THUNDER BAY HYDRO

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February 11, 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

OEB Board Staff Supplemental Interrogatories;
Supplemental Interrogatories of Energy Probe Research Foundation ("Energy Probe"); and
Vulnerable Energy Consumers Coalition (VECC) Supplemental Interrogatories

Enclosed please find the following:

- Two (2) paper copies of Thunder Bay Hydro's responses to the above mentioned Supplemental Interrogatories;
- Thunder Bay Hydro's summary of "Adjustments to Thunder Bay Hydro Electricity Distribution Inc. 2009 Cost of Service Application" as a result of the process to date; and
- Bill Impacts for the 1000 kWh Residential and 2000 kWh for General Service customers.

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

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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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CS/dt

Enclosures.

Electronic cc: Robert Mace, President (Thunder Bay Hydro Electricity Distribution Inc.)
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Board Staff Supplemental Interrogatories
2009 Electricity Distribution Rates
Thunder Bay Hydro Electricity Distribution Inc. (Thunder Bay)
EB-2008-0245

GENERAL

1. Ref: Energy Probe IR #2

In response of Energy Probe #2 a), Thunder Bay stated:

"Rates in the period of 2000 to 2007 were set in accordance with our costs and corresponding revenue requirement as they are today. From 2000 to 2002 the regulator was Ontario Hydro and in 2003 that regulator became the OEB."

a. Please confirm that, pursuant to Bill 35, Thunder Bay became subject to regulatory oversight by the Ontario Energy Board effective April 1, 1999.

Response

Confirmed. The second sentence of the response should not have been included.

b. Please confirm that Thunder Bay's unbundled distribution rates in 2001 and distribution rate adjustments per the first-generation PBR plan for May 1, 2002 were approved or set by Decisions and Orders of the Ontario Energy Board.

Response

Confirmed. The second sentence of the response should not have been included

OPERATING COSTS

2. Ref: E2/T3/S1 –Capital Budget Overview, E4/T2/S2 – Variance Analysis of OM&A Costs, Board staff IR #2

Board staff IR #2 requested Thunder Bay to identify, individually, maintenance and capital programs, if any, that Thunder Bay may consider as a candidate for a deferral, cut, or partial adjustment, given the current economic situation. In response, Thunder Bay ranked the following OM&A programs.

1 - Asbestos Removal (subject to a review of the level of activity required to meet environmental regulations)
2 - Substation Maintenance & Testing; and
3 - Recloser & Line Switch Maintenance.

Please provide the amounts budgeted for these programs in the 2009 OM&A forecast.

Response

Cost savings which could be realized if OM&A Programs were deferred or cut:

1. *Asbestos Removal* *$ 3,500*
2. *Substation Maintenance Testing* *$ 85,729*
3. *Recloser & Line Switch Maintenance* *$170,341.*

PCB Removal

3. Ref: E1/T2/S3/p6-8**– Changes in Methodology (PCB Removal)**

Board Staff IR #9

Thunder Bay's total PCB program cost is estimated to be $3.4M. Thunder Bay has included costs in 2009 ($461K) for the purpose of eliminating all PCBs in concentrations of >500 PPM and all PCB's in concentrations of >50 PPM in environmentally sensitive areas as per the legislation. The legislation requires that all remaining PCB's (>50 PPM in non-sensitive areas) be removed from service by 2025.

a. In response to Board staff IR #9, Thunder Bay indicated that $179K in 2009 and $108K thereafter (to 2020) are the amounts that are forecasted to be charged to capital regarding the PCB program. The table on page 9 of the response identifies $380K and $230K respectively under the heading of "transformer replacement". It is not readily apparent why there is a difference between the amounts for capital on page 7 and the amounts for transformer replacement on page 9. Please provide an explanation.

Response

Thunder Bay Hydro capitalizes labour and material for initial transformer installs and for subsequent changeouts, only the physical transformer itself is capitalized. See section- **1850 Line Transformers** *of the APH copied below:*

Note: The cost of removing and resetting line transformers shall not be charged to this account but to account 5035, Overhead Distribution Transformers - Operations or accounts 5055, Underground Distribution Transformers - Operations. The cost of line transformers used solely for street lighting or signal systems shall be included in account 1875, Street Lighting and Signal Systems.

On page 9 where the table in year 2009 indicates $380,000 under transformer replacement; that figure represents the entire cost to replace a transformer including the transformer, labour and miscellaneous materials.

On page 7 the capital cost for 2009 indicates $179,000 which is the component of the overall $380,000 that will be capitalized in accordance with OEB accounting guidelines and only includes the transformer purchases. The remaining portion of the transformer replacement of $201,000 will be charged to OM&A.

b. Please explain why Thunder Bay has elected to phase out all remaining PCBs by 2020 (at a total cost of $3.4M) when the legislation allows the phase out to extend to the end of 2025.

Response

Thunder Bay Hydro has elected to phase out all PCBs by 2020 primarily to minimize its costs associated with the disposal of PCB waste. The legislation introduced in September 2008 requires that waste be disposed of no later then 12 months after it is generated. Thus each year Thunder Bay Hydro must dispose of all PCB waste irrespective of whether its waste facilities are at or near capacity. There are fixed costs that are a component of PCB waste disposal i.e. transportation, administration and even within the disposal itself. To a certain extent even the costs associated with running the removal program for the additional 5 years contain some fixed cost components.

It was contemplated to accelerate the completion prior to 2020 in order to further reduce costs, however this had a significant taxing impact on our replacement capital projects and ongoing operations and thus 2020 was selected as a reasonable compromise. Additionally completing the program prior to the required date allows for; any unforeseen occurrences which could delay our program or accelerate the requirement to complete it.

c. For 2009 only, Thunder Bay has proposed spending of $461K, ($179k in capital and $282K in OM&A) on the PCB program. For the remaining years of the PCB program to 2020, Thunder Bay is estimating annual costs of $278K, ($108K in capital and $170K in OM&A). As currently structured, Thunder Bay's rates under 3rd Generation IRM will recover approximately $110K more annually for PCB treatment-related OM&A than will be required in the remaining years of the program. Please explain why Thunder Bay feels it is appropriate to have rates for the subsequent years of the PCB program reflect the OM&A costs that are necessary for 2009 only, and to have such rates in place until the date of the next rebasing of Thunder Bay's distribution rates.

Response

The 2009 expenses related to PCB OM&A costs presented in the filing were not the full 2009 expenditures, but were the 3 year average of costs anticipated in 2009, 2010 and 2011. Therefore the PCB OM&A costs should be recovered appropriately over the 2009, 2010 and 2011 rate years.

d. In response to Board staff IR #9 e), Thunder Bay indicated that all the transformers will have been fully amortized on retirement and as such there will be no write-offs or stranded costs. Please indicate whether asset retirement obligations ("ARO") were set up for these transformers in light of the requirements under the previous environmental legislation. If so, has Thunder Bay included ARO related depreciation or accretion expenses in the revenue requirements of previous rate applications? If so, please provide the amounts of these expenses.

Response

Based on the revised PCB costs and timing of expenses as supplied in response to Board staff IR #9 c) the ARO should be increased by $122,005 to a total of $512,186. The related annualized ARO depreciation and accretion expenses should be increased to an annualized total of $67,300. The remaining annualized OM&A impact should be decreased by $79,667 for an annualized total of $148,333. Therefore the total annualized OM&A impact is $215,633

In 2020 when the last PCB transformer is removed there will be no stranded Transformer or ARO costs.

Please note, Thunder Bay Hydro will be adjusting the 2008 financial statements to reflect the new estimated PCB removal costs and timing as outlined in response to Board Staff IR #9 c.

Compensation

4. Ref: E4/T2/S2/p2 – Variance Analysis of OM&A Costs, E4/T2/S4 – Employee Compensation, Board staff IR #10

The response to Board staff IR #10 c) revised the total amounts for compensation for the years 2006-2009. Thunder Bay also explained that " …further, the amount originally reported as total salary, wages and benefits charged to OM&A only included direct OM&A expenses, (the overhead accounts had not been considered) and did not include overtime." It is not clear whether or not the updated compensation amounts presented on page 12 include overhead accounts and overtime. Please confirm.

Response

This is to confirm that the revised compensation amounts presented on page 12 include the overhead accounts and overtime.

Forestry Management

5. Ref: E1/T2/S3/p.3 – Changes in Methodology (Forestry Management), Board staff IR #11

a. In Board staff IR #11, Board staff requested the Forestry Management related expenditures for 2006 EDR and 2008 Forecast. The latter was provided but not the former. Please provide the expenditure level for Forestry Management included in Thunder Bay's approved 2006 revenue requirement.

Response

The expenditure level for Forestry Management included in the Thunder Bay's approved 2006 revenue requirement was $327,390. We apologize for the oversight in not providing this piece in the initial response.

b. Thunder Bay is proposing that its vegetation management budget be inflated by approximately 50% for a period of 8 years to rectify historical under spending. Please explain to what extent undergrounding initiatives would mitigate the need for vegetation management in some areas of Thunder Bay's service area.

Response

Presently about 20% of Thunder Bay Hydro's system is underground versus overhead when compared on a circuit km basis. The underground network within the city has primarily been driven by the City of Thunder Bay's requirement that all new subdivisions be underground supplied. Conversion of the remaining 80% overhead system to underground would mitigate the requirement for forestry in the short term however some forestry activities would be required in the longer term due to rooting of mature trees and vegetation issues.

Thunder Bay Hydro has looked at converting its overhead system to underground and the associated capital replacement costs are generally three to four times that of replacement with an equivalent overhead system in the most ideal situations. Even when any reduced operating costs over and above forestry are considered, the payback is beyond the expected life of the equipment. Thus without a mandate from the City of Thunder Bay or its regulators Thunder Bay Hydro is unable to justify such an expense.

Purchased Services

6. Ref: E4/T2/S3 – Shared Services, Board staff IR #16

The purchased service listing in the response to Board staff IR #16 indicates $307K in 2008 and $312K in 2009 for the rental of office space (from the City of Thunder Bay) and that the price was negotiated.

a. Please provide the date the lease was signed with the city, the number of square feet rented and the cost per foot negotiated.

Response

The 2009 price methodology description would more appropriately read negotiation. Thunder Bay has not yet signed a lease with the City of Thunder Bay. The City has forwarded a draft lease agreement for our signing; however, Thunder Bay has not yet agreed to the terms. Thunder Bay leases 20,588.30 (19,656.3 + 932 for basement storage) square feet. The proposal was for $16.79 per square foot or $345,675 annually. Thunder Bay used $15.63 for 19,656.3 square feet for the bridge year and $15.89 for the test year. Thunder Bay does not consider the basement storage as leasable space and as such has not factored this into the calculation.

b. Please provide the comparative benchmarks Thunder Bay used/uses in its negotiations to ensure a market price.

Response

Thunder Bay Hydro previously verbally agreed with the City that Thunder Bay Hydro would pay the average rental rate ($14.94 per square foot for the space occupied exclusive of basement storage) of all of the other tenants in the building to ensure that the rent paid by the Utility was fair and that at some future date, a formal lease agreement would be put in place. . The Corporation of the City of Thunder Bay initiated a formal lease agreement process in the fall of 2007 proposing $16.79/sq ft. subject to annual CPI increases effective for November 1, 2007 (subsequently revised to March 1, 2008 commencement). Thunder Bay Hydro has met with the City to discuss the lease agreement and has hired an independent realtor to assess what a "Fair Market Rent" would be for the space we occupy. Although we have some benchmark costs, they are net of utilities. Given that Thunder Bay Hydro does not have access to this cost information, we are not able to confirm comparability. Lease negotiations continue.

Regulatory Costs

7. Ref: E1/T3/S2 –Pro Forma Financial Statements, Board staff IR #19

In the table provided in the response to Board staff IR #19, Thunder Bay identified the accounts it uses to record "regulatory"-type costs and the respective amounts.

a. Please confirm whether or not the amounts noted reflect full costs or are only the yearly amortized costs. If the latter, please provide the amortization term.

Response

All costs reported for 2006, 2007 and 2008 are full costs. For 2009 costs reported in Account 5655 are estimated full costs. The $33,000 reported in 5630 is an amortized cost. The estimated full cost in 2009 is $100,000 of which 1/3 has been expensed in the 2009 filing.

b. Under account "5655" costs described as "Ontario Energy Board- Cost Awards and Assessments" are presented (i.e. 2006 - $116K, 2007 -$125K, 2008 -$130K and 2009-$136K). Please breakout these amounts between "Cost Awards" and "Assessments".

Response

Details of account 5655 are as follows:

	Cost Awards	***Cost Assessments***	***Other***	***Total***
2006	*1,030*	*114,633*	*800*	*116,463*
2007	*7,485*	*113,753*	*4,184*	*125,422*
2008	*9,100*	*119,600*	*1,300*	*130,000*
2009	*9,523*	*126,527*		*136,050*

The allocation of the 2009 expenditures are an estimate based on historical costs.

Meter Reading Costs

8. Ref: E4/T2/S1 –OM&A Costs Table, Board staff IR #18

In response to Board staff IR #18, Thunder Bay indicated that meter reading costs are expected to diminish from $250K in 2009 to $125K in 2010 and then to $25K in 2011. This is due to the smart meter implementation plan that calls for nearly 100% deployment in 2009. If Thunder Bay plans for nearly 100% deployment in 2009, then why is there not a higher decline forecasted in meter reading costs for 2010?

Response

Although we plan to install all the new meters in 2009, this does not allow us sufficient time for prudent AMI systems testing. Our implementation plan dictates a minimum of three (3) billing periods (6 months) of reads on the new AMI system be reconciled to actual meter reads. We will not be in a position to begin this read data integrity check process until late fall of 2009.

Once the reads on the new AMI system are deemed accurate, we will then migrate away from the actual physical meter reading contractor.

RATE BASE

Capital Expenditures

9. Ref: E2/T2/S3/Table 1 – Variance Analysis on Gross Assets, Energy Probe IR#4

In its original application, Thunder Bay projected a capital cost of $861,909 for the Tarbutt Street Area Conversion/Rebuild for 2008, but the response to Energy Probe IR#4 indicates that actual costs to complete the project were $1,062,486. Board staff calculates this as a cost overrun of $200,577 or 23.3% over budget. Please explain the reasons for the cost overrun.

Response

The Tarbutt Street Area Conversion/Rebuild project began in 2007 with a scope of 156 poles and a total estimate of $2,065,650. The work began in October and by year end 151 poles had been set as 5 were deemed to be re-useable. The total expenditure in 2007 was $498,865. The remaining scope of work included: the pole hardware installation, guying, restringing, transformer installations and secondary installations. This work was scheduled to be completed in 2008 and estimated at $861,909.There were no changes to the scope of the work and the work proceeded without delays or incident. However, admittedly the estimate was overly optimistic based on significant reductions in the Frankwood project which was completed in 2007; that project redefined our per unit cost and how we planned and executed capital work. It was anticipated that further improvements in per unit cost could be realized in an overly ambitious attempt to lower costs. These additional reductions did not materialize and the Tarbutt project at its completion compared equally well to the Frankwood project when considering the Tarbutt project was more complex (i.e. back lot versus front lot construction). The overall capital program budget was maintained in 2008 in spite of the Tarbutt project exceeding the budget by reducing the scope of some of our smaller projects.

10. Ref: Board staff IR#25 and Energy Probe IR#7 – Amortization Rate for Computer Hardware

Thunder Bay states that it uses a 3-year amortization rate for computer hardware, except for printers, and confirms that this differs from the Board's standard guideline of 5-year depreciation for computer hardware.

A review of Thunder Bay's 2006 EDR application does not highlight any deviation from the Board's guideline on amortization rates documented in Appendix B of the *2006 Electricity Distribution Rate Handbook* (the "Handbook"). However, section 4.1 of the Handbook required a distributor to document and support variances from the Board's guidelines on amortization rates.

a. Please confirm whether Thunder Bay has previously documented, requested and received approval from the Board for a depreciation rate of 33.3% for computer hardware. If so, please provide references and details.

Response

Thunder Bay Hydro has not previously documented, requested or received approval from the Board for a depreciation rate of 33.3% for computer hardware.

b. How long has Thunder Bay used a 3-year depreciation life for computer hardware?

Response

Thunder Bay Hydro has been amortizing computer hardware over 3 years since December 2004.

c. If Thunder Bay has changed its useful economic life for computer hardware to 3 years since its 2006 distribution rate application, please provide an explanation. Please provide supporting documentation, including any amortization study to justify the 3-year economic life for computer hardware.

Response

Thunder Bay Hydro has based its decision to replace computer hardware every three years and therefore amortize on that basis due to warranty provisions of current computer hardware. Warranties are only for a 3 year basis. The expense of purchasing additional warranty is costly. Per review of the costs to purchase new equipment versus paying for extended warranty, it was more cost efficient to purchase new equipment every three years.

Thunder Bay Hydro has not relied on a specific study to base its replacement decision, but feels we are using a standard IT replacement policy in comparison to other organizations requiring similar computer equipment.

11. Ref: E2/T2/S3/Tables 1 and 2 – Variance Analysis on Gross Assets, VECC IR#10

a. For 2008, please provide a disaggregation of "All Other Infrastructure Capital" by account according to the following table format:

Response

2008 Other Infrastructure Details

	Account							
	1830	**1835**	**1840**	**1845**	**1850**	**1855**	**1860**	**Total**
Sum of Part A Capital	314,763	244,631	77,112	109,187	569,567	370,935	40,883	1,727,077
B81106, B81213, B81304	220,902	266,898	32,914	54,290	97,214	87,063	0	759,280
B82122 and B82315	10,417	8,096	2,552	3,614	16,693	12,276	547,938	601,585
Net WIP Adjustment	(106,064)	(196,275)	471	6,982	(76,771)	(55,306)	488	(426,474)
Total	**$440,017**	**$323,350**	**$113,049**	**$174,072**	**$606,702**	**$414,968**	**$589,309**	**$2,661,468**

Per review of the details of other infrastructure, it was noticed that Project B82122 for a total of $55,000 should have been capitalized in account 1808. The project has been incorrectly included as follows:

	Account							
	1830	**1835**	**1840**	**1845**	**1850**	**1855**	**1860**	**Total**
B82122	10,417	8,096	2,552	3,614	16,693	12,276	1,352	55,000

b. For 2009, please provide a disaggregation of "All Other Infrastructure Capital" by account according to the following table format:

Response

	Account							
	1830	**1835**	**1840**	**1845**	**1850**	**1855**	**1860**	**Total**
Conversion/Rebuild (Sum of B91221, B91230, B91237)	360,812	573,380	2,398	4,473	255,547	207,874		1,404,784
Other Infrastructure Capital Projects (Sum of A901, A911-A917, A921 and A922)	479,648	419,894	104,172	175,243	611,096	368,068	47,194	2,205,325
Total	**$840,470**	**$993,274**	**$106,570**	**$180,016**	**$866,643**	**$575,942**	**$47,194**	**$3,610,109**

12. Ref: E2/T3/S1/Appendix A – Historical Review of Capital Expenditures, Board staff IR#22

In response to Board staff IR #22, Thunder Bay provided the historical capital expenditures and the trended data as shown in E2/T3/S1/Appendix A. Thunder Bay also explained how it developed the extended trend line, on which Thunder Bay has based its conclusion that if it had not adopted rate minimization and under spent on capital beginning in 2004; its annual capital expenditures would be between $11 million and $12 million for 2009 rather than the $7.6 million proposed for 2009 (excluding smart meters). Thunder Bay explained that the trend was developed by extrapolating from 1994 data using Excel.

Board staff makes the following observations regarding Thunder Bay's trend analysis:

- The capital expenditures are nominal, not real. In other words, the data are not adjusted for inflation.
- Growth in customers and demand is not accounted for in the analysis.

While more sophisticated econometric analyses can be done, a relatively easy analysis can be done by adjusting capital expenditures for inflation, and also comparing the average annual growth rates in real capital expenditures and customers over different periods.

Board staff has prepared the attached spreadsheet to facilitate this analysis. The data shown in the spreadsheet are as follows:

Column A	Year
Column B	Annual Capital Expenditures (from response to Board staff IR #22)
Column C	Smoothed Capital Expenditures (from response to Board staff IR #22)
Column D	Extended Capital Expenditures (from response to Board staff IR #22)
Column E	Number of Customers (to be filled in)
Column F	GDP-IPI – Implicit Price Index (price deflator) for National Gross Domestic Product. Annualized from quarterly series. This is the same price deflator series which annual growth rate is used as the proxy for the inflation adjustment for the 2nd and 3rd Generation IRM plans. Source: Statistics Canada Series V1997757.
Column G	Real capital expenditures. Column B divided by Column F.

The spreadsheet also calculates the average annual geometric growth rate for the following periods:

• 1980 to 1994
• 1994 to 2007; and
• 1980 to 2007.

a. Please confirm whether or not Thunder Bay accounted for inflationary pressures and customer growth when preparing its original capital expenditures trend.

Response

Preamble

Board staff should note that the graph presenting historical Capex data was provided in order to illustrate that what was a trend over a number of years of moderate yearly growth in total Capex changed significantly in 1994. The application further indicates that extending the trend of yearly Capex investment through to 2009, using 1980 through 1994 data as a basis for the trend line, illustrates that current yearly Capex would be significantly higher had the trend not changed. The information was presented in order to proved background information on the historical trend of Capex investment. Evidence submitted related to the required level of annual Capex investment was supplied in Exhibit 2, Tab 3, Schedule 1, pages 3 through 6.

Nonetheless, some comment on the Board staff's interpretation of the previous Thunder Bay Hydro response to the interrogatory is required here as the supplemental question reflects a misunderstanding of the relationship between the Rate Minimization Philosophy, the Capex trends before and after 1994, and the then Commission electricity rate decisions which impacted the Capex trend.

The Rate Minimization Philosophy under which the utility operates was not implemented in 1994. Prior to the introduction of Bill 35, Ontario LDC's operated under a 'Power at Cost' regime rather than under a commercial business model. TBHEDI is assuming a level of OEB knowledge on this item and is not submitting further evidence. Upon the incorporation of Thunder Bay Hydro Electricity Distribution Inc., the shareholder implemented a Shareholder Declaration requiring the LDC to operate under a Rate Minimization Model. As reviewed in Exhibit 5, Tab 1, Schedule 1, the effect of this Rate Minimization Model is that the Shareholder does not extract a financial return in the form of either dividends or interest on debt held. The Shareholder has decided not to extract its allowed financial return in order to keep electricity cost low for customers in Thunder Bay. There is no relationship between the Hydro-electric Commission of Thunder Bay decisions to reduce capital spending starting in 1994 and the eventual introduction of the Rate Minimization Model.

Thunder Bay Hydro Electricity Distribution Inc. did not account for inflation or customer growth in the information presented. The information was not presented to reflect real, inflation adjusted Capex. The information was presented to illustrate that the previous trend of growing yearly Capex changed starting in 1994. The data was not adjusted to reflect customer growth.

b. Please confirm or correct the data provided in the attached table.

Response

Confirmed.

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.

Response

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.

d. Please provide Thunder Bay's observations and comments on whether there have been changes in inflation rates and customer growth in Thunder Bay in the two periods: 1980-94 and 1994-2007. Please provide Thunder Bay's comments on whether lower inflationary pressures on capital prices and labour rates, combined with lower customer growth, ignoring Thunder Bay's adoption of a rate minimization approach, would have lead to lower expected capital expenditures since 1994 than those estimated by Thunder Bay's "extended trend".

Response

Attempting to draw comparisons between customer growth and inflationary pressure between two periods of 15 and 13 years would oversimplify the data and lead to potentially incorrect conclusions. If Capex is adjusted for inflation and the real yearly Capex growth rate is compared to the customer growth rate for the periods suggested by OEB staff, the comparison would indicate that during the period of 1980-1994 customer growth averaged 1.07% and real Capex averaged 5.96%, while for 1995-2007 customer growth was .33% compared to real Capex of -2.62%. Taking inflation into account by calculating real Capex, there is no basis to conclude that average customer growth for a period has influenced average real Capex for Thunder Bay Hydro Electricity Distribution Inc. since 1980. In addition to the information requested by OEB staff, the supplied spreadsheet has been amended by Thunder Bay Hydro Electricity Distribution Inc. staff to further analyze this data relationship.

For the purpose of this analysis, average customer growth and average real Capex growth was calculated for five (5) year periods beginning in 1980. A statistical analysis of the significance of the relationship between customer growth and real Capex growth resulted in a correlation coefficient of .573 for these sets of data, indicating that no significant statistical relationship exists. As an example, a review of the data indicates that from 1980-1984 customer growth was .73% and real Capex growth was 1.54%, while from 1985-1989 average customer growth was higher at .84% while real Capex growth was -1.32%.

A further calculation of data correlation is also presented in the spreadsheet. The correlation coefficient of the yearly customer growth compared to real Capex for the entire period 1980-2007 is calculated to be .15116, indicating a very weak relationship between customer growth and real Capex.

OEB staff ask whether adjusting the calculated trend line for lower customer growth and lower inflationary pressures would have led to lower expected capital expenditures since 1994 than those estimated. As previously stated, the graph provided in Appendix A as referenced in your query, is presented to illustrate the historical annual Capex trend. More fulsome evidence supporting the appropriate level of annual Capex required to ensure the ongoing safety, integrity and reliability of the distribution system was presented in Exhibit 2, Tab 3, Schedule 1.

e. Based on the results of the spreadsheet and the analysis above, please provide an estimate of capital expenditures for the 2010 to 2014 period that would be sufficient to sustain the network, accommodate customer growth and rehabilitate the network in light of past capital under spending.

Response

Thunder Bay Hydro's estimates as per the evidence summarized under Total System Replacement Costs in Exhibit 2, Tab 3, Schedule 1, pages 3 through 6, is that annual expenditures on replacement capital should approximate $10.3M. Please also see evidence in Exhibit 2, Tab 1, Schedule 1, page 3.

Smart Meters

13. Ref: Board staff IR#28

In response to Board staff IR #28 a) i), Thunder Bay explained that costs related to: i) Changes to ancillary systems; and ii) Costs associated with Repair and Replacement of Customer Owned Equipment, are not included in the 2009 rate base and revenue requirement, or in the calculation of the funding adder. The aggregate capex and opex for these areas amount to approximately $600,000 for i) and $560,000 for ii).

a. Please provide further explanation of what changes to ancillary systems are necessary.

Response

Smart Meter Customer Presentment Tools-Capital……………………….$113,319
Annualized 4 year Operating Costs ………………………… $ 19,043
Smart Meter Entity MDM/R Costs-Capital……………………………….$ 68,040
Annualized 4 year Operating Costs……………………………..$233,858
Bill Print Modifications-Capital…………………………………………….$ 56,700
Customer Education Packages- Annualized 4 year Operating Costs………………………………………………………… .$ 41,760
Customer TOU Modifications/MDMR Integration-Capital…………….$ 56,700
Staff Training Costs- Annualized 4 year Operating Costs…………… $ 5,040.

b. Please provide further explanation of what is meant by "Costs associated with Repair and Replacement of Customer Owned Equipment". Is this related to replacement of defective meter bases?

Response

Yes, this relates to replacement of defective meter bases.

c. Please provide Thunder Bay's proposal for tracking and recovery of the above costs, if they are not recovered by way of the revenue requirement or factored into the smart meter funding adder.

Response

Thunder Bay Hydro intends to add them into the smart meter funding adder and will be tracking them in the smart meter variance account until such time as they are incorporated into the rate base, which will be 2012 (see Appendix A for the updated Smart Meter Adder Model).

Cost of Capital

14. Ref: Board staff IR #27, Energy Probe IR#26

In response to Energy Probe IR#26, Thunder Bay indicated that it has not yet determined if the forecasted debt for 2009 capital funding ($1.1M), which is not yet in place, will be with an affiliated party or a third party institution. Thunder Bay has taken the position that the forecasted interest rate of 6% is should be applicable to the loan, although it is not in yet in place.

The Board's deemed long-term debt rate, as documented in section 2.2.1 and Appendix A of the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, issued December 22, 2006, is intended as a proxy for what would constitute a market-based rate, based on currently available information, where no contracted rate is established. If Thunder Bay has not established the terms and rates for this forecasted debt, please explain why the rate for this new debt should be 6.0% rather than the Board's deemed long-term debt rate, which is based on January 2009 data.

Response

Thunder Bay Hydro is aware of Board policy and it is not our intention to go against such. At the time of filing we had based our calculation on 6% (the deemed debt rate was 6.1% for 2008 and the 2009 rate has not yet been determined) and simply responded that we felt the 6% was still applicable. It is not expected that the long-term debt will be in place by the end of April 2009.

15. Ref: Exhibit 6 – Revenue Deficiency Overview, Board staff IR#29, Energy Probe IR #29

Thunder Bay states that it requires a return on equity of 7.90% to be able to fully recover the capital costs for smart meter deployment in 2009, as shown by the tables provided in the response to Energy Probe IR#29. This is in contrast with its proposed ROE of 3.75%. Board staff notes that concepts of debt financing and return on equity are routinely applied at an aggregate level for financing of the firm's capital investments, rather than on a project basis.

a. In the tables shown in the response to Energy Probe IR#29, Thunder Bay demonstrated that an ROE of 7.90% is required to be able to fully recover the capital investment plus debt servicing costs (interest) on the 2009 smart meter capital expenditures over a 15 year economic life. Thunder Bay also stated that it will fund smart meters fully through debt financing. Thunder Bay stated that it has assumed a debt rate of 6.0% for purposes of calculating the rate adder. Please explain why a rate higher than the assumed 6.0% debt interest rate would be necessary to fully recover the principal and interest on the deemed equity portion.

Response

Due to the weighted average of the funding structure and rate of return, and the need to recover $4.4M in interest costs, formulaically, all other things given, the rate of return for equity funding needs to approximate 7.9% as presented in the response. However, as the total rate base increases (and the associated interest payments increase) the rate of return for equity funding decreases, and vice versa.

b. Shareholders' equity is not specifically tied to assets invested. Furthermore, economic regulatory rate-setting is based on allowing the firm to recover necessary and prudently incurred costs, including the opportunity to earn a market-based return on shareholders' equity, and taking into account market conditions and the business risk of the firm and industry relative to the overall market. Finally, the target return varies over time. When a utility rebases rates through a cost of service application, the allowed ROE will be set explicitly. For rate adjustments as part of IRM plans, the inflation adjustment in part accounts for changes in the cost of capital parameters. Thunder Bay, in accordance with the Board's *Guideline G-2008-0002: Smart Meter Costs and Recovery*, and with general regulatory rate-setting policy, will eventually be applying for recognition of smart meter capital costs in rate base.

Taking into account the above regulatory principles and practices, please explain Thunder Bay's rationale for proposing a different ROE for smart meter investments (7.90%) versus its proposed ROE of 3.75% for other shareholder equity.

Response

The Corporation of the City of Thunder Bay (the City) has never received a return on their investment in Thunder Bay Hydro since incorporation/restructuring in October 2000. The debt with the City bears no interest. Assuming a simple interest calculation using a 7% interest rate, the annual interest foregone approximates $2.3M (cumulatively from 2002 to 2008 $16.4M). Further, the City has not received dividends from Thunder Bay Hydro. The rate of return on equity has been considerably below the allowed rate of return. For simplicity and illustrative purposes only, assuming a spread of 5% (currently 8.57% versus 3.75%), a rate base of $70M and a debt/equity capital structure of 60/40, annually the City has foregone approximately $1.4M (cumulatively from 2002 to 2008 $9.8M). Finally, the City has reinvested the minimal return that they did seek. Having said such, Thunder Bay Hydro is not seeking additional equity injection by the City to fund the Smart Meter Initiative.

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.

In further reviewing the situation, Thunder Bay Hydro feels that using a 100% debt rate in the Smart Meter Model would more appropriately achieve the required funding of the Smart Meter project. Using the 100% debt reduces PILS funding in the Model, recognizing that the interest is tax deductible. The Smart Meter Adder Model (updated by Board Staff in November 2008) is attached as Appendix A to this document. The Model has been updated to reflect current costs based on the results of contract negotiations including volume purchase rates and price adjustments as examples.

The attached Model also includes direct capital costs of $303,000 for installations to be completed by the Metering Department as described in the following paragraph.

Metering Department's Cost Shift within Rate Order

In early 2008 when Thunder Bay Hydro's rate order was developed there was uncertainty as to how the SMART Metering initiative would be executed. At that time it was anticipated that Thunder Bay Hydro's Metering Department staff of three would continue with their typical duties of meter installation verifications, upgrades responding to meter trouble reports and other operational duties. Only a minor support role in the SMART Metering initiative was contemplated; that being engaged in only the most difficult metering installations with all remaining Smart Metering work falling within the installation contract to be awarded. Thus the Thunder Bay Hydro Metering

Department's costs were accounted for in the rate order as per that plan.

However late in 2008 the smart metering communications WAN network was determined to be based on pole mounted collectors and repeaters throughout the city in accordance with the winning bid supplier's system. Additionally, in discussions with Measurement Canada it was determined that upon replacement of any meter, a metering installation had to be brought into compliance with Measurement Canada's requirements. This represents over 500 three phase metering installations for General Service <50kW customers that need to be upgraded.

In discussions with our installation contractor it became apparent that the skills required for the more complex installations including the collectors/repeaters were not readily available and ensuring that the work was carried out to Thunder Bay Hydro's safety standards would be onerous and presented a substantial risk with respect to the initiative's schedule. Thus it was determined that the most effective and efficient means of executing this work would be to have it performed by Thunder Bay Hydro's own metering staff. This has had a significant impact on the Departments costs being significantly shifted from OM&A to Capital in accordance with the Smart Metering accounting guidelines.

The result of the foregoing produces a Smart Meter Rate Adder of $1.97 for 2009. In keeping with the OEB Board's principles of rate-making of effectiveness and stability for both the LDC and the customer, Thunder Bay Hydro is requesting that the "seed funding" collected to date be allowed to be carried over and applied to recover revenue requirement in 2010. The Smart Meter Adder Model ("Smart Meter Revenue Requirement Calculation" in Appendix A, page viii) shows an adder of $3.17 will be required in 2010 for an increase of 62% over the $1.97 adder calculated in 2009. This can be reduced to $2.34 for a 20% increase if the adder "seed funding" is applied to the revenue requirement of 2010. Should the Board not allow Thunder Bay Hydro a 2009 rate adder of $1.97, but rather require the funding collected to date to be used to decrease the revenue requirement for 2009, the result will be a rate adder of $1.18. The required adder of $3.17 for 2010 would then result in a 169% increase over the 2009 adder.

Further, the 2011 and 2012 years are very close to the $2.34 reduced 2010 adder requirement. Forcing Thunder Bay Hydro to use a Smart Meter Adder of $1.18 in 2009 will result in customer rates that will rise in 2009, significantly rise once again in 2010 and then drop in 2011.

Finally, Thunder Bay Hydro's request is akin to the standard "annualization" of costs over the three years to next rebasing.

COST ALLOCATION, RATE DESIGN AND VARIANCE ACCOUNTS

Revenue to Cost Ratios

16. Ref: E7/T1/S3/p.17, VECC IR # 7c), VECC IR # 8a)

In response to VECC IR #7 c), Thunder Bay provided a version of the Cost Allocation model in which the cost of the Transformer Ownership Allowance is excluded, which can be compared with the version in the pre-filed evidence which includes it as a “cost” item. The result of excluding the allowance is higher revenue-to-cost ratios for the classes that have transformer-related costs allocated to them, and lower revenue-to-cost ratios for those classes that do not have transformer-related costs allocated to them. In particular, the revenue-to-cost ratio of the General Service 1000-4999 kW class is 60.17% in the application and 43.41 % in the response to VECC IR #7c).

a. The revenue inputs to the Cost Allocation model for the General Service 1000-4999 kW class in 2006 are $1,158,847 and $789,375, in the pre-filed and VECC runs respectively. Please confirm that analogous amounts for 2009 are $1,069,706 and $1,402,432, as provided in response to VECC IR #8a). If these are not the analogous revenues, please provide the 2009 numbers that would be considered analogous to the 2006 data inputs.

<u>Response</u>

Confirmed.

b. Please provide the Monthly Service Charge and volumetric rate for the General Service 1000-4999 kW class that was approved for 2006 and hypothetical rates that would have produced sufficient revenue in 2006 in the VECC version such that the ratio would have been 60% instead of 43%.

<u>Response</u>

For the General Service 1000-4999 kW class, the 2006 approved Monthly Service Charge 2006 was $1,621.98 per month and the approved volumetric rate was $1.4268/kW. In the VECC version of the cost allocation model the revenue requirement or the "cost" for the General Service 1000-4999 kW class is $1,959,072. To achieve 60% revenue to cost ratio the revenue would be $1,959,072 times 60% or $1,175,443. However, $61,108 of miscellaneous revenue needs to be subtracted from $1,175,443 to determine the target distribution revenue of $1,114,335 to estimate the hypothetical rates. Comparing the $1,114,335 to the revenue of $1,158,847 shown in the original cost allocation study indicates a decrease in rates of 3.84% (i.e. $1,114,335/$1,158,847 -1 is 3.84%). This means the hypothetical rates that would have produced sufficient revenue in 2006 in the VECC version such that the ratio would have been 60% are a Monthly Service Charge of $1,559.70 per month and a volumetric rate of $1.372/kW. In other words, the hypothetical rates are the 2006 approved rates reduced by 3.84%.

c. Does Thunder Bay consider the original filing or the modified version provided in VECC IR #7c) to be a more valid representation of the revenue-to-cost ratio for the class in question?

Response

For the purposes of answering this interrogatory Thunder Bay Hydro has the following comments: After reviewing the two options suggested, it is Thunder Bay Hydro's opinion that neither option is preferred. The issue that is being addressed with the alternative in VECC 7c is how to properly address transformation allowance in the cost allocation study. In Thunder Bay Hydro's application the "cost" of the transformation allowance and the associated recovery of this cost was assigned to the rate class receiving the transformation allowance. In Thunder Bay Hydro's view, the proper way to account for this method in the cost allocation model would be to leave the "cost" of the transformation allowance in the cost allocation model but directly assign this cost to the classes that receive the transformation allowance. The cost allocation model has a direct assignment option which could be used for this purpose.

17. Ref: E8/T1/S9/Appendix A /p.7, Energy Probe IR # 27 c)

In the prefiled evidence, an increase in the revenue-to-cost ratio for the General Service 50-999 kW class from 66% to 73% is accomplished by increasing the Monthly Service Charge by 20.37% and the volumetric rate by 18.29% (ref: second from last column, p. 7 of 12). In the response to Energy Probe, an increase of twice as much (from 66% to 80%) is accomplished with increases of 31.96% and 28.70%. These calculated increases are approximately 1.5 times the increase that was applied for, whereas one might have expected them to be 2 times as much. Please confirm that the hypothetical rates provided in response to the Energy Probe interrogatory are correct, together with an explanation for the seeming anomaly identified here. Alternatively, please provide a corrected calculation of the rates and impact in the response to the interrogatory.

Response

The hypothetical rates provided in response to the Energy Probe interrogatory are correct. To justify this position the increases in the Monthly Service Charges will be discussed but the same justification can be applied to the volumetric rate. In the pre-filed evidence, an increase in the revenue-to-cost ratio for the General Service 50-999 kW class from 66% to 73% is accomplished within the increase of 20.37% for the Monthly Service Charge. However, this increase of 20.37% does not only represent a change in revenue-to-cost ratio but it also includes an overall increase in distribution rates of 8.78% to recover the revenue deficiency of $1,414,077 outlined in Exhibit 6/Tab 1/Schedule 1/Page 2. The resulting increase in the Monthly Service Charge for the revenue-to-cost ratio change is 11.59% (i.e. 20.37% minus 8.78%). When the revenue-to-cost ratio is further changed to 80% the expected percentage change in the Monthly Service Charge would be 11.59% times 2 plus 8.78% which is 31.96%. The expected percentage change is consistent with the actual outcome.

18. Ref: E8/T1/S9/Appendix A/p.9,; Energy Probe IR# 27 d)

In the prefiled evidence, an increase in the revenue-to-cost ratio for the General Service 1000-4999 kW class from 60% to 70% is accomplished by increasing the Monthly Service Charge by 26.72% and the volumetric rate by 15.67%. In the response to Energy Probe, an increase of twice as much (from 60% to 80%) is accomplished with increases of 44.86% and 26.31%. Again, these calculated increases are approximately 1.5 times the increase that was applied for, whereas one might have expected them to be 2 times as much. Please confirm that the hypothetical rates provided in response to the Energy Probe interrogatory are correct, or alternatively provide a corrected calculation of the rates and impact in the response to the interrogatory.

<u>Response</u>

See response to OEB Staff Supplemental Interrogatories #17 above.

Retail Transmission Service Rates

19. Ref: Board staff IR #46 b), c)

In response to Board staff IR #46 b), Thunder Bay provided a forecast of the wholesale cost of transmission service. In response to Board staff IR #46 c), Thunder Bay provided a forecast of its revenue from the proposed Retail Transmission Service Rates. There is a shortfall in the Network revenue of approximately 5% ($4.3M vs $4.6M), and a shortfall in the Connection revenue of approximately 10% ($3.7M vs. $3.3M).

a. Please explain why Thunder Bay is proposing RTSRs that produce a shortfall instead of a simple pass-through of the forecast cost.

<u>Response</u>

It was not Thunder Bay Hydro's intention to propose RTSRs that produce a shortfall. As noted in the response, Thunder Bay Hydro is not sure that this is necessarily a valid approximation of the costs; however, we will request the revised rates as per response in (b).

b. Please provide a calculation of Network and Connection RTSRs, similar to those in the tables in response to part c) of Board staff IR #46, that would produce revenues close to the forecast wholesale cost.

Response

NETWORK SERVICE

					% Increase	6.83%		
Rate Classification	*Metric*	*Loss Adjusted Consumption*		*Rate*		*Cost*		
Residential	*kwH*	356,068,327	$	0.0046		$1,635,733.69		
General Service less than 50 kW	*kwH*	150,410,896	$	0.0043		$ 642,761.84		
General Service greater than 50 to 999 kW	*kW*	749,395	$	1.7293		$1,295,949.72		
General Service greater than 1,000 to 4,999 kW	*kW*	579,358	$	1.8345		$1,062,804.48		
Street Lights	*kW*	32,677	$	1.3041		$ 42,615.16		
Sentinel Lights	*kW*	420	$	1.3109		$ 550.57		
Unmetered Scattered Load	*kwH*	1,395,059	$	0.0043		$ 5,961.61		
		(0)						
			Total			$ 4,686,377		

CONNECTION SERVICE

					% Increase	9.83%		
Rate Classification	*Metric*	*Loss Adjusted Consumption*		*Rate*		*Cost*		
Residential	*kwH*	356,068,327	$	0.0037		$1,329,691.88		
General Service less than 50 kW	*kwH*	150,410,896	$	0.0034		$ 512,129.45		
General Service greater than 50 to 999 kW	*kW*	749,395	$	1.3159		$ 986,149.62		
General Service greater than 1,000 to 4,999 kW	*kW*	579,358	$	1.4543		$ 842,571.04		
Street Lights	*kW*	32,677	$	1.0173		$ 33,242.06		
Sentinel Lights	*kW*	420	$	1.0386		$ 436.22		
Unmetered Scattered Load	*kwH*	1,395,059	$	0.0034		$ 4,749.99		
		(0)						
			Total			$ 3,708,970		

Deferral and Variance Accounts

20. Ref: E1/T3/S1/Attachment A/page 45 - 2007 Audited Financial Statements, Board staff IR #47 a), d)

The December 31, 2007 balances for Accounts 1584 and 1586 provided in the continuity schedule are credits of $671,317 and $647,640 respectively (including interest to April 30, 2009). The balances reported in the 2007 Audited financial Statements in Exhibit 1 at year-end 2007 were ($825,305) and ($589,654) respectively. Please reconcile the two sets of numbers. If the Board were to order disposition of the balances in accounts 1584 and 1586, which set of figures should it rely on?

Response

The difference between the two represents unbilled revenue net of the December power bill accrued for the audited financial statements.

Balances at December 31, 2007		
	RRR Filings – Cash Basis	*Full Accrual Basis*
Connection	*$627,439*	*$589,654*

The balance of the difference ($20,201) represents carrying charges for 2008 through to April 2009.

Network	*$645,731*	*$825,305*

The balance of the difference ($25,586) represents carrying charges for 2008 through to April 2009.

Consistent with past filings, Thunder Bay has reported the Regulatory balances for disposition based on the billed basis. (Per 2.0.23 RP-2004-0064, RP-2004-0069, RP-2204-0100, RP-2004-0117/0118 In the Matter of Review and Recovery of Regulatory Assets-Phase 2 Decision with Reasons 2004 December 09). Additionally, OEB Board staff sent e-mail correspondence in September of 2007 to Thunder Bay requesting disclosure of our method of reporting under 2.1.1 and 2.1.7 (see copy of e-mail on the following page).

Irena Kolodziej-Hefford/TBHYDRO
09/20/2007 11:55 AM

To Anshula.Ohri@oeb.gov.on.ca
cc Cindy Speziale/TBHYDRO@TBHYDRO
bcc Irena Kolodziej-Hefford/TBHYDRO
Subject Re: Quarterly Reporting: 1588 RSVA Power Sub-Account Global Adjustment Scanned by Trend Micro Scanned by Trend Micro

Anshula,

With regards to the inquiry below:

As per your Ontario Energy Board Compliance Bulletin 200701 dated September 11, 2007 Thunder Bay Hydro Corporation has been in compliance with quarterly reporting of commodity deferral accounts under section 2.1.1 of the RRR since 2005. However, since the 2005 Q1, Q2 and Q3 RRR filings do not include a separate line for the sub-account I have attached an Excel spreadsheet which reflects calculations that support the original sub-account balances.

Subsequent to 2005 year end, we recalculated the Global Adjustment non RPP sub account with data based on actual consumption (which was not available at the time 2005 Q4 2.1.1 was completed). The 1588 RSVA Power Sub-Account Global Adjustment was restated in Q1 2006 Triple R filing for the total amount in the "Other Adjustments Dr/-Cr to Date" in 2.1.1 report. That Excel spreadsheet with detail is also attached.

Regarding additional questions:

1. The global sub-account is included in the 1588 RSVA power control account balance in each quarter since January 2005
2. The December 2.1.1 RSVA quarterly filings are reported on a cash basis. The December 2.1.7 filing balance is reported on an accrual basis as it includes unbilled revenue adjustments (as per audited financial statements) and, therefore, does not equal the December 2.1.1 submission for the same period. The difference equals the revenue accrual
3. March, June and September 2.1.1 filings are reported on a cash basis
4. The filing deadlines are challenging to achieve since Thunder Bay Hydro month financial closing date occurs on the 20th day of the month which only leaves 10 days to prepare, check and submit the filing. This can be difficult if there are any complications with the month end close. It would be helpful to have an additional month to complete.

Please contact me if you have any additional questions.

Regards,
Irena Kolodziej-Hefford; B.Comm, CGA
Business & Regulatory Analyst
Thunder Bay Hydro Electricity Distribution Inc.
34 N. Cumberland Street
Thunder Bay, Ontario P7A 4L4
Phone (807)-343-1016 Fax (807)-343-2663

RSVA 4Q 2005 submitted to OEB Sep 2007.xls RSVA 4Q 2005 - Restated submitted to OEB Sep 2007.xls

"Anshula Ohri" <Anshula.Ohri@oeb.gov.on.ca>

Rural or Remote Electricity Rate Protection

21. Ref: E8/T1/S6 – Proposed Rate Schedule for 2009, Board's December 17, 2008 Letter to All Licensed Electricity Distributors and Retailers Re: Rural or Remote Electricity Rate Protection

In its December 17, 2008 letter, the Board announced a change to the RRRP rate from 0.10 cents per kWh to 0.13 cents per kWh. The Board also directed all distributors that have current rate applications before the Board to submit the Board's December 17, 2008 letter as an update to their evidence along with a request that the RRRP change in their tariff sheet be revised to 0.13 cents per kWh effective May 1, 2009. As of this date, Thunder Bay has not updated its application for this change.

Please confirm that Thunder Bay is updating its application to reflect the change to the RRRP rate.

<u>Response</u>

Thunder Bay did not receive the e-mail notification regarding this. Thunder Bay has submitted it's request to the OEB Board Secretary February 4, 2009.

APPENDIX A

Smart Meter Model
(Updated by Board Staff in November 2008)

THUNDER BAY HYDRO
SMART METER PROGRAM SUMMARY

RATE FILLING	2008 and Prior	2009	2010	2011	2012	TOTAL	UNIT COSTS/ METER
Total Meters Installed: 49,101							
Smart Meter Unit Costs (AMI)	$0	$5,694,040	$62,192	$62,192	$62,192	$5,880,617	$119.77
Smart Meter Other Unit Costs	$57,750	$243,978	$26,250	$0	$0	$327,978	$6.68
Smart Meter Installation Costs Per Unit	$0	$1,236,458	$0	$0	$0	$1,236,458	$25.18
Smart Meter Other Costs Per Unit	$961	$650,398	$0	$0	$0	$651,359	$13.27
Smart Meter Unit Costs						$8,096,412	$164.89
AMI Computer Hardware Costs	$0	$135,997	$0	$0	$0	$135,997	
SMI Computer Software Costs	$0	$20,948	$0	$0	$0	$20,948	
Other Computer Hardware Costs	$0	$0	$0	$0	$0	$0	
Other Computer Software Costs	$0	$0	$0	$0	$0	$0	
Computer Hardware/Software Costs						$156,945	
							4 Yr Avg
Incremental AMI O&M Expenses	$0	$286,828	$509,008	$170,049	$170,049	$1,135,934	$283,983
Incremental AMI Admin Expenses	$0	$0	$3,402	$0	$0	$3,402	$851
Incremental Other O&M Expenses	$29,025	$28,350	$28,350	$28,350	$28,350	$142,425	$35,606
Incremental Other Admin Expenses	$0	$0	$0	$0	$0	$0	
Incremental O&M and Admin Costs						$1,281,761	
Recoverable/Rate Adder Costs:						$9,535,118	$194.19
Deferrable Cost:							
Utility Safety & Mtce Capital Budget	$0	$222,722	$0	$0	$0	$222,722	$4.54
						$0	
MDMR Cost:						$0	
TOU Billing Budget	$0	$379,326	$435,219	$244,942	$245,176	$1,304,664	$26.57
						$0	
TOTAL SMART METER COST:	$59,961	$8,899,046	$1,064,421	$505,533	$505,768	$11,062,504	$225.30

Sheet 1 Utility Information Sheet

Name of LDC:	Thunder Bay Hydro Electricity Distribution Inc. EB-2008-0245
Licence Number:	
Date of Submission:	February 11, 2009

Contact Information

Name:	Updated Smart Meter Model as provided by OEB_Nov_08
Title:	Model indicates 100% Debt Funding As Explained in
Phone Number:	Response to OEB Interrogatory #15
E-Mail Address:	_

Sheet 2. Smart Meter Capital Cost and Operational Expense Data

Smart Meter Unit Installation Plan:	2006	2007	2008	2009	2010	2011	Later	Total
assume calendar year installation	Audited Actual	Audited Actual	Actual	Forecasted	Forecasted	Forecasted	Forecasted	
Planned number of Residential smart meters to be installed	-	-	-	48,928				48,928
Planned number of General Service Less Than 50 kW smart me	-	-	-	-				-
Planned Meter Installation (Residential and Less Than 50 kW (	-	-	-	48,928	-	-	-	48,928
Percentage of Completion	0%	0%	0%	100%	100%	100%	100%	
Planned number of General Service Greater Than 50 kW smart	-	-	-	-	-			-
Planned / Actual Meter Installations	-	-	-	48,928	-	-	-	48,928

Other Unit Installation Plan:	2006	2007	2008	2009	2010	2011	Later	Total
assume calendar year installation	Audited Actual	Audited Actual	Actual	Forecasted	Forecasted	Forecasted	Forecasted	
Planned number of Collectors to be installed				70				70
Planned number of Repeaters to be installed				40				40
Other : Please specify								
								-
								-
								-
								-

Capital Costs

1.1 ADVANCED METERING COMMUNICATION DEVIC	Asset Type	2006	2007	2008	2009	2010	2011	Later	Total
		Audited Actual	Audited Actual	Actual	Forecasted	Forecasted	Forecasted	Forecasted	
1.1.1 Smart Meter	Smart Meter				$ 5,694,040	$ 62,192	$ 62,192	$ 62,192	$ 5,880,617
may include new meters and modules, etc.									
1.1.2 Installation Cost	Smart Meter				$ 543,871				$ 543,871
may include socket kits plus shipping, labour, benefits, vehicle, etc.									
1.1.3a Workforce Automation Hardware	Comp. Hard.								$ -
may include fieldworker handhelds, barcode hardware, etc.									
1.1.3b Workforce Automation Software	Comp. Soft.				$ 72,265				$ 72,265
may include fieldworker handhelds, barcode hardware, etc.									
Total Advanced Metering Communication Device (AMCD)		**$ -**	**$ -**	**$ -**	**$ 6,310,176**	**$ 62,192**	**$ 62,192**	**$ 62,192**	**$ 6,496,753**

1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)

		2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted	2011 Forecasted	Later Forecasted	Total
1.2.1 Collectors	**Smart Meter**				$ 206,955				$ 206,955
1.2.2 Repeaters *may include radio licence, etc.*	**Smart Meter**				$ 10,773				$ 10,773
1.2.3 Installation *may include meter seals and rings, collector computer hardware, etc.*	**Smart Meter**				$ 692,587				$ 692,587
Total Advanced Metering Regional Collector (AMRC) (inclu		**$ -**	**$ -**	**$ -**	**$ 910,315**	**$ -**	**$ -**	**$ -**	**$ 910,315**

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)

		2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted	2011 Forecasted	Later Forecasted	Total
1.3.1 Computer Hardware	**Comp. Hard.**				$ 10,206				$ 10,206
1.3.2 Computer Software	**Smart Meter**								$ -
1.3.3 Computer Software Licence & Installation (inclu *may include AS/400 disc space, backup & recovery computer, UPS, etc*	**Comp. Soft.**				$ 125,791				$ 125,791
Total Advanced Metering Control Computer (AMCC)		**$ -**	**$ -**	**$ -**	**$ 135,997**	**$ -**	**$ -**	**$ -**	**$ 135,997**

1.4 WIDE AREA NETWORK (WAN)

		2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted	2011 Forecasted	Later Forecasted	Total
1.4.1 Activation Fees	**Smart Meter**								$ -
Total Wide Area Network (WAN)		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

1.5 OTHER AMI CAPITAL COSTS RELATE

		2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted	2011 Forecasted	Later Forecasted	Total
1.5.1 Customer equipment (including repair of damag	**Smart Meter**				$ 309,336				$ 309,336
1.5.2 AMI Interface to CIS	**Comp. Soft.**				$ 34,020	$ 68,040			$ 102,060
1.5.3 Professional Fees	**Smart Meter**			$ 30,250	$ 131,141				$ 161,391
1.5.4 Integration	**Comp. Soft.**				$ 113,318				$ 113,318
1.5.5 Program Management	**Smart Meter**			$ 28,461	$ 26,250	$ 26,250			$ 80,961
1.5.6 Other AMI Capital	**Smart Meter**				$ 226,643				$ 226,643
Total Other AMI Capital Costs Related To Minimum Functi		**$ -**	**$ -**	**$ 58,711**	**$ 840,708**	**$ 94,290**	**$ -**	**$ -**	**$ 993,710**
Total Capital Costs		**$ -**	**$ -**	**$ 58,711**	**$ 8,197,197**	**$ 156,482**	**$ 62,192**	**$ 62,192**	**$ 8,536,775**

O M & A

2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)

	2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted	2011 Forecasted	Later Forecasted	Total
2.1.1 Maintenance (Meter base repairs - materials) *may include meter reverification costs, etc.*				$ 222,722				$ 222,722
Total Incremental AMI Operation Expenses	**$ -**	**$ -**	**$ -**	**$ 222,722**	**$ -**	**$ -**	**$ -**	**$ 222,722**

2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)

	2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted	2011 Forecasted	Later Forecasted	Total
2.2.1 Maintenance				$ 57,154	$ 57,154	$ 57,154	$ 57,154	$ 228,614
Total Advanced Metering Regional Collector (AMRC)	**$ -**	**$ -**	**$ -**	**$ 57,154**	**$ 57,154**	**$ 57,154**	**$ 57,154**	**$ 228,614**

2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)

	2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted	2011 Forecasted	Later Forecasted	Total
2.3.1 Hardware Maintenance *may include server support, etc*								$ -
2.3.2 Software Maintenance- includes operator *may include maintenance support, etc.*				$ 112,895	$ 112,895	$ 112,895	$ 112,895	$ 451,581
Total Advanced Metering Control Computer (AMCC)	**$ -**	**$ -**	**$ -**	**$ 112,895**	**$ 112,895**	**$ 112,895**	**$ 112,895**	**$ 451,581**

2.4 WIDE AREA NETWORK (WAN)

	2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted	2011 Forecasted	Later Forecasted	Total
2.4.1 WIDE AREA NETWORK (WAN) *may include serial to Ethernet hardware, etc.*								$ -
Total Incremental Other Operation Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY

2.5.1 Business Process Redesign					$ 22,272	$ 25,257	$ 28,641	$ 76,170
2.5.2 Customer Communication				$ 55,681	$ 111,361			$ 167,042
may include project communication. etc.								
2.5.3 Program Management	$ -	$ 13,583	$ 15,442	$ 116,779	$ 116,779			$ 262,584
2.5.4 Change Management					$ 20,412	$ 3,150		$ 23,562
may include training, etc.								
2.5.5 Administration Cost				$ 136,618	$ 244,885	$ 244,885	$ 244,885	$ 871,274
2.5.6 Other AMI Expenses					$ 222,180			$ 222,180
Total 2.5 Other AMI OM&A Costs Related To Minimum Fun	**$ -**	**$ 13,583**	**$ 15,442**	**$ 309,078**	**$ 737,890**	**$ 273,292**	**$ 273,526**	**$ 1,622,811**
Total O M & A Costs	**$ -**	**$ 13,583**	**$ 15,442**	**$ 701,848**	**$ 907,939**	**$ 443,341**	**$ 443,575**	**$ 2,525,728**

Sheet 3. LDC Assumptions and Data

Assumptions:

1. Planned meter installations occur evenly through the year.
2. Year assumed January to December
3. Amortization is straight line and has half year rule applied in first year

	2006 EDR Data Information	2007	2008	2009	2010	2011	Later
Rate Base							
Deemed Short Term Debt %			0%	0%	0%	0%	0%
Deemed Debt (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Input)"	50%	50%	100%	100%	100%	100%	100%
Deemed Equity (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Inpu	50%	50%	0%	0%	0%	0%	0%
Deemed Short Term Debt Rate%			4.47%	4.47%	4.47%	4.47%	4.47%
Weighted Debt Rate (from 2006 EDR Sheet "3-2 COST OF CAPITAL	0.00%	0.00%	0.00%	6.00%	6.00%	6.00%	6.00%
Proposed ROE (from 2006 EDR Sheet "3-2 COST OF CAPITAL (Inpu	2.93%	2.93%	2.93%	3.75%	3.75%	3.75%	3.75%
Weighted Average Cost of Capital	1.47%	1.47%	0.00%	6.00%	6.00%	6.00%	6.00%
Working Capital Allowance %	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
2006 EDR Tax Rate							
Corporate Income Tax Rate *(from 2006 PILs Sheet "Test Year PILs,Tax Provision" Cell D 14)*	36.12%	36.12%	33.50%	33.00%	32.00%	30.50%	29.00%

Capital Data:	2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted	2011 Forecasted	Later Forecasted	Total
Smart Meter	$ -	$ -	$ 58,711	$ 7,841,597	$ 88,442	$ 62,192	$ 62,192	$ 8,113,135
Computer Hardware	$ -	$ -	$ -	$ 10,206	$ -	$ -	$ -	$ 10,206
Computer Software	$ -	$ -	$ -	$ 345,395	$ 68,040	$ -	$ -	$ 413,435
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capital Costs	$ -	$ -	$ 58,711	$ 8,197,197	$ 156,482	$ 62,192	$ 62,192	$ 8,536,775
	-	-	-	-	-	-	-	-

Operating Expense Data:	2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted	2011 Forecasted	Later Forecasted	Total
2.1 Advanced Metering Communication Device (AMCD)	$ -	$ -	$ -	$ 222,722	$ -	$ -	$ -	$ 222,722
2.2 Advanced Metering Regional Collector (AMRC)	$ -	$ -	$ -	$ 57,154	$ 57,154	$ 57,154	$ 57,154	$ 228,614
2.3 Advanced Metering Control Computer (AMCC)	$ -	$ -	$ -	$ 112,895	$ 112,895	$ 112,895	$ 112,895	$ 451,581
2.4 Wide Area Network (WAN)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.5 Other AMI OM&A Costs Related To Minimum Functionali	$ -	$ 13,583	$ 15,442	$ 309,078	$ 737,890	$ 273,292	$ 273,526	$ 1,622,811
Total O M & A Costs	$ -	$ 13,583	$ 15,442	$ 701,848	$ 907,939	$ 443,341	$ 443,575	$ 2,525,728

Smart Meter Revenue Requirement Calculation

Average Asset Values	2007			2008			2009			2010			2011			Later		
	Audited Actual			Actual			Forecasted			Forecasted			Forecasted			Forecasted		
Net Fixed Assets Smart Meters	$ -			$ 28,377.13			$ 3,844,902.25			7,412,454			$ 6,955,625.19			$ 6,481,087.97		
Net Fixed Assets Computer Hardware	0			0			4,848			9,185			8,165			7,144		
Net Fixed Assets Computer Software	0			0			155,428			306,934			261,669			178,982		
Net Fixed Assets Tools & Equipment	0			0			0			0			0			0		
Net Fixed Assets Other Equipment	0			0			0			0			0			0		
Total Net Fixed Assets	0	0		28,377	28,377		4,005,178	4,005,178		7,728,573	7,728,573		7,225,459	7,225,459		6,667,214	6,667,214	
Working Capital																		
Operation Expense	13,583			15,442			701,848			907,939			443,341			443,575		
Working Capital %	2,037	2,037		2,316	2,316		105,277	105,277		136,191	136,191		66,501	66,501		66,536	66,536	
Smart Meters included in Rate Base		2,037			30,693			4,110,455			7,864,764			7,291,960			6,733,750	
Return on Rate Base																		
Deemed Short Term Debt %				0.00%	0		0.00%	0		0.00%	0		0.00%	0		0.00%	0	
Deemed Long Term Debt %	50.00%	1,019		100.00%	30,693		100.00%	4,110,455		100.00%	7,864,764		100.00%	7,291,960		100.00%	6,733,750	
Deemed Equity %	50.00%	1,019		0.00%	0		0.00%	0		0.00%	0		0.00%	0		0.00%	0	
		2,037			30,693			4,110,455			7,864,764			7,291,960			6,733,750	
Deemed Short Term Debt Rate%				4.47%	0		4.47%	0		4.47%	0		4.47%	0		4.47%	0	
Weighted Debt Rate *(3. LDC Assumptions and Data)*	0.00%	0		6.00%	1,842		6.00%	246,627		6.00%	471,886		6.00%	437,518		6.00%	404,025	
Proposed ROE *(3. LDC Assumptions and Data)*	2.93%	30		2.93%	0		3.75%	0		3.75%	0		3.75%	0		3.75%	0	
Return on Rate Base		30	30		1,842	1,842		246,627	246,627		471,886	471,886		437,518	437,518		404,025	404,025
Operating Expenses																		
Incremental Operating Expenses *(3. LDC Assumptions and Data)*			13,583			15,442			701,848			907,939			443,341			443,575
Amortization Expenses																		
Amortization Expenses - Smart Meters		0			1,957			265,301			529,635			534,656			538,803	
Amortization Expenses - Computer Hardware		0			0			510			1,021			1,021			1,021	
Amortization Expenses - Computer Software		0			0			34,539			75,883			82,687			82,687	
Amortization Expenses - Tools & Equipment		0			0			0			0			0			0	
Amortization Expenses - Other Equipment		0			0			0			0			0			0	
Total Amortization Expenses			0			1,957			300,350			606,539			618,364			622,510
Revenue Requirement Before PILs			13,613			19,241			1,248,826			1,986,363			1,499,222			1,470,110
Calculation of Taxable Income																		
Incremental Operating Expenses			-13,583			-15,442			-701,848			-907,939			-443,341			-443,575
Depreciation Expenses			0			-1,957			-300,350			-606,539			-618,364			-622,510
Interest Expense			0			-1,842			-246,627			-471,886			-437,518			-404,025
Taxable Income For PILs			30			0			0			0			0			0
Grossed up PILs *(5. PILs)*			17			-69			-78,456			-95,644			7,545			39,111
Revenue Requirement Before PILs			13,613			19,241			1,248,826			1,986,363			1,499,222			1,470,110
Grossed up PILs *(5. PILs)*			17			-69			-78,456			-95,644			7,545			39,111
Revenue Requirement for Smart Meters			**13,630**			**19,171**			**1,170,370**			**1,890,719**			**1,506,767**			**1,509,221**
			49,631			49,522			49,631			49,691			49,750			49,810
ADDER Calculation			**0.023**			**0.032**			**1.965**			**3.171**			**2.524**			**2.525**
Funding Adder included in Rates			**0.270**			**0.270**			**1.965**			**2.336**			**2.524**			**2.524**

Sheet 5. PILs

PILs Calculation

INCOME TAX	2006 Audited Actual	2007 Audited Actual	2008 Actual	2009 Forecasted	2010 Forecasted	2011 Forecasted	Later Forecasted
Net Income	$0	$30	$0	$0	$0	$0	$0
Amortization	$0	$0	$1,957	$300,350	$606,539	$618,364	$622,510
CCA - Smart Meters	$0	$0	($2,348)	($318,173)	($609,921)	($567,152)	($526,756)
CCA - Computers	$0	$0	$0	($177,800)	($211,820)	($34,020)	$0
CCA - Other Equipment	$0	$0	$0	$0	$0	$0	$0
Change in taxable income	$0	$30	($391)	($195,623)	($215,202)	$17,192	$95,755
Tax Rate *(3. LDC Assumptions and Data)*	$0	$0	$0	$0	$0	$0	$0
Income Taxes Payable	$0	$11	($131)	($64,556)	($68,865)	$5,243	$27,769

ONTARIO CAPITAL TAX	2006	2007	2008	2009	2010	2011	Later
Smart Meters	$0	$0	$56,754	$7,633,050	$7,191,857	$6,719,393	$6,242,783
Computer Hardware	$0	$0	$0	$9,696	$8,675	$7,655	$6,634
Computer Software	$0	$0	$0	$310,855	$303,012	$220,325	$137,638
Tools & Equipment	$0	$0	$0	$0	$0	$0	$0
Other Equipment	$0	$0	$0	$0	$0	$0	$0
Rate Base	$0	$0	$56,754	$7,953,601	$7,503,545	$6,947,373	$6,387,055
Less: Exemption	$0	$0	$0	$0	$0	$0	$0
Deemed Taxable Capital	$0	$0	$56,754	$7,953,601	$7,503,545	$6,947,373	$6,387,055
Ontario Capital Tax Rate	$0	$0	$0	$0	$0	$0	$0
Net Amount (Taxable Capital x Rate)	$0	$0	$128	$17,896	$5,628	$0	$0

Gross Up

	PILs Payable	PILs Payable	PILs Payable	PILs Payable	PILs Payable	PILs Payable	PILs Payable
Change in Income Taxes Payable	$0	$11	($131)	($64,556)	($68,865)	$5,243	$27,769
Change in OCT	$0	$0	$128	$17,896	$5,628	$0	$0
PIL's	$0	$11	($3)	($46,660)	($63,237)	$5,243	$27,769
	Gross Up	Gross Up	Gross Up	Gross Up	Gross Up	Gross Up	Gross Up
	$0	$0	$0	$0	$0	$0	$0
	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs
Change in Income Taxes Payable	$0	$17	($197)	($96,352)	($101,272)	$7,545	$39,111
Change in OCT	$0	$0	$128	$17,896	$5,628	$0	$0
PIL's	**$0**	**$17**	**($69)**	**($78,456)**	**($95,644)**	**$7,545**	**$39,111**

Adjustments to Thunder Bay Hydro's 2009 Cost of Service Application

Intervenor	Ref #	Description	Working Capital- 15%	Rate Base	Return on Rate Base 1.91%	OM&A*	Cost of Power	Amortization*	Accretion*	Revenue Offset*	Revenue Requirement
		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				
OEB Staff	9	PCB Plan-Original	(34,200)	(101,000)	(2,582)	(228,000)		(4,040)			(234,622)
		PCB Plan-Revised	22,250	89,500	2,134	148,333		3,580			154,047
		ARO -2008 original	-	(65,181)	(1,245)			(46,500)	(18,600)		(66,345)
		ARO-2008 revised due to longer phase-in	-	187,186	3,575			41,779	21,941		67,295
OEB Staff	18	Meter Reading Costs-original	(38,250)		(731)	(255,000)					(255,731)
		Meter Reading Costs-3 yr avg	20,250		387	135,000					135,387
OEB Staff	24	Cost of Power -Commodity,									
Energy Probe	9	Network & Connection Charges	1,766		34		11,772				34
Energy Probe	33										
		Amortization included in OM&A for Working Capital Allowance	(44,335)		(847)	(295,567)		295,567			(847)
	34	Cost of Power - Commodity	(475,629)	(475,629)	(9,085)		(3,170,860)				(9,085)
OEB Staff	25										
Energy Probe	7	Computer Amortization	-	50,000	955			(100,000)			(99,045)
Energy Probe	6	Smart Meter related costs in rate base-Meter & Service OM&A originally	(90,048)		(1,720)	(600,319)					(602,039)
		Three year annualized	63,778		1,218	425,186					426,404
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 1.3% rising to 2.5% in 2011	-		-					(195,000)	(195,000)
Energy Probe	18	Board of Director Costs	(2,211)		(42)	(14,743)					(14,785)
			(576,630)	(315,124)	(7,948)	(685,110)	(3,159,088)	190,386	3,341	240,000	(259,331)
		Estimated PILS Impact									(57,564)
		Revised Revenue Deficiency									$ 1,055,392

Adjustments to Thunder Bay Hydro's 2009 Cost of Service Application

OEB Staff	28	
OEB Staff *	13 & 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

RESIDENTIAL

		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			10.95			11.02	0.07	0.64%	0.06%
1,000 kWh	Distribution (kWh)	1,000	0.0138	13.80	1,000	0.0139	13.90	0.10	0.72%	0.09%
	Smart Meter Rider (per month)			0.27			1.97	1.70	629.63%	1.51%
	LRAM & SSM Rider (kWh)	1,000			1,000	0.0004	0.40	0.40	#DIV/0!	0.36%
	Regulatory Assets (kWh)	1,000	0.0000	0.00	1,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**25.02**			**27.29**	**2.27**	**9.07%**	**2.02%**
	RTS Charges (kWh)	1,046	0.0062	6.48	1,045	0.0083	8.67	2.19	33.76%	1.95%
	Sub-Total-Delivery Charges			**31.50**			**35.96**	**4.46**	**14.15%**	**3.97%**
	WMS Charges (kWh)	1,046	0.0062	6.48	1,045	0.0062	6.48	(0.01)	(0.09%)	(0.00%)
	Debt Retirement (kWh)	1,046	0.0070	7.32	1,045	0.0070	7.31	(0.01)	(0.09%)	(0.01%)
	Cost of Power Commodity (kWh)	600	0.0500	30.00	600	0.0560	33.60	3.60	12.00%	3.21%
	Cost of Power Commodity (kWh)	446	0.0590	26.30	445	0.0650	28.91	2.62	9.95%	2.33%
	Total Bill			**101.60**			**112.27**	**10.66**	**10.49%**	**9.50%**

GENERAL SERVICE < 50 kW

		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			17.06			18.18	1.12	6.57%	0.51%
2,000 kWh	Distribution (kWh)	2,000	0.0125	25.00	2,000	0.0133	26.60	1.60	6.40%	0.73%
	Smart Meter Rider (per month)			0.27			1.97	1.70	629.63%	0.77%
	LRAM & SSM Rider (kWh)	2,000			2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Regulatory Assets (kWh)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Sub-Total			**42.33**			**46.75**	**4.42**	**10.44%**	**2.01%**
	RTS Charges (kWh)	2,091	0.0056	11.71	2,090	0.0077	16.09	4.38	37.38%	1.99%
	Sub-Total-Delivery Charges			**54.04**			**62.84**	**8.80**	**16.28%**	**4.01%**
	WMS Charges (kWh)	2,091	0.0062	12.96	2,090	0.0062	12.96	(0.01)	(0.07%)	(0.00%)
	Debt Retirement (kWh)	2,091	0.0070	14.64	2,090	0.0070	14.63	(0.01)	(0.07%)	(0.00%)
	Cost of Power Commodity (kWh)	750	0.0500	37.50	750	0.0560	42.00	4.50	12.00%	2.05%
	Cost of Power Commodity (kWh)	1,341	0.0590	79.14	1,340	0.0650	87.07	7.93	10.02%	3.61%
	Total Bill			**198.29**			**219.50**	**21.21**	**10.70%**	**9.66%**

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