Board Staff Interrogatories
Thunder Bay Hydro Electricity Distribution Inc.
2013 Electricity Distribution Rates
EB-2012-0167

EXHIBIT 1 - ADMINISTRATIVE

1-Staff-1
Ref: E1-T1-S6
Thunder Bay Hydro indicates that the current version of its conditions of service is under review.

a) When will Thunder Bay Hydro provide the Board with a copy of the new Conditions of Service?
b) Please identify any rates and charges that are included in the Thunder Bay Hydro's current conditions of service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered.
c) Please provide a schedule outlining the revenues recovered from these rates and charges from 2006 to 2011 and the revenue forecasted for the 2012 and 2013.
d) Please explain whether in the applicant's view, these rates and charges should be included on the applicant's tariff sheet.

1-Staff-2
Ref: E1-T2-S1 p.2
Thunder Bay Hydro is requesting rates effective May 1, 2013 and notes it requires the Rate Order by April 15, 2013 to implement rates on May 1, 2013.

a) Will Thunder Bay Hydro be requesting the Board to declare its existing rates interim effective May 1, 2013 in the event that it appears that the new rates won't be available for a May 1, 2013 implementation?
b) In the event that the new rates are not available for a May 1, 2013 implementation, will Thunder Bay Hydro be seeking recovery of forgone revenue?

EXHIBIT 2 - RATE BASE

2-Staff-3
Ref: E1-T2-S1 p.8
Thunder Bay Hydro states that its capital spending forecasted in 2012 and 2013 is increasing at a similar pace as in previous years (exclusive of the new Maintenance Facility scheduled for 2013 in the amount of $3.3M.)

Below are the historical and forecasted capital expenditures.

Capital Expenditures	2007 Actual	2008 Actual	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 CGAAP	2013 MCGAAP
Pre- Contributions	$ 6,142,480	$ 8,383,382	$ 8,203,623	$ 8,857,086	$ 10,076,841	$ 11,190,568	$ 10,859,540	$ 14,434,468	$ 13,122,177
Contributions	($953,374)	($1,425,904)	($650,000)	($1,188,775)	($2,499,649)	($2,958,053)	($2,022,925)	($1,044,834)	($989,985)
Capital Expenditures	$ 5,189,106	$ 6,957,478	$ 7,553,623	$ 7,668,311	$ 7,577,192	$ 8,232,515	$ 8,836,615	$ 13,389,634	$ 12,132,192
Source: E2-T3-S1 Table 2-3.1									

a) Please confirm that the 2013 capital (CGAAP) excluding the New Maintenance facility totals about $10,089,000.
b) Please provide an analysis that supports Thunder Bay Hydro's claim that its capital spending forecasted in 2012 and 2013 is increasing at a similar pace as in previous years (exclusive of the new Maintenance Facility scheduled for 2013 in the amount of $3.3M.).

2-Staff-4

<u>Ref: E2-T3-S1 p.4-7</u>

Thunder Bay Hydro is proposing to spend $3.3M in 2013 to design and build a new stand-alone maintenance facility

a) Was a consultant hired to assist Thunder Bay Hydro in the planning, needs assessment, costing and preparation of a business case for this project? If so please identify the consultant and provide any studies or reports prepared by the consultant.
b) Does Thunder Bay Hydro consider the description on pages 5-7 to be the business case for this project?
c) What will the facility cost on a per sq. ft. basis?
d) Has Thunder Bay Hydro reflected any operating savings in its 2013 OM&A that it will realize with the replacement of the existing with a new one? If so, what were the savings?

2-Staff-5

<u>Ref: E2-T3-S3 p.7 table 2-3.6</u>

Please confirm that the total cost shown in table 2-3.6 is $6,000 less than the total PCB Management Program cost approved in Thunder Bay Hydro's last cost of service application (2009).

2-Staff-6

<u>Ref: E2-T5-S1-5</u>

Please prepare a table which lists the change items described in schedules 1-5 such that the items total to the difference between 2013 Net Plant (CGAAP) and 2013 Net Plant (MCAAP).

2-Staff-7

<u>Ref: E2-Appendix 2-D</u>

Please complete the tables below.

Thunder Bay Hydro Reliablity Indices
2005 to 2011

Index	Includes outages caused by loss of supply							Excludes outages caused by loss of supply						
	2005	2006	2007	2008	2009	2010	2011	2005	2006	2007	2008	2009	2010	2011
SAIDI														
SAIFI														
CAIDI														

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index
CAIDI = Customer Average Interruption Duration Index

Three Year Historical Average

	Includes loss of supply	Excludes loss of supply
SAIDI		
SAIFI		
CAIDI		

2-Staff-8

Ref: (i) EB-2009-0397 Filing Requirements Update dated May 17, 2012 and (ii) E2-T6-S1

Thunder Bay Hydro appears to not meet the threshold for a detailed plan in that its expenditures do not exceed 3% of the rate base.

a) Please provide the calculation for the threshold as required per section 2.3 of reference (i).
b) Confirm that Thunder Bay Hydro does not exceed the threshold value for providing a detailed GEA Plan.
c) Reference (i) section 4.1.1 calls for a five year horizon for the Basic GEA Plan. Please provide information or discussion (as indicated in section 4.1.1) about the outlook for the remaining years of the five year period.
d) In accordance with section 4.3.2, please provide a summary of the expectations regarding OM&A over the 5 years.
e) In accordance with section 3 page 20 of the Filing Requirements, confirm that Thunder Bay Hydro is not pursuing or seeking any cost recovery for smart grid activities or expenditures
f) In accordance with sec 4.2.2.2, page 16 of the requirements, please indicate the method and criteria that will be used to prioritize expenditures in accordance with the planned development of the system.

2-Staff-9

Ref: (i) E2-T3-S2 p.17 and (ii) E2-T6-S1 p.1and (iii) E9-T4-S1 p.1

Reference (i) under the heading "2012 and 2013 Project related to GEA" reflects $415,175 and $375,786 as the amount for 2012 and 2013 to be funded by Thunder Bay Hydro Rate Base (in the second column of table 2-3.4). Reference (ii) under the heading “Green Energy Act Plan – Capital Expenditures” at line 5 states that Thunder Bay Hydro “… estimated gross capital spending requirements of $375,786 (revised) in 2012 and $563,679 (revised) in 2013”. Reference (iii) shows the amount of (eligible) Renewable Capital Investment in for 2013 is $375,786

a) Please reconcile the differences in 2012 and 2013 between references (i) and (ii) and if required, provide a revised Capital Expenditure Table 2-3-4 for reference (i) and a revised Table 9-4.1 for reference(iii).
b) Please confirm that in 2013 only 6 of the reclosers are eligible for FIT consideration, as indicated in reference (iii) at line 16.
c) Please clarify where capital expenditures for communications equipment, control equipment etc. related to the installation of reclosers will appear?
d) If there are further capital costs please provide a detailed breakdown and description of all of the components e.g. reclosers, communications, control modifications, etc. which make up the gross capital spending requirements for the Green Energy Act Plan in 2013.
e) Please provide revised tables 2-3.4, 9-4.1 and Appendix 2B table 9 all on a consistent basis with the “revised” numbers.

2-Staff-10

Ref: (i) E2 App-2B Green Energy Act Plan p.33 and (ii)E2 App-2B Green Energy Act Plan p.36

Thunder Bay Hydro states on page 33, that certain investments which were made before October 21, 2009, “would qualify as Renewable Enabling Improvements. However due to the timing of these renewable generation applications, Thunder Bay Hydro presents that the investments related to the legacy RESOP facilities … should be funded in accordance with the mechanism approved for ‘enhancements’ (as defined in the pre October 21, 2009 Distribution System Code.”

In regard to reference (i):

a) Is Thunder Bay Hydro making any claims in this application which it thinks is not in accordance with the published material of the Board?
b) Is Thunder Bay Hydro requesting some special consideration by the Board, and if so what is the request?

In regard to reference (ii) Thunder Bay Hydro refers to a consensus which allowed for a significant increase in Birch TS’ ability to accommodate future renewable generation.

c) Please provide further detail including original and revised ability to accommodate.

EXHIBIT 3 - OPERATING REVENUE

3-Staff-11

Ref: E3-T2-S1

Thunder Bay Hydro states that its preferred approach is to use separate multivariate regression models for billed consumption for the Residential, GS < 50 kW, and GS 50-999 kW classes, in contrast to the purchased system kWh model. Due to the timing and frequency of meter reads and billing cycles, before the complete deployment of smart meters, billed calendar monthly consumption data would not be available. As such, Thunder Bay Hydro states that '[it] estimated the amount consumed in a month by rate class using an equation to prorate billing that was used in the process for unbilled revenue.'

Please provide further explanation, including the methodology or equation used to derive the calendar monthly consumption data on a rate class level.

3-Staff-12

Ref: E3-T2-S1 – Load Forecast – Residential Model

For the multivariate regression model of Residential consumption, the following summary is provided on sheet "Stats Sum" of the Excel spreadsheet "Thunder Bay Hydro 2013 Load Forecast_20121108.xls.

	Residential	
R Square	95%	
Adjusted R Square	95%	
	Coefficients	*t Stat*
Intercept	(2,222,087)	(0.71)
Heating Degree Days	14,195	43.51
Cooling Degree Days	34,410	4.66
Number of Days in Month	835,518	8.11
Spring Fall Flag	(889,871)	(4.68)
CDM Activity	(1.26)	(4.83)

a) The model has a constant term that is statistically insignificant, with a t-statistic of -0.71. Why was the constant retained if it was statistically insignificant?
b) This equation has no variable to account for market size or economic activity. What, if any, variables were tried to reflect market size and/or economic activity? Provide a summary of any results and an explanation for why these variables were ultimately rejected in the proposed model.
c) The CDM variable is statistically significant, and has a negative estimated coefficient, as expected. Analysis of the spreadsheet "Thunder Bay Hydro 2013 Load Forecast_20121108.xls" indicates that Thunder Bay Hydro has constructed a measure of CDM impacts specific to the Residential class for 2006 to 2010, and has then added on the Residential impacts for 2011 CDM programs. The estimated coefficient value is -1.26. The CDM variable used appears to be derived from "net" OPA measurements.

    i. Does Thunder Bay Hydro agree that the load forecast would be affected by “gross” CDM impacts: If so, why were “net” CDM savings rather than “gross” CDM savings used in the equation?
    ii. Please provide Thunder Bay Hydro’s views of why the estimated CDM coefficient of -1.26 is reasonable, and what impacts, other than CDM, are being captured by this variable.

d) Please provide the Mean Absolute Percentage Error (“MAPE”) of the estimated Residential model based on the monthly data.

3-Staff-13

Ref: E3-T2-S1, E3-Appendix 3-B – Load Forecast – GS < 50 kW Model

For the multivariate regression model of GS <50 kW consumption, the following summary is provided on sheet “Stats Sum” of the Excel spreadsheet “Thunder Bay Hydro 2013 Load Forecast_20121108.xls.

	GS < 50 kW	
R Square	77%	
Adjusted R Square	76%	
	Coefficients	*t Stat*
Intercept	5,439,400	2.31
Heating Degree Days	4,308	17.49
Cooling Degree Days	20,139	3.61
Number of Days in Month	164,058	2.11
Spring Fall Flag	(456,769)	(3.18)
CDM Activity	(5.17)	(6.87)

a) This equation has no variable to account for market size or economic activity. What, if any, variables were tried to reflect market size and/or economic activity? Provide a summary of any results and an explanation for why these variables were ultimately rejected in the proposed model.

b) The CDM variable is statistically significant, and has a negative estimated coefficient, as expected. The estimated coefficient value is -6.87. The CDM variable used appears to be derived from “net” OPA measurements.
    i. Does Thunder Bay Hydro agree that the load forecast would be affected by “gross” CDM impacts? If so, why were “net” CDM savings rather than “gross” CDM savings used in the equation?
    ii. The use of “net” CDM savings rather than “gross” CDM savings could argue for a coefficient greater than 1 in absolute value, and possibly close to -1.65 based on the aggregate “net-to-gross” adjustment. Please provide Thunder Bay Hydro’s views of why the estimated CDM coefficient of -5.17 is reasonable, and what impacts, other than CDM, are being captured by this variable.

c) Please provide the Mean Absolute Percentage Error (“MAPE”) of the estimated GS < 50 kW model based on the monthly data.

3-Staff-14
Ref: E3-T2-S1 – Load Forecast – GS > 50 kW (to 999 kW) Model

For the multivariate regression model of GS > 50 (to 999) kW consumption, the following summary is provided on sheet “Stats Sum” of the Excel spreadsheet “Thunder Bay Hydro 2013 Load Forecast_20121108.xls.

	GS > 50 kW	
R Square	94%	
Adjusted R Square	94%	
	Coefficients	*t Stat*
Intercept	189,185	0.07
Heating Degree Days	9,133	39.84
Cooling Degree Days	40,343	7.78
Number of Days in Month	392,929	5.18
Spring Fall Flag	(639,548)	(4.81)
CDM Activity	(3.63)	(5.16)
Ontario Real GDP Monthly (	22,719	3.19
Number of Customers	5,040	3.52
Number of Peak Hours	8,807	2.45

a) The model has a constant term that is statistically insignificant, with a t-statistic of 0.07. Why was the constant retained if it was statistically insignificant?
b) In contrast with the Residential and GS < 50 kW models, this variable includes measures for both market size (number of customers) and economic activity (real Ontario GDP). This class is comprised of moderately large commercial customers, and which might be expected to be driven by both local and more macroeconomic activity. Please explain the rationale for inclusion of both market and economic activity variables when these variables were not included in both the Residential and GS < 50 kW models.
c) Please explain the rationale for including both the number of days in the month as well as the number of Peak Hours in a month as explanatory variables. Why would not the Number of Business Days in the month be a more appropriate variable reflecting the economic activity of customers in this class?
d) The CDM variable is statistically significant, and has a negative estimated coefficient, as expected. The estimated coefficient value is -3.63. While the CDM variable used appears to be derived from “net” OPA measurements.
    i. Does Thunder Bay Hydro agree that the load forecast would be affected by “gross” CDM impacts? If so, why were “net” CDM savings rather than “gross” CDM savings used in the equation?
    ii. The use of “net” CDM savings rather than “gross” CDM savings could argue for a coefficient greater than 1 in absolute value, and possibly close to -1.65 based on the aggregate “net-to-gross” adjustment. Please provide Thunder Bay Hydro’s views of why the estimated CDM coefficient of -3.63 is reasonable, and what impacts, other than CDM, are being captured by this variable.
e) Please provide the Mean Absolute Percentage Error (“MAPE”) of the estimated GS > 50 kW model based on the monthly data.

3-Staff-15

Ref: E3-T2-S1 Table 3-2.21 – Load Forecasting and CDM Adjustment

In Table 3-2.21, Thunder Bay Hydro provides the data for the adjustment of "gross" to "net" CDM impacts for the adjustment of the load forecast for 2012 and 2013 CDM impacts. This is replicated below:

Table 3-2.21: Average Net to Gross Percentage

	OPA 2006-2010 Final CDM Results (Gross)	OPA 2006-2010 Final CDM Results (Net)	# Difference	% Difference of Net
2006	3,625,491	3,246,310	379,181	11.7%
2007	12,821,744	6,046,051	6,775,693	112.1%
2008	13,497,193	8,583,640	4,913,553	57.2%
2009	19,428,898	12,494,278	6,934,620	55.5%
2010	20,258,011	12,510,028	7,747,983	61.9%
2011	18,761,204	10,995,318	7,765,886	70.6%
2012	18,159,424	10,739,336	7,420,088	69.1%
2013	17,798,355	10,554,593	7,243,762	68.6%
Total	124,350,320	75,169,554	49,180,766	65.4%

a) On page 5 of E3-T2-S1, Thunder Bay Hydro states: "Table 3-2.21 outlines the average net to gross factor of 65.4% based on information provided in the OPA 2006-2010 Final CDM Results for Thunder Bay Hydro (Appendix 3-A)". Appendix 3-A contains the regression data, while Appendix 3-B contains the Final CDM Results for 2011. Please explain what data and data source are used in Table 3-2.21.

b) Please update Table 3-2.21 to reflect the final 2011 CDM results as issued by the OPA in the fall of 2012 and as contained in E3/Appendix-3B.

c) Thunder Bay Hydro has estimated a "net-to-gross" conversion factor of 65.4%, which is based on the overall difference of "net" to "gross" results over the total period from 2006 to 2010, and including the estimated persistence of 2006 to 2010 CDM programs on 2012 and 2013 demand.

   i. Why should the estimated results for 2012 and 2013, which are forecasts, be taken into account in calculating the conversion factor?

   ii. In the alternative, if reliance should be placed on these as being the OPA's final estimates of the persistence of CDM programs up to 2011 on 2013 consumption in Thunder Bay Hydro's service territory, then why should not the 2013 data, with a factor of 68.6% (or as updated in response to part a)), be the suitable measure for the 2013 test year load forecast?

3-Staff-16

Ref: E 3-T2-S1   Load Forecasting

Thunder Bay Hydro has calculated CDM variables by segmented linear interpolation of the annual results. In the spreadsheet “Thunder Bay Hydro 2013 Load Forecast_20121108.xls” the system CDM variable is shown in column F of Sheet ‘CDM Activity’, while the Residential, GS < 50 kW, GS 50 – 999 kW, and GS > 1000 kW CDM variables are shown in columns L, S, Z and AG respectively. The methodology used appears to “gross up” the results so that the amounts accumulated add up to the annual OPA CDM results. Thus while the Residential CDM variable for 2006 adds up to 3,246,310 kWh as reported by the OPA on a net basis. However, the December 2006 value X 12 months = 5,993,188 kWh, as shown in cell N26. This is higher than the 3,246,310 kWh which is the reported OPA number.

a) Please explain the rationale for “grossing up” to annualize what is already an annualized CDM result as reported by the OPA.
b) Please provide Thunder Bay Hydro’s views on the impact that its interpolation method to construct a monthly CDM series from the reported annual CDM results reported by the OPA has on the regression results and on the load forecast (before the manual adjustment for 2012 and 2013 CDM programs) if the CDM variable does not reflect the seasonality/cyclicality of CDM program impacts.

3-Staff-17

Ref: E 3-T2-S1   Table 3-2.22 – Load Forecasting and CDM Adjustment

On pages 16-17 and in Table 3-2.22 of this exhibit, Thunder Bay Hydro documents its methodology for estimating the manual adjustment to account for 2012 and 2013 CDM programs on the 2013 load forecast. The manual adjustment is comprised of 6,479,424 kWh for the 2012 program and 6,479,424 kWh for the 2013 program the sum of which is multiplied by the 1.654 net-to-gross conversion factor. The result totals 21,469,292kWh.

Board staff understands that the results as reported by the OPA are “annualized” (i.e. assume that all CDM programs, including the current year’s program, are in effect for the full year, from January 1 to December 31). This is documented on page 15 of E3-Appendix 3-B. While the full year effect for persistence of prior year CDM programs would be in place for the full year, CDM programs implemented in a given year would not have the full impact in the first year, due to timing.

The “full year” results, as measured by the OPA, at present will be used for the basis of the LRAMVA amount. However, the “full year” results in the first year of a CDM program, will overstate the actual results unless the program was implemented on January 1 of that year.

In the absence of any other information, a “half-year” rule (i.e. assuming that half of the incremental impact of programs introduced in a year is actually realized in the calendar year of introduction) may be a proxy for the actual impact, ignoring all other factors (i.e. seasonality).

a) Please provide Thunder Bay Hydro’s understanding of the results as published by the OPA (i.e. are the full year or do they only reflect the period that a CDM program in in place in its first year).
b) If a “half-year” rule is used to account for the fact that 2013 CDM programs will not have a full year impact on 2013 actual consumption, please provide Thunder Bay Hydro’s perspective that the adjustment for the 2012 and 2013 CDM programs on 2013 demand would be estimated as 6,479,424 kWh X 1.5 (reflecting full year impact of 2012 CDM and half-year impact of 2013 CDM on 2013) X 1.654 = 16,075,451kWh. (Alternatively, the updated net-to-gross conversion factor, as discussed in the preceding interrogatory, could be used).
c) While the above is to adjust the load forecast which is on an “actual” year basis, the LRAMVA is based on the measured OPA results reported on a full year basis. Please confirm that the LRAMVA threshold would continue to be based on the “full year” CDM results of 2,157,479 kWh (i.e. persistence of 2011 CDM) + 6,479,424 X 2 (i.e. persistence of 2012 and impact of 2013 CDM) results, for a total of 15,116,327 kWh, as documented in Table 3-2.22. In the alternative, please explain Thunder Bay Hydro’s proposal for the kWh used to derive the threshold for the LRAMVA for 2013.

EXHIBIT 4 - OPERATING COSTS

4-Staff-18

Ref: E4-T1-S1

Please identify the inflation rate used for the 2013 OM&A forecast and the source document for the inflation assumptions.

4-Staff-19

Ref: E4-T1-S1

OMERS has announced a three-year contribution rate increase for its members and employers for the years 2011, 2012, and 2013.

a) Please state whether or not Thunder Bay Hydro’s proposed pension costs include this increase.
b) If so, please provide the forecasted increase by years and the documentation to support the increases.
c) If not, please state how the Thunder Bay Hydro proposes to deal with this increase.

4-Staff-20

Ref: E4-T1-S1

Please provide details of employee benefit programs, including pensions and other costs charged to OM&A for the last Board-approved rebasing application, Historical, Bridge and Test Years.

4-Staff-21

Ref: E4-T1-S1 p.5

Thunder Bay Hydro states that it will have a one-time building demolition cost in 2013 Test Year and it has reduced the cost to $15,000 to recognize 25% of the net incremental cost in 2013.

a) Is this amount related to the new Maintenance Facility project?

4-Staff-22

Ref: E4-T2-S2

Does Thunder Bay Hydro pay property taxes? If so, what is the amount and where are they included in the 2013 revenue requirement?

4-Staff-23

Ref: E4-T2-S5 p.5-6

Thunder Bay Hydro indicates that it provides services to three affiliates, its parent Thunder Bay Hydro Corporation (TBHC) which is 100% owned by the City of Thunder Bay, Thunder Bay Renewable Power Inc. (TBRPI) and Thunder Bay Hydro Utility Services Inc. (TBHUSI).

The pricing of shared services transactions, either on a fully allocated or cost plus basis, for 2013 are presented in table 4-2.19 which is reproduced below.

Table 4-2.19 - Shared Serivces

Year: 2013 Test Year

Shared Services

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service
From	To			$	$
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Utility Services Inc.	Conservation & Demand Mgmt, Utility Billing Services, Meter Services, IT Services	Cost + Greater of Bank Prime OR Approved ROE (3.75% EB-2008-0245)	$253,703	$244,533
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Corp.	Board Honourarium	Fully Allocated Costs	$1,500	$1,500
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Renewable Power Incorporated	Corporate/Administrative Costs	Fully Allocated Costs	$88,895	$88,895

The evidence states that TBHUSI provides services to other utilities apart from its affiliates "…. thus, charging fully-allocated costs plus a markup which is greater of the bank prime rate or Thunder Bay Hydro's ROE of 3.75%."

a) In table 4-2.19, under the pricing methodology header the terms “cost” and “fully allocated costs” are used. Please explain the difference in how “cost” and “fully allocated cost” are calculated
b) Please confirm Thunder Bay Hydro does not directly provide any services to non-affiliate companies or utilities. If not confirmed, please identify accounts where costs and revenues are recorded.
c) Please identify the accounts that are used to record the shared services revenues shown in table 4-2.19.
d) For 2013 why isn’t Thunder Bay Hydro using a ROE of 7% to calculate the price it charges TBHUSI? Please recalculate the “Price for the Service” using 7%.

4-Staff-24

Ref: E4-T2-S3 p.1-5 (OM&A cost driver & explanatory notes)

a) The OM&A cost driver explanatory notes (6a, 12a, 12b, 12c, 15a, 15b) indicate that there were cost reductions and cost increases during the 2009-2013 period related to the Smart Meter program. In some years there were increases, in other years decreases. All else equal, as compared to 2009 Board approved, are the 2013 overall metering costs higher or lower (include meter reading and billing costs if appropriate). In the response please identify the main reasons for the overall increase or decrease between 2009 and 2013 (do not provide year-on-year numbers for the intervening years).

b) What was the tree trimming budget in 2009 Board approved and what is the forecast for 2013?

4-Staff-25

Ref: E4-T2-S3 p.2 Table 4-2.8 and note (6c) and E4-T1-S1 p2 line 7

Please explain why the $46,000 or some portion, in one-time expenditure in 2012 for Distribution Station demolition, was not eliminated from the 2013 test year and reconcile with the explanation given at E4-T1-S1 p2 line 7.

4-Staff-26

Ref: E4-T2-S3

The evidence provides OM&A variance explanations regarding the $2.7 M increase between 2013 and 2009 Board approved.

Please complete, and edit or add lines as necessary, the table below. The purpose of the table is to provide a summary of the main reasons for the $2.7 M increase.

OM&A Expenditures

		Amount
2009 Board Approved		$ 11,935,063
	Inflation	
	Salary/wage increases	
	Change in capitalization policy	
	Forestry	
	Overtime	
	IT market salaries	
	Benefits/Pensions	
	Regulatory expenses	
	Adds to staff	
	Net Metering/Billing	
2013 Test Year		$ 14,682,415
2013 vs 2009		$ 2,747,352

4-Staff-27

Ref: E4-T2-S5 Table 4-2.15 and Table 4-2.19 - Shared Services

Table 4-2.15 indicates Thunder Bay Hydro provided $47,442 in services in 2009 for "Administrative Costs" (at a cost of $45,727 to Thunder Bay Hydro) to Thunder Bay Hydro Energy Services Inc. Table 4-4.19 indicates that no services are to be provided to Thunder Bay Hydro Energy Services Inc. in 2013.

a) In that there no longer is offsetting revenue from Thunder Bay Hydro Energy Services, did Thunder Bay Hydro remove its costs to provide this service from its 2013 Revenue Requirement?

4-Staff-28

Ref: E4-T6-LRAM

Thunder Bay Hydro has requested recovery of an LRAMVA amount for 2011 lost revenues and persisting 2012 lost revenues associated with its 2011 CDM programs in the total amount of $40,315, including carrying charges of $1,060. Thunder Bay has requested recovery over a one-year period.

a) Please confirm the scope of Thunder Bay's LRAMVA claim is for lost revenues in 2011 and persisting lost revenues in 2012 associated with Thunder Bay's 2011 CDM programs.
b) Please discuss the appropriateness of Thunder Bay recovering persisting 2012 lost revenues from its 2011 CDM Programs at this time given that no final results are available..

c) Please provide an updated LRAMVA calculation and carrying charges, with applicable rate riders, based only on lost revenues in 2011 from 2011 CDM programs.

d) Please confirm that the load forecast underpinning Thunder Bay's 2011 rates was not adjusted to account for Thunder Bay's CDM Targets.

EXHIBIT 5 - COST OF CAPITAL AND RATE OF RETURN

5-Staff-29

Ref: E5-T1-S1 p. 1

Thunder Bay Hydro is requesting a return on equity in accordance with the Cost of Capital Parameter Updates for 2012 COS Applications issued in March 2012. The Board has subsequently issued an update dated November 2012 and given the timeline for this proceeding, updated Parameters which are normally issued in March may be available.

a) Will Thunder Bay Hydro be proposing to use the latest available updated Parameters to calculate its 2013 revenue requirement?

5-Staff-30

Ref: E5-T1-S1 p. 1

Thunder Bay Hydro utilizes a 7% return on equity to calculate its 2013 cost of capital requirement to be recovered from rate payers. Thunder Bay Hydro also states it "... understands that the OEB will be finalizing the ROE for 2013 rates based on January 2013 market interest rate information. Thunder Bay Hydro's use of an ROE of 7% is without prejudice to any revised ROE that may be adopted by the OEB in early 2013."

a) Please elaborate what is meant by the statement "Thunder Bay Hydro's use of an ROE of 7% is without prejudice to any revised ROE that may be adopted by the OEB in early 2013." Does it include the possibility that Thunder Bay Hydro on its own initiative may revise the ROE proposed for 2013 during this proceeding?

b) In that the ROE Thunder Bay proposes for 2013 is materially lower than the ROE in the Board's Cost of Capital Parameters for 2013, please clarify whether Thunder Bay Hydro intends to seek the Board's approval prior to the next COS, or equivalent, application to move the ROE closer to the Board's ROE parameter?

5-Staff-31
Ref: E5-T1-S1

The table below identifies the instruments comprising the LTD portion of the 2013 rate base.

Table 5-1.3 - Thunder Bay Hydro's debt and capital structure

DEBT AND CAPITAL COST STRUCTURE Weighted Debt Cost								
Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Promissory Note	The Corporation of the City of Thunder Bay**	Y	Sept. 1, 2001	31,452,941		0.00%	2001	0
2012 Infrastructure Financing	Unknown	N	Oct. 1, 2012	5,800,000	25	4.41%	2012	255,780
2013 Infrastructure Financing	Unknown	N	Jan. 1, 2013	6,150,000	25	4.41%	2013	271,215
Smart Meter Financing in Rate Base	TD Commercial Bank	N	Jan. 1, 2012	6,688,761	15	5.27%	2013	352,498
Annualization of Projected Debt over the rebasing period	N/A	N	Jan. 1, 2013	2,768,526	25	4.41%	2013	122,092
			2013 Total Long Term Debt	52,860,228		Total Interest Cost for 2013		1,001,585
**The Promissory Note for the City of Thunder Bay will be updated to reflect conversion of a portion of the debt to equity.						Weighted Debt Cost Rate for 2013		1.89%

a) Please confirm that Thunder Bay Hydro's revenue requirement for 2013 reflects a rate base 56% of which is capitalized by way of Long Term Debt in the amount of $52.880 M.
b) Please explain what is meant by the footnote "The Promissory Note for the City of Thunder Bay will be updated to reflect conversion of a portion of the debt to equity." Does this involve an actual cash infusion from the city of Thunder Bay or is it just a notional realignment of deemed levels of capitalization? All things being equal, what long term debt and at what rate, will replace the reduced principal of the promissory note?
c) Regarding 2012 Infrastructure Financing, why is the Debt Holder unknown even though there is an Oct. 1, 2012 issue date?
d) What is the current status of the 2012 and 2013 Infrastructure Financing arrangements?
e) Does Thunder Bay Hydro have the option of renegotiating the 5.27% interest rate associated with the Smart Meter financing held by the TD commercial bank?

EXHIBIT 6 – CALCULATION OF REVENUE DEFICIENCY AND SURPLUS

6-Staff-32
Ref: E1-T1-S1
Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF (version 3.0) with any corrections or adjustments that Thunder Bay Hydro wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

EXHIBIT 7 – COST ALLOCATION

7-Staff-33

Ref: E7-T1-S2

Table 7-1.5 shows that Street Lighting has the largest scaling factor of any rate class, in other words the load of that class has decreased the least of any class since 2004. Table 7-1.6 shows that the costs allocated to Street Lighting is 1.7% of the total distribution revenue requirement, compared to 5.8% in 2009.

a) Please identify which costs have been allocated differently in 2013 versus 2009, such that the proportion of cost allocated to Street Lighting is significantly smaller to yield this seemingly anomalous outcome.
b) Please explain the rationale for decreasing the proportion of cost allocated to Street Lighting for the USoA accounts that are responsible for the majority of the lower percentage shown in Table 7-1.6.

7-Staff-34

Ref: E7-T1-S2

Table 7-1.6 shows that the costs allocated to the General Service 1000 to 4999 kW class is 6.5% of the total distribution revenue requirement, compared to 11.2% in 2009, whereas the scaling factor for this class in Table 7-1.5 is similar to many of the other classes.

a) Please identify which costs have been allocated differently in 2013 versus 2009, such that the proportion of cost allocated to the General Service 1000 to 4999 kW class is significantly smaller than in the previous cost-of-service application.

7-Staff-35

Ref: E7-Appendix 7-A; Rate Order EB-2012-0015

Worksheet I 6.1 shows the existing Residential Monthly Charge as $11.72. The Rate Order currently in effect has a Service Charge of $9.85 together with a rate rider of ($1.58) in effect until April 30, 2014 and a rate rider of $2.24 in effect until the next cost-of-service rate order.

a) Please explain how the input to Worksheet I 6.1 is derived from the approved charge and rate riders, or provide a corrected version of the existing monthly charge.

7-Staff-36

Ref: Cost Allocation Model 20121108

The installed cost of each Smart Meter for the Residential class is input to Worksheet I 7.1 as $86.15, and for the General Service class as $438.39.

a) Please confirm that these costs are consistent with the costs that are the basis of the rate rider(s) approved in Rate Order EB-2012-0015.

EXHIBIT 8 - RATE DESIGN

8-Staff-37
Ref: E8-T1-S1 p. 3
Regarding the proposal to change the fixed/variable split for the residential and GS< 50kw classes, the evidence states “In addition, when the current approved 2012 smart meter incremental rate rider (SMIRR), which is assumed in the calculation of revenue at existing rates…”.

a) Please identify the specific table(s) where the revenue at existing rates includes the SMIRR.

8-Staff-38
Ref: E8-T1-S1
Thunder Bay has stated that it intends to maintain fixed/variable ratios unchanged from the status quo. However, the proposed rate structure would increase the Residential monthly service charge to $13.65 from $11.72 currently, while it would decrease the volumetric rate from $0.0124 per kWh to $0.0119.

a) Please provide a correction for the proposed Residential rates, or provide the rationale for the proposed structure which would have a higher fixed/variable ratio than the current approved structure.

8-Staff-39
Ref: E8-T1-S2
Please update the proposed Retail Transmission Service Rates with the Ontario Uniform Transmission Rated approved by the Board on December 20, 2012.

8-Staff-40
Ref: E8-T1 Appendix 8-C
Upon completing all interrogatories from Board staff and intervenors, please provide an updated Appendix 8-C (or Appendix 2-W according to the filing requirement version) for all classes at the typical consumption / demand levels (i.e. 800 kWh for residential, 2,000 kWh for GS<50).

EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS

9-Staff-41
Ref: E9-T2-S4 Table 9-2.12, Account 1595
Thunder Bay Hydro requesting disposition of residual amounts from its 2008 and 2009 rate proceedings. Board staff notes that there was no disposition approved in the 2008

rate year. However, there were dispositions approved for the 2009 and 2010 rate years. Board staff also notes that both, 2009 and 2010 rate riders ended on March 31, 2011, and would have residual balances in account 1595 as of December 31, 2011.

a) Please confirm the years for which the residual account balances are requested for disposition.

b) Thunder Bay Hydro has used kWh as the allocator for account 1595. According to the Board's EDDVAR 1report, this account balance is to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented. Please recalculate the rate riders as per the Board's guidance confirm whether Thunder Bay agrees with this approach or not. If not, please explain why.

9-Staff-42

Ref: E9-T2-S4 Table 9-2.12 and Tab "Allocations of Balances" of the 2013 EDDVAR Continuity Schedule model

The PDF version of the evidence for the Group 2 account balances allocated to various rate classes is not consistent with the allocations of Group 2 account balances in the EDDVAR model.

a) Please explain the use of the proposed allocators.
b) Please file a version of the rate rider calculations that use the default allocators established in the EDDVAR report and the Board's continuity schedule.

9-Staff-43

Ref: E9-T2-S4 Table 9-2.13 and Tab "Rate Rider Calculations" of the 2013 EDDVAR Continuity Schedule model

The PDF version of the evidence for the rate rider calculations applicable to various rate classes does not appear to be consistent with the rate rider calculations in the EDDVAR model.

a) Please indicate which evidence should the Board rely on for the purpose of this proceeding and why.
b) Please file the amended evidence as necessary.

9-Staff-44

Ref: E9-T2-S1

a) Please identify the drivers for the balances in Account 1518 and Account 1548.
b) Staff notes that there are large balances in the account(s) noted in part a). Please explain whether or not Thunder Bay Hydro has considered a change to the appropriate retail service charges.
c) Please provide a schedule identifying all revenues and expenses, listed by Uniform System of Account (USoA) number, that are incorporated into the

[1] EB-2008-0046 Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR), page 21

variances recorded in Account 1518 and Account 1548 for 2011, the forecast for 2012 and the forecast for 2013.

d) Please confirm whether or not Thunder Bay Hydro has followed Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548. Please explain if Thunder Bay Hydro has not followed Article 490. In other words, please confirm that the higher of, the relevant revenues (i.e. account 4082, Retail Services Revenue and/or account 4084, STR Revenue) and the incremental expenses in the associated expense accounts (i.e. account 5315, Customer Billing, and possibly 5305, Supervision and 5340, Miscellaneous Customer Accounts Expenses) is reduced (i.e. revenues debited or expenses credited) at the end of each period, with an offsetting entry to the variance account. Please explain if the applicant has not followed Article 490.
e) Please confirm that all costs incorporated into the variances reported in Account 1518 and Account 1548 are incremental costs of providing retail services.