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March 24, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
26th Floor - 2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Thunder Bay Hydro Electricity Distribution Inc.
2009 Cost of Service Application
OEB File No. EB-2008-0245
Final Submission

Enclosed please find two (2) paper copies of Thunder Bay Hydro's Final Submission.

An electronic copy of our complete application has been submitted through the OEB's RESS on-line filing system.

In addition, an electronic copy of 'Appendix A', has been forwarded via email, along with the PDF Version of the Final Submission.

If you require any further information, please contact the undersigned at (807) 343-1118.

Yours truly,

Cindy Speziale

Cindy Speziale, CA
Vice President, Finance

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Rachel Chen (Institutional Energy Analysis Inc.)
Michael Buonaguro (Public Interest Advocacy Centre)
Bill Harper (Econalysis Consulting Services)

EB-2008-0245

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 **Thunder Bay Hydro Electricity Distribution Inc.** for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2009.

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
(THUNDER BAY)

FINAL SUBMISSION

March 24, 2009

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
2009 RATES

EB-2008-0245

FINAL SUBMISSION BY THUNDER BAY

INTRODUCTION

This is the final submission of Thunder Bay related to the setting of 2009 rates for Thunder Bay Hydro Electricity Distribution Inc. ("Thunder Bay") effective May 1, 2009.

Thunder Bay has addressed the issues in the final submission of Board Staff and Intervenors where deemed necessary.

As noted in the Introduction to Board Staff's submission, Thunder Bay is a licensed electricity distributor serving approximately 49,500 customers in the City of Thunder Bay and Fort William First Nation Reserve. Thunder Bay is owned by the City of Thunder Bay. Thunder Bay filed its 2009 rebasing application (the "Application") on September 8, 2008. Thunder Bay requests approval of its proposed distribution rates and other charges effective May 1, 2009. If a final rate order is not issued in time for a May 1, 2009 effective date, Thunder Bay requests that its proposed rates be declared interim, effective May 1, 2009. The Application is based on a future test year cost of service methodology.

Thunder Bay's requested revenue requirement for 2009 includes the recovery of its costs to provide distribution services, a Return on Equity ("ROE") that is less than the OEB allowed return, and the funds necessary to service its debt required to meet the increased capital needs.

Thunder Bay has considered the impacts on its customers, with a goal of minimizing those impacts.

SUMMARY OF CHANGES TO THE COST OF SERVICE APPLICATION

Thunder Bay, after taking into consideration the various issues during the interrogatory process, is forecasting a revised revenue deficiency of $998,503 on forecasted distribution revenue of $17,145,154. This represents an increase in total revenues of approximately 6.18%.

In response to the comments received regarding the "Adjustments to Thunder Bay Hydro's 2009 Cost of Service Application" forwarded on March 6, 2009, Thunder Bay has provided a summary of the changes to the filed application in an excel working format (Appendix A). The excel spreadsheet allows the calculations underpinning the amounts to be reviewed and any confusion minimized.

RATE OF RETURN

The following dialogue, as per Exhibit 1, Tab 2, Schedule 1, page 4, summarizes Thunder Bay's Return on Equity.

> Thunder Bay has assumed a return on equity of 3.75% consistent with our Shareholder's "Rate Minimization Model". Thunder Bay acknowledges that this is well below the OEB approved MARR; however, is sufficient to fund the capital investment and operating and maintenance cost requirements.
>
> The Corporation of the City of Thunder Bay, the sole shareholder of Thunder Bay Hydro Corporation (shareholder of Thunder Bay Hydro) provides the following governing principle in the Shareholder Declaration:
>
> > "Distribution Co shall be operated in accordance with a "rate minimization model" to the extent possible without jeopardizing the reliability and

> efficiency of the electricity distribution system of Thunder Bay Hydro or the economic development of Thunder Bay."

In subsequent documents related to EDR 2008-0245, several references to this 'Rate Minimization Model' under which Thunder Bay operates have been made. In order to assist the Board in its decision, some additional clarification regarding this model is appropriate.

Over the course of the interrogatory and issues process it has become apparent that there is some confusion regarding the nature of the Rate Minimization Model. This is understandable since, to the best of our knowledge, Thunder Bay is the only utility operating under such a model.

Upon incorporation of Thunder Bay, the City of Thunder Bay being the sole Shareholder established a Shareholder Declaration which established certain principles of governance and to outline its expectations and objectives relating to Thunder Bay Hydro. One of the governing principles directed that the LDC be operated "…in accordance with a 'rate minimization model' to the extent possible without jeopardizing the reliability and efficiency of the electricity distribution system of Thunder Bay Hydro or the economic development of Thunder Bay". In order to support this model, when Thunder Bay was incorporated the Shareholder established the terms of the long term debt held by the City to require no interest payment, nor repayment of principal. The Shareholder has also made the decision not to receive any dividend payments from the utility. This effectively has become the key component of the Rate Minimization Model: that the Shareholder is declining to receive any direct financial return from its investment in the utility, from either interest payment or dividends, in order to keep local distribution rates lower than they otherwise would be. This is the working meaning of the Rate Minimization Model. The Shareholder's motivation in implementing the model was the economic challenges facing Thunder Bay. Without going into detail, the economy of Thunder Bay has experienced little or no growth over the last 20 years. Declines in the traditional industries in the region have created challenging economic times, and provided the underlying motivation for the Shareholder to attempt to keep electricity rates low in order to support local economic development.

Notwithstanding the Rate Minimization Model, Thunder Bay has historically worked to remain as efficient as possible in order to keep electricity rates low for our customers. It is safe to say that this motivation was commonplace amongst municipal electric utilities prior to the Bill 35. Many LDC’s then took pride in operating efficiently in order to pass on low rates their customers. To some extent this motivation still influences decisions at many Ontario LDC’s. With the clarity provided by hindsight, it is possible to examine past decisions that were made with the intent to prudently reduce utility spending in order to keep rates low to local electricity customers. In some cases, admittedly, short term spending reduction decisions proved to have negative long-term implications. Board staff has rightly identified this in relation to past decisions regarding forestry and capital expenditure levels. Thunder Bay does, however, wish to provide clarity that past and current approaches to expense management and appropriate investment levels are not influenced by the existence of the ‘rate minimization model’.

OPERATING REVENUE

Load Forecast

With regards to the load forecast Board staff in their submission provides a detailed analysis and review on the customer forecast, the load forecast and the weather normalization process. It is Thunder Bay's understanding that Board staff is suggesting various improvements to the load forecasting process for future forecasting purposes but state the following in regards to the load forecast proposed by Thunder Bay to be used to design 2009 rates.

> *"For the purpose of this Application, given the detailed analysis undertaken by Thunder Bay in developing the load forecast, Board staff is of the view that*

Thunder Bay's proposed load forecast is rigorous enough to reasonably underpin Thunder Bay's 2009 rates."

Thunder Bay agrees with the views of Board staff.

SEC did not make any submission with regards to the load forecast. VECC and Energy Probe take a number of pages within their submissions to express concerns with the load forecasting methodology and suggest the proposed forecast is too low. Thunder Bay will attempt to briefly address the issues raised by VECC and Energy Probe and show that their proposed changes to the forecast are unreasonable considering the current economic climate.

In preparing for the 2009 rate application, Thunder Bay had reviewed the OEB's decision of the 2008 rate applications. Within the area of load forecasting, the method used by many distributors was accepted by the Board. However, there were concerns from Board staff and Intervenors that the method used was too simplistic. In particular there were concerns that the methodology utilized only a single year of weather-normalized historical load (i.e. 2004) to determine the future load. It is interesting to note that now Energy Probe is suggesting this approach should be used for Thunder Bay's forecast (EP pages 27 and 28).

Thunder Bay noted in the case of Toronto Hydro, the load forecasting methodology used appeared to have a higher level of acceptance with parties. The Board's Decision on the Toronto Hydro case it stated:

"The Board accepts the forecast advanced by the Applicant, as amended throughout the process. This provides for a very small increase in load in 2008 of 0.03% and a small decrease in 2009 of 0.06% over 2006.

Going forward, the Board encourages the Applicant to work with OPA, IESO, and perhaps others to understand differences in methodology employed by each. Of special interest is the development of methodology to account for the specific effects of CDM activities in forecasts. The success of LRAM and SSM applications is *dependent on fully developed evidence respecting the effects of CDM activities on throughput. The Applicant can make a very important contribution to the sector by working with stakeholders to bring needed clarity to this aspect of forecasting and utility operations."*

In summary, the Board approved the Toronto Hydro load forecast as proposed but also encouraged Toronto Hydro to work with the OPA, IESO and others to understand the differences in methodology employed by each. Thunder Bay prepared a load forecast for the 2009 rate application using a similar method based on the outcome of the Toronto Hydro case.

Thunder Bay understands that to a certain degree the process of developing a load forecast for cost of service rate application is an evolving science for electric distributors in the province. Thunder Bay expects to improve the load forecasting methodology in future cost of service rate applications by taking into consideration comments made by parties to this application as well as other cost of service rate applications for 2009 and onward. However, for the purposes of this application Thunder Bay submits the load forecasting methodology is reasonable.

With regards to the overall process of load forecasting, it is Thunder Bay's view that the "Toronto Hydro" approach or the top down approach is appropriate. Thunder Bay knows by month the exact amount of kWhs purchased from the IESO and others for use by customers of Thunder Bay. With a regression analysis these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. To use a bottom up approach as suggested by Energy Probe in which the monthly billed kWh of a class is related to other monthly variables is problematic. The monthly billed amount is not the amount consumed in the month but the amount billed. The amount billed is based on billing cycle meter reading schedules whose reading dates vary and typically are not at month end. The amount billed could include consumption from the month before or even further back. By using a regression analysis to relate rate class billing data to a variable such as heating degree days does not appear to be logical, since the resulting regression model would attempt to relate heating degree days in a month to the amount billed in the month, not the amount consumed. In Thunder Bay's view, variables such as heating degree days impact the amount consumed not the amount billed. It is possible to estimate the amount consumed in a month based on the amount bill but until smart meters are fully deployed this would only be an estimate which in Thunder Bay's view would reduce the accuracy of a regression model that is based on monthly billing data. In addition, in could be difficult to obtain monthly historical billing data for each rate class as far back as purchase data was available. For example, since the General Service rate class was split between GS < 50 kW and GS > 50 kW during the distribution rate unbundling process in 2000/2001 it is highly unlikely historical monthly billing data is available for these two classes past 2000.

The process of preparing a proper weather normalized load forecast is a critical component of a cost of service rate application, Thunder Bay would suggest that from a pure pragmatic perspective it would be advisable for the Board to provide additional details in the filing requirement on how a weather normalized load forecast should be determined. This would serve to reduce the time spent between Board staff, Intervenors and Distributors in disputing the "theory" of preparing a proper method to determine a weather normalized forecast

In their submissions, Energy Probe and VECC raised a number of issues at a very detailed level. Thunder Bay will attempt to respond to these issues but in order to be of assistance to the Board the issues will be addressed at a higher level.

<u>Adjustments to the Forecast</u>

The following table summarizes the adjustment to the load forecast proposed by Energy Probe and VECC.

Adjustment to Forecast Description	Energy Probe (GWh)	VECC (GWh)
Loss Factor Adjustment to 4.1%	5.9	
Loss Factor Adjustment to 3.8%		8.8
Corrected CDM Adjustment	3.0	3.0
Use Hydro One 2004 weather normalized average use data.	1.5	
Total	**10.4**	**11.8**

Based on the above, Thunder Bay agrees with the adjustment resulting from a corrected CDM adjustment. The adjustment had been reflected in the adjustments table previously. However, Thunder Bay does not agree with the adjustments suggested by Energy Probe and VECC with regards to losses. In response to OEB Staff IRR #48 and Energy Probe #23b, the proposed loss factor was updated to address the double counting of the supply facilities loss factor component of the total loss factor. The double count issue only applied to the proposed loss factor to be included in the tariff sheet for billing of commodity and other charges. It did not apply to the calculation of the loss factor used in the load forecast. The loss factor used in the load forecast was 4.7% which represents the average difference between actual purchased and actual billed amounts from 2000 to 2007. The actual numbers did not change which means the average loss factor from 2000 to 2007 did not change. In addition, Thunder Bay does not agree with the adjustment suggested by Energy Probe to reflect Hydro One 2004 weather normalized usage data. It appears to Thunder Bay that Energy Probe is using a method, previously rejected by Intervenors, to increase Thunder Bay's load forecast

Based on the above discussion it is Thunder Bay's submission that the appropriate load forecast for 2009 is outlined in the response to OEB staff IRR#51 which shows a total billed amount for 2009 of 995.7 GWh. It is Thunder Bay's view this amount should be used when final rates are determined.

OPERATIONS, MAINTENANCE AND ADMINISTRATION

Polychlorinated Biphenyls ("PCB") Program

Thunder Bay has capitalized as an "Asset Retirement Obligation" ARO the discounted costs for Oil Destruction, Destruction of PCB Solid Waste Material, Additional Destruction and Transport expected over the plan horizon of 2008 to 2020. This represents future costs of disposal related to an asset that is used and useful in providing services to ratepayers. The discounted cost of $512,186 will be amortized over the 12 year period. Additionally, the period "accretion costs" (similar to interest expense) of $189,294 will be charged to income over the 12 year period ending 2020. As Thunder Bay actually incurs the costs and provides for payment of such, the accounting treatment will be to draw-down the ARO liability reflected on the balance sheet (these payments will not affect income). As such, Thunder Bay fails to see that there is any double counting of costs in rates.

Thunder Bay had originally included accretion as part of its OM&A costs for the purpose of the calculation of the revenue requirement, however, to be consistent with the inclusion of the asset in rate base, the appropriate treatment would be to show the ARO liability as part of Thunder Bay's existing long term debt in the cost of capital. The resulting impact is an increase in Thunder Bay's weighted cost of debt by .09%, which in turn impacts the Rate of Return. The 2009 increase in revenue requirement is approximately $11,200. This has been reflected in Appendix A.

Forestry

In its final arguments the Ontario Energy Board stated that a 75-100% increase from the average spending of the years 2003 – 2007 should be adequate to sustain its forestry operations. Thunder Bay agrees and expects that a sustainable forestry program, once corridors are established through regular tree trimming, can be accomplished for approximately $517,800 at an average cost of $3,336/km. However, given that under spending occurred for an extended period of time the line corridors must be re-established which will take a significantly greater effort in the interim at a cost of approximately $767,000 annually at an average cost of $7,058/km. As such, Thunder Bay has not adjusted this cost.

<u>Thunder Bay Hydro Corporation Board of Director Costs</u>

Thunder Bay confirms that the $14,743 represents the costs originally included in OEB account 5605 that has been removed, as noted in the summary in Appendix A.

<u>Non-recurring Expenses</u>

Board Staff’s submission, pages 15 and 16, refers to Meter-Reading costs and suggests that “the Board may wish to adjust Thunder Bay’s 2009 revenue requirement to ensure that the ratepayers benefit from this expected cost reduction.” Thunder Bay has, in fact already adjusted for this cost reduction and was summarized on the “Adjustments to Thunder Bay Hydro’s 2009 Cost of Service Application” forwarded on March 6, 2009 (reference was noted as OEB Board #18 and reduced OM&A by $255,000 and added the three year annualized costs of $135,000). The $135,000 has now been adjusted to $107,500 to recognize four year annualization versus three.

RATE BASE

<u>Working Capital</u>

Thunder Bay does not agree with Energy Probe’s recommendation to have the Board direct Thunder Bay to prepare working cash (lead lag) study due to the cost of such. Thunder Bay suggests the standard continue.

<u>Capital Expenditures</u>

Thunder Bay notes that 2.6 of Vulnerable Energy Coalition’s (VECC) final argument notes “the increase capital replacement expenditures by about $300K per year for each year 2009-2011” should read $800K as per Exhibit 2/Tab 3/ Schedule 1, pages 2 and 3.

In the OEB Staff submission it is noted that Thunder Bay did not provide the revised spreadsheet with its customer numbers as had been requested. Thunder Bay's response to the request (OEB Supplemental Interrogatory #12) is as follows:

"c. Please provide Thunder Bay's number of customers for the period 1980 to 2007 inclusive, and calculate the growth rates as per the attached excel spreadsheet.

<u>Response</u>

Customer data has been inserted into the supplied spreadsheet and customer growth rates for each year as well as the periods requested by OEB staff have been calculated."

The actual spreadsheet however, was inadvertently not attached to Thunder Bay's response. Given that the conclusion on the matter is to be considered in the next rebasing, we will not forward at this time.

The issue of contingencies was raised by some Intervenors. Specifically, that Thunder Bay should estimate only the expected required amounts for capital projects. The estimates provided for all capital projects represented the expected total cost of each. All estimates will contain some form of contingency, whether they are explicit or inherent within the components. Contingencies at Thunder Bay represent small unknowns that are expected but difficult to quantify. Thunder Bay has chosen to clearly illustrate the contingency of each project within its internal business case reviews. In doing so Thunder Bay is demonstrating the confidence of the estimate which is effective for internal, as well as rate making purposes. As further experience is gained in large scale capital replacement projects, it is expected that contingencies will be at the 10% or lower levels and these will continue to represent our anticipated actual costs.

Also as presented in the evidence Thunder Bay has developed the first 10 years of its 20 year capital plan. Projects for the following year are clearly defined and typically already designed. As such when current year projects are completed more efficiently than expected, any under expenditure is utilized towards one or more of the following years' projects. Thunder Bay's budget is constantly reviewed and updated (projects added, deferred, revised) as circumstances warrant.

Thunder Bay's 2008 capital expenditures exclusive of work-in-progress and contributed capital, amounts to $5.536M compared to the forecast of $5.530M.

Having said the foregoing, Thunder Bay does not agree that an $800,000 adjustment to the opening assets in service as suggested by Energy Probe regarding the Kam River Crossing project, nor the $417,014 adjustment for contingencies as suggested by Energy Probe and Schools Energy Coalition, is appropriate.

<u>Contributions and Grants</u>

Thunder Bay confirms that the actual capital contributions for 2008 are significantly more than what had been forecasted; however, contrary to the conclusion reached by Energy Probe, this does not result in any adjustment to the rate base. As noted in Thunder Bay's response to OEB Interrogatory #20, sustaining capital originally forecasted at approximately $1.2M would be coming in around $1.6M; however, this increase was 100% offset by the capital contributions. The variance from forecast for the contributions is offset by the variance in the forecast of the "customer driven" capital work. The resulting net impact to the rate base is therefore nil.

Should Thunder Bay be directed to update the capital contributions amount, the corresponding increase in the capital should likewise be updated. As the name indicates, "Contributions in kind" are assets turned over to Thunder Bay. The accounting for this is to increase the capital assets and increase contributed capital. Given that the impact on the rate base is zero, Thunder Bay did not include in its forecast the assets that would be offset by contributions in kind. Refer to the immediately preceding section for the actual 2008 net capital expenditures (line 312).

DEPRECIATION & AMORTIZATION

a) Computer Hardware

As per Energy Probe's analysis with regards to the over amortization of computer hardware and software, Thunder Bay Hydro agrees to the following:

Given that Thunder Bay has not had a detailed depreciation study to support the change from the five to three year amortization for computer hardware, Thunder Bay will commence amortizing computer hardware over the five year period for regulatory reporting purposes as suggested throughout this rate process. Thunder Bay's decision to go to a three year amortization was not intended to go against the OEB Guidelines; however, such was the result. Thunder Bay will review the cost of obtaining a depreciation study and determine whether to proceed in this direction.

Energy Probe has suggested that computer software should also be based on a 5 year amortization. Because the OEB had not provided direct guidance on amortization for computer software, Thunder Bay adopted the policy of amortizing computer software over 3 years, the main driver being the rapid pace of technological change. As such, Thunder Bay does not agree with Energy Probe's submission that the depreciation expense should be based on a five year amortization.

The total net impact of the adjusted amortization is as follows:

Computer Hardware	$ 77,605
Computer Software	103,122
Total Revised	180,727
Per Rate Filing	310,418
Net Change	$129,691

TAXES

Thunder Bay agrees that the income and capital taxes should be updated to the most recent information known to the Board when the Decision is issued.

Capital Tax

As provided in our response to Energy Probe Interrogatory #24(d), Thunder Bay followed Option B of the PILS Simple guidelines, as per the following excerpt from the 2006 OEB Tax Model Completion Instructions v1.0, as provided by OEB Board in the 2006 EDR Application process:

> *Test Year OCT, LCT – This worksheet is designed to calculate the Ontario Capital Tax and the Large Corporation Tax based on the two options provided in the rate handbook. The applicant can elect to use Option 1 based on deemed values or Option 2 based on actual calculations from tax schedules.*
>
> *Option 1 is an automatic calculation. For Option 2 the applicant must use the 2004 Income Tax Return Federal T2, Schedule 33 and Ontario CT23 plus prepare any supporting schedules to support non distribution eliminations.*
>
> *Please note that Option 2 can produce a larger value than Option 1. This is expected.*

As is evident in the PILS filings, the actual capital tax base is significantly higher than the regulated rate base.

Thunder Bay disagrees with Energy Probe's position that these costs are reflected elsewhere in the revenue requirement. The regulatory liabilities are accruing a "carrying charge" that has not been included in revenue requirement, however, will be included in the repayment of the amounts to customers. In addition, there is a capital tax cost to

Thunder Bay for this taxable capital base. Thunder Bay fails to see how the seeking a recovery of the capital tax on balances that form part of the taxable capital is double counting – the PILS are not related to carrying charges and are not included elsewhere in the revenue requirement.

Finally, Thunder Bay wishes to note that goodwill is not a component of the capital tax base. The term "Goodwill/CEC" was used as that is commonly what the timing differences related to; however, the amount in CEC relates to the organization costs.

Income Tax

Tax Rates

Thunder Bay agrees with Energy Probe's comment regarding the apprenticeship tax and the fact that the resulting income tax rate will change if the regulatory taxable income changes and that this level of tax credit is independent of the level of regulatory taxable income.

Thunder Bay has done, in essence, what Energy Probe has suggested. The income tax rate as shown is a function of the apprenticeship tax credit as a percentage of the taxable income and would change as taxable income changes. The rate, as shown, is not fixed.

Impact of the Federal Budget

Thunder Bay has not made any changes to the test year to reflect changes in the January 27, 2009 Federal Budget. Thunder Bay will do so at the time of the Board Decision, as per introductory paragraph to this section.

REVENUES

Non-Utility Operations

Energy Probe states that:

> *"Revenue from non-utility operations (account 4375) net of expenses of non-utility operations (account 4380) was approximately $24,000 in 2006, $29,000 in 2007 and is forecast at $72,000 in 2008, but only $7,000 in 2009 (Exhibit 3, Tab 3, Schedule 1). Based on the year-to-date figures for November, 2008, the net revenue is approximately $42,000 (Energy Probe Interrogatory #44).*
>
> *No reasons have been provided for the significant decrease to $7,000 in 2009 from the 2006 through 2008 (November year-to-date) average of more than $31,000."*
>
> *Energy Probe submits that Thunder Bay has under forecast the net revenues associated with non-utility revenues for the test year. Energy Probe submits that in light of the historical net revenue figures in 2006 through 2008, an increase from $7,000 to $25,000 is appropriate."*

Thunder Bay wishes to make reference to Thunder Bay's response to Energy Probe Interrogatory #14(d) which does explain the variance.

> *"There has been a significant reduction forecast for 2009 as compared to 2008 in the net income from accounts 4375 and 4380 as a result of the sale of the Water Heater Rental assets by TBHESI in 2008. As a result, 2009 does not include any revenues or expenses related to these activities."*

Therefore, Thunder Bay does not see that an increase to $25,000 is appropriate.

COST ALLOCATION & RATE DESIGN

Treatment of Transformer Ownership Allowance

VECC disagree with the Cost Allocation results of the Informational Filings relating to the handling of the transformer allowance. Energy Probe and SEC did not make any submission with regards to handling of transformer allowance. Board Staff submits that the logic in the cost allocation model in the format provided to distributors is internally inconsistent, and that the adjustment requested by VECC corrects the inconsistency. However, Board staff also notes that cost allocation is an imprecise procedure, and many factors can affect the outcome in addition to the Transformer Ownership allowance. The range of revenue to cost ratios accepted by the Board reflects this situation.. Thunder Bay agrees with Board staff's submission.

VECC submission proposes removing the cost of the transformer ownership allowance from the allocation of the revenue to the customer classes. VECC proposes to allocate the transformer ownership allowance directly to the GS 50 – 999 and GS 1000 – 4999 classes after the cost allocation adjustments have been completed. This results in a set of revenue-to-cost ratios provided in which VECC feels is a more appropriate starting point.

Although alternative methods have been cited, Thunder Bay submits it is most appropriate at this time for LDC's to apply consistent methodology until an alternative has been developed, tested, and approved by the Board. For this reason, Thunder Bay submits the Board should approve the Transformer Allowance method used in the Cost Allocation model and the resulting revenue to cost ratios for use in the 2009 Application with a view of addressing this subject through a consultation process under the direction of the Board.

Revenue to Cost Ratios

VECC has expressed concern that Thunder Bay's calculated revenues at 100% cost allocation do not reconcile with the 2009 Base Revenue Requirement and suggest an adjustment by made to reconcile the difference. VECC also suggest that calculation of revenue to cost ratios should reflect miscellaneous revenue. As result, it is Thunder Bay's understanding of VECC's submission, that VECC has proposed an alternate method to determine the "starting point" revenue to cost ratios which includes adjustments for transformation ownership allowance, miscellaneous revenues and reconciliation of 2009 Base Revenue Requirement. Thunder Bay disagrees with VECC’s proposal and submits its "starting point" revenue to cost ratios is consistent with the calculation resulting from the Board's cost allocation model. Thunder Bay used the resulting revenue to cost ratios from the cost allocation model and followed an iterative process of allocating different proportions of revenue to the classes while trying to achieve desirable revenue to cost ratios. Thunder Bay is proposing rates that are fair and balanced to all customers by bringing all classes closer to paying their fair share of costs that are attributed to them. While it is true the use of a different starting point would obviously result in slightly different results, the reduction of revenue by one class would have to be picked up by the other classes.

The Board Report on Cost Allocation dated November 28, 2007 stated cost allocation “calls for the exercise of some judgment both in terms of the cost allocation methodology itself …” and it is therefore recognized there will be differences of opinions on how some issues are handled. Thunder Bay is not looking for winners or losers in the allocation of the revenue requirement but attempted to move the ratios toward the Board's acceptable range while trying to keep the bill impact to reasonable levels for all customer classes.

All parties have agreed with Thunder Bay to move the Street Light class ratios half way to the low end of the Board’s acceptable range for the 2009 rate year with two further equal movements in the ratio to achieve the lower end of the Board's range by 2011. Board staff and SEC also agree with Thunder Bay's proposal to use the same approach for the GS 50 – 999 and GS 1000 – 4999 classes by moving the ratios halfway to the low end of the Board's acceptable range and achieve ratios that are at the low end of the Board's range by 2011. However, Energy Probe and VECC do not agree with Thunder Bay's approach to the GS 50 – 999 and GS 1000 – 4999 classes. Energy Probe and VECC submit the revenue to cost ratio for these classes should move to the low end of the Board's acceptable range in 2009. In addition, with VECC's suggested approach to address transformation ownership allowance the starting point revenue to cost ratio for the GS 1000 – 4000 kW class would move from 60.17% to 43.41%. While the ratio for all other classes will essentially remain the same within 1% to 3%. If the revenue to cost ratio for the for the GS 1000 – 4000 kW class was then move to the lower end of the Board's range as suggested by Energy Probe and VECC it would move from 43.41% to 80% which would mean distribution charges would increase to this class by almost 100%. As a result, Thunder Bay strongly disagrees with Energy Probe's and VECC's submission and suggest it is more fair and reasonable at this time to phase in the movement of revenue to cost ratios for the GS 50 – 999 and GS 1000 – 4999 classes especially considering the current economic downturn.

The table below outlines the summary of revenue to cost ratio information presented by Board staff in their submission.

Revenue to Cost Ratio [%]

Customer Class	Updated Cost Allocation Run 2	Response to VECC IR 7c	Application: Exhibit 7 / Tab 1 / Schedule 2	Board Policy Range
Residential	126.08	128.71	119.13	85 – 115
GS < 50 kW	113.61	115.55	113.61	80 – 120
GS 50-999 kW	65.96	66.09	72.98	80 – 180
GS 1000 - 4999 kW	60.17	43.41	70.09	80 – 180
Street Lights	13.51	14.03	41.75	70 – 120
Sentinel Lights	105.21	109.17	105.21	70 – 120
USL	111.25	114.91	111.25	80 – 120

In the Board's Report on Cost Allocation the quality of data used to complete the cost allocation was an issue raised by the Board. Considering this issue Thunder Bay submits the revenue to cost ratios proposed by VECC are similar to Thunder Bay's proposal considering the level of confidence with the results of the cost allocation study. As a result, Thunder Bay suggest the Board should accept Thunder Bay's proposal outlined above under the column titled "Application: Exhibit 7 / Tab 1 / Schedule 2" which is supported with all of the facts through to the bill impacts included with the submitted Application.

Thunder Bay further submits it has applied for rates within the OEB Cost Allocation Guidelines. Any approach that is being cited as being more appropriate than that used by the 2008 and 2009 rate filers should be reviewed by the Board and communicated to the applicants for future year filings. Thunder Bay submits it will apply any changes directed by the Board in its Decision.

Loss Factors

Board staff, Energy Probe and VECC made submissions with respect to loss factors. Board staff and Energy Probe agree with the loss factors proposed by Thunder Bay and updated in response to OEB staff IR #48 and Energy Probe #23b. Board staff also noted there is no rate class for customers above 5000 kW, but that a TLF has been approved for this size category in the past. Staff submits that the separate loss factors do no harm, and that the proposed factors are based on the SFLF in the same way as other distributors that do have customers in this range. Thunder Bay confirms that since there are no longer customers above 5000 kW there is no need to continue to include a TLF on its tariff schedule for this category of customers.

VECC submitted that the TLF for Secondary Metered Customer < 5,000kW should be 1.0447 instead of the proposed 1.0448 and the TLF for Primary Metered Customer < 5,000kW should be 1.0344 instead of the proposed 1.0343. Thunder Bay submits the differences are due to rounding and further submits the proposed TLFs outlined in response to Board Staff IR#48 are reasonable.

Smart Meter Rate Rider/Adder

Thunder Bay agrees with embedding the smart meter rate to the base distribution MSC on the tariff for each class and as such, will be reflected in the draft rate order at the time of the Board's decision.

LRAM AND SSM

Thunder Bay believes that the evidence it has filed supports its application for recovery of lost revenues and shared savings. However in response to Energy Probe's comments with respect to Thunder Bay's absence of the provision of an independent third party review of its 2007 LRAM and SSM claims, Thunder Bay submits that a 10% reduction of the amounts sought for the 2007 delivery year would be appropriate as 2007 is the year that the independent third party review was made part of the CDM Guidelines and stipulated as a need on a go forward basis. In looking only at the 2007 delivery year this essentially reduces the amounts in question to $167,446. Further, Thunder Bay submits that the 10% reduction is appropriate only to those programs funded by 3rd tranche CDM dollars. The result of using only 3rd tranche funded CDM dollars is that the Ontario Power Authority (OPA) programs would be excluded. The reason for this is that the OPA has asserted that those programs have undergone third party evaluations. A duplication of verification efforts would be uneconomical for rate payers. It should be noted that the OPA performed enough verification of results that it paid Thunder Bay as its contractor for services rendered. In the end not including the OPA programs in this calculation effectively reduces the amounts in question by $50,278 to a new total of $117,168. Thunder Bay therefore agrees that an $11,717 reduction to LRAM and SSM (10% reduction of $117,168) is appropriate.

COST OF CAPITAL

<u>Long Term Debt Rate</u>

On page 27 of the Board Staff's submission, the comment is made "….forecasted debt financing for smart meter investments in the amount of $1.1 million". Thunder Bay wishes to correct the foregoing statement in that the $1.1 million financing included in the 2009 Cost of Service Rate Application is not for smart meters but rather for the increased capital spending, exclusive of smart meter capital expenditures, above what Thunder Bay deems it can fund internally. The financing for the Smart Meters is approximately $8.2 million and has been dealt with as part of the Smart Meter Funding Model.

Further on this point, although Thunder Bay had previously indicated that it was felt that the 6% could be realized on this debt, we concur that the rate in the application should be in accordance with the February 24, 2009 rates. As mentioned in the application, Thunder Bay will be increasing external financing over the next several years to support the increased capital expenditures required and rates in subsequent years are uncertain, therefore, we concur that strict application of Board policy would be in Thunder Bay's best interest.

Thunder Bay would like to note that the Board's rates are not solely for affiliated debt, but rather are the debt rates to be used as per predetermined criteria and that it is simply the "cap" rate for any affiliate debt.

SMART METERS

It is apparent that clarification of the "Meter Department's Cost Shift within Rate Order" section of Thunder Bay's response to OEB Interrogatory #15 is required. The costs of Meter Department totaling $600,319 were originally included in the OM&A costs (OEB Accounts 5065, 5070 and 5075). As noted in the response, it became apparent that Thunder Bay would utilize this departments' staff and as such, the costs should be removed from the revenue requirement. The revised amount of $425,186 was added back into revenue requirement and represents the three average operating and maintenance costs of the department after removing the costs associated with the Smart Meter capital work. The amount has been revised to $453,000 to reflect the four year average operating costs.

<u>The Smart Meter Model</u>

Thunder Bay wishes to reiterate the response as provided to OEB Board Staff Supplemental Interrogatory #15:

> *Thunder Bay Hydro operates on the rate minimization model and as such does not have the flexibility to take on a capital project of such magnitude and finance such internally in the debt/equity ratio that matches the deemed capital structure (40% equity) as set out by the Board. The smart meter funding adder model makes this assumption. If the smart meters were allowed to be included in the rate base, the bulk of the financing costs on the smart meter capital would be included in the capital structure (meaning that Thunder Bay Hydro would be recovering the interest on substantially the full debt amount) and Thunder Bay Hydro would have increased its rate of return on equity sufficient to fund the shortfall approximated at $44,000. It is Thunder Bay Hydro's intention to have the Smart Meter Adder funding reflect interim funding as if the amounts had been incorporated into the rate base. At the time of rebasing (2012), Thunder Bay Hydro will include the debt at the actual interest rate in the capital structure and will increase the return on equity sufficient to fund the full operations of the corporation including the Smart Meter Project.*

The rationale for revising the model to reflect 100% debt funding was to recognize the interest deductibility for PILS funding component.

CLOSING REMARKS

There have been a number of comments/suggestions offered for consideration in filing Thunder Bay's next Cost of Service Application. Thunder Bay wishes to acknowledge such and comment that it will consider all issues raised during this entire process in preparing for the next rate application based on a future test year cost of service methodology.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

March 24, 2009

Cindy Speziale, CA
Vice President, Finance
Thunder Bay Hydro Electricity Distribution Inc.

APPENDIX A

SUMMARY OF CHANGES

2009 Test Year Revenue Requirement

	As Filed	As Revised	Decrease(Increase) from Original Filing	
OM&A	$ 12,340,964	$ 11,913,121	$ 427,843	
Amortization	$ 4,573,436	$ 4,443,745	$ 129,691	
Return on Rate Base	$ 1,437,190	$ 1,390,620	$ 46,570	$ 678,784
Low Voltage	$ -	$ -	$ -	
PILS	$ 970,138	$ 895,458	$ 74,680	
Transformer Allowance	$ 410,405	$ 410,405	$ -	
Smart Meters	$ 742,598	$ 1,173,277	$ (430,679)	
Service Revenue Requirement	$ 20,474,731	$ 20,226,626	$ 248,105	
Revenue Offset	$ (1,802,790)	$ (1,497,790)	$ (305,000)	$ (305,000)
Base Revenue Requirement	$ 18,671,941	$ 18,728,836	$ (56,895)	$ 373,784

cspezial:
Represents the decrease in revenue deficiency

cspezial:
Return has changed due to the Rates on Long-term and Short-term debt changing to 7.62% and 1.33% respectively. Additionally the asset retirement obligation liability has now been included as part of the long-term debt at 6% in the Capital Structure revising the weighted average return on debt which in turn increased the Rate of Return.

Intervenor	Ref #	Description	Working Capital- 15%	Rate Base	Return on Rate Base* 1.86%	OM&A*	Cost of Power (does not impact Revenue Requirement)	Amortization*	Accretion*	Revenue Offset*	Revenue Requirement (represents the sum of the columns with
			Revenue Requirement Impact			2009 Test Year Revenue/Expenses					
		Revenue Deficiency on Rate Filing									$ 1,414,077
OEB Staff	51	LRAM/SSM-Revised kwh purchases due to reduced LRAM/SSM load impact									$ (41,790)
Final Submission		Impact on the Rate Base due to the updated Cost of Capital Parameters to be used for rate-setting in 2009 Cost of Service electricity distribution rate applications. -1.91%	(12,819,420)	(62,350,228)	(1,437,190)						(1,437,190)
Final Submission		Revised Rate Base using 1.82%	12,819,420	62,350,228	1,364,976						1,364,976
OEB Staff	9	PCB Plan-Original	(34,200)	(101,000)	(2,515)	(228,000)					(230,515)
		PCB Plan-Revised	21,263	89,500	2,060	141,750					143,810
		PCB Plan-Original Amortization included in OM&A	(606)	2,020	26	(4,040)					(4,014)
		PCB Plan-Revised Amortization included in OM&A	537	(1,790)	(23)	3,580					3,557
		ARO -2008 original	(2,790)	(65,181)	(1,264)				(18,600)		(19,864)
		ARO-2008 revised due to longer phase-in	3,291	187,186	3,543				21,941		25,484
		ARO -2008 original amortization	(6,975)	69,750	1,168	(46,500)					(45,332)
		ARO-2008 revised amortization due to longer phase-in	6,267	(62,669)	(1,049)	41,779					40,730
Final Submission		Impact on the Rate Base due to including Asset Retirement Obligation in the long-term debt of Cost of Capital @ 6%			33,064						33,064
Final Submission		Removal of the Accretion Costs as now recovered as part of Return on Rate Base consistent with other financed assets	(3,291)		(61)				(21,941)		(22,002)
OEB Staff	18	Meter Reading Costs-original	(38,250)		(711)	(255,000)					(255,711)
		Meter Reading Costs-3 yr avg	16,125		300	107,500					107,800
OEB Staff Energy Probe	24 9	Cost of Power -Commodity, Network & Connection Charges	1,766		33		11,772				33
Final Submission		Amortization included in OM&A for Working Capital Allowance	777		14	5,181		(5,181)			14
Energy Probe	33	Amortization included in OM&A for Working Capital Allowance	(44,335)		(825)	(295,567)		295,567			(825)
	34	Cost of Power - Commodity	(475,629)		(8,846)		(3,170,860)				(8,846)
OEB Staff Energy Probe	25 7	Computer Amortization	-	64,846	1,206			(129,691)			(128,485)

cspezial:
Return has changed due to the Rates on Long-term and Short-term debt changing to 7.62% and 1.33% respectively. Additionally the asset retirement obligation liability has now been included as part of the long-term debt at 6% in the Capital Structure revising the weighted average return on debt which in turn increased the Rate of Return.

Intervenor	Ref #	Description	Working Capital- 15%	Rate Base	Return on Rate Base* 1.86%	OM&A*	Cost of Power (does not impact Revenue Requirement)	Amortization*	Accretion*	Revenue Offset*	Revenue Requirement (represents the sum of the columns with
		Revenue Deficiency on Rate Filing									$ 1,414,077
OEB Staff	51	LRAM/SSM-Revised kwh purchases due to reduced LRAM/SSM load impact									$ (41,790)
		Revenue Requirement Impact – 2009 Test Year Revenue/Expenses									
Energy Probe	6	Smart Meter related costs in rate base-Meter & Service OM&A originally	(90,048)		(1,675)	(600,319)					(601,994)
		Three year annualized	67,950		1,264	453,000					454,264
OEB Staff	48	Loss Factor-original 104.78 Loss Factor-revised 104.48% This will be reflected in the Bill Impact Analysis.	-		-						-
Energy Probe	8(j)	Proceeds on disposal	-		-					(4,000)	(4,000)
Energy Probe	36	Interest Income assumptions-original 3.05% and no variance disposition	-		-					439,000	439,000
		Revised interest rate to 1.3% on cash balance exclusive of regulatory balances	-		-					(130,000)	(130,000)
Final Submission		Regulatory Costs adjustment to annualize over four versus three years	(1,238)		(23)	(8,250)					(8,273)
Energy Probe	18	Board of Director Costs	(2,211)		(41)	(14,743)					(14,784)
			(581,598)	182,662	(46,570)	(699,629)	(3,159,088)	160,695	(18,600)	305,000	(299,104)
		Estimated PILS Impact									(74,680)
		Revised Revenue Deficiency									$ 998,503

Intervenor	Ref #	
OEB Staff	28 13 &	
OEB Staff *	15	Smart Meter Costs now included in the Smart Meter Funder Adder Model now includes - Meter base repair costs and ancilliary system OM&A Costs. Meter & Service Department direct capital costs associated with Smart Meter installation in the amount of $303,000 has been incorporated in the model.
OEB Staff Energy Probe OEB Staff *	29 28 15	Rate of Return on Smart Meter required to be 7.9%. Thunder Bay has revised the Smart Meter Model now to reflect the fact that the funding will be 100% debt financed as explained in the response to OEB #15. Adjusting the debt component versus trying to force the rate of return on equity to be such that the interest would be recovered is felt to be more representative of the actual result when rolled into rate base. For example, in doing this, the PILS funding is lower to recognize that the interest is a tax deductible expense.
Energy Probe	29	Computer Software CCA class 100% versus 55%. Thunder Bay has made this adjustment to the model.
OEB*	19	RTS rates revised to agree to projected IESO charges

* Supplemental Interrogatory