service Rates

47. Ref: General

a. Please provide an estimate of the change in Atikokan Hydro's wholesale Connection cost due to the change in wholesale transmission rates in November 2007. Please express the difference:

i. as an annual total amount,
ii. as an amount in $/kW, based on the line connection rate having decreased from $0.82 to $0.59 per kW, and the transformation rate having increased from $1.50 to $1.61 per kW, and
iii. as a percentage amount, based on the line connection rate having decreased by approximately 28%, and the transformation rate having increased by approximately 7%.

b. Please provide an estimate of the revenue shortfall in Atikokan Hydro's currently approved retail transmission connection rates. (In other words, what has been the annual amount added to Account 1586 compared to the annual revenue from the retail transmission connection rates?) Please provide the response in dollar terms and as a percent.

48.Ref: Exhibit 9 / Tab 1 / Schedules 4 and 9

Please provide Impact Calculations for customers in the GS > 50 kW class that have demand larger than 1000 kW, using the correct existing Retail Transmission Service Rates in the calculation of the 2007 bill.

Loss Factors

49.References:

i. Exhibit 4, Tab 2, Schedule 9
ii. Exhibit 1, Tab 1, Schedule 5
iii. Exhibit1, Tab 1, Schedule 6

• The 1st reference provides a calculation of actual distribution loss factors (DLF) for 2002 to 2006 and an average for the 5-year period. This reference further provides the Supply Facilities Loss Factor (1.0045) and proposed 2008 total loss factors (TLF) for secondary and primary metered customers < 5,000 kW plus corresponding DLFs.

• The 2nd reference provides the proposed TLF for 2008 for secondary and primary metered customers < 5,000 kW.

• The 3rd reference provides a comparison between the 2007 approved and 2008 proposed TLFs for secondary and primary metered customers < 5,000 kW.

a. The loss factor calculation in rows A to H in the 1st reference follows the framework of the 2006 EDR Handbook Schedule 10-5, wherein the factor calculated customarily corresponds to DLF for secondary metered customer < 5,000 kW. This is consistent with the title "Distribution Loss Adjustment Factor" of row H which states that the 5-yr average of actually observed DLFs is 1.0753. In the table below the title "Total Utility Loss Adjustment Factor", the loss factor 1.0753 is shown with TLF – Secondary Metered Customers rather than with DLF – Secondary Metered Customers.

1. Please confirm if the loss factor 1.0753 is related to DLF – Secondary Metered Customers and not to TLF – Secondary Metered Customers.

2. If the above is confirmed, please re-calculate TLF and make appropriate corrections in all 3 references.

3. If the above is not confirmed, please explain the discrepancy.

b. Please provide an explanation for the increase in the actual loss factor from 2002 to 2003 (1.0669 to 1.0811) and from 2005 to 2006 (1.0665 to 1.0821).

c. Please explain the rationale for proposing that the loss factor for 2008 be an average of the loss factors for the 5-year period (1.0753) rather than a lower value such as the actual loss factor in 2005 (1.0665).

d. Please describe any steps that are contemplated to decrease Atikokan Hydro's loss factor during the test year (2008) and/or during a longer planning period.

SMART METERS

Atikokan Hydro is not one of the thirteen licensed distributors authorized by Ontario Regulation 427/06 to conduct discretionary metering activities with respect to smart meters. In its decision on Atikokan Hydro's 2007 IRM application (EB-2007-0505), the Board confirmed its understanding that Atikokan Hydro would not be undertaking any smart metering activity (i.e. discretionary metering activity) in 2007.

50.Ref: Exhibit 1 /Tab 1 /Schedule 7

On page 2, Atikokan Hydro states that it "has not included any costs related to Smart Metering. In decision EB-2007-0505 dated April 12, 2007, the Board approved $0.25 per month per metered customer. At the present time, it is unclear how Smart Metering costs will be recovered and therefore Atikokan Hydro requests to be included in any provincial mandate of Smart Metering Costs recovery."

a) Please confirm if any costs have been incurred by Atikokan Hydro with respect to Smart Metering until the date of the filing of this application. If so, please provide:
   i. An itemized cost breakdown; and
   ii. Associated number of smart meter installations.

b) Please confirm that, in Test Year 2008, Atikokan Hydro is going to maintain its current rate adder which was approved by the Board in the April 12, 2007 Decision and Order (EB-2007-0505). If not:

i. Please provide the Smart Meter Rate Adder Atikokan Hydro is intending to implement in Test Year 2008.
ii. Please provide justification for the amount of this Smart Meter Rate Adder and explain fully how the new amount for Smart Meter Rate Adder was calculated.

DEFERRAL AND VARIANCE ACCOUNTS

51. Ref: Exhibit1/Tab3/ Schedules1,2,3 & Exhibit1/Tab3/Schedule 5

a. The accounting guidelines in the December 2005 FAQ #3 of the Accounting Procedures Handbook (APH) require that an accounting entry in Account 1565 is offset by an entry in Account 1566. In the 2007 and 2008 pro forma financial statements, the balances in Account 1565 do not equal the balances in Account 1566. Please explain why.

b. In the reconciliation between the audited financial statements and RRR filings, Atikokan Hydro stated in Exhibit1/Tab3/Schedule 5 that an accounting error had been made in Account 3046, Balance Transferred from Income. Please provide any additional information that is available to update the Board on the status of the investigation of the causes of the error, its impact and adjustments made or to be made.

52. Ref: Exhibit2/Tab3/Schedule 6

a. Is the Applicant using the Board-prescribed interest rate, as per the Board's letter to LDCs dated November 28, 2006, for construction work in progress (CWIP) since May 1, 2006?

b. If not, what interest rate has the Applicant been using for CWIP?

c. If not using the Board-prescribed interest rates, what would the impact on rate base, revenue requirement, and CWIP be if the Applicant did use the prescribed interest rates?

53. Ref: Exhibit 5 /Tab1/Schedule1

Please explain how Atikokan Hydro uses the following deferral and variance accounts:
a. 1518
b. 1548
c. 1590

54. Ref: Exhibit 5 /Tab1/Schedule 2

What are the interest rates being used to calculate carrying charges for each regulatory deferral and variance account for the period from January 1, 2005 to present?

55. Ref: Exhibit 5 /Tab1/Schedule 2

Atikokan Hydro has requested disposition of all regulatory variance and deferral accounts, including accounts which have been closed by the Board and/or have a nil balance. Please list the accounts, including the balances that are being requested for disposition.

56. Ref: Exhibit 5/Tab1/Schedule 2 & Exhibit 1/Tab1/Schedule 7

a. What authority has Atikokan Hydro received from the Board to debit account 1555 in Exhibit 5/Tab1/Schedule 2 with $1,708 for the January 1 to April 30, 2007 period, particularly since in Exhibit 1/Tab1/Schedule 7 Atikokan Hydro stated that “it is unclear how smart metering costs will be recovered”.
b. Please explain the cause of this debit.
c. What authority has Atikokan Hydro received to request disposition of the Smart Metering account since it is not one of the utilities identified for rapid deployment of Smart Meters.

57. Ref: Exhibit 5/Tab1/Schedule 3

The Applicantis requesting disposition of regulatory variance accounts in Exhibit 5/Tab1/Sch3. The totals in the exhibit do not agree to totals reported to the Board as per 2.1.1 of the Reporting and Record Keeping Requirements for the period ending December 31, 2006. Please provide the information as shown in the attached continuity schedule for regulatory assets and provide a further schedule reconciling the continuity schedule with the amounts requested for disposition on Exhibit 5, Tab 1, Schedule 3. Please note that forecasting principal transactions beyond December 31, 2006 and the accrued interest on these forecasted balances and including them in the attached continuity schedule is optional.

58. Ref: Exhibit 5/Tab1/Schedules 2&3

It is common practice in the electricity sector is to use audited numbers for the last fiscal year as the basis for balances in the deferral and variance accounts for disposition, with interest forecasted up to the start of the new rate year.

a. Please provide the regulatory precedent for principal transactions being forecasted beyond December 31, 2006 for accounts requested for disposition.
b. Please recalculate the appropriate rate rider schedules using the December 31, 2006 balances with interest forecasted to April 30, 2008.

c. Please explain the nature of these forecasted principal transactions and why they were made.

PILs

59. For the 2005 and 2006 tax years, please provide the following:

i. Notices of Assessment, and any Notice(s) of Re-assessment, including Statement of Adjustments, received from the Ontario Ministry of Finance for the 2005 and 2006 tax years. Please note that these are not the NIL Assessments from the Canada Revenue Agency.
ii. Any correspondence between the Ontario Ministry of Finance and Atikokan Hydro regarding any tax items, or tax filing positions that may be in dispute, or under consideration or review, that may affect the tax situation of the utility for 2006 or future years.

60. Ref: Exhibit 4/Tab3/Schedule1 Tax Calculations

a) The regulatory net income shown for 2006 actual, 2007 bridge and 2008 test years seem to be in error. Please refer to the 2006 audited financial statements and the pro-forma 2007 income statement. The 2008 test year number should be average rate base, multiplied by the equity thickness proposed, and the ROE% applied for in the application. Please recalculate the numbers for this exhibit.

b) In 2006 actual there is a deduction shown of $256,286. This amount does not appear in the actual 2006 T2 tax return filed with the application. Please explain why the Applicant took this deduction. The 2006 actual numbers should be taken directly from the tax return, unless the tax return is incorrect.

c) The 2006 federal T2 tax return shows a non-capital loss carry-forward of $218,040. The Applicant should be able to forecast with reasonable

accuracy the actual 2007 taxable income before utilization of the 2006 loss carry-forward. This amount should be used for the bridge year tax forecast.

There may be sufficient loss carry-forward at the end of 2007 to shelter 2008 from income tax PILs. Please provide a continuity table of the loss carry-forward at the end of 2006, plus any 2007 taxable loss, less any amounts that might be utilized in 2007 and proposed to be used for 2008. The tax rates for 2008 are now 11% for federal, and 5.5% for Ontario, or a combined rate of 16.5%. Please use this tax rate if required in the calculations.