THUNDER BAY HYDRO

34 Cumberland Street N.
Thunder Bay, ON P7A 4L4
tel (807) 343-1111
www.tbhydro.com

March 25, 2013

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
27th Floor – 2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Thunder Bay Hydro Electricity Distribution Inc. – 2013 Cost of Service Electricity Distribution Rate Application EB-2012-0167 Written Responses to Supplemental Interrogatories

Please find enclosed Thunder Bay Hydro Electricity Distribution Inc.'s written responses to the supplemental interrogatories as filed by Board Staff, Association of Major Power Consumers in Ontario, Energy Probe, School Energy Coalition, and the Vulnerable Energy Consumers Coalition.

These responses are being filed pursuant to the Board's e-Filing Services. Two hard copies of the responses will be delivered to the Board via courier. In addition, one hard copy and one electronic copy will be forwarded to all intervenors listed above.

Also attached please find the following:

- 2013_EDDVAR_Continuity_Schedule_CoS_v2_Mar 25 2013.xls
- 2013_Rev_Reqt_Work_Form_Supplemental.xls
- LFCD<AWF_TBHEDI_25032013.xls

If you require any further information, please contact the undersigned at (807) 343-1016.

Yours truly,

Cindy Speziale, CA
Vice President, Finance

Thunder Bay Hydro Electricity Distribution Inc.

2013 Electricity Distribution Rates

EB-2012-0167

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EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-18s

Ref: 1-Staff-32

Please provide an updated RRWF that reflects any changes agreed to by Thunder Bay Hydro as a result of the supplemental interrogatories and the changes in the cost of capital parameters based on the Board's February 14, 2013 letter related to the Cost of Capital Updates for 2013 Cost of Service Applications for Rates Effective May 1, 2013.

Thunder Bay Hydro Response

Please see Thunder Bay Hydro's response to 1-VECC-47s b).

1-SEC-18s

Ref: 1-Staff-21

Please answer the interrogatory and include all changes to the RRWF as a result of the interrogatory responses. As an example, please include changes in rate base identified in 2-AMPCO-5.

Thunder Bay Hydro Response

Please see Thunder Bay Hydro's response to 1-VECC-47s b).

1-VECC-47s

Ref: 1-Staff-32

a) Please explain why Thunder Bay is not proposing to update its Application (and hence the RRWF) for the changes in 2012 actual capital expenditures and other changes made as part of the responses to the first set of interrogatories?

b) Upon completing the responses to all interrogatories please provide an updated RRWF with any corrections or adjustments.

c) Please provide a table in the format shown below and which shows all the proposed adjustments made from the original filing in both the first and supplementary interrogatories. An example of the table requested is shown below:

Reference	Item	Regulated ReturnOn Capital	Regulated RateOf Return	RateBase	Working Capital	Working Capital Allowance	Amortization	PILs	OM&A	Service Revenue Requiremen
	OriginalSubmissionOctober2012	2,875,064	6.97%	41,694,299	51,873,750	6,743,588	1,379,137	-	6,325,500	10,579,701
BoardStaffIR#4,Board StaffIR#5c(b)&EP IR#7	UpdateofSmartMeterModelandCapitalContinuitySchedulestoreflectactualSMadditionsfor2012&proposed2013	6,067		87,000	0	-	6,000		-	12,067
		2,881,131	6.97%	41,781,299	51,873,750	6,743,588	1,385,137		6,325,500	10,591,768

Thunder Bay Hydro Response

a) With the first set of interrogatories, Thunder Bay Hydro made changes in the 2012 actual capital expenditures and other changes in its working files; however, due to its materiality threshold calculated at $87,000, no single adjustment or the combination of all adjustments resulted in a change to the revenue requirement of over the threshold. As a result, Thunder Bay Hydro did not update the RRWF in the first set of interrogatories.

b) Please see an updated RRWF with all corrections and adjustments from the first set and supplemental interrogatories filed in Thunder Bay Hydro's March 25, 2013 submission. Also, please see ***Appendix Is-1*** for a revised Bill Impacts.

c) Below please find a table of all the proposed adjustments made from the original filing in both the first and supplementary interrogatories.

Reference	Item	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance	Amortization	PP&E Return Adjustment	PILS	OM&A	Service Revenue Requirement	Revenue Offsets	Base Revenue Requirement	Gross Revenue Deficiency
	Original Submission	3,723,132	3.94%	94,393,281	111,439,285	14,487,107	3,247,244	0	0	14,682,415	21,652,791	1,751,736	19,901,055	1,559,334
5-Staff-29	Cost of Capital update issued March 2013	3,672,568	3.89%	94,393,281	111,439,285	14,487,107	3,247,244	0	0	14,682,415	21,602,227	1,751,736	19,850,491	1,508,771
	Change	-50,564	-0.05%	0	0	0	0	0	0	0	(50,564)	0	(50,564)	(50,564)
8-Staff-39	Cost of Power update	3,662,318	3.89%	94,129,843	109,412,842	14,223,669	3,247,244	0	0	14,682,415	21,591,977	1,751,736	19,840,242	1,498,521
	Change	(10,250)	0.00%	(263,438)	(2,026,443)	(263,438)	0	0	0	0	(10,250)	0	(10,250)	(10,250)
	Adjustment to ARO	3,657,503	3.89%	94,006,087	109,412,842	14,223,669	3,247,244	0	0	14,682,415	21,587,162	1,751,736	19,835,427	1,493,706
	Change	(4,815)	0.00%	(123,756)	0	0	0	0	0	0	(4,815)	0	(4,815)	(4,815)
2-SEC-5	Remove Reclosers 2 of 3	3,655,386	3.89%	93,951,657	109,412,842	14,223,669	3,245,852	0	0	14,682,415	21,583,652	1,751,736	19,831,917	1,490,196
	Change	(2,118)	0.00%	(54,430)	0	0	(1,392)	0	0	0	(3,510)	0	(3,510)	(3,510)
2-Energy Probe-6a	Remove RBD	3,651,061	3.89%	93,840,491	109,412,842	14,223,669	3,238,185	0	0	14,682,415	21,571,661	1,751,736	19,819,925	1,478,205
	Change	(4,325)	0	(111,167)	0	0	(7,667)	0	0	0	(11,992)	0	(11,992)	(11,992)
4-Energy Probe-14c	Remove LEAP doubleup	3,650,959	3.89%	93,837,891	109,392,842	14,221,069	3,238,185	0	0	14,662,415	21,551,559	1,751,736	19,799,824	1,458,103
	Change	(101)	0.00%	(2,600)	(20,000)	(2,600)	0	0	0	(20,000)	(20,101)	0	(20,101)	(20,101)
	Setup Student funding	3,650,959	3.89%	93,837,891	109,392,842	14,221,069	3,238,185	0	0	14,662,415	21,551,559	1,768,236	19,783,324	1,441,603
		0	0.00%	0	0	0	0	0	0	0	0	16,500	(16,500)	(16,500)
	Increase property tax	3,651,086	3.89%	93,841,141	109,417,842	14,224,319	3,238,185	0	0	14,687,415	21,576,686	1,768,236	19,808,450	1,466,730
		126	0.00%	3,250	25,000	3,250	0	0	0	25,000	25,126	0	25,126	25,126
	Adjust for 2012 Actuals	3,631,812	3.89%	93,304,978	109,417,716	14,224,303	3,201,779	0	0	14,687,292	21,520,883	1,772,099	19,748,785	1,407,064
		(19,274)	0	(536,163)	(126)	(16)	(36,406)	0	0	(123)	(55,803)	3,863	(59,666)	(59,666)

Total Change (152,270)

1-Staff-45s

Ref: E1-T1-S2

Following publication of the Notice of Application the Board received one letter of comment. Has Thunder Bay Hydro replied to the letter? If so, please file a copy of the reply with the Board, ensuring that the author's contact information except for the name is redacted. If a response was not sent, please explain why and indicate whether Thunder Bay Hydro intends to respond.

Thunder Bay Hydro Response

Thunder Bay Hydro concurs that one letter of comment was received following publication of the Notice of Application. Thunder Bay Hydro appreciates any interest that its stakeholders has in its rate applications and considers all comments. However, this letter of comment did not include any questions that required a response; thus, Thunder Bay Hydro has not and does not plan to provide a response as the proposed return on equity will be addressed through the interrogatory process.

EXHIBIT 2 – RATE BASE

2-Energy Probe-19s

Ref: 2-AMPCO-3

The response indicates that Thunder Bay Hydro anticipated an increase in contractor hourly costs when renewing the exiting Forestry Management contract for 2013. What is the status of this renewal, and what is the actual impact in contractor hourly costs relative to what was anticipated?

Thunder Bay Hydro Response

Thunder Bay Hydro confirms a 5% increase to the outside service costs for the existing Forestry Management contract, was agreed to November 30, 2012, which was very close to the anticipated costs for 2013.

2-VECC-47s

Ref: E2-T3-S1, pg. 2 / Appendix 2-A

a) Please explain how the $800,000 target capital expenditure gradient referred to in this interrogatory was arrived at (the components of, and rationale for).

b) Has it been Utility policy to since 2009 to increase capital expenditures by 800k per annum? Was this policy approved by the Utility's Board of Directors? If yes, please provide the analysis that was presented to the Board in support of this figure.

Thunder Bay Hydro Response

a) The $800,000 yearly increase in capital expenditure was arrived at after due consideration as to the ability of the utility to increase its capital construction capacity and with due regard for the rate impact on our customers of increased capital investment. Unlike many Ontario LDC's, the geographic location of Thunder Bay limits the available options for retaining outside contractors to undertake distribution construction activities. As such, the most efficient course of action was determined to be that of increasing our internal capacity to undertake increased construction activity. Increasing this capacity required adding and training trades staff and it was determined that each yearly incremental increase of $800,000 in capital expenditures would require both additional staff and the realization of internal efficiencies. It was determined that an $800,000 'gradient' was manageable in terms of capacity increase, and that it would still allow the utility to reduce the risk associated with aging distribution infrastructure. As well, 'ramping up' capital investment slowly over time as compared to a one time increase would result in a lesser initial rate impact to our customers.

b) Thunder Bay Hydro's asset management plan as set out in EB-2008-0245 (Thunder Bay's 2009 Cost of Service Application) indicated that an $800K increment in the replacement capital would be a manageable amount and that such would be revisited in the next COS application. Thunder Bay Hydro's updated Asset Management Plan as filed for 2013 has generally continued on with the $800K annual increment. The strategy of gradually increasing annual capital investment has been incorporated in the utility's Strategic Plan for a number of years and is reviewed and approved by the Board of Directors as a component of the annual Budget Approval process. This increased capital investment is also reviewed with the Shareholder during the Annual Shareholder Meeting. In addition, management regularly reports to the Board of Directors an update on the Capital Infrastructure Assessment and management's plan. Board of Director's approval of the plan is based upon the approval of the annual budget. Please see ***Appendix Is-2*** which is excerpts from various minutes of the Board of Directors meetings spanning 2007 to 2012.

2-Energy Probe-20s

Ref: 2-AMPCO-5

Please update the response with a revised Table 2-1.1 that reflects the lower closing rate base in 2012 and its consequential impact on 2013 under both CGAAP and MCGAAP.

Thunder Bay Hydro Response

Below please find an updated Table 2-1.1 with 2012 actuals.

Table 2-1.1 - Rate Base Calculations

	2009 Board approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge (CGAAP)	2013 Test (CGAAP)	2013 Test (MCGAAP)
Fixed Assets Opening Balance	60,721,376	61,016,106	61,199,061	62,895,512	64,506,734	74,312,922	74,312,922
Fixed Assets Closing Balance	63,383,477	61,199,061	62,895,512	64,506,734	74,312,922	82,801,861	83,848,428
Average Fixed Asset Balance	62,052,427	61,107,583	62,047,286	63,701,123	69,409,828	78,557,391	79,080,675
Working Capital Allowance	13,480,846	12,893,612	13,579,694	14,628,533	15,247,630	14,059,928	14,224,303
Rate Base	75,533,273	74,001,196	75,626,981	78,329,656	84,657,458	92,617,319	93,304,978

2-Energy Probe-22s

Ref: 2-Energy Probe-3 & 2-AMPCO-5

Please reconcile the actual 2012 closing net book value of $74,450,808 shown in the response to 2-AMPCO-5 with the figure of $77,737,071 in the response to 2-Energy Probe-3. In addition to the adjustment for Work in Progress, what adjustment has been made for account 2320 - ARO?

Thunder Bay Hydro Response

The balance presented in the updated Table 2-1.1 was presented incorrectly. Below are tables which present the Rate Base Calculations reconciled to the Fixed Asset Continuity Statements, using 2012 updated information.

Thunder Bay Hydro
Reconciliation of Fixed Assets for Rate Base Calculations and Fixed Asset Continuity Statements
2012 Updated

	2012 (CGAAP) Updated
Fixed Assets Opening	
Total opening Assets	155,027,528
Less Opening Work In Process	2,950,259
Less Opening Transformer ARO	161,743
Less Opening Distribution Equipment ARO	
Less Opening Accumulated Depreciation	(87,478,705)
Less Opening Transformer ARO Accum Dep	69,913
Less Opening ARO Distribution Equipment Accum Dep	
Fixed Assets Opening Balance	**64,506,734**
Fixed Assets Closing	
Total Closing Assets	171,776,463
Less Closing Work In Process	3,204,185
Less Closing Transformer ARO	299,629
Less Closing Distribution Equipment ARO	
Less Closing Accumulated Depreciation	(94,039,392)
Less Closing Transformer ARO Accumulated Depreciati	79,665
Less Clossing ARO Distribution Equipment Accum Dep	
Fixed Assets Closing Balance	**74,312,922**

Rate Base Calculations

	2012 (CGAAP) Updated
Fixed Assets Opening Balance	64,506,734
Fixed Assets Closing Balance	74,312,922
Average Fixed Asset Balance	69,409,828
Working Capital Allowance	15,247,630
Rate Base	84,657,458

2-Energy Probe-21s

Ref: 2-Energy Probe-2 & Exhibit 2, Tab 2, Schedule 1 & Exhibit 2, Tab 3, Schedule 1

a) The responses indicate that the items removed from Thunder Bay Hydro's infrastructure have been reflected through net capital additions rather than gross capital additions and disposals. Does this account for the difference in the additions shown in the fixed asset continuity schedules in Exhibit 2, Tab 2, Schedule 1 and the figures shown in Table 2-3.1 in Exhibit 2, Tab 3, Schedule 1?

b) Are there any other factors that contribute to the differences noted above? If yes, please provide details.

Thunder Bay Hydro Response

a) The figures shown in Table 2-3.1 in Exhibit 2, Tab 3, Schedule 1, include the gross up for the scrapped assets and non-utility assets as taken from the financial statement versus the additions shown in the fixed asset continuity schedules in Exhibit 2, Tab 2, Schedule 1 which net the scrapped assets and exclude non-utility assets.

b) Please see answer to a) above.

2–VECC–48s

Ref: 2-AMPCO-5

a) Please update the Application for the changes in 2012 and 2013 rate base (see also 2-Energy Probe 5; 1-VECC-47s).

Thunder Bay Hydro Response

a) Please see Thunder Bay Hydro’s response to IR#2-Energy Probe-20s.

2-Staff- 46s

Ref: 2-Staff-4

a) Please provide your best estimate of the incremental property taxes Thunder Bay Hydro will incur because of the new maintenance building/garage.

b) Please provide the amount of operating savings (supported by rationale), on a full year basis, Thunder Bay will realize due to the replacement of an old facility with a new one.

Thunder Bay Hydro Response

a) Thunder Bay Hydro is unable to provide an estimate at this time with regards to the incremental property taxes related to new maintenance building/garage. Thunder Bay Hydro has requested this information from the City of Thunder Bay.

b) The replacement facility is not anticipated to be completed until the latter part of 2013. As a result, 2013 operating expenses are not anticipated to change. The requirement to replace the facility was not driven by achieving operational savings. Currently Thunder Bay Hydro does not have all required information to calculate new operational costs and operational savings due to the new facility.

   Please refer to Thunder Bay Hydro's response to interrogatory 2-VECC-3(d).

2-Staff-47s

<u>Ref: 2-VECC-3</u>

Please provide a copy of the Internal Business Case Review that was prepared for the new maintenance building/garage.

Thunder Bay Hydro Response

Please see ***Appendix Is-3*** for a copy of the Internal Business Case Review requested.

Additionally please refer to ***Appendix Is-4.***

2-Energy Probe-24s

<u>Ref: 2-Energy Probe-5</u>

Please confirm that Thunder Bay Hydro is not requesting a funding adder associated with the $210,440 that is being closed to rate base and that the funding adder is strictly related to the external funding amounts shown in the response to part (a).

Thunder Bay Hydro Response

Thunder Bay Hydro has revisited its proposed funding for its renewable generation project and confirms that the $210,440 closed to rate base in 2013 is not to be included in the funding adder. The remaining $353,239 is proposed to be externally funded by the IESO and is requested to be deferred in account 1531 Renewable Connection Generation. Please see Thunder Bay Hydro's response to 2-Staff-48s for further detail.

2-AMPCO-35s

Ref: 2-STAFF-4

The response to Board Staff IR#4 indicates that it is anticipated that any OM&A efficiencies/savings realized because of the new facility will be overshadowed by the increase in property value due to the new building and the expected property tax adjustment.

Please provide a calculation that Thunder Bay relies upon to support the above statement.

Thunder Bay Hydro Response

Please refer to response 2-Staff-46s.

2-VECC-49s

Ref: 2-VECC-1

a) Please explain the significant change in capital contributions from the City from years 2010 through 2013 (forecast).

b) Are the 2012 figures reported in this interrogatory actuals or a forecast?

Thunder Bay Hydro Response

a) Contributions received from the City are directly related to City projects for each year. The amount of work completed depends on direction from the City and is dependent on City budgets, City capital programs, government funding etc. The 2013 estimate is based on one known project related to moving six poles. There are no other City projects for 2013 that Thunder Bay Hydro is currently aware of.

b) The 2012 figures reported in this interrogatory were updated figures based on actual. Upon further updating the contributions received from the City of Thunder Bay for 2012 are $311,255.

2-Staff-48s

Ref: 2-Staff- 9

Please refer to the Revised Table 9 and clarify whether the gross investment amount to be funded by “External Funding” totaling $353,239 corresponds to the amount Thunder Bay Hydro proposes to recover from the IESO as shown in E9-T4-S1 p.4 table 9-4.2.

Revised Table 9 - Cost Distribution of TBHEDI System Developments (Appendix 2B)

Year	2012	2013	2013
Gross Investment	$375,786	$187,893	$375,786
Activity Definition (by the DSC)	"Enhancement"	"Enhancement"	"Renewable Enabling Improvement"
External Funding	$0	$0	$353,239
Funded by TBHEDI Rate Base	$375,786	$187,893	$22,547
Number of Reclosers	6	3	6
Average Cost/Recloser	$62,631	$62,631	$62,631

Does the rate base proposed for 2013 include any of the amounts shown in revised table 9 as “Funded by TBHEDI Rate Base”?

Thunder Bay Hydro Response

Thunder Bay Hydro confirms that the gross investment amount to be funded by “External Funding” totaling $353,239 corresponds to the amount Thunder Bay Hydro proposes to recover from the IESO as shown in E9-T4-S1 p.4 table 9-4.2 and also proposes to defer in account 1531 Renewable Connection Generation until collected. In addition, Thunder Bay Hydro confirms that the rate base proposed for 2013 includes the total amount of $210,440 shown as “Funded by TBHEDI Rate Base.” However, due to recent changes to its GEA Plan, Thunder Bay Hydro has reduced its proposed amount in rate base to $77,643 in 2013 as the number of required RESOP reclosers have changed from 3 to 1, which has been reflected in the RRWF. After revisiting its original application and responses to the first round of interrogatories, Thunder Bay Hydro is retracting its need of a GEA funding adder as all of the funding has been proposed as discussed above. For the amounts funded by rate base, Thunder Bay Hydro proposes to treat these expenditures no differently than other capital expenditures such that any over or under spending will be adjusted through rebasing in its next Cost of Service.

2-Staff-49s

Ref: 2-Energy Probe-6 b) 1, 2

Please demonstrate how the staff productivity and reduced rental costs, due to the new RBD truck, and additional staff productivity, due to the new single bucket truck, are reflected in the OM&A proposed for 2013.

Thunder Bay Hydro Response

Thunder Bay Hydro has been renting RBD trucks for the past three years. Some years two RBDs have been rented to enable the work crews to complete their planned activities. The cost to rent an RBD averages $6,500/month, assuming continuous rental payments, pay back will occur in approximately 3 years. A new single bucket truck will replace the maintenance prone shift truck #87, which has become unreliable for use as the after-hour on-call lines vehicle. Once the new single bucket has been put into service, truck #87 can be put into general Line fleet for use by non-critical work groups. Both units will allow efficient use of manpower in both the Capital and Operating & Maintenance groups.

2-Energy Probe-23s

Ref: 2-Staff-6 & Exhibit 4, Tab 2, Schedule 3

Please reconcile the change in OM&A due to the change in capitalization policy of $1,264,420 shown in Table 4-2.8 in Exhibit 4, Tab 2, Schedule 3 with the figures provided in the response to 2-Staff-6.

Thunder Bay Hydro Response

The following reconciliation analyzes the change in OM&A due to the change in capitalization policy of $1,264,420 shown in Table 4-2.8 in Exhibit 4, Tab 2, Schedule 3 with the figures provided in the response to 2-Staff-6.

Reconciliation of OM&A Change due to change in Capitalization Policy

Overhead Allocated to Capital		
Downtime	(296,021)	
Material	(311,819)	
Supervisory	(320,645)	
Engineering	(230,725)	
Fleet	(498,737)	(1,657,947)
Less Overhead impacts do to depreciation adjustment		288,714
Transformer Maintenance Capitalized		112,670
		(1,256,563)
Other		(7,857)
Amount reported on Table 4-2.8		(1,264,420)

2–VECC–50s

<u>Reference: 2-VECC-6</u>

Is TBH applying for a variance account to be used in association with its GEA spending? If not, what methodology does it propose to use to collect (or refund) any variance in the planned GEA spending?

Thunder Bay Hydro Response

Please see Thunder Bay Hydro's response to 2-Staff-48s.

EXHIBIT 3 – OPERATING REVENUE

3-Staff-50s

Ref: 3-Staff-12

a) Was the population of Thunder Bay, as a Census Metropolitan Area, tried as a measure for market size? If not, why not? If so, what were the results?

b) Please estimate the load forecast for Residential consumption including Ontario Real GDP and other variables but excluding the Number of Customers and the intercept term. Please provide the regression statistics, the MAPE based on monthly residuals, and the forecasts for the 2012 bridge and 2013 test years.

Thunder Bay Hydro Response

a) The population of Thunder Bay, as a Census Metropolitan Area, was not tried as a measure for market size. However, Thunder Bay Hydro did attempt to use Number of Customers in the Residential class as a variable and it did not prove to be a statistically significant variable (i.e. the T-stat was significantly below the absolute value of 2). In Thunder Bay Hydro's view Number of Customers in the Residential class is a better indication of market size than population. As a result, Thunder Bay Hydro believes the issue of market size was explored with the Number of Customers variable but was excluded since it was not statistically significant.

b) The regression analysis for Residential consumption has been rerun including Ontario Real GDP and other variables but excluding the Number of Customers and the intercept term. The following provides the regression statistics, the MAPE based on monthly residuals, and the forecasts for the 2012 bridge and 2013 test years including the CDM manual adjustment.

Statistics - Residential		
R Square	99.9%	
Adjusted R Square	99.2%	
F Test	22130.1	
Variable	Coefficients	T-stat
Intercept	-	0.00
Heating Degree Days	14,138	43.44
Cooling Degree Days	35,314	4.86
Number of Days in Month	696,561	14.24
Spring Fall Flag	(866,624)	(4.61)
CDM Activity	(1.63)	(4.34)
Ontario Real GDP Monthly %	16,342	1.37
MAPE Monthly Residuals	2.8%	
2012 Bridge Billed (GWh)	341.0	
2013 Test Billed (GWh)	337.4	

3-Staff-51s

Ref: 3-Staff-14

With respect to the response to part c) of 3-Staff-14, why would not the use of a single variable for the number of business days in the month instead of two variables for the number of days in the month and the number of peak hours in the month be preferable in terms of model parsimony and more realistically relating to the general operating hours of this class of customers?

Thunder Bay Hydro Response

The two variables being the number of days in the month and the number of peak hours were included since these variables were statistically significant in the regression analysis supporting the GS > 50 kW model. In addition, the resulting R-square and adjusted R-square were 94% which indicates the resulting prediction formula, including the two variables, have a good fit with actual data. Also, the correlation between the two variables indicates they were not highly correlated with each other and are two independent variables that are contributing to a good prediction formula.

In order to respond to this interrogatory the regression analysis was rerun for the GS > 50 kW model by not including the number of days in the month and the number of peak hours but including the number of business days in the month. The statistical results from this analysis deteriorated compared to the proposed model.

3-Staff-52s

Ref: 3-Staff-12, 3-Staff-13, 3-Staff-14 and 3-Staff-16

Please re-run each of the Residential, GS < 50 kW and GS 50-999 kW models excluding the CDM variable. In each case, provide the regression statistics, the MAPE based on the monthly residuals, and the forecasts for the 2012 bridge and 2013 test years.

Thunder Bay Hydro Response

The regression analysis for the Residential, GS < 50 kW and GS 50-999 kW models has been rerun excluding the CDM variable. For each case the following tables provide the regression statistics, the MAPE based on monthly residuals, and the forecasts for the 2012 bridge and 2013 test years including the CDM manual adjustment.

Statistics: Residential		
R Square	94.2%	
Adjusted R Square	94.1%	
F Test	612.0	
Variable	Coefficients	T-stat
Intercept	(2,319,058)	(0.69)
Heating Degree Days	14,211	40.64
Cooling Degree Days	35,086	4.43
Number of Days in Month	827,134	7.49
Spring Fall Flag	(881,952)	(4.33)
MAPE Monthly Residuals	3.0%	
2012 Bridge Billed (GWh)	345.8	
2013 Test Billed (GWh)	341.2	

Statistics: GS < 50 kW		
R Square	69.6%	
Adjusted R Square	68.7%	
F Test	85.7	
Variable	Coefficients	T-stat
Intercept	5,204,384	1.93
Heating Degree Days	4,331	15.38
Cooling Degree Days	19,250	3.02
Number of Days in Month	164,681	1.85
Spring Fall Flag	(472,250)	(2.88)
MAPE Monthly Residuals	4.6%	
2012 Bridge Billed (GWh)	143.4	
2013 Test Billed (GWh)	141.7	

Statistics: GS 50 - 999 kW		
R Square	92.9%	
Adjusted R Square	92.5%	
F Test	273.1	
Variable	Coefficients	T-stat
Intercept	2,944,450	1.07
Heating Degree Days	9,194	37.06
Cooling Degree Days	41,333	7.36
Number of Days in Month	392,676	4.78
Spring Fall Flag	(621,188)	(4.32)
Ontario Real GDP Monthly %	5,409	0.80
Number of Customers	3,477	2.29
Number of Peak Hours	8,955	2.30
MAPE Monthly Residuals	2.5%	
2012 Bridge Billed (GWh)	291.8	
2013 Test Billed (GWh)	288.4	

3-Staff-53s

<u>Ref: 3-Staff-15, 3-Staff-17, 3-VECC-11 and 3-VECC-15</u>

Board staff in 2013 cost of service applications proceedings has proposed an approach to account for the persistence of 2011 and 2012 CDM programs, and the impact of 2013 CDM programs on 2013 demand (consumption, measured in kWh) that corresponds to the amount used to establish the amount of CDM savings for 2013 (and hence 2014) for the LRAMVA.

Under this approach, the 2011 CDM results and their persistence, as measured and reported by the OPA for Thunder Bay Hydro are used. One then assumes an equal increment for each of 2012, 2013, and 2014 so as to achieve Thunder Bay Hydro's CDM target of 7,810,000 kWh. Board staff views this approach as being preferable as there are actual results on what the utility has achieved to date, which can then be taken into account on what more will be needed to achieve the cumulative four-year target. In using the measured and reported results from the 2011 programs, including the persistence into 2013, Board staff views that an improved estimate of the CDM impact of 2011-2013 programs on the LRAMVA threshold for 2013 (and 2014) would result, along with the corresponding adjustment to the 2013 test year load forecast.

Based on the final 2011 OPA results filed in Thunder Bay Hydro's Application, Board staff has prepared the following table, which is also provided in working Microsoft Excel format:

Load Forecast CDM Adjustment Work Form (2013)

Thunder Bay Hydro Electricity Distribution Inc. ***EB-2012-0167***

4 Year (2011-2014) kWh Target:					
47,380,000					
	2011	2012	2013	2014	Total
%					
2011 CDM Programs	4.55%	4.55%	4.55%	4.29%	17.95%
2012 CDM Programs		13.68%	13.68%	13.68%	41.03%
2013 CDM Programs			13.68%	13.68%	27.35%
2014 CDM Programs				13.68%	13.68%
Total in Year	**4.55%**	**18.23%**	**31.90%**	**45.31%**	**100.00%**
kWh					
2011 CDM Programs	2,157,479	2,157,479	2,157,479	2,031,020	8,503,456
2012 CDM Programs		6,479,424	6,479,424	6,479,424	19,438,272
2013 CDM Programs			6,479,424	6,479,424	12,958,848
2014 CDM Programs				6,479,424	6,479,424
Total in Year	**2,157,479**	**8,636,903**	**15,116,327**	**21,469,292**	**47,380,000**
				Check	47,380,000

Net-to-Gross Conversion				
	"Gross"	**"Net"**	**Difference**	**"Net-to-Gross" Conversion Factor ('g')**
2006 to 2011 OPA CDM programs: Persistence to 2013	1	1	0	0.00%

	2011	**2012**	**2013**	**2014**	**Total for 2013**
Amount used for CDM threshold for LRAMVA	2,157,479	6,479,424	6,479,424		15,116,327
Manual Adjustment for 2013 Load	2,157,479	6,479,424	3,239,712		11,876,615

Forecast *Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)*	 *Only 50% of 2013 CDM impact is used based on a half year rule*

The methodology for this is as follows:

For the top table

- The 2011-2014 CDM target is input into cell B4;
- Measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 are input into cells C13 to F13;
- Based on these inputs, the residual kWh to achieve the 4 year CDM target is allocated so that there is an equal incremental increase in each of the years 2012, 2013 and 2014.

The second table (Net-to-Gross) is to calculate the conversion from “net” to “gross” results.

While the LRAMVA is based on the “net” OPA-reported results, the load forecast is impacted also by CDM savings of “free riders” and “free drivers”. While Board staff has input values of “1” in each of cells D24 and E24, in the absence of other information, these should be populated with the measured “gross” and “net” CDM savings for the persistence of all CDM programs from 2006 to 2011 on 2013, as reported in the final OPA reports, filed in the Application and in response to 3-VECC-11.

For the last table, two numbers are calculated:

- The “Amount used for CDM threshold for LRAMVA” is the sum of the persistence of 2011 and 2012 CDM programs and the annualized impact of 2013 CDM programs on 2013; and
- “Manual Adjustment for 2013 Load Forecast” represents the amount to be reflected in the 2013 load forecast. This amount uses the “gross” impact, which is calculated by multiplying each year’s CDM program impact or persistence by (1 + g) from the second table. In addition, the impact of the 2013 CDM programs on 2013 “actual” consumption is divided by 2 to reflect a “half year” rule. Since the 2013 CDM programs are not in effect at midnight on January 1, 2013, the “annualized” results reported in the OPA report will overstate the “actual” impact. In the absence of information on the timing and uptake of CDM programs in their initial year, a “half-year” rule may proxy the impact.

a) Please input the “gross” and “net” cumulative kWh CDM savings from all CDM programs from 2006 to 2011 on 2013 as measured in the final OPA reports into, respectively, cells D24 and E24.

b) Please derive the class CDM kWh and kW savings that would correspond with the “net” CDM savings above.

c) Please provide Thunder Bay Hydro’s comments on the methodology above to develop the CDM savings that will underlie the 2013 CDM amount for the LRAMVA and the corresponding CDM adjustment for the 2013 test year load forecast. Is this approach consistent with the inclusion of the CDM variable in the regression analysis to develop the load forecast before the CDM adjustment? What refinements to this approach should be considered?

Thunder Bay Hydro Response

a) The “gross” and “net” cumulative kWh CDM savings from all CDM programs from 2006 to 2011 on 2013 as measured in the final OPA reports have been entered, respectively, into cells D24 and E24 and provided in the live spreadsheet titled “LFCDMAWF_TBHydro_20130313 EXCEL_Completed.”

b) The class CDM kWh and kW savings that would correspond with the “net” CDM savings of 15,116,327 kWh shown above is provided in Exhibit 3, Tab 2 Schedule 1, Page 17 of 20, Table 3-2.23 in the application.

c) Thunder Bay Hydro agrees with the methodology used to determine the CDM savings that will underlie the 2013 CDM amount for the LRAMVA. With regards to the manual CDM adjustment for the 2013 test year load forecast, Thunder Bay Hydro agrees it should be a value that represents the gross level. However, the 2011 value should not be included in the manual CDM adjustment. The results of the 2011 programs and how they persist into 2013 have been reflected in the CDM Activity variable since the 2011 programs impacts on the actual 2011 power purchases used in the regression analysis. In Thunder Bay Hydro’s view to include the 2011 value in the manual CDM adjustment would be a double count. With regards to the 2013 value used in the manual CDM adjustment, Thunder Bay Hydro is concerned with using the “half year rule” since it is Thunder Bay Hydro’s understanding that there should be consistent treatment on how the load forecast is adjusted and how the LRAMVA threshold is determined. Since a full year amount is used in the LRAMVA threshold calculation for 2013 then a full year for 2013 should be used in the manual CDM adjustment.

   Please note, as calculated in IR#4-Staff-28, rate riders to collect the lost revenues in 2011 from 2011 CDM programs resulted in $0.0000/kWh for the Residential and General Service < 50 kW classes in Table 4-6.4. The total lost revenues plus carrying charges equates to $20,418, and thus, Thunder Bay Hydro requests that this balance be deferred until its 2014 IRM LRAM claim.

3-Energy Probe-25s

Ref: 3-VECC-7

The response indicates that over the period 1999-2011 residential customers were billed on a bi-monthly basis, while all other classes are billed on a monthly basis. Does Thunder Bay have any plans to move residential customers to monthly billing? If yes, please provide details, including the timing of the change.

Thunder Bay Hydro Response

Thunder Bay Hydro confirms that there are no plans to move residential customers to monthly billing at this time.

3-VECC-51s

Ref: Staff #12 c), VECC #15

a) With respect to VECC #15 a), if the difference between gross and net savings does not represent the CDM that would have occurred even without a CDM program, please provide Thunder Bay's understanding as to what the difference represents.

b) With respect to Staff 12 c), please confirm that, for any given year, the difference between gross and net OPA reported savings does not reflect all of the CDM activity that will take place without any incentive being provided. If not confirmed, please explain why.

Thunder Bay Hydro Response

a) Thunder Bay Hydro's understanding of the difference between gross and net savings is that of the industry. It is not sufficient to say that the only difference between gross and net is participation (savings) "even without a CDM program" as purported. The conclusion seems to imply that the only explanation for the difference is free ridership. However, this is not what the industry, which includes EM&V experts, researchers and utility conservation specialists understand. Although free ridership is part of the difference it is only one piece. Also included in the difference, but not limited to, are the following; free drivers (spill over), changes in the level of energy service, energy efficiency standards, interactive effects and persistent factors. Because the difference has multiple inputs the simple "even without a CDM program" explanation is insufficient.

b) Thunder Bay Hydro cannot confirm that the difference between gross and net as reported by the OPA "does not reflect all of the CDM activity that will take place without any incentive being provided." CDM activity taking place without any incentive provided occurs and one explanation for this is called spillover. Spillover activity occurs when persons or businesses install measures without incentive participation due to influence from the program itself. For example, a homeowner may see an advertisement for CFL rebates and then while shopping sees some CFLs and makes a decision to buy based on his or her recollection of the advertisement without redeeming the coupon. Although unable to confirm, Thunder Bay Hydro assumes that the OPA follows standard industry treatment of accounting for differences as described in IR#VECC 51s-a) and IR#Board Staff-12 c). Thunder Bay Hydro assumes that those differences at times require OPA estimations based on the best available information at the time and in the absence of such Thunder Bay Hydro also assumes that the OPA would rely on supporting data from other vetted sources.

3-Staff-54s

Ref: 3-VECC-13

In the table shown in response to part a), why is the number of streetlighting connections for December 2012, at 13,119, lower than the 2012 annual average of 13,172?

Thunder Bay Hydro Response

In August 2012, Thunder Bay Hydro was notified that the City of Thunder Bay streetlighting account had removed 91 of its connections from service, thus, the December 2012 count is less than the annual average for 2012.

3-VECC-52s

Ref: VECC #8 b)

a) Please re-do the regression analysis in VECC #8 b) but exclude "number of customers" as an explanatory variable and provide the resulting equation and its statistical properties. Please provide a projection for 2013 Residential use based on the resulting equation.

Thunder Bay Hydro Response

a) The regression analysis for the Residential model outlined in VECC #8 b) has been rerun to exclude "number of customers" as an explanatory variable. The resulting equation and its statistical properties along with a projection for 2013 Residential use based on the resulting equation are provided below. Since the

2013 Residential use projection reflects the results of the equation the projection is before the manual adjustment for CDM.

Statistics: Residential		
R Square	95.4%	
Adjusted R Square	95.2%	
F Test	505.9	
Variable	Coefficients	T-stat
Intercept	(8,442,095)	(2.37)
Heating Degree Days	14,276	45.05
Cooling Degree Days	34,351	4.80
Number of Days in Month	814,005	8.14
Spring Fall Flag	(842,427)	(4.56)
CDM Activity	(0.4)	(1.04)
Northwest Employment	61,368.1	3.30
2013 Test Billed (GWh)	345.3	

3-VECC-53s

Ref: VECC #9 b)

a) Please provide a projection for 2013 GS<50 use based on the equation estimated in part (b) – (ii).

Thunder Bay Hydro Response

a) The projection for 2013 GS<50 kW use based on the equation estimated in VECC #9 b) – (ii) is 142.5 GWh. This projection reflects the results of the equation which means the projection is before the manual adjustment for CDM.

3–VECC–54s

Reference: VECC #18 a)

a) Please respond to the second part of the question, i.e. is Thunder Bay proposing that its Application be based on CGAAP or MCGAAP?

Thunder Bay Hydro Response

a) Thunder Bay Hydro's application should be based on MCGAAP.

3-Energy Probe-26s

Ref: 3-Energy Probe-11

Please provide a breakdown of the estimated loss on disposal of the assets noted in the response to part (e) that total $63,970 due to all assets not being fully depreciated into the same categories as the response provides for the 2013 CGAAP gain.

Thunder Bay Hydro Response

See table below for breakdown of loss on disposal of assets.

Infrastructure Removal

		Asset Cost Removal	Accumumlated Depreciation Removal	Net Loss on Dispostion	Returned to Inventory for Re Use	Total Net Loss
1830	Poles, towers and fixtures	216,435	213,933	2,502		2,502
1830	Steel Cross Arms	1,274	422	852	852	0
1835	OH Conductors & Devices - Switches	27,097	26,024	1,073		1,073
1835	OH Conductors & Devices - Primary & Neutral Cables	328,450	305,947	22,503		22,503
1850	Line Transformers - Vault Combined	17,024	16,128	896		896
1850	Line Transformers - Enclosure Combined	21,896	20,745	1,151		1,151
1850	Line Transformers - Pole Top Combined	243,541	167,194	76,347		
1850	Line Transformers - Pad Mount Transformer Single Phase	5,460	5,179	281	77,395	30,399
1850	Line Transformers - Pad Mount Transformer 3 Phase	85,722	54,556	31,166		
1855	Services - OH Conductors	112,593	139,045			
1855	Services - UG In Duct	31,895	0	5,443		5,443
		1,091,387	949,173	142,214	78247	63,967

3-Energy Probe-27s

Ref: 3-Energy Probe-11 & Exhibit 2, Tab 5, Schedule 1, Table 2-5.1

a) The response to part (e) of 3-Energy Probe-11 indicates that land from a decommissioned station result in proceeds of $60,000. Where in Table 2-5.1 is this land being shown as removed from rate base at its original cost?

b) Please show the links between the $63,970 loss indicated in the response to part (e) of 3-Energy Probe-11 to the disposals shown in Table 2-5.1.

Thunder Bay Hydro Response

a) The original cost of the land in question was $390. As this was deemed immaterial it was not shown as removed on Table 2-5.1.

b) Please see response to 3-Energy Probe-26s.

3–VECC–55s

Ref: Energy Probe #11 a)

a) Actual Other Operating Revenues for 2012 are materially higher (i.e. by roughly $150,000) than forecast in the Application. Please explain why and whether or not the forecast for 2013 should be adjusted upwards.

Thunder Bay Hydro Response

a) The forecast for 2013 should not be adjusted. The difference in 2012 is in large part due to revising the interest and dividend income amounts to exclude interest on regulatory assets and the excluding of OPA related CDM activities or renewable generation activities in revenues from non-utility operations and/or expenses of non-utility operations as directed per interrogatory 3-Energy Probe -11 b) & c). These revisions were correspondingly made to the forecasted 2013 amounts in the 3-Energy Probe 11 response.

EXHIBIT 4 – OPERATING REVENUE

4-Staff-55s

<u>Ref: 4-Staff-21</u>

a) Please explain why Thunder Bay Hydro is expensing (over 2013-2016) the demolition of the old building rather than charging it to Maintenance Facility capital project?

Thunder Bay Hydro Response

a) Thunder Bay Hydro reviewed CGAAP and APH Guidance with respect to the recognition of assets. It was Thunder Bay Hydro's professional judgement that the demolition of the old garage did not meet the three essential characteristics of assets as found on page 6 of Article 410 of the APH (reproduced below) and as such was a period cost. The demolition of the old garage is not necessary to have the new garage built and it was therefore concluded that there was no future benefit to the incurrence of such cost and as such was included as an OM&A cost in 2013. The actual demolition cost has been annualized over the four year period and hence 2013 forecast reflects $15,000 in OM&A costs for the demolition.

<u>Excerpt from Article 410</u>

"Assets have three essential characteristics:

i. they embody a future economic benefit i.e. they have the potential to contribute, directly or indirectly, to the flow of cash or cash equivalents to the entity;

ii. the entity controls access to the benefit; and

iii. the transaction or event giving rise to the entity's right to, or control of, the benefit has already occurred".

4-Energy Probe-28s

<u>Ref: 4-AMPCO-11 & 4-Energy Probe-12</u>

Please explain the difference in the OM&A costs per customer in 2011 of $238.32 shown in the AMPCO response and the $243.01 shown in the Energy Probe response.

Thunder Bay Hydro Response

The source of the AMPCO response to compare members within Thunder Bay Hydro's cohort is the 2011 OEB Yearbook which calculates OM&A costs using total customer count (metered and non-metered) whereas the Energy Probe response in Table 4-1.4 uses an average metered customer count for 2011. There is also a slight variance in total OM&A for 2011 by less than 2% that contributes to the difference.

4-SEC-19s

Ref: 4-Energy Probe-12, E4-S1-T1, Pg.4

Please explain the significant difference between the 2012 Bridge Year forecast ~~($3,785,463)~~ *should read ($13,785,464)* and the 2012 Bridge Year actuals ($13,315,975).

Thunder Bay Hydro Response

Thunder Bay Hydro's 2012 actual results are coming in $469,489 lower than originally projected. The material drivers for the variance are the following:

Professional Fees	$111,402
Overtime	$100,509
Overhead Costs	$ 91,834

Professional fees:

> Human Resources professional fees were projected to be much larger than actual given that at the time of projecting the fiscal 2012 there was two lawsuits outstanding. One was a Human Rights claim which had the potential to be quite significant. Thunder Bay Hydro's response to interrogatory 4-SEC-8 discloses that the lawsuits were settled and the amounts.
>
> Safety & Training were projected to be $27,000; however, given positive audit results in 2009 and a lack of revenue, funds budgeted for consultants to address specific studies were ultimately not approved due to other priorities. Thunder Bay Hydro is embarking on an Employee Engagement strategy which was just started in 2012 and will continue into 2013.
>
> Corporate Matter professional fees are significantly lower than projected given fewer significant procurement issues.

Fiscal year 2012 was an unusually calm year with respect to both the mid-summer lighting and fall storm activity and as such the overtime on the maintenance was much less than projected. Overtime is directly related to overheads and as such the overhead costs are also much lower than projected given the reduced overtime.

4-VECC-55s(a)

Ref: E4,T1,S1

2012 OM&A was approximately 470k less than forecast. Please explain main reasons for the underspending in 2012.

Thunder Bay Hydro Response

Please refer to Thunder Bay Hydro's response to 4-SEC-19s.

4-AMPCO-36s

Ref: 4-AMPCO-14

Please provide the frequency of Thunder Bay's Tree Trimming program in 2013 compared to 2009.

Thunder Bay Hydro Response

Thunder Bay Hydro adopted an escalated tree trimming program in 2009. Based on the analysis presented in Section 2 of the Thunder Bay Hydro Asset Management Plan, this period of escalation is intended to last for approximately 10 years. Upon completion of this 10-year period, Thunder Bay Hydro intends to proceed with a 7-year tree trimming cycle.

4-VECC-56s

Ref: Exhibit 4, Tab 2, pg. 4

a) Please explain the methodology for estimating the bad debt amount of $130,000.

Thunder Bay Hydro Response

a) Thunder Bay Hydro estimated the bad debt amount of $130,000 in 2013 by calculating the 4 year average of this expense from 2009 through to 2012.

4-Staff-56s

Ref: 4-staff-22

a) Does Thunder Bay Hydro's recording of Property Taxes conform with the Accounting Procedures Handbook?

b) Will Thunder Bay Hydro be increasing its proposed Revenue Requirement for 2013 by the expected increase of $82,397 in Property Taxes?

Thunder Bay Hydro Response

a) Per the Accounting Procedures Handbook ("APH"), account 5012 Station Buildings and Fixtures Expenses includes station supplies and expenses which includes "Taxes (e.g. property taxes)". Account 6105 Taxes Other than Income Taxes includes "payments-in-lieu of taxes, capital taxes, payments equivalent to municipal and school taxes, property taxes". Per review of property taxes paid on Station properties four properties pay a "payment-in-lieu of taxes" in addition to direct municipal taxes. Thunder Bay Hydro had reported all property taxes paid on Station properties in account 5012. As a result, Thunder Bay Hydro has not been conforming with the APH. This incorrect presentation has no impact on rate calculations as both APH accounts are included in calculations.

b) Subsequent to the original interrogatory responses, Thunder Bay Hydro received the remaining MPAC property assessments for all properties. As a result Thunder Bay Hydro has revised the estimate and the annualized increase has been estimated at $25,000. Thunder Bay Hydro has adjusted the 2013 revenue requirement for this change.

4-Energy Probe-29s

<u>Ref: 4-AMPCO-10 and 4-SEC-7</u>

Please explain why the actual expenditures shown in Table 4-2.8 for 2012 in the AMPCO response are $13,253,975 while the actual figure provided in Table 4-1.2 in the SEC response is $13,315,975. Is the difference due to a non-recoverable expense in 2012? Please provide a reconciliation of the two figures noted above, and if necessary, please indicate which one is the correct figure for 2012 actual expenditures.

Thunder Bay Hydro Response

The $62,000 difference is a result of an additional adjusting journal entry for the year end made for allocation of I.T. costs subsequent to the generation of the worksheet for Table 4-1.2. The correct figure for the 2012 actual expenditures is the $13,315,975.

4-Energy Probe-30s

Ref: 4-Energy Probe-13

Where has the copy of the Board's Accounting Procedures Handbook - Frequently Asked Questions referred to in the response to part (b) been provided?

Thunder Bay Hydro Response

The copy of the Board's Accounting Procedures Handbook – Frequently Asked Questions, August 2008 was inadvertently missed to be included as an Appendix in Thunder Bay Hydro's February 22, 2013 submission. Please refer to Q&A #8 in regards to accounting treatment for smart meters upon receiving a Rate Order found in ***Appendix Is-5***.

4-AMPCO-37s

Ref: 4-AMPCO-28

Please confirm the reduction in payroll costs and confirm this reduction is included in the OM&A forecast for 2013.

Thunder Bay Hydro Response

Thunder Bay Hydro has not quantified the reduction in payroll costs as a result of the new salary schedules in isolation. The 2013 payroll budget has been struck using the new salary schedules as applicable.

Thunder Bay Hydro had not previously provided for student funding in the 2013 forecast for the reasons noted in response to 4-AMPCO-28 b); however, Thunder Bay Hydro's best estimate of the 2013 student funding is $16,500 and is reflected in the adjustments to the COS Application.

4-Staff-57s

Ref: 4-Staff-27

Was the position providing administrative support to the water heating rental business affiliate that was eliminated redeployed within Thunder Bay Hydro or did it result in a net reduction in staffing levels?

Thunder Bay Hydro Response

Thunder Bay Hydro confirms the position providing administrative support to the water heating rental business affiliate that was eliminated resulted in a net reduction in staffing levels.

4-Staff-58s

Ref: 4-SEC-15

Please explain why “City of Thunder Bay Realty Services” is identified as a non-affiliated vendor?

Thunder Bay Hydro Response

Thunder Bay Hydro confirms that “City of Thunder Bay Realty Services” was included as a non-affiliated vendor for 2012 in error and should not have been included in this list.

4-Energy Probe-31s

Ref: 4-Energy Probe-16 & Exhibit 2, Tab 2, Schedule 1 &
Exhibit 4, Tab 2, Schedule 7

The response provided is both incomplete and confusing.

a) Please provide the requested information for 2009 through 2011 and 2012 actual in the form of a table that shows the depreciation expense calculated by Thunder Bay based on its depreciation of assets when they go into service on the first line, the depreciation expense that would have been recorded if the half year rule had been utilized on the second row and the difference in the third row.

b) The response indicates that the tables listed have been calculated using the OEB methodology which calculated depreciation using the half year rule and compared to the depreciation presented in Thunder Bay Hydro's rate application.

   i. For each of Tables 2-2.1 through 2-2.5 and 2-5.1, please indicate the depreciation methodology used in the table (half year or in-service date).

   ii. For each of Tables 4-2.25 through 4-2.28 please indicate the depreciation methodology used to calculate the figures in the Depreciation Expense column used in the table (half year or in-service date).

c) Please provide tables for 2009 and 2010 in the same format as Table 4-2.25 provided for 2011.

d) Please explain the difference in the depreciation figures shown in Table 4-2.26 for 2012 provided in the response to the Energy Probe interrogatory. As part of the explanation, please indicate if one column is based on the mid-year methodology and the other column is based on the in-service date methodology. Please also confirm that this table reflects actual data for 2012.

e) For financial accounting purposes (not regulatory accounting) does Thunder Bay Hydro calculate depreciation expense based on the in-service date and then use the same depreciation figures to adjust accumulated depreciation to calculate net book values? If the response is yes, is this reflected in the fixed asset continuity schedules and depreciation schedules filed as part of the current application? If the response is no, please explain why not and clearly indicate what depreciation methodology is used for depreciation expense and additions to accumulated depreciation.

Thunder Bay Hydro Response

a) See attached Tables for 2009-2012 as requested.

Thunder Bay Hydro
2009
Comparison of Depreciation at 1/2 Year Calculation and Actual

Account	Description	Depreciation Calculated by Thunder Bay Hydro	Depreciation Based on the 1/2 Year Rule	Difference
1611	Computer Software (Formally known as Account 1925)	65,006	47,173	17,833
1808	Buildings	71,842	75,853	(4,011)
1810	Leasehold Improvements	6	2	4
2320	ARO	36,125	31,042	5,083
	Infrastructure	4,844,980	4,861,371	(16,391)
1915	Office Furniture & Equipment (10 years)	36,748	38,019	(1,271)
1920	Computer Equipment - Hardware	82,798	77,261	5,537
1930	Transportation Equipment - 5 year	86,516	103,250	(16,734)
	Transportation Equipment -8 year	232,931	258,832	(25,901)
1935	Stores Equipment	-	-	-
1940	Tools, Shop & Garage Equipment	70,171	67,818	2,353
1945	Measurement & Testing Equipment	22,199	22,199	$ -
1950	Power Operated Equipment	2,429	6,570	(4,141)
1955	Communications Equipment	796	934	(138)
1995	Contributions & Grants	(367,800)	(386,013)	18,213
1996	Hydro One Current		28,855	(28,855)
	Total	**5,184,747**	**5,233,166**	**(48,419)**

Thunder Bay Hydro
2010
Comparison of Depreciation at 1/2 Year Calculation and Actual

Account	Description	Depreciation Calculated by Thunder Bay Hydro	Depreciation Based on the 1/2 Year Rule	Difference
1611	Computer Software (Formally known as Account 1925)	30,321	28,448	1,873
1808	Buildings	72,044	76,231	(4,187)
1810	Leasehold Improvements	17	3	14
2320	ARO	40,750	31,042	9,708
	Infrastructure	4,967,275	4,898,260	69,015
1915	Office Furniture & Equipment (10 years)	35,481	39,440	(3,959)
1920	Computer Equipment - Hardware	61,322	63,830	(2,508)
1930	Transportation Equipment - 5 year	101,348	67,224	34,124
	Transportation Equipment -8 year	277,850	324,249	(46,399)
1935	Stores Equipment	-	-	-
1940	Tools, Shop & Garage Equipment	67,190	67,652	(462)
1945	Measurement & Testing Equipment	21,965	23,941	(1,976)
1950	Power Operated Equipment	16,008	16,122	(114)
1955	Communications Equipment	1,549	2,314	(765)
1995	Contributions & Grants	(509,632)	(459,781)	(49,851)
1996	Hydro One Current	35,240	43,330	(8,090)
	Total	**5,218,728**	**5,222,305**	**(3,577)**

Thunder Bay Hydro
2011
Comparison of Depreciation at 1/2 Year Calculation and Actual

Account	Description	Depreciation Calculated by Thunder Bay Hydro	Depreciation Based on the 1/2 Year Rule	Difference
1611	Computer Software (Formally known as Account 1925)	20,824	23,228	(2,404)
1808	Buildings	72,044	76,231	(4,187)
1810	Leasehold Improvements	423	127	296
2320	ARO	(17,795)	9,803	(27,598)
	Infrastructure	5,222,178	5,039,524	182,654
1915	Office Furniture & Equipment (10 years)	38,918	45,624	(6,706)
1920	Computer Equipment - Hardware	61,075	60,482	593
1930	Transportation Equipment - 5 year	79,223	84,864	(5,641)
	Transportation Equipment -8 year	343,040	348,584	(5,544)
1935	Stores Equipment	-	-	-
1940	Tools, Shop & Garage Equipment	64,281	57,174	7,107
1945	Measurement & Testing Equipment	23,528	25,735	(2,207)
1950	Power Operated Equipment	19,176	19,462	(286)
1955	Communications Equipment	7,294	9,833	(2,539)
1995	Contributions & Grants	(628,096)	(568,935)	(59,161)
1996	Hydro One Current	50,893	50,893	-
	Total	**5,357,006**	**5,282,629**	**74,377**

Thunder Bay Hydro
2012
Comparison of Depreciation at 1/2 Year Calculation and Actual

Account	Description	Depreciation Calculated by Thunder Bay Hydro	Depreciation Based on the 1/2 Year Rule	Difference
1611	Computer Software (Formally known as Account 1925)	93,245	94,580	(1,335)
1808	Buildings	72,044	76,231	(4,187)
1810	Leasehold Improvements	4,004	3,901	103
2320	ARO	9,752	9,803	(51)
	Infrastructure	5,816,699	5,812,323	4,376
1915	Office Furniture & Equipment (10 years)	43,707	44,541	(834)
1920	Computer Equipment - Hardware	95,718	98,613	(2,895)
1930	Transportation Equipment - 5 year	102,774	102,757	17
	Transportation Equipment -8 year	348,512	361,391	(12,879)
1935	Stores Equipment	582	-	582
1940	Tools, Shop & Garage Equipment	63,212	62,185	1,027
1945	Measurement & Testing Equipment	23,178	21,625	1,553
1950	Power Operated Equipment	18,964	19,462	(498)
1955	Communications Equipment	15,012	17,512	(2,500)
1995	Contributions & Grants	(668,555)	(668,555)	-
1996	Hydro One Current	50,893	50,893	-
	Total	**6,089,741**	**6,107,262**	**(17,521)**

b)

i. For each of Tables 2-1.1 through 2-2.3 the depreciation method used was in-service date. For tables 2-2.4 through 2.2-5 and 2.5.1 the half year methodology was used as an estimate of the in-service date.

ii. For tables 4-2.25 through 4.2-28 the depreciation methodology used to calculate the figures in the Depreciation Expense column (Column (h)) was the half year rule.

c) Below are Depreciation and Amortization Tables for 2009 and 2010 prepared in the same format as Table 4-2.25 provided for 2011.

Table 4-2.25 - Amortization Expense for 2009

Appendix 2-CE
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013 (Note Thunder Bay Hydro adopting IFRS effective January 1, 2014)

Year 2009 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2009 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2009 Depreciation Expense (h) = (e) / (f)	2009 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 765,366	$ 529,501	$ 235,866	$ -	$ 235,866	5	$ 0	$ 47,173	$ 65,006	$ (17,833)
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1805	Land	$ 133,038		$ 133,038	$ -	$ 133,038			$ -	$ -	$ -
1808	Buildings	$ 3,895,055	$ 121,308	$ 3,773,747	$ 37,793	$ 3,792,643	50	$ 0	$ 75,853	$ 71,842	$ 4,011
1810	Leasehold Improvements	$ -	$ -	$ -	$ 33	$ 17	10	$ 0	$ 2	$ 6	$ (4)
2320	ARO	$ 512,186	$ -	$ 512,186	$ -	$ 512,186	16.5	$ 0	$ 31,042	$ 36,125	$ (5,083)
	Infrastructure	**$ 129,513,277**	**$ 10,701,300**	**$ 118,811,977**	**$ 6,645,671**	**$ 122,134,812**			**$ 4,861,371**	**$ 4,844,980**	**$ 16,391**
1905	Land	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1910	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 1,248,800	$ 883,627	$ 365,173	$ 30,038	$ 380,192	10	$ 0	$ 38,019	$ 36,748	$ 1,271
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -	5	$ 0	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 2,596,573	$ 2,249,631	$ 346,942	$ 78,725	$ 386,305	5	$ 0	$ 77,261	$ 82,798	$ (5,537)
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1930	Transportation Equipment - 5 year	$ 1,409,831	$ 977,355	$ 432,476	$ 167,545	$ 516,249	5	$ 0	$ 103,250	$ 86,516	$ 16,733
	Transportation Equipment -8 year	$ 3,795,749	$ 1,968,618	$ 1,827,132	$ 487,047	$ 2,070,655	8	$ 0	$ 258,832	$ 232,931	$ 25,901
1935	Stores Equipment	$ 63,417	$ 63,417	$ (0)	$ -	$ (0)	10	$ 0	$ (0)	$ -	$ (0)
1940	Tools, Shop & Garage Equipment	$ 2,335,062	$ 1,698,621	$ 636,441	$ 83,471	$ 678,177	10	$ 0	$ 67,818	$ 70,171	$ (2,354)
1945	Measurement & Testing Equipment	$ 221,991	$ -	$ 221,991	$ -	$ 221,991	10	$ 0	$ 22,199	$ 22,199	$ (0)
1950	Power Operated Equipment	$ 3,583	$ -	$ 3,583	$ 124,234	$ 65,700	10	$ 0	$ 6,570	$ 2,429	$ 4,141
1955	Communications Equipment	$ 163,392	$ 158,720	$ 4,672	$ -	$ 4,672	5	$ 0	$ 934	$ 796	$ 138
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1995	Contributions & Grants	$ (9,055,928)	$ -	$ (9,055,928)	$ (1,188,775)	$ (9,650,316)	25	$ 0	$ (386,013)	$ (367,800)	$ (18,213)
1996	Hydro One Current	$ 548,576	$ -	$ 548,576	$ 345,595	$ 721,374	25	$ 0	$ 28,855	$ -	$ 28,855
WIP	Work in Progress	$ 962,145	$ -	$ 962,145	$ 314,551	$ 1,119,421			$ -	$ -	$ -
				$ -		$ -			$ -		$ -
	Total	$ 139,112,114	$ 19,352,097	$ 119,760,017	$ 7,125,928	$ 123,322,981			$ 5,233,165	$ 5,184,748	$ 48,417

Table 4-2.25 - Amortization Expense for 2010

Appendix 2-CE
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013 (Note Thunder Bay Hydro adopting IFRS effective January 1, 2014)

Year 2010 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2010 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2010 Depreciation Expense (h) = (e) / (f)	2010 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 765,366	$ 630,197	$ 135,169	$ 14,146	$ 142,242	5	$ 0	$ 28,448	$ 30,321	$ (1,873)
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1805	Land	$ 133,038		$ 133,038	$ -	$ 133,038			$ -	$ -	$ -
1808	Buildings	$ 3,932,848	$ 121,308	$ 3,811,540	$ -	$ 3,811,540	50	$ 0	$ 76,231	$ 72,044	$ 4,187
1810	Leasehold Improvements	$ 33	$ -	$ 33	$ -	$ 33	10	$ 0	$ 3	$ 17	$ (13)
2320	ARO	$ 512,186	$ -	$ 512,186	$ -	$ 512,186	16.5	$ 0	$ 31,042	$ 40,750	$ (9,708)
	Infrastructure	**$ 131,222,868**	**$ 12,025,876**	**$ 119,196,992**	**$ 7,724,152**	**$ 123,059,069**			**$ 4,898,260**	**$ 4,967,275**	**$ (69,015)**
1905	Land	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1910	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 1,278,837	$ 917,266	$ 361,571	$ 65,653	$ 394,398	10	$ 0	$ 39,440	$ 35,481	$ 3,959
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -	5	$ 0	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 2,675,299	$ 2,385,218	$ 290,081	$ 58,137	$ 319,149	5	$ 0	$ 63,830	$ 61,322	$ 2,508
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1930	Transportation Equipment - 5 year	$ 1,174,147	$ 842,294	$ 331,854	$ 8,532	$ 336,120	5	$ 0	$ 67,224	$ 101,348	$ (34,124)
	Transportation Equipment -8 year	$ 4,282,796	$ 2,065,780	$ 2,217,016	$ 753,953	$ 2,593,992	8	$ 0	$ 324,249	$ 277,850	$ 46,399
1935	Stores Equipment	$ 63,417	$ 63,417	$ (0)	$ -	$ (0)	10	$ 0	$ (0)	$ -	$ (0)
1940	Tools, Shop & Garage Equipment	$ 2,418,534	$ 1,753,612	$ 664,921	$ 23,204	$ 676,523	10	$ 0	$ 67,652	$ 67,190	$ 462
1945	Measurement & Testing Equipment	$ 221,991	$ -	$ 221,991	$ 34,833	$ 239,408	10	$ 0	$ 23,941	$ 21,965	$ 1,976
1950	Power Operated Equipment	$ 127,817	$ -	$ 127,817	$ 66,805	$ 161,219	10	$ 0	$ 16,122	$ 16,008	$ 114
1955	Communications Equipment	$ 163,392	$ 163,392	$ (1)	$ 23,141	$ 11,570	5	$ 0	$ 2,314	$ 1,549	$ 765
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1995	Contributions & Grants	$ (10,244,703)	$ -	$ (10,244,703)	$ (2,499,649)	$ (11,494,527)	25	$ 0	$ (459,781)	$ (509,632)	$ 49,851
1996	Hydro One Current	$ 894,171	$ -	$ 894,171	$ 378,150	$ 1,083,246	25	$ 0	$ 43,330	$ 35,240	$ 8,090
WIP	Work in Progress	$ 1,276,696	$ -	$ 1,276,696	$ 481,362	$ 1,517,377			$ -	$ -	$ -
				$ -		$ -			$ -		$ -
	Total	$ 140,898,733	$ 20,968,360	$ 119,930,373	$ 7,132,420	$ 123,496,583			$ 5,222,304	$ 5,218,727	$ 3,577

d) Column (h) is based on ½ year rule, column (l) see answer to b I above. This is to confirm that Table 4-2.26 for 2012 is based on actual data.

e) Thunder Bay Hydro calculates depreciation based on the in-service date. The entry is a DR to Depreciation Expense and a CR to Accumulated Depreciation. This is reflected in the fixed asset continuity schedules.

4-Energy Probe-32s

Ref: 4-Energy Probe-14

a) The response to part (c) indicates that $20,000 for LEAP funding was recorded twice in error. Does this mean that the overall OM&A forecast for 2013 should be reduced by this amount? If no, please explain why not.

b) Thunder Bay Hydro's forecast for 2013 OM&A is $14,682,415, which is shown as the total OM&A in Appendix 2-G. However, this appendix shows total recoverable OM&A of $14,658,215, which is a reduction of $24,200 related to donations. Please explain why Thunder Bay Hydro believes it is appropriate to recover this amount from ratepayers.

Thunder Bay Hydro Response

a) Thunder Bay Hydro had noted that $20,000 of LEAP funding had been recorded twice in error. Thunder Bay Hydro has amended the 2012 Revenue Requirement by this adjustment.

b) The adjustment for non-recoverable items of $24,200 in 2013 was presented incorrectly on Appendix 2-G. This amount relates to LEAP payments which are recoverable from ratepayers.

EXHIBIT 5 – COST OF CAPITAL AND RATE OF RETURN

5-Board Staff-59s(a-c)

<u>Ref: 5-Staff-29 and 5-Staff-31</u>

a) Please provide a yes/no answer to part a) of interrogatory 5-Staff-31. If the answer is "no", please reconcile your answer with the table found at E5-T1-S2 p.3.

b) Please provide copies of any precedent decisions that Thunder Bay Hydro is relying on in support of its proposal to "amortize" the interest expense the utility is expecting to incur over the period 2013 to 2016 so that an "average" amortized interest expense is factored into the revenue requirement.

c) Please explain why Thunder Bay Hydro believes that its proposed method to calculate the costs of the long term debt portion of rate base is preferred to the Board's general policy and practice, as documented in the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), whereby the weighted average cost of long-term debt (both actual and forecasted in the test year) is applied to the 56% deemed long-term debt capitalization. In your answer please consider that the inflation measure under the IRM plan also reflects the indirect impacts of changes in the cost of capital in the general market, and hence will adjust the distribution rates during the term of the IRM plan from 2014 until Thunder Bay Hydro next rebases its rates.

Thunder Bay Hydro Response

a) Yes, Thunder Bay Hydro is using a 56% Deemed Long Term Debt capitalization rate to apply to Rate Base resulting in a Deemed Long-Term Debt of $52.880M.

b) Thunder Bay Hydro knows of no precedent decision to support the amortization of the interest expense. Thunder Bay Hydro is unique in that it has not sought the full ROI, which in turn causes Thunder Bay Hydro to be very sensitive to annual cost swings as there is very little room to absorb increased costs without risking going offside its Debt Service Coverage covenant.

c) Thunder Bay Hydro understands that the request deviates from the Board's general policy and practice, as documented in the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084). Thunder Bay Hydro's rationale is based on the fact that it is unique. The following is a copy of the Return on Equity section of the 2013 Cost of Service Application (Exhibit 1, Tab 2, Schedule 1, page 6).

Return on Equity
Thunder Bay Hydro has assumed a return on equity of 7.00% which is lower than the 9.12% in the Cost of Capital Parameter Updates for 2012 Cost of Service

Applications issued by the OEB on March 2, 2012; however, this rate is sufficient to fund the capital investment and operating and maintenance cost requirements. The Corporation of the City of Thunder Bay, the sole shareholder of Thunder Bay Hydro Corporation (shareholder of Thunder Bay Hydro) provides the following governing principle in the Shareholder Declaration:

"DistributionCo shall be operated in accordance with the Rate Minimization Model."

Consistent with this principle, essentially to keep electricity rates as low as possible and to encourage economic development by foregoing debt and dividend payments, the Note Payable to the City of Thunder Bay was set up without any provision for the payment of interest or the repayment of principal. Additionally, the Corporation of the City of Thunder Bay does not seek a dividend from Thunder Bay Hydro.

Thunder Bay Hydro is not a significantly "growing" utility. Customer growth has been rather flat for a very long time (annual customer increase has been less than .5% for the last few years); and consumption has been on a steady decline since 2008. This translates to Distribution Revenues increasing very minimally annually during the IRM period resulting in any ROI in the rebasing year to be significantly squeezed by the third year of IRM. Thunder Bay Hydro must ensure that the debt service coverage covenant in the existing and future financing agreements will be met. Thunder Bay Hydro's Asset Management Plan calls for capital investment above the level of internal funding ability and as such will require external financing annually throughout the IRM period. Thunder Bay Hydro's mechanism for ensuring the covenant will be met is twofold; one is an increase in the ROE and the second is to incorporate the Board's concept of "annualization" of costs over the years to the next Cost of Service rebasing. Thunder Bay Hydro's goal is to ensure the safe and reliable delivery of electricity to its customers.

5-Energy Probe-33s(a-f)

Ref: 5-Energy Probe-17 and E5-T1-S1&2 and 5-Staff-29

a) The response to part (a) is not complete. The interrogatory asked for an explanation of the difference between the 25 year term shown in Table 5-1.3 and the five year financing agreement noted on page 2 of Exhibit 5, Tab 1, Schedule 1 (line 11). Please provide a response.

b) Based on the response to part (c), is it just a coincidence that the amount of annualized debt of $2,768,526 that results in total long term debt of $52,860,228 in Table 5-1.3 which is the same amount of deemed long term debt shown in Exhibit 5, Tab 1, Schedule 2 for the 2013 test year?

c) Please confirm that the loans of $5,800,000 and $6,150,000 will now be 30 year term loans.

d) Please provide the current rate available from Infrastructure Ontario for a 30 year term loan.

e) Please provide the date at which the $5,800,000 loan is expected to be put in place.

f) Please provide the date at which the $6,150,000 loan is expected to be put in place.

Thunder Bay Hydro Response

a) The reference to a five year financing agreement is not referring to the term of the financing sought, but rather a “long-term credit facility” that can be drawn upon annually based on capital expenditures. The RFP was seeking input on various terms with various amortizations, but made reference to longer amortization being preferred in an effort to match the term of the loan with the life of the assets financed.

b) Yes and no. The reason that the total Long-Term Debt in Table 5-1.3 is the same amount of deemed long term debt shown ins Exhibit 5, Tab 1, Schedule 2 for the 2013 test year, is that Thunder Bay Hydro is reducing the non-interest bearing promissory note to the City of Thunder Bay by the amount required to bring such to match the deemed amount.

c) Thunder Bay confirms that it is 30 year term loans that are currently in the process of being approved with the financial institution.

d) Infrastructure Ontario's (IO) posted 30 year term amortized loan rates have been as follows:

   a. March 5, 2013 3.95%
   b. March 22, 2013 4.04%

   Thunder Bay Hydro has adjusted the $5.8M debt to the most recent IO rule of 4.04%.

e) Current plans are to have the $5,800,000 loan in place no later than April 30, 2013.

f) As per the COS application, Thunder Bay plans to put the annual financing in place in September of each year.

EXHIBIT 7 – COST ALLOCATION

7-VECC-57s

Ref: VECC #28

a) With respect to VECC 28 (a), the Services Weighting factor is intended to reflect the relative investment in service assets (i.e. Account #1855) for each class on a per customer basis. Please confirm that the service connections for Street Light, Sentinel Light and USL customers are owned by the customer and that Thunder Bay is not responsible for maintenance or replacement.

b) With respect to VECC 28 (b), please confirm that the weighting factors were calculated based on the resources required "per bill" as opposed to "per class".

c) With respect to VECC 28 (b), please explain why a GS<50 customer requires less resources on a per bill basis than Residential when for both classes the billing parameters are the same and the billing quantities are provided by the SME/IESO.

d) With respect to VECC 28 (e), the question was with respect to meter reading not billing. Please explain fully why the meter reading for GS>1000 requires less time per customer than that for Residential or GS<50.

Thunder Bay Hydro Response

a) Thunder Bay Hydro confirms that it does not have any investment in Street Lights and USLs and as such does not maintain or replace such. Thunder Bay Hydro does however own, rent and maintain a small number of Sentinel Lights.

b) Thunder Bay Hydro confirms that the weighting factor is based on a per bill basis.

c) A GS<50 customer requires less resources on a per bill basis than Residential as the cost per bill is comprised of a number of inputs of which SME/IESO activity is only one. Other inputs are staff time and billing volumes. Once Thunder Bay Hydro allocates these factors the result is a lower level of allocated resources.

d) GS>1000 customers require less meter reading attention as electronic readings have a more direct route into the billing system. SME/IESO intermediate steps with GS<50 class necessitate more checks and balances to ensure accuracy, integrity and validity of meter data for bill input.

7-AMPCO-38s

<u>Ref: 7-AMPCO-33</u>

Please reproduce Table 7-1.7 with the proposed 2013 revenue to cost ratio for the GS 1000 to 4999 kW class set at 80% and provide the corresponding bill impacts.

Thunder Bay Hydro Response

In responding to this question it assumed Table 7-1.7 provided in response to 7-AMPCO-33b) is to be updated to set the proposed 2013 revenue to cost ratio for the GS 1000 to 4999 kW class at 80%. The following is the reproduced Table 7-1.7 as requested with the proposed 2013 revenue to cost ratio for the GS 1000 to 4999 kW class set at 80%. In addition, the bill impacts are provided as ***Appendix Is-6.***

Table 7-7.1 Revenue to Cost Ratios

Class	2012 Board Approved	2013 Updated Cost Allocation Study	2013 Proposed Ratios	2014 Proposed Ratios	2015 Proposed Ratios	Board Targets Min to Max	
Residential	110.88%	100.31%	103.49%	103.49%	103.49%	85.0%	115.0%
General Service < 50 kW	114.32%	102.89%	103.49%	103.49%	103.49%	80.0%	120.0%
General Service 50 to 999 kW	80.00%	73.82%	80.00%	80.00%	80.00%	80.0%	120.0%
General Service 1000 to 4999 kW	73.14%	127.43%	80.00%	80.00%	80.00%	80.0%	120.0%
Street Lighting	70.00%	235.03%	235.03%	235.03%	235.03%	70.0%	120.0%
Sentinel Lighting	107.94%	106.57%	106.57%	106.57%	106.57%	80.0%	120.0%
Unmetered Scattered Load	113.68%	161.92%	161.92%	161.92%	161.92%	80.0%	120.0%

Exhibit 8 – Rate Design

8-VECC-58s

Ref: VECC #32 b)

a) Both Atikokan and Kenora have recently had their rates rebased using an updated cost allocation. For each utility, please indicate the value of the Residential service charge in the rebasing year and compare this with the "ceiling" value as determined by Sheet O2 of its cost allocation.

Thunder Bay Hydro Response

a) To the best of Thunder Bay Hydro's knowledge the following table provides for Atikokan and Kenora the value of the Residential service charge in the rebasing year and the comparable "ceiling" value as determined by Sheet O2 of the cost allocation model for Atikokan and Kenora from their most recent cost of service application.

Distributor	Approved Residential Monthly Service Charge (COS)	Minimum System with PLCC Adustment (Ceiling Fixed Charge From Cost Allocation Model)
Atikokan Hydro Inc (2012 COS)	$33.99	$36.07
Kenora Hydro Electric Corporation Ltd (2011 COS)	$18.77	$20.85

EXHIBIT 9 – DEFERRAL AND VARIANCE ACCOUNTS

9-Staff-60s

Ref: 9-VECC-33 (b)

Thunder Bay Hydro stated: "Thunder Bay Hydro has determined the unaudited 2012 actuals for sub-account 1508 IFRS implementation costs to be ($94,983) including carrying charges. A credit balance represents a receivable to Thunder Bay Hydro."

a) Does Thunder Bay Hydro now have an audited balance, for the year-ended December 31, 2012, for sub-account 1508 IFRS implementation costs? If so please confirm the amount.

b) Thunder Bay Hydro describes the $94,983 as a "credit" balance for the year 2012. Should this be more appropriately described as a debit balance in that this amount would be recovered from customers?

c) Has there been a change in the mandatory changeover date for IFRS based reporting? If so, what is the new date and is Thunder Bay Hydro still requesting the disposition of the transitional costs in this proceeding?

d) The APH FAQ October 2009 #2 re: 1508 Other Regulatory Assets, "Sub-account Deferred IFRS Transition Costs" states:

    In the distributor's next cost of service rate application immediately after the IFRS transition period, the balance in this sub-account should be included for review and disposition.

    (i) Please confirm the amount of IFRS transition costs Thunder Bay Hydro is proposing to this dispose in this application.

    (ii) Please provide the justification for disposing the IFRS transition costs in this rate application rather than in the one subsequent to the transition period.

Thunder Bay Hydro Response

a) Thunder Bay Hydro is currently undergoing an audit for the year-ended December 31, 2012, and thus, does not have audited balances at this time.

b) Thunder Bay Hydro confirms that the $94,983 is more appropriately described as a debit balance that is to be recovered from customers.

c) Thunder Bay Hydro has deferred adopting IFRS until 2014, however the Accounting Standards Board (AcSB) has recently allowed for an additional one-year optional deferral to 2015. Thunder Bay Hydro has reconsidered the disposal of its transition IFRS costs in light of APH FAQ #2 and will continue to accrue costs in the deferral account and will not be filing for disposition with this rate rebasing but rather in a future IRM or next cost of service rate application. A revised EDDVAR Continuity Schedule has been submitted to reflect this change.

d)

(i) Please refer to Thunder Bay Hydro's response to part c).

(ii) Please refer to Thunder Bay Hydro's response to part c).

APPENDICES

Appendix Is-1

1-VECC-47s

File Number:	EB-2012-0167
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	March 25, 2013

Appendix 2-W
Bill Impacts

Table 1-2.1: Bill Impact: Residential and General Service Less than 50kW

Customer Class: **Residential**

Consumption 800 **kWh** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 9.8500	1	$ 9.85	$ 13.5300	1	$ 13.53	$ 3.68	37.36%
Smart Meter Incremental Rev Req	Monthly	$ 1.8667	1	$ 1.87	$ -	1	$ -	$ (1.87)	(100.00%)
Distribution Volumetric Rate	per kWh	$ 0.0124	800	$ 9.92	$ 0.0119	800	$ 9.52	$ (0.40)	(4.03%)
Smart Meter Disposition Rider	Monthly	$ (1.3167)	1	$ (1.32)	$ (1.3167)	1	$ (1.32)	$ -	0.00%
LRAM & SSM Rate Rider	per kWh	$ 0.00004	800	$ 0.03	$ -	800	$ -	$ (0.03)	(100.00%)
Stranded Asset Rate Rider	Monthly	$ -	1	$ -	$ 2.2700	1	$ 2.27	$ 2.27	
Sub-Total A				$ 20.35			$ 24.00	**$ 3.65**	**17.94%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0034)	800	$ (2.72)	$ (0.0029)	800	$ (2.32)	$ 0.40	(14.71%)
Tax Charge Rate Rider	per kWh	$ (0.0003)	800	$ (0.24)		800	$ -	$ 0.24	(100.00%)
						1	$ -	$ -	
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 17.39**			**$ 21.68**	**$ 4.29**	**24.67%**
RTSR - Network	per kWh	$ 0.0064	836	$ 5.35	$ 0.0065	827	$ 5.38	$ 0.03	0.53%
RTSR - Line and Transformation Connection	per kWh	$ 0.0049	836	$ 4.10	$ 0.0047	827	$ 3.89	$ (0.21)	(5.05%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 26.84**			**$ 30.95**	**$ 4.11**	**15.33%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	836	$ 4.35	$ 0.0044	827	$ 3.64	$ (0.71)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	836	$ 0.92	$ 0.0012	827	$ 0.99	$ 0.07	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	836	$ 5.85	$ 0.0070	827	$ 5.79	$ (0.06)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	800	$ 59.20	$ 0.0740	800	$ 59.20	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	535	$ 33.70	$ 0.0630	530	$ 33.36	$ (0.34)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	150	$ 14.89	$ 0.0990	149	$ 14.74	$ (0.15)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	150	$ 17.75	$ 0.1180	149	$ 17.57	$ (0.18)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 97.40**			**$ 100.82**	**$ 3.42**	**3.51%**
HST		13%		$ 12.66	13%		$ 13.11	$ 0.44	3.51%
Total Bill (including HST)				$ 110.07			$ 113.93	$ 3.87	3.51%
Ontario Clean Energy Benefit [1]				$ (11.01)			$ (11.39)	$ (0.38)	3.45%
Total Bill on RPP (including OCEB)				**$ 99.06**			**$ 102.54**	**$ 3.49**	**3.52%**
Total Bill on TOU (before Taxes)				**$ 104.55**			**$ 107.30**	**$ 2.75**	**2.63%**
HST		13%		$ 13.59	13%		$ 13.95	$ 0.36	2.63%
Total Bill (including HST)				$ 118.14			$ 121.25	$ 3.10	2.63%
Ontario Clean Energy Benefit [1]				$ (11.81)			$ (12.12)	$ (0.31)	2.62%
Total Bill on TOU (including OCEB)				**$ 106.33**			**$ 109.13**	**$ 2.79**	**2.63%**
Loss Factor (%)		4.48%			3.42%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **General Service Less Than 50 kW**

Consumption 2000 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 17.8400	1	$ 17.84	$ 27.2500	1	$ 27.25	$ 9.41	52.75%
Smart Meter Incremental Rev Req	Monthly	$ 6.8417	1	$ 6.84	$ -	1	$ -	$ (6.84)	(100.00%)
Distribution Volumetric Rate	per kWh	$ 0.0130	2000	$ 26.00	$ 0.0137	2000	$ 27.40	$ 1.40	5.38%
Smart Meter Disposition Rider	Monthly	$ 3.4917	1	$ 3.49	$ 3.4917	1	$ 3.49	$ -	0.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0002	2000	$ 0.40	$ -	2000	$ -	$ (0.40)	(100.00%)
Stranded Asset Rate Rider	Monthly		1	$ -	$ 6.5200	1	$ 6.52	$ 6.52	
Sub-Total A				$ 54.57			$ 64.66	**$ 10.09**	**18.49%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0030)	2000	$ (6.00)	$ (0.0035)	2000	$ (7.00)	$ (1.00)	16.67%
Tax Charge Rate Rider	per kWh	$ (0.0002)	2000	$ (0.40)	$ -	2000	$ -	$ 0.40	(100.00%)
							$ -	$ -	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 48.17**			**$ 57.66**	**$ 9.49**	**19.70%**
RTSR - Network	per kWh	$ 0.0061	2090	$ 12.75	$ 0.0062	2068	$ 12.82	$ 0.08	0.61%
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	2090	$ 9.61	$ 0.0044	2068	$ 9.10	$ (0.51)	(5.32%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 70.53**			**$ 79.59**	**$ 9.05**	**12.84%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2090	$ 10.87	$ 0.0044	2068	$ 9.10	$ (1.76)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2090	$ 2.30	$ 0.0012	2068	$ 2.48	$ 0.18	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2090	$ 14.63	$ 0.0070	2068	$ 14.48	$ (0.15)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	1000	$ 87.00	$ 0.0870	1000	$ 87.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0630	1337	$ 84.25	$ 0.0630	1324	$ 83.40	$ (0.85)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	376	$ 37.24	$ 0.0990	372	$ 36.86	$ (0.38)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	376	$ 44.38	$ 0.1180	372	$ 43.93	$ (0.45)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 259.57**			**$ 266.90**	**$ 7.32**	**2.82%**
HST		13%		$ 33.74	13%		$ 34.70	$ 0.95	2.82%
Total Bill (including HST)				$ 293.32			$ 301.60	$ 8.28	2.82%
Ontario Clean Energy Benefit [1]				$ (29.33)			$ (30.16)	$ (0.83)	2.83%
Total Bill on RPP (including OCEB)				**$ 263.99**			**$ 271.44**	**$ 7.45**	**2.82%**
Total Bill on TOU (before Taxes)				**$ 264.45**			**$ 270.09**	**$ 5.64**	**2.13%**
HST		13%		$ 34.38	13%		$ 35.11	$ 0.73	2.13%
Total Bill (including HST)				$ 298.82			$ 305.20	$ 6.38	2.13%
Ontario Clean Energy Benefit [1]				$ (29.88)			$ (30.52)	$ (0.64)	2.14%
Total Bill on TOU (including OCEB)				**$ 268.94**			**$ 274.68**	**$ 5.74**	**2.13%**

Loss Factor (%) Current: 4.48% Proposed: 3.42%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **General Service 50 to to 999 kW**

Consumption 100 **kW**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 241.7800	1	$ 241.78	$ 311.6800	1	$ 311.68	$ 69.90	28.91%
Distribution Volumetric Rate	per kW	$ 1.3603	100	$ 136.03	$ 1.7272	100	$ 172.72	$ 36.69	26.97%
LRAM & SSM Rate Rider	per kW	$ 0.00011			$ -			$ -	
Sub-Total A				$ 377.81			$ 484.40	**$ 106.59**	**28.21%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (0.9127)	100	$ (91.27)	$ (1.4598)	100	$ (145.98)	$ (54.71)	59.94%
Global Adjustment Rate Rider	per kW	$ (0.1051)	100	$ (10.51)	$ 0.7802	100	$ 78.02	$ 88.53	(842.34%)
Tax Charge Rate Rider	per kW	$ (0.0410)	100	$ (4.10)	$ -	100	$ -	$ 4.10	(100.00%)
							$ -	$ -	
Smart Meter Entity Charge					$ -	100	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 271.93**			**$ 416.44**	**$ 144.51**	**53.14%**
RTSR - Network	per kW	$ 2.4300	104	$ 253.89	$ 2.4536	103	$ 253.75	$ (0.14)	(0.05%)
RTSR - Line and Transformation Connection	per kW	$ 1.7458	104	$ 182.40	$ 1.6885	103	$ 174.62	$ (7.78)	(4.26%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 708.22**			**$ 844.82**	**$ 136.60**	**19.29%**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	104	$ 0.54	$ 0.0044	103	$ 0.46	$ (0.09)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	104	$ 0.11	$ 0.0012	103	$ 0.12	$ 0.01	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	104	$ 0.73	$ 0.0070	103	$ 0.72	$ (0.01)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	100	$ 7.40	$ 0.0740	100	$ 7.40	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kW	$ 0.0630	67	$ 4.21	$ 0.0630	66	$ 4.17	$ (0.04)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	19	$ 1.86	$ 0.0990	19	$ 1.84	$ (0.02)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	19	$ 2.22	$ 0.1180	19	$ 2.20	$ (0.02)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 717.26**			**$ 853.77**	**$ 136.51**	**19.03%**
HST		13%		$ 93.24	13%		$ 110.99	$ 17.75	19.03%
Total Bill (including HST)				$ 810.50			$ 964.76	$ 154.26	19.03%
Ontario Clean Energy Benefit [1]				$ (81.05)			$ (96.48)	$ (15.43)	19.04%
Total Bill on RPP (including OCEB)				**$ 729.45**			**$ 868.28**	**$ 138.83**	**19.03%**
Total Bill on TOU (before Taxes)				**$ 718.15**			**$ 854.58**	**$ 136.43**	**19.00%**
HST		13%		$ 93.36	13%		$ 111.10	$ 17.74	19.00%
Total Bill (including HST)				$ 811.51			$ 965.67	$ 154.16	19.00%
Ontario Clean Energy Benefit [1]				$ (81.15)			$ (96.57)	$ (15.42)	19.00%
Total Bill on TOU (including OCEB)				**$ 730.36**			**$ 869.10**	**$ 138.74**	**19.00%**

Loss Factor (%)	4.48%	3.42%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **General Service 50 to to 999 kW Interval Metered**

Consumption 100 kW

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 241.7800	1	$ 241.78	$ 311.6800	1	$ 311.68	$ 69.90	28.91%
Distribution Volumetric Rate	per kW	$ 1.3603	100	$ 136.03	$ 1.7272	100	$ 172.72	$ 36.69	26.97%
LRAM & SSM Rate Rider	per kW	$ 0.00011			$ -			$ -	
Sub-Total A				$ 377.81			$ 484.40	**$ 106.59**	**28.21%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (0.9127)	100	$ (91.27)	$ (1.4598)	100	$ (145.98)	$ (54.71)	59.94%
Global Adjustment Rate Rider	per kW	$ (0.1051)	100	$ (10.51)	$ 0.7802	100	$ 78.02	$ 88.53	(842.34%)
Tax Charge Rate Rider	per kW	$ (0.0410)	100	$ (4.10)	$ -	100	$ -	$ 4.10	(100.00%)
							$ -	$ -	
Smart Meter Entity Charge					$ -	100	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 271.93**			**$ 416.44**	**$ 144.51**	**53.14%**
RTSR - Network	per kW	$ 2.5777	104	$ 269.32	$ 2.6027	103	$ 269.17	$ (0.15)	(0.05%)
RTSR - Line and Transformation Connection	per kW	$ 1.9295	104	$ 201.59	$ 1.8662	103	$ 193.00	$ (8.59)	(4.26%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 742.84**			**$ 878.61**	**$ 135.77**	**18.28%**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	104	$ 0.54	$ 0.0044	103	$ 0.46	$ (0.09)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	104	$ 0.11	$ 0.0012	103	$ 0.12	$ 0.01	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	104	$ 0.73	$ 0.0070	103	$ 0.72	$ (0.01)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	100	$ 7.40	$ 0.0740	100	$ 7.40	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kW	$ 0.0630	67	$ 4.21	$ 0.0630	66	$ 4.17	$ (0.04)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	19	$ 1.86	$ 0.0990	19	$ 1.84	$ (0.02)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	19	$ 2.22	$ 0.1180	19	$ 2.20	$ (0.02)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 751.88**			**$ 887.57**	**$ 135.68**	**18.05%**
HST		13%		$ 97.74	13%		$ 115.38	$ 17.64	18.05%
Total Bill (including HST)				$ 849.63			$ 1,002.95	$ 153.32	18.05%
Ontario Clean Energy Benefit [1]				$ (84.96)			$ (100.30)	$ (15.34)	18.06%
Total Bill on RPP (including OCEB)				**$ 764.67**			**$ 902.65**	**$ 137.98**	**18.04%**
Total Bill on TOU (before Taxes)				**$ 752.78**			**$ 888.38**	**$ 135.60**	**18.01%**
HST		13%		$ 97.86	13%		$ 115.49	$ 17.63	18.01%
Total Bill (including HST)				$ 850.64			$ 1,003.87	$ 153.23	18.01%
Ontario Clean Energy Benefit [1]				$ (85.06)			$ (100.39)	$ (15.33)	18.02%
Total Bill on TOU (including OCEB)				**$ 765.58**			**$ 903.48**	**$ 137.90**	**18.01%**

Loss Factor (%) 4.48% 3.42%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Bill Impacts

Customer Class: **General Service 1,000 to 4,999 kW**

Consumption 2000 **kW**

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 2,794.5500	1	$ 2,794.55	$ 2,848.0100	1	$ 2,848.01	$ 53.46	1.91%
Distribution Volumetric Rate	per kW	$ 2.2314	2000	$ 4,462.80	$ 2.2629	2000	$ 4,525.80	$ 63.00	1.41%
Sub-Total A				$ 7,257.35			$ 7,373.81	**$ 116.46**	**1.60%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (0.7755)	2000	$ (1,551.00)	$ (1.3534)	2000	$ (2,706.80)	$ (1,155.80)	74.52%
Global Adjustment Rate Rider	per kW	$ (0.0924)	2000	$ (184.80)	$ 0.7057	2000	$ 1,411.40	$ 1,596.20	(863.74%)
Tax Charge Rate Rider	per kW	$ (0.0371)	2000	$ (74.20)	$ -	2000	$ -	$ 74.20	(100.00%)
							$ -	$ -	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 5,447.35**			**$ 6,078.41**	**$ 631.06**	**11.58%**
RTSR - Network	per kW	$ 2.5777	2090	$ 5,386.36	$ 2.6027	2068	$ 5,383.42	$ (2.94)	(0.05%)
RTSR - Line and Transformation Connection	per kW	$ 1.9295	2090	$ 4,031.88	$ 1.8662	2068	$ 3,860.05	$ (171.84)	(4.26%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 14,865.60**			**$ 15,321.88**	**$ 456.29**	**3.07%**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	2090	$ 10.87	$ 0.0044	2068	$ 9.10	$ (1.76)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	2090	$ 2.30	$ 0.0012	2068	$ 2.48	$ 0.18	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	2090	$ 14.63	$ 0.0070	2068	$ 14.48	$ (0.15)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	1000	$ 87.00	$ 0.0870	1000	$ 87.00	$ -	0.00%
TOU - Off Peak	per kW	$ 0.0630	1337	$ 84.25	$ 0.0630	1324	$ 83.40	$ (0.85)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	376	$ 37.24	$ 0.0990	372	$ 36.86	$ (0.38)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	376	$ 44.38	$ 0.1180	372	$ 43.93	$ (0.45)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 15,054.64**			**$ 15,509.19**	**$ 454.56**	**3.02%**
HST		13%		$ 1,957.10	13%		$ 2,016.20	$ 59.09	3.02%
Total Bill (including HST)				$ 17,011.74			$ 17,525.39	$ 513.65	3.02%
Ontario Clean Energy Benefit [1]				$ (1,701.17)			$ (1,752.54)	$ (51.37)	3.02%
Total Bill on RPP (including OCEB)				**$ 15,310.57**			**$ 15,772.85**	**$ 462.28**	**3.02%**
Total Bill on TOU (before Taxes)				**$ 15,059.51**			**$ 15,512.38**	**$ 452.87**	**3.01%**
HST		13%		$ 1,957.74	13%		$ 2,016.61	$ 58.87	3.01%
Total Bill (including HST)				$ 17,017.25			$ 17,528.99	$ 511.75	3.01%
Ontario Clean Energy Benefit [1]				$ (1,701.72)			$ (1,752.90)	$ (51.18)	3.01%
Total Bill on TOU (including OCEB)				**$ 15,315.53**			**$ 15,776.09**	**$ 460.57**	**3.01%**

Loss Factor (%) 4.48% 3.42%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Umetered Scattered Load**

Consumption 150 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 8.9100	1	$ 8.91	$ 6.9600	1	$ 6.96	$ (1.95)	(21.89%)
Distribution Volumetric Rate	per kWh	$ 0.0130	150	$ 1.95	$ 0.0101	150	$ 1.52	$ (0.44)	(22.31%)
Sub-Total A				$ 10.86			$ 8.48	**$ (2.39)**	**(21.96%)**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0044)	150	$ (0.66)	$ (0.0036)	150	$ (0.54)	$ 0.12	(18.18%)
Tax Charge Rate Rider	per kWh	$ (0.0005)	150	$ (0.08)	$ -	150	$ -	$ 0.08	(100.00%)
Smart Meter Entity Charge					$ -	150	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 10.13**			**$ 7.94**	**$ (2.19)**	**(21.63%)**
RTSR - Network	per kWh	$ 0.0061	157	$ 0.96	$ 0.0062	155	$ 0.96	$ 0.01	0.61%
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	157	$ 0.72	$ 0.0044	155	$ 0.68	$ (0.04)	(5.32%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 11.80**			**$ 9.58**	**$ (2.22)**	**(18.83%)**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	157	$ 0.81	$ 0.0044	155	$ 0.68	$ (0.13)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	157	$ 0.17	$ 0.0012	155	$ 0.19	$ 0.01	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	157	$ 1.10	$ 0.0070	155	$ 1.09	$ (0.01)	(1.01%)
Energy - RPP - Tier 1	per kWh	$ 0.0740	150	$ 11.10	$ 0.0740	150	$ 11.10	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	100	$ 6.32	$ 0.0630	99	$ 6.25	$ (0.06)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	28	$ 2.79	$ 0.0990	28	$ 2.76	$ (0.03)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	28	$ 3.33	$ 0.1180	28	$ 3.29	$ (0.03)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 25.24**			**$ 22.88**	**$ (2.35)**	**(9.32%)**
HST		13%		$ 3.28	13%		$ 2.97	$ (0.31)	(9.32%)
Total Bill (including HST)				$ 28.52			$ 25.86	$ (2.66)	(9.32%)
Ontario Clean Energy Benefit [1]				$ (2.85)			$ (2.59)	$ 0.26	(9.12%)
Total Bill on RPP (including OCEB)				**$ 25.67**			**$ 23.27**	**$ (2.40)**	**(9.34%)**
Total Bill on TOU (before Taxes)				**$ 26.58**			**$ 24.10**	**$ (2.48)**	**(9.33%)**
HST		13%		$ 3.45	13%		$ 3.13	$ (0.32)	(9.33%)
Total Bill (including HST)				$ 30.03			$ 27.23	$ (2.80)	(9.33%)
Ontario Clean Energy Benefit [1]				$ (3.00)			$ (2.72)	$ 0.28	(9.33%)
Total Bill on TOU (including OCEB)				**$ 27.03**			**$ 24.51**	**$ (2.52)**	**(9.32%)**

Loss Factor (%) 4.48% 3.42%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Sentinel Lighting**

Consumption 0.2 kW

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 6.4000	1	$ 6.40	$ 6.8900	1	$ 6.89	$ 0.49	7.66%
Distribution Volumetric Rate	per kW	$ 5.1350	0.2	$ 1.03	$ 5.5289	0.2	$ 1.11	$ 0.08	7.67%
Sub-Total A				$ 7.43			$ 8.00	**$ 0.57**	**7.66%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (2.4061)	0.2	$ (0.48)	$ 1.1274	0.2	$ 0.23	$ 0.71	(146.86%)
Tax Charge Rate Rider	per kW	$ (0.4698)	0.2	$ (0.09)		0.2	$ -	$ 0.09	(100.00%)
Smart Meter Entity Charge						0.2	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6.85**			**$ 8.22**	**$ 1.37**	**19.99%**
RTSR - Network	per kW	$ 1.8420	0	$ 0.38	$ 1.8599	0	$ 0.38	$ (0.00)	(0.05%)
RTSR - Line and Transformation Connection	per kW	$ 1.3779	0	$ 0.29	$ 1.3327	0	$ 0.28	$ (0.01)	(4.26%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 7.52**			**$ 8.88**	**$ 1.36**	**18.03%**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	0	$ 0.00	$ 0.0044	0	$ 0.00	$ (0.00)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	0	$ 0.00	$ 0.0012	0	$ 0.00	$ 0.00	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	0	$ 0.00	$ 0.0070	0	$ 0.00	$ (0.00)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	0	$ 0.01	$ 0.0740	0	$ 0.01	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kW	$ 0.0630	0	$ 0.01	$ 0.0630	0	$ 0.01	$ (0.00)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	0	$ 0.00	$ 0.0990	0	$ 0.00	$ (0.00)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	0	$ 0.00	$ 0.1180	0	$ 0.00	$ (0.00)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 7.79**			**$ 9.15**	**$ 1.36**	**17.41%**
HST		13%		$ 1.01	13%		$ 1.19	$ 0.18	17.41%
Total Bill (including HST)				$ 8.81			$ 10.34	$ 1.53	17.41%
Ontario Clean Energy Benefit [1]				$ (0.88)			$ (1.03)	$ (0.15)	17.05%
Total Bill on RPP (including OCEB)				**$ 7.93**			**$ 9.31**	**$ 1.38**	**17.45%**
Total Bill on TOU (before Taxes)				**$ 7.79**			**$ 9.15**	**$ 1.36**	**17.41%**
HST		13%		$ 1.01	13%		$ 1.19	$ 0.18	17.41%
Total Bill (including HST)				$ 8.81			$ 10.34	$ 1.53	17.41%
Ontario Clean Energy Benefit [1]				$ (0.88)			$ (1.03)	$ (0.15)	17.05%
Total Bill on TOU (including OCEB)				**$ 7.93**			**$ 9.31**	**$ 1.38**	**17.45%**
Loss Factor (%)		4.48%			3.42%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

Consumption **2400** **kW**

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 2.1600	1	$ 2.16	$ 1.1500	1	$ 1.15	$ (1.01)	(46.76%)
Distribution Volumetric Rate	per kW	$ 13.0610	2400	$ 31,346.40	$ 6.9298	2400	$ 16,631.52	$ (14,714.88)	(46.94%)
Sub-Total A				$ 31,348.56			$ 16,632.67	**$ (14,715.89)**	**(46.94%)**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (1.5474)	2400	$ (3,713.76)	$ (1.3424)	2400	$ (3,221.76)	$ 492.00	(13.25%)
Global Adjustment Rate Rider	per kW	$ (0.1097)	2400	$ (263.28)	$ 0.7100	2400	$ 1,704.00	$ 1,967.28	(747.22%)
Tax Charge Rate Rider	per kW	$ (0.2863)	2400	$ (687.12)	$ -	2400	$ -	$ 687.12	(100.00%)
Smart Meter Entity Charge						2400	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26,684.40**			**$ 15,114.91**	**$ (11,569.49)**	**(43.36%)**
RTSR - Network	per kW	$ 1.8325	2508	$ 4,595.03	$ 1.8503	2482	$ 4,592.59	$ (2.44)	(0.05%)
RTSR - Line and Transformation Connection	per kW	$ 1.3496	2508	$ 3,384.15	$ 1.3053	2482	$ 3,239.86	$ (144.29)	(4.26%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 34,663.58**			**$ 22,947.36**	**$ (11,716.22)**	**(33.80%)**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	2508	$ 13.04	$ 0.0044	2482	$ 10.92	$ (2.12)	(16.24%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	2508	$ 2.76	$ 0.0012	2482	$ 2.98	$ 0.22	7.98%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	2508	$ 17.55	$ 0.0070	2482	$ 17.37	$ (0.18)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	1400	$ 121.80	$ 0.0870	1400	$ 121.80	$ -	0.00%
TOU - Off Peak	per kW	$ 0.0630	1605	$ 101.10	$ 0.0630	1589	$ 100.08	$ (1.03)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	451	$ 44.68	$ 0.0990	447	$ 44.23	$ (0.45)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	451	$ 53.26	$ 0.1180	447	$ 52.72	$ (0.54)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 34,892.98**			**$ 23,174.69**	**$ (11,718.29)**	**(33.58%)**
HST		13%		$ 4,536.09	13%		$ 3,012.71	$ (1,523.38)	(33.58%)
Total Bill (including HST)				$ 39,429.07			$ 26,187.40	$ (13,241.67)	(33.58%)
Ontario Clean Energy Benefit [1]				$ (3,942.91)			$ (2,618.74)	$ 1,324.17	(33.58%)
Total Bill on RPP (including OCEB)				**$ 35,486.16**			**$ 23,568.66**	**$ (11,917.50)**	**(33.58%)**
Total Bill on TOU (before Taxes)				**$ 34,896.23**			**$ 23,175.91**	**$ (11,720.31)**	**(33.59%)**
HST		13%		$ 4,536.51	13%		$ 3,012.87	$ (1,523.64)	(33.59%)
Total Bill (including HST)				$ 39,432.74			$ 26,188.78	$ (13,243.95)	(33.59%)
Ontario Clean Energy Benefit [1]				$ (3,943.27)			$ (2,618.88)	$ 1,324.39	(33.59%)
Total Bill on TOU (including OCEB)				**$ 35,489.47**			**$ 23,569.90**	**$ (11,919.56)**	**(33.59%)**
Loss Factor (%)		4.48%			3.42%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Microfit**

Consumption 5 kW

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 5.2500	1	$ 5.25	$ 5.4000	1	$ 5.40	$ 0.15	2.86%
Sub-Total A				$ 5.25			$ 5.40	**$ 0.15**	**2.86%**
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
						5	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 5.25**			**$ 5.40**	**$ 0.15**	**2.86%**
RTSR - Network			5	$ -		5	$ -	$ -	
RTSR - Line and Transformation Connection			5	$ -		5	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 5.25**			**$ 5.40**	**$ 0.15**	**2.86%**
Wholesale Market Service Charge (WMSC)			5	$ -		5	$ -	$ -	
Rural and Remote Rate Protection (RRRP)			5	$ -		5	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)			5	$ -		5	$ -	$ -	
Energy - RPP - Tier 1			5	$ -		5	$ -	$ -	
Energy - RPP - Tier 2			0	$ -		0	$ -	$ -	
TOU - Off Peak			3	$ -		3	$ -	$ -	
TOU - Mid Peak			1	$ -		1	$ -	$ -	
TOU - On Peak			1	$ -		1	$ -	$ -	
Total Bill on RPP (before Taxes)				**$ 5.25**			**$ 5.40**	**$ 0.15**	**2.86%**
HST		13%		$ 0.68	13%		$ 0.70	$ 0.02	2.86%
Total Bill (including HST)				$ 5.93			$ 6.10	$ 0.17	2.86%
Ontario Clean Energy Benefit [1]				-$ 0.59			-$ 0.61	-$ 0.02	3.39%
Total Bill on RPP (including OCEB)				**$ 5.34**			**$ 5.49**	**$ 0.15**	**2.80%**
Total Bill on TOU (before Taxes)				**$ 5.25**			**$ 5.40**	**$ 0.15**	**2.86%**
HST		13%		$ 0.68	13%		$ 0.70	$ 0.02	2.86%
Total Bill (including HST)				$ 5.93			$ 6.10	$ 0.17	2.86%
Ontario Clean Energy Benefit [1]				-$ 0.59			-$ 0.61	-$ 0.02	3.39%
Total Bill on TOU (including OCEB)				**$ 5.34**			**$ 5.49**	**$ 0.15**	**2.80%**

Loss Factor (%) 4.48% 3.42%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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2-VECC-47s

Item No. 2007 PSD1

Corporate Division: Distribution Company

Preparation Date: June 7, 2007

Board Meeting Date: June 28, 2007

Subject: ***ASSET MANAGEMENT UPDATE***

Purpose of Report

To inform the Board of Directors of the overall strategy that the Executive Team has taken with regards to the implementation of an Asset Management philosophy as well as overview the findings of the Risk Assessments carried out in 2006/7 and provide an overview the initiatives required to correct the significant findings from the Risk Assessments.

Comments

Thunder Bay Hydro has been attempting to implement an Asset Management Strategy for some time and this has been a challenging undertaking largely not fulfilling the expectations of the Executive Team or the Board of Directors. In July of 2006 a new Vice President of Power Systems was hired with considerable expertise in Asset Management to implement this philosophy in support of the Corporate Strategy and Strategic Goals of the Corporation.

<u>New Organization for Power Systems Division</u>
The first undertaking to employ Asset Management was the implementation of a new organizational structure within the Power Systems Division that will not only support but facilitate an Asset Management philosophy. This was completed in September of 2006.

<u>System Wide Risk Assessment</u>
The first step in any effective asset management strategic plan is to develop a detailed inventory of all assets and determine the condition as well as the risk associated with all assets. In 2006 a risk management consultant was utilized in the development of risk assessment tools for staff to perform assessments and enabled them to accurately identify where our most significant risks existed and be able to consistently assess our system not only as our assessments progressed but also from one person to the next. The risk assessment of the entire system is largely complete at this point with the exception of three underground subdivisions which remain outstanding. Future risk assessments will be carried out on a one third of the system basis whereby all system component assessments will be updated every three years.

Safety Concern Reports

It was determined during the risk assessments that significant public as well as employee risks where identified during inspections that required immediate attention. A process that coincides with the risk assessments was developed whereby during system inspections a Safety Concern Report can be completed that will be forwarded to the appropriate Supervisor to determine a corrective plan of action or response to the Safety Concern Report. During this year's inspections approximately 50 Safety Concern Reports were received and this translated into 25 immediate pole changes due to serious concerns and many crossarm replacements as well as many serious substation and underground issues being addressed immediately.

Development of Programs

The results of the risk assessment were reviewed and programs were developed to address significant findings as well as other known issues that must be dealt with.

Outlined below are some of the significant findings with respect to overhead lines:

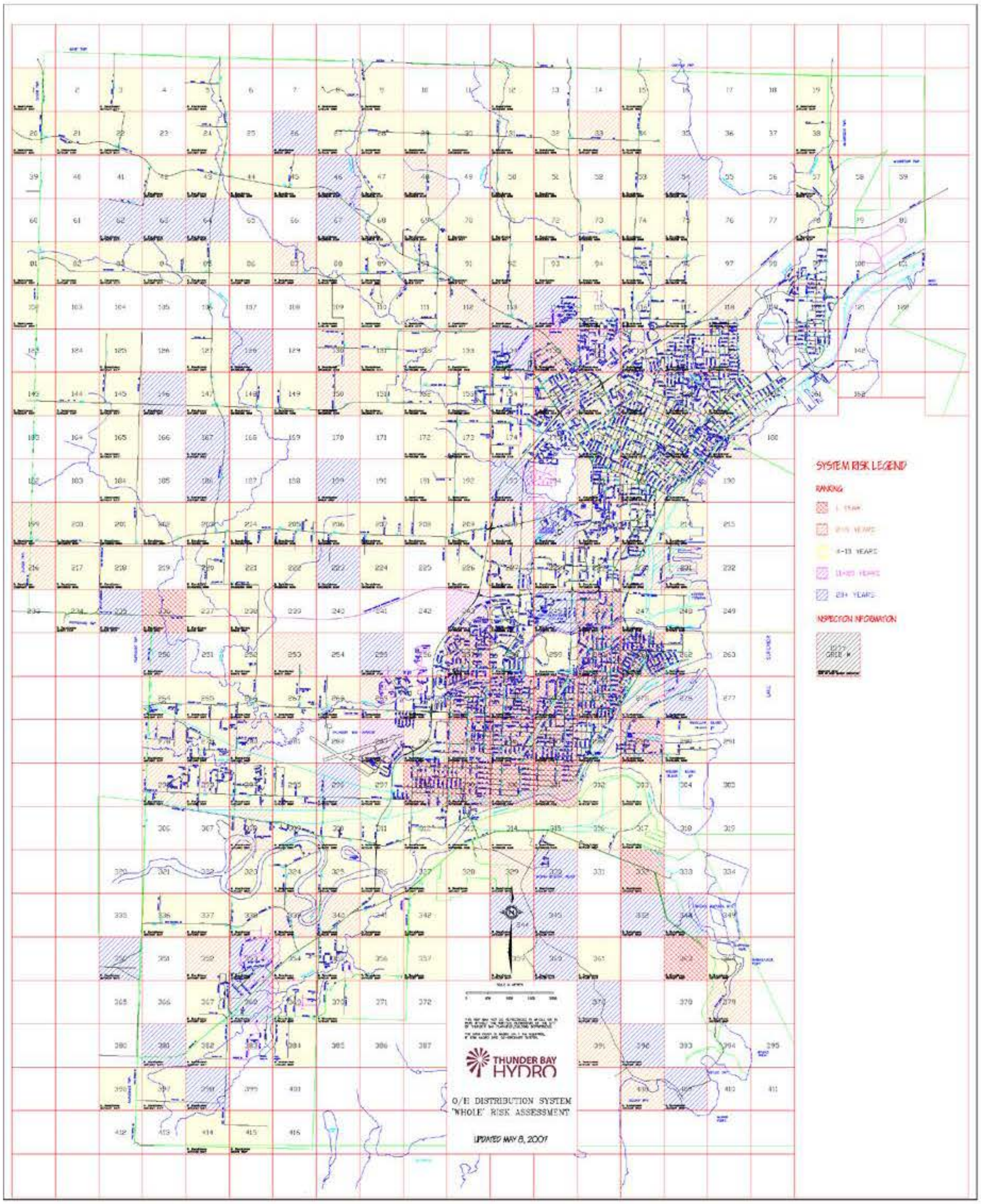
- A significant number (approximately 2000) poles where determined by our risk assessments and previous pole testing to be potentially unstable and need to be replaced, while many more are nearing end of life. Any poles that were confirmed to be unstable i.e. damaged or clearly rotten where immediately replaced. This category of risk was ranked "Red" and requiring immediate replacement within the 20 year capital plan.
- Presently there are over nineteen thousand wood poles in the Thunder Bay Hydro distribution system. The majority of these poles are at or beyond forty years while the industry standard planning life cycle of a wood pole is forty years. Actual life spans of poles can range from 25 years up to 60 years depending on environmental factors. The areas of the city in which the condition of the poles is a serious concern are the Westfort especially east of Edward St., Red River Ward, McKellar Ward, and the Current River Ward area.
  The average age of poles in the critical areas are well beyond forty years, and in order to replace the required number of poles per year, large scale projects of up to 150 poles each are required as the condition of the poles is beyond the ability of a replace individual poles as they reach end of life program. In future years, TBH's overall annual pole replacement program must increase, from typically 150 – 200 pole replacements to 500 of the poles to ensure the system is maintained in a sustainable condition.
  In order to replace 19,100 poles every forty years on average requires 480 poles be replaced each year. With an average replacement cost of $10,000 - 12,000/pole (this reflects the average cost for a pole replacement and includes the cost of transformers, switches, conductors,

and framing), the anticipated annual cost to replace these poles is approximately $4.8 - 5.76M/year.

- TBH has approximately 53.4 km of what are known as restricted conductor types in service today. As these overhead conductors and ground wires age substantially beyond their respective design lives, there is increasing pressure on owners of all utilities with these conductors to know their present physical condition and make decisions on major capital expenditures for removing them.
  TBH has established a program to remove approximately 7 km/year on average of the total restricted conductor that remains in service during the capital program years of 2008 to 2015, ultimately eliminating this conductor from its system. Additionally, these conductors will be closely monitored for failure rate escalation and during the annual risk assessments will receive a high priority risk ranking ensuring that they are replaced as soon as possible.
- Porcelain post standoff insulators have been determined to fail unexpectedly and this has been of significant concern such that procedures have been put in place to manage the associated risks. When working on poles with this type of insulator where the tension in the wire has changed or the pole has been bumped causing a change in tension, the insulator has often failed unexpected. It is extremely difficult to predict which insulators will fail even by up close inspection. While this is a significant concern the procedures in place are felt to be adequate and the plan for replacement will be on an “as required” basis or as work is scheduled in the vicinity of this type of standoff insulator.
- Porcelain lightning arrestors have been determined to fail catastrophically during direct lightning strikes in the vicinity of the arrestor and this has been of significant concern such that procedures have been put in place to manage the associated risks. When working on poles with this type of arrestor, where the fuse has been activated, there is a significant concern with re-energizing the arrestor due to the possibility of the arrestor failing catastrophically while staff is in close proximity to the equipment. It is extremely difficult to predict which arrestors will fail even by up close inspection. While this is a significant concern the procedures in place are felt to be adequate and the plan for replacement will be on an “as required” basis or as work is scheduled in the vicinity of this type of arrestor.
- Wood pins were used circa 1940 to 1970 where a wooden pin would affix the insulator to a wooden crossarm. As some of these pins approach 60 years of service, they are prone to failure allowing the conductor to drop onto the crossarm, potentially starting a pole fire or drop from the crossarm to ground level or heights where contact with the general public is possible.
  Wood pins have been determined to fail unexpectedly and this has been of significant concern such that procedures have been put in place to manage the associated risks. When working on poles with wood pins

where the tension in the wire has changed or the pole has been bumped causing a change in tension this type of insulator support has often failed unexpectedly. It is extremely difficult to predict which wood pins will fail even by up close inspection. While this is a significant concern the procedures in place are felt to be adequate and the plan for replacement will be on an “as required” basis or as work is scheduled in the vicinity.

For an overview of the overhead lines risk assessment results see the following page for the Overhead Distribution System ‘Whole’ Risk Assessment, updated May 8, 2007.


SYSTEM RISK LEGEND
RANKING
1 YEAR
4-13 YEARS
23+ YEARS
INSPECTION INFORMATION
THUNDER BAY
HYDRO
O/H DISTRIBUTION SYSTEM
'WHOLE' RISK ASSESSMENT
UPDATED MAY 8, 2007

Outlined below are some of the significant findings with respect to substations:

- Based on the risk assessment all of existing 16 4/25kV substations will have to be retired or replaced over the next 20 years due to most of the transformers presently being 50 to 60 years old and other auxiliary equipment reaching end of useful life.
- John St Substation needs to be retired as soon as possible. The major concern with this station is the transformer oil analysis is indicating the transformers are at end of life as well as there are major H&S concerns not only for employees but also for the public that need to be addressed. The soonest this station can be retired given the existing 20 year capital plan is 2011.
- Transformer testing as well as the risk assessment has indicated that Hardisty and Walsh substations will need to be replaced or retired within 10 years as these facilities will be at end of life. Additionally major work will be required at McPherson and Mary over the next 10 years.
- A detailed schedule and plan for the replacement or elimination of all 4/25 kV substations will be developed with the completion of the 20-year capital plan in its entirety.

For an overview of the substations risk assessment results see the following two pages.

4kV STATIONS
2006 'WHOLE' RISK ASSESSMENT

Station Inspected #	Station Inspected Name	Date Inspected	Inpected By	'Whole' Version	Public Safety Risk Rating	Worker Safety Risk Rating	Equipment Failure Risk Rating	Concern Report	Date Reviewed	Overall Risk Rating
1	Walsh	14-Dec-06	P. Boote	5	Red (1 yr)	Orange (2-3 yrs)	Red (1 yr)	Yes	15-Dec-06	
3	Hardisty	14-Dec-06	P. Boote	5	Orange (2-3 yrs)	Red (1 yr)	Red (1 yr)	Yes	15-Dec-06	
4	Vickers	14-Dec-06	P. Boote	5	Red (1 yr)	Orange (2-3 yrs)	Red (1 yr)	Yes	15-Dec-06	
5	Donald	13-Dec-06	P. Boote	5	Orange (2-3 yrs)	Yellow (4-10 yrs)	Yellow (4-10 yrs)	Yes	14-Dec-06	
6	McPherson	13-Dec-06	P. Boote	5	Red (1 yr)	Yellow (4-10 yrs)	Yellow (4-10 yrs)	Yes	14-Dec-06	
7	Mary	13-Dec-06	P. Boote	5	Yellow (4-10 yrs)	Not Done	Red (1 yr)	No	14-Dec-06	
9	Mountdale	18-Dec-06	P. Boote	5	Red (1 yr)	Yellow (4-10 yrs)	Red (1 yr)	Yes	19-Dec-06	
11	High	13-Dec-06	P. Boote	5	Yellow (4-10 yrs)	Yellow (4-10 yrs)	Purple (11 - 20 yrs)	No	14-Dec-06	
12	Camelot	13-Dec-06	P. Boote	5	Red (1 yr)	Orange (2-3 yrs)	Orange (2-3 yrs)	Yes	14-Dec-06	
13	John	18-Dec-06	P. Boote	5	Red (1 yr)	Red (1 yr)	Red (1 yr)	Yes	19-Dec-06	
14	Algoma	13-Dec-06	P. Boote	5	Orange (2-3 yrs)	Yellow (4-10 yrs)	Yellow (4-10 yrs)	Yes	14-Dec-06	
15	Genville	13-Dec-06	P. Boote	5	Red (1 yr)	Yellow (4-10 yrs)	Purple (11 - 20 yrs)	Yes	14-Dec-06	
16	McDonell	13-Dec-06	P. Boote	5	Red (1 yr)	Yellow (4-10 yrs)	Orange (2-3 yrs)	Yes	14-Dec-06	
18	Balsam	13-Dec-06	P. Boote	5	Yellow (4-10 yrs)	Yellow (4-10 yrs)	Purple (11 - 20 yrs)	No	14-Dec-06	
19	Broadway	18-Dec-06	P. Boote	5	Red (1 yr)	Yellow (4-10 yrs)	Yellow (4-10 yrs)	Yes	19-Dec-06	
21	Windemere	13-Dec-06	P. Boote	5	Red (1 yr)	Yellow (4-10 yrs)	Yellow (4-10 yrs)	Yes	14-Dec-06	
22	Brock	18-Dec-06	P. Boote	5	Yellow (4-10 yrs)	Orange (2-3 yrs)	Yellow (4-10 yrs)	Yes	19-Dec-06	
23	Alice	14-Dec-06	P. Boote	5	Yellow (4-10 yrs)	Orange (2-3 yrs)	Yellow (4-10 yrs)	Yes	15-Dec-06	
36	Mapleward	18-Dec-06	P. Boote	5	Red (1 yr)	Red (1 yr)	Yellow (4-10 yrs)	Yes	19-Dec-06	
		Primary Risk Rating			11 Red (1 yr)	10 Yellow (4-10 yrs)	8 Yellow (4-10 yrs)			23 Yellow (4-10 yrs)
		Secondary Risk Rating			5 Yellow (4-10 yrs)	5 Orange (2-3 yrs)	5 Red (1 yr)			19 Red (1 yr)
		Tertiary Risk Rating			3 Orange (2-3 yrs)	3 Red (1 yr)	3 Purple (11 - 20 yrs)			10 Orange (2-3 yrs)
		Quatenary Risk Rating			0 Purple (11 - 20 yrs)	0 Purple (11 - 20 yrs)	2 Orange (2-3 yrs)			3 Purple (11 - 20 yrs)

Appendix Is-2

2006 Substation Dissolved Gas Analysis

TX	Age	Retrofilled	CO	Ethylene		Furans	IFT	Forecasted Annual Probability of Failure (Present)	Forecasted Annual Probability of Failure 15 yr Ave	Transformer Replacement Priority	Recommended Operation	DGA Recheck Rate
1T1	40	2002				Not Detectable		1.50%	2.20%	Low	Normal	Annually
1T2	42	No				112 ppb	22.7	1.70%	2.40%	Low	Normal	Annually
1T3	42	No				109 ppb		1.70%	2.40%	Low	Normal	Annually
3T1	58	1996				82 ppb	22.6	3.80%	5.30%	Medium	Normal	Annually
3T2	54	No	585 ppm	53 ppm		65 ppb	17.3	4.00%	5.70%	Medium	Replace or recondition oil immediately to avoid sludging	Immediately
4T1	53	No				1295 ppb	20.8	4.40%	6.30%	High		
4T2	48	No				14 ppb		2.30%	3.30%	Medium	Normal	Annually
5T1	49	No				18 ppb		2.40%	3.50%	Medium	Normal	Annually
5T2	44	1999				11 ppb		1.80%	2.70%	Low	Normal	Annually
6T1	49	2001				155 ppb		4.30%	6.20%	High	Consider Replacement	3 Months
7T1	52	No				24 ppb		0.042	0.06	High	Consider Replacement	6 Months
7T2	40	2001				36 ppb		2%	2%	Low	Normal	Annually
9T1	41	2003				24 ppb		0.016	0.023	Low	Normal	Annually
11T1	47	No				198 ppb		2%	3%	Medium	Normal	Annually
12T1	38	No				Not Detectable		1.40%	2.00%	Low	Normal	Annually
12T2	38	No				Not Detectable		1.40%	2.00%	Low	Normal	Annually
13T1R	56	1998				109 ppb		5.10%	7.30%	High	Consider Replacement	No Recommendation
13T1W	56	1998				209 ppb	19	5.10%	7.30%	High	Consider Replacement	No Recommendation
13T1B	56	1998				193 ppb	20	5.10%	7.30%	High	Consider Replacement	No Recommendation
13T1 (Spare)	56	No				56 ppb		Spare	Spare	Spare		
13T2R	60	No				511 ppb		5.40%	7.50%	High	Consider Replacement	No Recommendation
13T2W	60	No				1046 ppb	20.9	5.40%	7.50%	High	Consider Replacement	Annually
13T2B	60	No				786 ppb	20.5	5.40%	7.50%	High	Consider Replacement	Annually
14T1	48	1991				14 ppb		2.30%	3%	Medium	Normal	Annually
14T1(Spare R)	58	No				179 ppb	15	Spare	Spare	Spare	Replace Oil	Spare
14T1(Spare W)	58	No				211 ppb	13.7	Spare	Spare	Spare	Replace Oil	Spare
14T1(Spare B)	58	No				86 ppb	23.7	Spare	Spare	Spare	Re-check Oil Before Resuming To Service	Spare
15T1	38	No				14 ppb		1.40%	2.00%	Low	Normal	Annually
16T1	53	1999				83 ppb	23.4	2.90%	4.20%	Medium	Normal	Annually
16T2	48	No				16 ppb		2.30%	3.30%	Medium	Normal	Annually
18T1	47	No				119 ppb		2.10%	3.10%	Medium	Normal	Annually
18T2	35	No				N.D.		2.20%	3.10%	Medium	Normal	6 Months
19T1	27	1996				19 ppb		1.00%	1.20%	Low	Normal	Annually
21T1	51	No				771 ppb		2.90%	4.20%	Medium	Normal	Annually
21T2	48	2000				41 ppb		2.30%	3.30%	Medium	Normal	Annually
22T1	58	No				118 ppb		3.80%	5.30%	Medium	Normal	Annually
22T2	54	No				108 ppb		3.10%	4.40%	Medium	Normal	Annually
23T1	35	No				21 ppb		1.30%	1.90%	Low	Normal	Annually
36T1R	39	No				39 ppb		1.40%	2.10%	Low	Normal	Annually
36T1W	39	No				30 ppb		1.40%	2.10%	Low	Normal	Annually
36T1B	39	No				30 ppb		1.40%	2.10%	Low	Normal	Annually
36T1S	39	No				13 ppb		SPARE	SPARE	SPARE	SPARE	SPARE
Northwood	35	No	955 ppm	59 ppm		59 ppb		1.60%	2.20%	Low	Re-check Oil Immediately	Immdediately
Waverly	35	No				N.D.		1.20%	1.70%	Low	Normal	Annually

Outlined below are some of the significant findings with respect to underground subdivisions:

- Thunder Bay Hydro’s underground subdivision networks were mostly installed in the 70’s when the city experienced significant growth. These subdivisions have been in service for some 30 years and were in need of an exhaustive assessment to determine how best to proceed given that the cables have an expected lifespan of 30 to 40 years. To date, 96 of the 99 subdivisions have been assessed and assigned risk ratings.
- The four subdivisions yielding red risk ratings (i.e. immediate attention required) are College Park, County Park, Egan Place and Tuxedo Park. The common issues affecting these subdivisions are end of life cables as well as operational concerns.
- Two subdivisions, Academy Heights and Annala, have been assessed with an orange rating; i.e. attention required in the next one to four years. The predominant issues in these subdivisions are the same as those in the red assessed subdivisions.
- The overall rating of the subdivisions inspected thus far is yellow, and for the most part the issues identified can be addressed through preventive, and where necessary corrective maintenance. The remaining six subdivisions however, will require an extensive overhaul, which necessitates the installation of new cables, transformers, foundations and switchgear.

For an overview of the subdivisions risk assessment results please see the following page.

2007 RESIDENTIAL UNDERGROUND
'WHOLE' RISK ASSESSMENT

OPERATING GRID INSPECTED	NUMBER OF TX	PREFIX	DATE PHASES INSPECTED														
			RED				WHITE				BLUE				THREE PHASE		
			Loop 1	Loop 2	Loop 3	Loop 4	Loop 1	Loop 2	Loop 3	Loop 4	Loop 1	Loop 2	Loop 3	Loop 4	Loop 1	Loop 2	Loop 3
ACADEMY HEIGHTS	53	HT	3/6/07	3/8/07			3/8/07				3/8/07	3/28/07	2/28/07		2/28/07		
ADMIRAL COURT	2	CT					3/27/07										
ANNALA	5	KT					3/28/07										
AUDREY ST.	1	CT															
BAGDON	3	KT					4/23/07										
BAGDON	1	LT									2/15/07						
BELAIR	4	BT					4/12/07										
BIRCH GROVE	3	FT	5/14/07														
BLACK	1	KT	4/23/07														
BLACK BAY	4	CT	5/16/07	5/16/07	5/16/07												
BLUCHER	3	BT					4/20/07										
BRENTWOOD	2	FT					3/16/07										
BROAD OAKS	14	CT					3/8/07										
CARDINAL	1	KT															
CASTLEGREEN	17	LT	3/7/07								3/7/07						
CHERRY RIDGE	12	BT	2/24/07				3/20/07										
CHUCKREY	1	CT															
CLARK	1	KT															
COLLEGE PARK	81	AT	2/27/07	3/8/07			3/28/07				2/27/07						
COLLINS PLACE	4	MT									2/24/07						
COUNTY PARK	100	KT	3/13/07				3/13/07				3/9/07	3/13/07					
CRESTWOOD APTS	9	MT					5/16/07										
DAWSON HEIGHTS 1	8	FT	3/16/07														
DAWSON HEIGHTS 2	2	FT					3/16/07										
DAWSON WOODS	12	FT	5/11/07	5/11/07													
DIN ERA	2	LT									2/15/07						
DIPAOLO	1	PT	3/24/07														
EGAN PLACE	4	GT					5/17/07										
EMPIRE ROW HOUSING	1	MT	5/29/07				5/29/07				5/29/07						
FACCA	4	KT					4/23/07										
FAIRVIEW	10	KT	4/2/07														
FASSINA	12	FT	5/11/07	5/11/07													
FOXBOROUGH	7	CT									3/15/07						
GARDEN BRIAR	3	PT									4/2/07						
GARDENIA	8	LT					3/19/07										
GIBBON ST	1	JT									5/15/07						
GORDONVALE	2	KT									2/24/07						
GREENRIDGE 1	5	CT	3/7/07														
GREENRIDGE 2	0	CT															
GREENRIDGE 3	9	CT	3/7/07														
HELLINIC VILLAGE	5	HT	2/28/07								2/28/07						
HIGHLAND COURT	2	ET									4/26/07						
HILLCOURT	11	ET	5/9/07														
HODDER NORTH & SOUTH	11	CT	5/10/07				5/17/07										
JAMES ST. NORTH	60	AT	6/5/07	6/5/07			6/5/07	6/5/07			6/4/07	6/4/07					
JAMES ST. SOUTH	66	AT	5/30/07	6/4/07			5/30/07	6/4/07			5/30/07	6/4/07					
JAMIESON	5	FT	4/16/07														
JOHN ST. OHC	2	BT									5/3/07						
JUNOT TERRACE	9	BT					4/20/07				4/24/07						
LARSON	2	KT									4/23/07						
LASALLE PLACE	3	AT									5/3/07						
LOPEZ	2	BT					4/12/07										
MACLEOD	3	KT					4/23/07										
MELODY CRT	2	PT					4/3/07										
MOUNT FOREST	25	CT	3/6/07														
MOUNTAINVIEW ESTATES	1	ET									4/26/07						
MOUNTAINVIEW TERRACE	10	CT					3/8/07										
NORTWESTER VALLEY ESTATES	10	CT									4/26/07						
OAKDALE	5	KT					4/23/07										
PAMONA	1	ET	5/9/07														
PARKDALE	43	PT	3/16/07	3/8/07	3/20/07	3/24/07					3/16/07						
PARKWOOD ESTATES	9	GT									2/15/07						
PASANEN	2	FT	5/14/07														
PEROZAK	3	KT					4/23/07										
PERVAIS	2	ST	3/16/07														
PICTON	5	BT									4/24/07						
PIGAT	5	FT	4/16/07														
PIGAT	2	CT									4/27/07						
PRADAL	4	KT					4/23/07										
R.G. PIPER	2	KT					4/23/07										
RED RIVER ROAD	7	RT					5/16/07				5/15/07						
REGINA	1	FT	5/14/07														
RIVER TERRACE	30	BT	5/9/07	5/9/07			5/9/07				5/9/07	5/9/07					
RIVER TERRACE SOUTH	29	BT	3/16/07								3/15/07						
RIVER TERRACE SOUTH STAGE 2	35	BT	3/16/07	3/15/07			3/16/07				3/15/07	3/15/07					
RIVER TERRACE SOUTH STAGE 3	9	BT					3/16/07										
RIVERDALE ESTATES	2	CT	3/16/07														
RIVERPARK	9	KT	4/23/07	4/23/07													
SCOTLAND	1	CT									4/26/07						
SEGGEWISS	2	CT					4/26/07										
SEQUOIA PARK	14	BT	5/2/07				5/2/07				5/2/07						
SHERWOOD ESTATES	41	FT	4/16/07				4/19/07	4/19/07	4/18/07								
SILVERTREE PARK	8	FT									2/15/07						
SOMERSET	3	CT									4/26/07	4/26/07					
STEPHEN ST.	2	DT									4/5/07						
SUNCREST	2	LT									5/15/07						
SUPERIORVIEW	26	LT					3/7/07										
TAMARACK	1	BT					5/3/07										
TERRA NOVA	4	BT									2/28/07	2/28/07					
TUXEDO	7	CT															
TUXEDO PARK	15	KT									2/8/07						
VESTAVALE MOBILE	10	ET															
WELLINGTON EAST	7	LT									2/15/07						
WELLINGTON HEIGHTS	9	LT	3/16/07				3/19/07				2/15/07						
WHEELER	2	CT					3/19/07										
WHITEGATES 1	8	KT	3/6/07														
WHITEGATES 2	4	KT	3/6/07														
WILLOW TERRACE	3	CT	2/28/07														
WINDSOR	6	BT					4/20/07										
WOODCREST	14	FT	4/26/07	4/26/07	4/26/07	4/26/07											

UPDATED APRIL 22, 2007

Development of a 20 Year Capital Plan

The development of a 20 year plan including the programs to address the significant H&S as well as environmental issues along with the replacement of end of life equipment as it arises over the next 20 years is required. Presently five years of the plan have been developed however as a minimum half the plan must be developed prior determining with reasonable certainty whether the rate of planned replacements is adequate to address all equipment as they approach end of life.

Development of a Maintenance Program

Thunder Bay Hydro lacks any structured maintenance plan for its lines and underground assets. Maintenance to these assets has largely been a replace upon failure approach. While a somewhat documented maintenance program existed for its substations it has largely fallen behind schedule and the plan lacks any real strategy. A maintenance program will be developed and for lines it will continue to be a largely replace on failure approach; however key equipment within the system will receive programmed maintenance.

Communication of Plan, Vision and Direction

In order for the plan, vision and strategic direction to be effectively carried out by staff at all levels it must be clearly communicated and understood by all staff. This was accomplished with specific and measurable targets being assigned to all management staff within the Power System Division. Additionally the staff at large within PSD has received presentations outlining our overall approach and more specific presentations have been given to individual departments. Also many of the staff were consulted in the development of the capital and maintenance plans as well as the supporting processes.

Metrics Implementation

Implementation of Metrics for all departments supporting the plan, vision and direction has been developed and these have been communicated to all staff at a general staff meeting. This represents a significant step to measurement of performance of individuals as well as individual departments and targeting areas for improvement with respect to the execution of the capital and maintenance programs as well as on going operations. These metrics have been developed to not only support corporate strategic objectives but also to foster team work and coordination by having common metrics applied to individual departments.

Conclusion

The consequences of not addressing the aging infrastructure as well as the significant findings of the risk assessments are serious. Failing to act will allow the system condition to continue to deteriorate to where the number of poles requiring immediate replacement will exceed the ability of the utility to deal with them. In recent years we have been replacing approximately 0.8 - 1% of our poles which indicates an average replacement horizon of over 100 years.

Obviously this is not sustainable and our program going forward needs to be in the order of 2.5% in the long term.

Presently TBH replaces approximately 80 - 100 poles per year due to concerns with respect to stability of the structure and the associated H&S concerns on an as required basis. With the significant building of the system in the 50's and again in the 70's this number is expected to rise dramatically over the next 10 years requiring a programmed approach to deal with this issue. Likewise should the stations not be partially retired or rehabilitated within 15 years they will be in a condition that the utility will not be able to manage their replacement due to the number of stations reaching end of life simultaneously.

Attachments

Attached is chapter #1 from a book that the VP of Power Systems has been writing and while it is a work in progress it provides key pertinent information outlining what is Asset Management which is largely not completely understood in the business world and why it needs to be understood and supported by organizations from the Board of Directors all the way to Front Line Staff.

Recommendations

None

Respectfully Submitted: Emanuel DaRosa
Vice President, Power Systems

Signature:

Excerpt from Report 2007 D8.4 *Proposed 2008 Capital and Operations Budgets for Thunder Bay Hydro Electricity Distribution Inc.,* dated November 2, 2007

<u>Expenditures</u>

As previously indicated, significant decisions are required by the Board related to the utility's strategy for the removal and destruction of PCB's from the distribution system, and to the appropriate level of Capital Investment in the distribution system in 2008. The attached budget package reflects the resources required to move forward with the PCB strategy and to increase the capital investment in the system by $1M in 2008. These specific items will be discussed in detail during the budget presentation. In order to help Directors prepare for this discussion, the following is a synopsis of the issues and budget impacts.

PCB Removal and Destruction Strategy

The proposed PCB regulations are still sitting with the Federal Government. While they are widely expected to be passed into law, likely next year, there is a question of whether the proposed deadlines will change given the delay in enacting the regulations. The Board was updated earlier in the year on the strategy being undertaken by the utility to prepare for the impact of the new regulations. The 2008 Budget package reflects the continuation of this strategy in 2008. The financial impact of proceeding in 2008 is an incremental increase in capital investment for new transformers of $332,000 and increased operating expenses to undertake the replacement work of $250,000. A decision to not proceed with the PCB strategy in 2008 (in view of the delay in enacting the regulations) would improve the cash flow of the utility by approximately $569,000, part of which would be reflected in increased Net Income before PILS of $250,000.

The decision on whether to proceed is a complex one. The potential advantages and risks will be fully discussed during the budget presentation and ultimately the Board will need to decide on a course of action. If required, the 2008 Budget package will be amended to reflect the Board's decision prior to acceptance.

Increased Capital Investment in the Distribution System

During the budget discussion, a review of our current capital investment level and the influences on this level will be fully reviewed. As the Board is aware, a thorough review of the condition of the distribution system and an analysis of the risks associated with the system has been conducted. The conclusions point to the need to increase the yearly investment in rebuilding aging distribution infrastructure.

Ultimately, a fully supported analysis of an appropriate level of system investment will be made to the OEB during the utility's next full Distribution Rate hearing (hopefully in 2009). As the Board has been advised, the formalization of a 20 year capital plan with supporting analysis is currently underway and will be presented to the Board as it develops. While the appropriate long term level of capital expenditure required to ensure distribution system safety and reliability has yet to be accurately determined, it is the strong recommendation of the President and the Vice President, Power Systems that Thunder Bay Hydro needs to immediately prepare to increase capital investment in the distribution system. As such, the presented 2008 Budget package reflects an increase in Capital Expenditure on Line Upgrades and Replacements of $1M.

It is proposed that the increase in capital investment for 2008 be funded through existing operating capital. While Ms. Speziale will more fully review the financial implications of this proposed expenditure, the Board should be aware that the potential impact of this expenditure on Net Income is relatively small (estimated at a $18,000 reduction in Net Income before PILS). There would be, of course, a significant impact from a cash flow perspective of approximately $962,000. It is the opinion of Ms. Speziale that this impact is manageable for 2008 given our working capital strength, and recognizing that the recovery of continued increased capital investment through distribution rates will be subject to OEB approval. In other words, the utility is capable of internally funding a one year, $1M increase in Capital Expenditure leading up to a formal regulatory review in 2009.

This is a significant recommendation which will be more fully explored during the budget presentation. If the Board decides not to accept the recommendation for increased Capital Investment the 2008 Budget package will be amended to reflect the Board's decision prior to acceptance.

Excerpt from Report 2008 D8.6 2009 *Electricity Distribution Rate Application Overview*, dated April 21, 2008

Capital Investment

The EDR application seeks an increase in the level of annual capital investment in the distribution system. The application reviews the historical level of investment and notes that the trend of gradual inflationary increases in investment reversed in 1995 in response to three years of electric rate decreases. Had this trend not reversed in 1995, annual capital investment would likely be in the $7-$9M range annually. The application reviews the distribution system asset condition assessment, and ties this assessment to the Board's decision to increase capital investment in 2008 by $1M. Estimates of the total cost of replacing our distribution infrastructure are presented and the appropriate yearly investment level is projected.

Using this rationale, the application requests funding for capital investment approximately $1.5M higher than the 2008 budgeted level. The application indicates that a trend of increasing capital investment will be required in the future and that the utility will be building both its internal and external capacity to undertake increased capital construction over the three years before the next full rate application. The incremental investment will be in external construction resources, internal labor, technical capacity, and materials, tools, and equipment. The incremental investment also includes $200K in capital investment related to PCB removal. This item is detailed later in the report.

The $1.5M incremental increase in capital investment is not directly recovered each year through rates. Rather, the application reflects that capital investment is funded through a combination of debt and equity investment. The application reflects recovery of the interest expense associated with projected debt increases and an increase in the Return on Equity earned to 3.75% (from a historical level of 2.93%) to support equity investment and financing covenants.

Excerpt from Report 2008 D8.3 *Proposed 2009 Capital and Operations Budgets for Thunder Bay Hydro Electricity Distribution Inc.,* dated October 30, 2008

Strategic Items Impacting Budget

Increased Capital Investment

The 2009 Capital Budget reflects the Board approved approach to increased investment in rebuilding the utility's distribution infrastructure. The Capital Budget reflects an additional $1.M in capital investment in infrastructure over the approved 2008 budget. This brings total budgeted distribution system capital to $7,141,646 from $5,697,843 in 2008. This increased amount includes $201K (under budget line Regulatory/Legal) in investment related to PCB management as previously discussed.

An increased level of distribution system rebuild activity directly impacts forestry activity undertaken by the utility. 2009 forestry activity is budgeted to increase by $200K as compared to 2008 levels. Due to the accounting treatment of these costs, the increase impacts O&M expenses rather than capital expenditures.

In total, 2009 Part "C" Miscellaneous Capital Requirements are consistent with 2008. It should be noted that the budget contains a provision of $230K for rolling stock ordered from 2008 budgeted funds which will not be received until 2009. Therefore, new 2009 Part "C" Capital is budgeted $127K lower than 2008.

Excerpt from Report 2009 D8.5 *Proposed 2010 Capital and Operations Budgets for Thunder Bay Hydro Electricity Distribution Inc*., dated November 19, 2009

Strategic Items Impacting Budget

<u>Increased Capital Investment</u>

The 2010 Capital Budget reflects the Board approved approach to increased investment in rebuilding the utility's distribution infrastructure. The Capital Budget reflects an additional $800K in capital investment in infrastructure over the approved 2009 budget. This brings total budgeted distribution system capital to $7,715,062 from $5,697,843 in 2008. This increased amount includes investments related to PCB management as previously discussed.

An increased level of distribution system rebuild activity directly impacts forestry activity undertaken by the utility. 2009 forestry activity was budgeted to increase by $200K as compared to 2008 levels, and this increased activity level is sustained in 2010.

Total budgeted expenditures for Miscellaneous Capital are comparable to 2009 with the exception of Rolling Stock. An increased expenditure in this area is required to support the growing distribution system capital program.

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2-Board Staff-47s

THUNDER BAY HYDRO

BUSINESS CASE REVIEW FORM

DEPARTMENT: Operations	DATE: July 9, 2012	BCR NO.

TYPE OF REQUEST

Initial ☐	Supplemental ☒	Scope Change ☒

CATEGORY

Capital ☒	Major Repair ☐	Lease ☐	Other ☐

PROJECT TITLE

Maintenance Garage Replacement (Demolition, Design and Build Project)

BRIEF PROJECT DESCRIPTION (see page 2 for more details)

TBH pre-demo/build activities include: asbestos and lead paint removal, phase one and two environmental site assessments, sub-surface geotechnical study, relocate stored material, evaluate design and build proposals, select the General Contraqctor for award and then prequalify the awarded General Contractor. In addition TBH paid a Engineering company to assist in the development of the specifications and the revie wof the original RFP documents, which subsequently lead to the cancellation of this project in 2011

TBH's intent is to use a "Turn Key" construction concept where the contractor will design a new maintenance garage, demolish the exisiting annex so this property footprint can be used to build the new garage, temporarily support the exposed end wall of the old garage, and construct the new maintenance garage for TBH

PROJECT COST (see page 3 for more details)

Amount Included In 20-Year Capital Plan	$ 3,300,000
Cost Previously Incurred	$ 60,000
Proposed during current year	$ 3,300,000
Total project cost	$ 3,360,000

FINANCIAL ANALYSIS

Annual Benefits (additional revenues, cost savings.):	End-of-life building replacement	Payback period – years: N/A

SCHEDULE – Month/Year

Beginning of Work: **Fall 2012**	Completion of Work: **October 2013**

APPROVALS

Title	Signature	Date
AME Manager Dipankar Chakrabarti		
Lines Superintendent Garrett Mouland		
Operations Superintendent Duane Szyszka		
VP, Power Systems Don Zimak		
VP, Finance Cindy Speziale		
President Rob Mace		

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

DEPARTMENT: Operations	DATE: July 09, 2012	BCR NO.

PROJECT TITLE

Maintenance Garage Replacement (Demolition, Design And Build Project)

DESCRIBE CURRENT SITUATION AND WHY PROJECT IS REQUIRED

The maintenance garage and annex building are 1932 vintage construction and have multiple areas of concern as listed below:

- The maintenance garage has a sloped floor (numerous issues received to date, ground penetrating radar confirmed in 2009 that a second floor exists under the current floor -- pricing to remove and replace the floor(s) was received in 2009 -- $120,000)
- The maintenance garage floor is sinking as evident with the +1/2" cracks and the concrete patch work that exists around the perimeter of the interior walls
- Fleet garage floor currently has an in-floor ladder type catch trough for water/oil collection that used to go to the COTB sewer system (since blanked off), although TBH uses oil absorption matting/pads throughout the various trough levels, this collection trough has cracks in the concrete and may have or may be leaching contaminates under the floor.
- Annex roof leaking (repair cost received for the flat annex roof was ~$50,000).
- The maintenance garage and annex structural issues (the outside and inside walls are cracking, the outside walls are bowed, the wall footings are separating from the floors – repair cost unknown).
- The maintenance garage west brick wall is deteriorating due to pre-1970 fire damage and is now “chalk like” – no drilling is allowing on the wall
- The maintenance garage fire code compliance (there is no sprinkler system, annunciated fire alarm panel, field addressable heat and smoke detection devices – pricing to install was received in 2007 -- ~$75,000).
- Maintenance garage / annex asbestos assessment (annex wall vermiculite was removed in 2009 ($30,000).
- The maintenance garage / annex lead paint (removal of the burgundy coloured paint in the annex was done in 2010 ($10,000).
- Overhead garage doors are no longer manufactured (prices received in 2008 to replace all three doors was $16,500)
- Building security concerns (price to install a new internal sensing system, additional door sensors, and video surveillance is $30,000)
- The maintenance garage building ventilation does not meet today’s minimum building code requirement for a repair / garage facility – cost to upgrade unknown.
- The maintenance garage ceiling is too low for completing some elevated repair work on the new larger line trucks (17’H ceiling 13’H bucket trucks) – cost to raise the roof unknown
-

PROPOSED SOLUTION

Demolish the annex and use this footprint to construct a new maintenance garage.

TBH will continue to use the old maintenance garage to complete maintenance activities during the demolition and construction phases, so daily operations are not negatively impacted.

The new maintenance garage will be furnished with most of the equipment from the old facility and some new equipment. To limit any operational issues during regular business hours, the transition from the old to new facility will take place over a weekend and will involve the mechanical group and labourer staff.

Once the new maintenance garage is fully operational; a separate project will oversee the demolition and removal of the old garage building.

BUSINESS CASE REVIEW FORM – PROJECT DESCRIPTION

OPTIONS EXAMINED

A local architectural / engineering company recommeded against refurbishing or repairing the exisiting garage / annex because of the age of this structure (78 years old) and the fact that TBH can not afford to have its mechanical / lines group adversely impacted during any retro-fit activities that may limit or increase vehicle repair times for an extended period of time.

Utilization of external repair facilities has been investigated with negative results. Equipment down time increases substantially because third party repair technicians are not familiar with our specialty equipment and TBH is not given any priority; they are placed in que with all other customers. TBH 's repair staff productivity suffers because they are utilized to transport vehicles to and from these other shops.

Acquisition of another building off site was also investigated, logistics of shuttling personnel to and from the other site back to the Operations Centre, security concerns, site supervision, convenience and repair efficiencies were too substantial to make this a viable consideration

EXPECTED BENEFITS (financial calculations if monetary benefits)

TBH would have a facility that is environmentally compliant, and would meet building/fire safety code requirements and be able to fulfill the needs of TBH for another 70+ years.
TBH would also have a facility with:

- Improved safety aspects (shower and eye wash facilities, access/egress doors spaced as per building code requirements, adequately sized vehicle entry doors, additional vehicle entry doors to eliminate manoeuvring vehicles inside the shop)
- Improved ergonomics (flat floor, utilization of the large vehicle hoist would allow the mechanics to stand under the line trucks instead of lying under them), elevated ceiling height with overhead crane capability, enhanced lighting, ventilation and accessibility, and elevated storage facilities incorporated within the garage.
- Improved industrial hygiene via automatic air exchange devices – Carbon Dioxide sensing that is linked to supply and exhaust air fans.
- Fire suppression, annunciation, fire separation walls, and after hour monitoring capabilities.
- Improved environmental aspects (wash bay and the main shop will have a below ground storage tank to collect run-off water or fluid leaks, and the welding bay would have improved exhaust scrubbing capabilities)
- Improved operational components (separate wash bay, separate welding area, drive-through load out door, small tool repair area, and an oil storage/dispensing area).

VARIANCE – estimated cost versus annual plan

Estimate cost per Page 1	$ 3,300,000
Amount included in 20-Year Capital Plan Envelope	$ 3,300,000
Variance	$ 0

THUNDER BAY HYDRO

BUSINESS CASE REVIEW FORM – COST ESTIMATE

DEPARTMENT: Operations	DATE: July 09, 2012	BCR NO.

PROJECT TITLE

Maintenance Garage Replacement (Demolition, Design And Build Project)

COST ESTIMATE BREAKDOWN - $000

Activities	Labour	Overheads	Trucking	Material	Overheads	Transformer	Overheads	Contractor	Overheads	Total
Demolish and remove the annex and then design and build a new maintenance garage	$	$	$	$	$	$	$	$3,000,000	$	$3,000,000
Sub-total	$	$	$	$	$	$	$	$	$	$ 3,000,000
Contingency 10%	$	$	$	$	$	$	$	$	$	$ 300,000
Total	$	$	$	$	$	$	$	$	$	$ 3,300,000

Appendix Is-4

2-Staff-46s-b

VICE PRESIDENT'S REPORT
to the President

Corporate Division: Power System Division

Preparation Date: November 12, 2012

Board Meeting Date: November 22, 2012

Subject: ***New Maintenance Garage Update***

Purpose of Report

This report will provide information to the President and Board of Directors regarding the construction status for the new Maintenance Garage. The existing 1932 vintage maintenance garage building incorporates an attached cold storage room (Annex). Since the Annex is part of the new maintenance facility footprint, it will be demolished to facilitate the construction.

Comments

Thunder Bay Hydro's new Maintenance Garage budget for 2013 is $3.3M. Included in this budget is the use of an Owner's Engineer which was awarded to FORM Architecture Engineering. FORM will represent TBH and is tasked with reviewing the Design-Build proposal submissions, providing an award recommendation, and acting as the field project manager and contract and construction site intermediary for Thunder Bay Hydro. FORM's services will cost TBHEDI ~$66K.

Four construction proposal submissions were received (Manshield, Tom Jones, Northwest and Finnway). One of these was deemed non-compliant due to an incomplete submission (Finnway).The new maintenance garage project is being awarded to Tom Jones Corporation (TJC). TJC's submitted cost to build a 10,900 sq/ft maintenance garage was $3.183M.

TBH, FORM and representatives from TJC met on Friday November 9, 2012 to review the submitted proposal drawings, discuss project timelines and to identify items needing change or inclusion into the drawings before acceptance of the final drawings can occur. Follow up meetings between the three parties will occur weekly until final drawing acceptance occurs.

Formal contract signing is anticipated to occur on or before Friday November 16, 2012.

- TBH's acceptance of the final building design is anticipated by December 2012
- TJC is planning to apply for permitting in December 2012
- TJC will be ordering the building steel in December 2012
- TJC to demolish the Annex in January 2013
- Footprint excavation and construction starting in March 2013
- Planned building completion is by October 30, 2013

Respectfully Submitted: Don Zimak
Vice President, Power Systems

Signature:

PRESIDENT'S REPORT
to the Board of Directors

Item No. 2012 D8.9

Corporate Division: Distribution Company

Preparation Date: April 18, 2012

Board Meeting Date: April 26, 2012

Subject: ***FLEET MAINTENANCE FACILITY TENDER APPROVAL***

Purpose of Report

To obtain the Board's approval to proceed with the construction of a new Fleet Maintenance Facility with an adjusted projected budget.

Comments

The Board will recall that the 2011 Approved Capital Budget contained a provision of $1 million representing 50% of the total cost of constructing a new Fleet Maintenance building. The project was to span two years at a total projected cost of $2 million.
As the Board is aware, upon receiving competitive tenders from general contractors, management decided to make no contract award given that the tenders came in significantly over budget. (The attached document outlines the history of the tender and provides additional updated information for the information of the Board).
Given the variance between the budget and tender numbers, management felt it was prudent to review our planning assumptions as well as reconsider potential alternatives to constructing a new facility.

During this 'reconsideration' phase, the underlying conclusion that the existing facility has outlived its useful life and requires replacement did not change. In the past the Board has toured the facility and, having seen firsthand the state of the building, agreed with management's assessment that the facility requires replacement. As a reminder, while the exact age of the building is unknown, it is believed that portions of the building were constructed 80 plus years ago.

During the 'reconsideration', management revisited options including refurbishing the existing facility, outsourcing our fleet maintenance needs, and purchasing an existing off-site facility to which our fleet maintenance operations would be moved.

After discussion and analysis, these alternatives were rejected as being less efficient in the long term as compared to rebuilding the facility on site, immediately adjacent to the fleet which it services. Outside analysis has indicated the current building cannot be refurbished for a reasonable investment. Internal analysis has concluded that options which involve the wholesale contracting out of the maintenance function, or the relocation of that function any significant distance away from the Operations Centre would have significant negative impacts on the efficiency of the utility's operations, maintenance and construction activities. Given that the utility's annual construction program has more than doubled in the past 5 years, the ability to maintain high fleet availability is critical to maintaining productivity. It is predicted that moving the maintenance facility off-site might easily result in a 10% productivity decrease. The President will further discuss these other options if the Board desires.

In retrospect, the single issue that has delayed the construction of the Fleet Maintenance Facility is the fact that the utility initially received bad advice related to the construction cost of a new facility. Original estimates indicated that a modest facility could be constructed, and the old building could be demolished, for approximately $2 million. Obviously the original tenders came in significantly in excess of this amount. Recent information received from a local architectural firm estimates that the current cost to be approximately $3.6 million. In reviewing the architectural estimate, we believe that changes can be made to the manner in which the work is tendered and undertaken which would allow efficiencies to be gained. Management is therefore recommending that the Board approve the tendering of the Fleet Maintenance Facility with a project budget of $3.3 million.

The original 2011 Approved Capital Budget contained a provision of $1 million as the first funding component of this project. This budget provision was not expended. The 2012 Approved Capital Budget does not contain any provision for this project. Ultimately the capital investment required to replace the Fleet Facility will be included in the 2013 Cost of Service Rate Application to the OEB as part of the utility's capital investment plan. In the event that the 2013 OEB decision supports a capital investment program with less activity than is applied for, adjustments will be made to the long term infrastructure investment plan to accommodate the Fleet Facility investment. Simply stated, utility operations, maintenance and construction programs are totally reliant on a well maintained fleet, and the utility cannot continue to safely and effectively maintain this fleet in the current facility.

If any Director requires further information on this issue prior to the Board meeting they should not hesitate to contact the President directly.

Attachments

Thunder Bay Hydro's Maintenance Facility Construction Project Update

Recommendations

THAT, the Board of Directors approves a budget of $3,300,000 for the design and construction of a new Fleet Maintenance Building and the related demolition of the existing Annex and Fleet Maintenance Building

Respectfully Submitted: Robert Mace
President

Signature:

Item No. 2010 PSD 12

Corporate Division: Power System Division

Preparation Date: Sept 8, 2010

Board Meeting Date: Sept 23, 2010

***Subject*: Equipment Maintenance Facility ICM Application**

Purpose of Report

To provide information to the President and Board of Directors such that a decision can be made to endorse an Incremental Capital Application (ICM) to the Ontario Energy Board (OEB) for the inclusion of an additional $1.2M and $0.97M in 2011 and 2012 respectively for the construction of a new Equipment Maintenance Facility.

Comments

As per previous discussions with the board and Thunder Bay Hydro's (TBH's) latest Cost of Service (COS) Application to the OEB; TBH's assets require significant replacement given the extensive growth and construction of distribution plant in the 60's and 70's followed by low growth in the 90's to present day. TBH successfully presented a case to the OEB to increase its replacement distribution capital spending from historical levels of $3M to $10.3M which would represent a sustainable level of replacement distribution capital on a go forward basis.

TBH in its 2009 COS Application proposed to increase its distribution capital replacement program incrementally at approximately $800K per year. This would allow for a prudent, reasonable and manageable increase in its replacement distribution capital program.

TBH has followed the plan laid out in its 2009 COS Application. It has been efficient in managing it distribution capital program and has not only matched the proposed expenditures but also matched the proposed rate of distribution plant replacement.

Part of TBH's operation is the maintenance of work equipment which is undertaken in its maintenance garage. The garage is attached to another structure known as the annex which was used for the storage of material and equipment.

TBH has long been aware that these structures constructed in 1932 were in need of replacement. All resources have been directed at distribution plant replacement given the results of the condition/risk assessments carried out and in accordance with its 2009 COS Application. However, the condition of the annex has continued to deteriorate and is such that now it needs to be demolished due to concerns around the structural integrity of the building and roof. TBH has vacated the annex and is presently using sea cans for storage of materials that previously were kept in the annex.

The condition of the attached maintenance garage is also very poor and in need of replacement. TBH has concerns that the removal of the annex will leave the attached maintenance garage's structure unsupported and in a state of significant risk as well. The condition of the garage is such that rehabilitation is not an effective option as the costs to rehabilitate this structure would be similar if not exceed construction of a new steel building and yet still result in a lower life expectancy then replacement.

Contracting out the fleet service portion is not a viable alternative due to the specialized nature of the equipment involved, size of the fleet, turn around time by local service providers, and the inefficiencies of transporting vehicles to and from a service provider.

Estimates for the removal of the annex, maintenance garage and construction of a new maintenance garage are $2.0M. TBH is proposing to rebuild this facility staged over two years in order to minimize the rate impact to its customers. The expenditures would be $1.0M in 2011 and $1.0M in 2012.

The maintenance garage and annex building are 1932 vintage construction and have multiple areas of concern as listed below:

- The maintenance garage has a sloped floor (numerous issues received to date, ground penetrating radar confirmed in 2009 that a second floor exists under the current floor -- pricing to remove and replace the floor(s) was received in 2009 -- $120,000)
- The maintenance garage floor is sinking as evident with the +1/2" cracks and the concrete patch work that exists around the perimeter of the interior walls
- Fleet garage floor currently has an in-floor ladder type catch trough for water/oil collection that used to go to the COTB sewer system (since blanked off), although TBH uses oil absorption matting/pads throughout the various trough levels, this collection trough has cracks in the concrete and may have or may be leaching contaminates under the floor.
- Annex roof leaking (repair cost received for the flat annex roof was ~$50,000).
- The maintenance garage and annex structural issues (the outside and inside walls are cracking, the outside walls are bowed, the wall footings are separating from the floors – repair cost unknown).
- The maintenance garage west brick wall is deteriorating due to pre-1970 fire damage and is now "chalk like" – no drilling is allowing on the wall
- Maintenance garage / annex asbestos assessment (annex wall vermiculite was removed in 2009 – price to complete remaining ACM removal ~$40,000).

- The maintenance garage / annex lead paint (removal of the burgundy coloured paint in the annex was done in 2010 – price to complete remaining lead paint removal in the garage area is ~$30,000).
- Building security concerns (price to install a new internal sensing system, additional door sensors, and video surveillance is $30,000)
- The maintenance garage building ventilation does not meet today's minimum building code requirement for a repair / garage facility – cost to upgrade unknown.
- The maintenance garage ceiling is too low for completing some elevated repair work on the new larger line trucks (17'H ceiling 13'H bucket trucks) – cost to raise the roof unknown
- TBH has a large vehicle hoist ($45,000) that can't be used inside the fleet garage because of the sloped floor

TBH would have a facility that is functional, environmentally compliant, and would meet building/fire safety code requirements:

- Improved safety aspects (shower and eye wash facilities, access/egress doors spaced as per building code requirements, adequately sized vehicle entry doors, additional vehicle entry doors to eliminate maneuvering vehicles inside the shop)
- Improved ergonomics (flat floor, utilization of the large vehicle hoist would allow the mechanics to stand under the line trucks instead of lying under them), elevated ceiling height with overhead crane capability, enhanced lighting, ventilation and accessibility, and elevated storage facilities incorporated within the garage.
- Improved industrial hygiene via automatic air exchange devices – Carbon Dioxide sensing that is linked to supply and exhaust air fans.
- Fire suppression, annunciation, fire separation walls, and after hour monitoring capabilities.
- Improved environmental aspects (wash bay and the main shop will have a below ground storage tank to collect run-off water or fluid leaks, and the welding bay would have improved exhaust scrubbing capabilities)
- Improved operational components (separate wash bay, separate welding area, drive-through load out door, small tool repair area, and an oil storage/dispensing area).

Attachments

None

Recommendations

That the President endorses the ICM Application to the OEB for the construction of a new maintenance facility to be spread out over two years starting in 2011.

Respectfully Submitted: Emanuel DaRosa
Vice President, Power Systems

Signature:

Pictures of the Existing Maintenance Garage and Annex

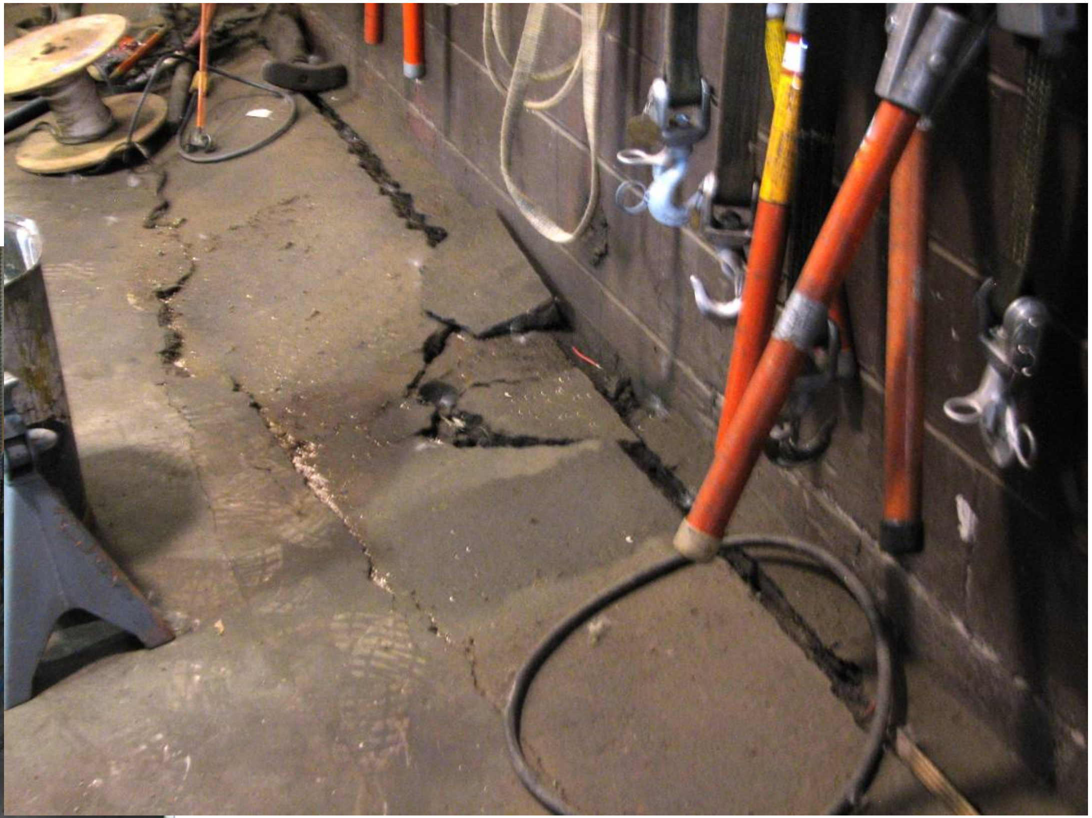
Emanuel DaRosa
Vice President, Power Systems
Thunder Bay Hydro
Power Systems Division

Sept 23, 2010

Maintenance Garage Pictures

Maintenance Garage Pictures

Maintenance Garage Pictures



Maintenance Garage Pictures

Maintenance Garage Pictures

Questions ??

"You can't help someone get up a hill without getting closer to the top yourself."

H. Norman Schwarzkopf

Appendix Is-5

4-Energy Probe-30s

Ontario Energy Board
Accounting Procedures Handbook
Frequently Asked Questions
August 2008

INDEX

New accounts approved for recording the disposition and recoveries/ refunds of deferral and variance account balances:

Q.1 For regulatory asset/liability balances of deferral and variance accounts approved for recovery in 2008 (e.g., as part of the 2008 EDR and IRM applications process), what account should be used to record these recoveries collected (or refunded) in rates?

A.1 The Board has approved a new control account to record the disposition and recoveries of deferral and variance account balances for electricity distributors receiving approval to recover (or refund) account balances in rates as part of the regulatory process. The account is 1595, Disposition and Recovery of Regulatory Balances Control Account. In addition, the Board approved Sub-account - Disposition of Account Balances Approved in 2008, to capture amounts approved for recovery (or refund) through the 2008 rate review process and a sub-account for carrying charges (i.e., Sub-account - Carrying Charges for Disposition of Account Balances Approved in 2008). The 1595 account and sub-accounts come into effect on May 1, 2008.

The Board may consider approving additional sub-accounts under this control account 1595 to accommodate the recording of disposition and recoveries of deferral and variance account balances, approved as part of other regulatory processes in the future.

Q.2 What items are recorded in the new sub-account of 1595 (Sub-account - Disposition of Account Balances Approved in 2008)?

A.2 Distributors approved to recover (or refund) account balances, as part of the 2008 regulatory process (i.e., 2008 EDR and 2008 IRM rate applications or other) will use this sub-account to record the approved amount of each regulatory asset/liability account approved for recovery (or refund). The offsetting entries will be to the respective approved regulatory asset/liability accounts to transfer the approved amount from those accounts into the new sub-account, inclusive of accumulated interest, if applicable. The date of these entries is the start of the recovery period, which normally coincides with the start of rate year for most distributors (e.g. May 1, 2008 or date specified by the Board).

In addition, the distributor will also record in the sub-account of 1595 the amounts recovered or refunded in rates over the approved period (e.g., May 1, 2008 to April 30, 2009, or period specified by the Board). These amounts will draw down the recoverable (or refundable) balance created in this sub-account.

Q.3 Do carrying charges apply to the 1595 sub-account (Sub-account - Disposition of Account Balances Approved in 2008)?

A.3 Yes. The Board-prescribed accounting interest rates will be applied to the monthly opening principal balance (i.e., net of refund/recovery and carrying charges) in this sub-account to calculate the carrying charge amounts. The distributor will record these carrying charges in account 1595, Sub-account - Carrying Charges for Disposition of Account Balances Approved in 2008, and the offsetting entry will be to account 4405 or 6035.

In addition, the distributor will need to segregate and record in a second separate sub-account the cumulative carrying charge balances transferred from the respective approved regulatory asset/liability accounts in Sub-account - Carrying Charges Transferred to Account 1595. No additional carrying charges will be added to these transferred amounts (i.e., no interest on interest is applicable). Consequently, only the principle amounts transferred to Sub-account - Disposition of Account Balances Approved in 2008, net of recoveries/refunds will be eligible for carrying charges.

Q.4 Do the residual balances in the sub-accounts of 1595 require Board review and approval?

A.4 The residual balances in principal and carrying charges sub-accounts at the end of the collection (or refund) period will require Board review and approval consistent with the requirements for other deferral and variance accounts. To facilitate review of the residual balance, the distributor should ensure finalization of collection of recoveries (or refunding) activities are completed. The timing associated with this usually coincides with the completion of a distributor's billing cycles to the end of the approved period and after recording all applicable revenues/refunds in the account. See also FAQ #6 below.

Q.5 Are there additional procedures for account balances approved for disposition and recovery on a forecast basis (e.g., forecast of an account balance as of a date not supported by year-end audited financial statements)?

A.5 In this circumstance, the distributor will record the approved forecast amount(s) in 1595 (sub-account) consistent with the requirements outlined in FAQ #2 above. However, the distributor will need to true up the forecasted amount(s) approved for disposition in rates to actual when the actual amount is verifiable (e.g. RRR submission of financial statements, USoA trial balance and quarterly balances, etc.). In addition, the distributor will need to bring forward the trued-up account balance(s) for Board review in a subsequent rate setting proceeding. In the interim period until the account is reviewed, the distributor should track the difference between the forecast and actual amounts in order to provide information needed for regulatory purposes and to facilitate the true up.

Additional guidance provided on the finalization and use of the previous disposition and recovery account (2004 - 2007 rate years):

Q.6 The Board has indicated that a future proceeding (post 2008) will address settlement of the residual balance in account 1590, Recovery of Regulatory Asset Balances, (after the approved recoveries/refunds are finalized and recorded). Are there additional accounting procedures needed to finalize the residual balance in the account?

A.6 A distributor's billing cycles for the regulatory asset/liability recovery (or refund) rate riders may not coincide with the date to the end of approved collection period of April 30, 2008 (or other date approved by the Board) and therefore straddle this date. The distributor should ensure distribution revenues generated by rate riders during these transition billing cycles are included as part of the regulatory asset recoveries and these amounts are recorded in account 1590. Accordingly, the distributor will need to track and record the regulatory asset rate rider(s) amounts in billings on or after April 30, 2008, as they occur. The discontinuance of a rate rider at the end of its approved term should be done on the same basis as the rate rider was initially phased in to ensure customers in the same billing cycles are not over charged (or over refunded).
A distributor should maintain records to support all entries in account 1590 to

facilitate disposition of the account balance in a Board proceeding or audit review in the future.

Q.7 Should recordings for regulatory asset recoveries continue in account 1590, where the distributor received Board approval to continue the 2006 EDR regulatory asset rate rider in rates after April 30, 2008?

A.7 The recording of these recoveries should continue in account 1590, Recovery of Regulatory Asset Balances. Also, in the circumstance where a distributor continues to recover interim rate recovery for prior years' regulatory assets (e.g. 2003 or 2004 account balances), the distributor should record these recoveries in this account and not account 1595.

Additional accounting guidance provided for smart meters revenue requirement approved in a rate order:

Q.8 Please provide an example for smart meter accounting where the distributor has received Board approval for its smart meters investment and the associated revenue requirement in a rate order.

A.8 The following example is provided to illustrate the accounting treatment applicable to the smart meters variance accounts upon the Board's review of a distributor's in-service smart meters, which results in the issuance of a rate order to the distributor. The information in this **illustrative example** is not precedent setting and does not imply Board approval of any smart meter policy matter. The specific approval of these matters in the individual decision and order of a distributor apply.

Assume a distributor filed an application with the Board in 2008. In the application, it shows that as of December 31, 2007, the distributor installed 15,000 smart meters in service for residential customers in 2007. At an average cost of $200, the investment in smart meters was $3,000,000 (15,000 × $200). As well, assume for simplicity, 15 years useful life and the half-rule for the in-service smart meters apply for amortization purposes. Note on an actual basis GAAP accounting treatment may differ. In addition, assume funding received for the smart meter initiative through a smart meter rate adder in the 2006 to 2007 period was $214,000. For simplicity, this illustration assumes there are no other concurrent smart meter investments or funding activities for the distributor.

Based on the revenue requirement calculation of $250,000 shown below, assume the Board issued a rate order, which included a rate adder effective May 1, 2008 for one year to recover the net revenue requirement amount of $36,000 from residential customers ($250,000 - $214,000). The journal entries for the variance and other related accounts are separately shown below in three sections: A. the initial recordings in the variance accounts; B. the reclassification to various accounts on issuance of rate order and; C. a summary of the account balances.

The accounting illustrated below in **Section A**, conforms to the Board's instructions outlined in a letter of June 13, 2006 to distributors in the period prior to Board review and approval of smart meters.

The ensuing issuance of the Board order approving the smart meters investment and the associated (net) revenue requirement for the smart meters in rates triggers the accounting recognition of the investment in smart meters as assets and the funding received for the smart meters as revenues. Consequently, this requires the accounting reclassification of these items recorded in the variance accounts to their applicable asset and revenue USoA accounts as shown in **Section B** below.

Following the reclassification clearance of amounts from the variance accounts to their applicable accounts, the balances in the variance accounts should be zero (assuming no other smart meter investment or funding activities) as shown in **Section C** below. Therefore, no true up of the 1555 and 1556 variance account balances are required or no recordings of the recoverable (or refundable) net revenue requirement amount in account 1595 are required.

In summary, the approved revenue requirement, net of the funding received for the period, results in a net revenue requirement amount of $36,000 recoverable in rates via an approved rate adder. This amount will be recorded in the distribution revenue account 4080 over the recovery period from May 1, 2008 to April 30, 2009 and not the smart meter variance accounts or account 1595.

Calculation of Smart Meters Approved Revenue Requirement per Assumptions Provided

Smart Meters as of December 31, 2007

Investment in Smart Meters (recorded in Account 1555)	$ 3,000,000	
(Assume 15,000 in-service residential meters @ $200 each)		
Carrying charges at prescribed interest rates (avg. 5%):		
Account 1555 (applied to net of investment and funding)	$ 69,650	
Account 1556 (applied to expenses on average basis)	2,919	
Total Interest (debit)	$ 72,569	
Return Calculation (per assumptions shown):		
Average smart meters in rate base (half-year average)	$ 1,500,000	
Return on rate base (assume 5.25%) deemed debt (60%)	900,000	$ 47,250
Return on rate base (assume 9.00%) deemed equity (40%)	600,000	54,000
Return on smart meters before PILs		$ 101,250
Add:		
OM&A expenses (recorded in Account 1556)		16,754
Amortization expense (recorded in Sub-account of 1556)		100,000
Carrying charges recoverable (recorded in Sub-account of 1556)		2,919
PILs gross-up (for simplicity 35% tax rate used, not actual tax rate)		29,077
Revenue Requirement		$ 250,000
Less:		
Funding collected in rates (recorded in Sub-account of 1555)		214,000
Approved Net Revenue Requirement		$ 36,000

Notes:

(1) The Board issued a rate order effective May 1, 2008 for the recovery of the Net Revenue Requirement amount of $36,000 through a rate adder for the residential rate class.

(2) There will be no future true-up of the $36,000 amount in the variance accounts because the residual amount is not recorded in a variance account. Consequently, the rate adder billed to customers will be recorded in distribution revenues (account 4080).

Illustrative Journal Entries per the Assumptions made for the Smart Meters Above

No.	Account	Description	Debit	Credit
	Section A - Initial Recordings in the Variance Accounts (Up to December 31, 2007)			
		(for simplicity shown on a cumulative basis up to Dec. 31, 2007)		
		Smart Meter Capital Asset		
1	1555	Smart Meter Capital & Recovery, Sub-account Capital	3,000,000	
	2205	Accounts Payable/Bank		3,000,000
		To record smart meter investment in variance account		
2	4080	Distribution Services Revenues-Residential	214,000	
	1555	Smart Meter Capital & Recovery, Sub-account Recovery		214,000
		To record smart meter ("seed money") funding in variance account		
3	1555	Smart Meter Cap. & Recov., Sub-account Carrying Charges	69,650	
	4405	Interest and Dividend Income		69,650
		To record carrying charges net of investments and funding amounts		
		Smart Meters OM&A Expenses		
1	5175	Maintenance of Meters	16,754	
	2205	Accounts Payable		16,754
		To record OM&A expenses (for simplicity one account used)		
2	5695	OM&A Contra Account	16,754	
	5175	Maintenance of Meters		16,754
		To transfer OM&A expenses to smart meter contra account		
3	1556	Smart Meter OM&A	16,754	
	5695	OM&A Contra Account		16,754
		To record OM&A expenses to variance account		
4	1556	Smart Meter OM&A, Sub-account Amortization Expense	100,000	
	1555	Smart Meter Cap. & Recov., Sub-account Accum. Amort.		100,000
		To record smart meter amortization expense		
5	1556	Smart Meter OM&A, Sub-account Carrying Charges	2,919	
	4405	Interest and Dividend Income		2,919
		To record carrying charges		

No.	Account	Description	Debit	Credit
	Section B - Reclassification to Various Accounts on Issuance of Rate Order (as of May 1, 2008)			
		Smart Meter Capital Asset		
1	1860	Meters, Sub-account Smart Meters - Residential	3,000,000	
	1555	Smart Meter Capital and Recovery, Sub-account Capital		3,000,000
		To transfer approved smart meters to asset account		
2	1555	Smart Meter Cap. & Recov., Sub-account Accum. Amort.	100,000	
	2105	Accumulated Amortization, Sub-account Smart Meters		100,000
		To transfer accumulated amortization to asset account		
3	4405	Interest and Dividend Income	69,650	
	1555	Smart Meter Cap. & Recov., Sub-account Carrying Charges		69,650
		To reverse carrying charges as return on asset provides long-term interest for recovery		
		Smart Meters OM&A Expenses		
1	5695	OM&A Contra Account	16,754	
	1556	Smart Meter OM&A		16,754
		To transfer approved OM&A expenses to contra account		
2	5175	Maintenance of Meters	16,754	
	5695	OM&A Contra Account		16,754
		To transfer OM&A expenses to expense account		
3	5705	Amortization Expense, Sub-account Smart Meters	100,000	
	1556	Smart Meter OM&A, Sub-account Amortization Expense		100,000
		To transfer amortization expense to expense account		
4	4405	Interest and Dividend Income	2,919	
	1556	Smart Meter OM&A, Sub-account Carrying Charges		2,919
		To reverse carrying charges, which are included in the revenue reqmt.		
		(Note: Re-recognized as revenue when collected in future rates)		
5	1555	Smart Meter Capital and Recovery, Sub-account Recovery	214,000	
	4080	Distribution Services Revenues - Residential		214,000
		To transfer funds (previously collected) to revenue account		

No.	Account	Description	Debit	Credit
	Section C - Summary of Account Balances (As of May 1, 2008)			
	1555	Smart Meter Capital and Recovery	0	
	1556	Smart Meter OM&A	0	
	1860	Meters, Sub-account Smart Meters - Residential	3,000,000	
	2105	Accumulated Amortization, Sub-account Smart Meters	100,000	
	4080	Distribution Services Revenues - Residential		214,000
	4405	Smart Meter Cap. & Recov., Sub-account Carrying Charges	0	
	5175	Maintenance of Meters	16,754	
	5695	OM&A Contra Account	0	
	5705	Amortization Expense, Sub-account Smart Meters		100,000
	NB	The net revenue requirement amount of $36,000 to be recovered in rates		
		will be recorded in account 4080		

Pro-forma Partial Income Statement (April 30, 2009 assuming no other transactions)

Revenues:		
Distribution 4080 (prior rate adder)	214,000	
Distribution 4080 (new adder May 1, 2008 to Apr 30, 2009)	36,000	250,000
Expenses:		
OM&A	16,754	
Amortization	100,000	
Long-term interest (per return on asset)	47,250	
PILs (for simplicity gross-up and expense assumed same)	29,077	193,081
Net Income (1)		**56,919**

(1) Comprised of return and carrying charges ($54,000 + $2,919)

Pro-forma Partial Balance Sheet (April 30, 2009 assuming no other transactions)

Fixed Assets:	
Smart Meters - Residential	2,900,000
Regulatory Assets (Smart Meters):	
Balance in Account 1555	0
Balance in account 1556	0

Q.9 The distributor received a rate order that included approval of the revenue requirement for smart meters installed up to April 30, 2007, as part of the 2008 IRM application process. The rate order approved a rate adder for the smart meters (net) revenue requirement effective in rates on May 1, 2008. No revenue requirement was approved for these smart meters in the past. How should the distributor account for the smart meters and the rate adder?

A.9 The distributor should follow the guidance provided above in FAQ #8. Due to the Board's approval of the smart meters and the associated (net) revenue requirement for the smart meters in a rate order, this triggers the accounting recognition criteria for assets and revenues. Accordingly, this requires the reclassifications of items and amounts recorded in the variance accounts 1555 and 1556 to their applicable asset and revenue accounts as shown in Section B of Answer #8 above.

The revenues (or refunds) derived for the net revenue requirement via a rate adder or a permanent rate adder in the approved rate order are recorded in account 4080, as indicated in FAQ #8, <u>not</u> the smart meter variance accounts or account 1595.

Q.10 How should the distributor account for the additional smart meter installations after receiving approval of the initial/previous smart meter revenue requirement in a rate order (as cited in FAQs 8 and 9 above)?

A.10 Board review and approval of all smart meters installations, whether initial or additions, are required. Until such time the Board issues an order approving the revenue requirement associated with the additional smart meters, the accounting treatment for the variance accounts should continue in the same manner as cited above in FAQ# 8 Section A, Initial Recordings in Variance Accounts, in accordance with the Board's instructions in a letter of June 13, 2006 to distributors.

When the Board reviews and approves the additional smart meter installations through the approval of the (net) revenue requirement in a rate order, the accounting treatment cited above in FAQ #8, Section B, Reclassification to Various Accounts on Issuance of Rate Order, applies.

Q.11 By letter of January 16, 2007, the Board issued an accounting instruction related to stranded meter costs. This included the requirement to record in a new sub-account of account 1555 the stranded costs associated with conventional or accumulation meters removed at the time of installation of smart meters. Has this accounting requirement changed in light of Board decisions and orders related to this matter?

A.11 This account was provided to allow for the accounting of the impairment of conventional meter assets (or stranded asset costs) to conform to the requirements under GAAP and to allow the Board flexibility to decide how this matter can be dealt with through the review of distributors' applications. Accordingly, where the Board has approved a distributor's proposal for stranded meter costs treatment in a decision and/or order, the distributor should follow the distributor-specific instruction or direction related to the treatment of the stranded meter costs provided in the decision and/or order.

Additional accounting guidance provided for CDM transactions:

Q.12 What is the accounting treatment for fixed assets arising from a distributor's conservation and demand management (CDM) activities, which have been funded through the Ontario Power Authority (OPA) programs?

A.12 The Board does not regulate CDM programs of electricity distributors funded through OPA or other initiatives outside the distribution rates framework (referred to here collectively as "non-utility" activities). The transactions arising from such activities should be separate from distribution activities.

The distributor will use account 2075, Non-Utility Property Owned or Under Capital Leases, to record capital assets funded or created by OPA or other non-utility activities. These assets are not included in rate base and the associated amortization expenses are not included in the revenue requirement of the distributor.

In addition, the distributor will record transactions arising from non-utility CDM revenues and expenses in account 4375, Revenues from Non-Utility Operations, and 4380, Expenses from Non-Utility Operations, respectively. These amounts also are not included in the revenue requirement. Separate sub-accounts under accounts 2075, 4375 and 4380 should be used to differentiate these CDM transactions from other non-utility transactions.

Q.13 Should the recording of CDM expenses continue in account 1565 for the 3rd tranche CDM spending where the distributor has received approval to continue spending after September 30, 2007?

A.13 The recording of these expenses should continue in account 1565 and contra account 1566.

Accounting guidance provided for various other items and accounts:

Q.14 Hydro One distribution received Board approval to continue its regulatory assets – phase II rate rider (established in the Board's 2004 proceeding Final Recovery of Regulatory Assets - Phase II) on an interim basis until the establishment of its new rates for 2008. As a result, the historic low voltage (LV) charges included in Hydro One's regulatory assets – phase II rate rider will continue as a charge to embedded distributors beyond April 30, 2008.

How should the distributor account for these LV charges in the period from May 1, 2008 until an order is issued to discontinue the charge?

A.14 Accounting guidance on the treatment for LV charges arising from Hydro One regulatory asset recoveries was provided in APH-FAQs December 2005 (#8 Scenarios A and B). Note that while the scenarios cite an earlier period, the May 1, 2006 date (i.e., effective date of 2006 EDR regulatory assets approval for most distributors) can be substituted for the April 1, 2005 date in scenario A to make these examples germane to most distributors.

The accounting procedures in the original set-up of a distributor's books on recognition of the total historic Hydro One LV charges was to debit account 1586 and credit account 2405 (liability). On approval of the LV recorded in 1586, the distributor was required to transfer this amount to account 1590 for recovery purposes. The liability associated with the LV recorded in 2405 was reduced by amounts (charged by and) paid to Hydro One over a 36-months period (shown in Entry 5, December 2005 FAQ #8 example). Entry 5 is especially important to consider in light of the continuation of the Hydro One's LV charges after April 30, 2008.

Procedures to address the continuation of LV charges after April 30, 2008 (through the Hydro One regulatory asset rate rider) are as follows.

1. The distributor should determine whether the Hydro One LV charges up to April 30, 2008 cover the obligation (originally) recorded in 2405. (Note in the December 2005 FAQ #8 example, this was journal entry #1 for an amount of $90,000.)

2. If the LV obligation amount in account 2405 is Nil as of April 30, 2008, recordings to this account should cease. If not, recordings should continue until such time that the obligation amount reduces to Nil.

3. When the account 2405 amount is nil, all Hydro One charges after April 30, 2008 should be recognized as LV expenses and therefore recorded in account 4750, Charge – LV.

4. In the case of a distributor where the distributor's regulatory asset rate rider continues after April 30, 2008, these recoveries should continue to be record in account 1590. However, the portion attributable to the LV recovery should be transferred to account 4075, Billed – LV.

5. Lastly, Account1550, LV Variance Account, will record the net of amounts recorded in accounts 4075 and 4750. Accounting guidance on account 1550 was provided in the Board's letter of June 13, 2006 to distributors.

In summary, these procedures address the need to draw down the (original) obligation in account 2405 to Nil, record the subsequent LV charges after April 30, 2008, as expenses in account 4750 and, if applicable, record any LV recoveries included in the distributor's own regulatory asset rate rider continued after April 30, 2008, in account 4075. In terms of the disposition of amounts recorded in account 1550, the distributor can bring this forward in a future rate-setting proceeding.

Q.15 The Market Rules for the Transitional Arrangements of Wholesale Metering requires distributors that are metered market participants to acquire wholesale meters from Hydro One (transmission) and to arrange for servicing of these meters through a meter service provider. Please advise where the distributor should record the items listed below.

a) Assets: the distributor acquires wholesale meters at $5,200 per meter point (i.e., exit fee paid to Hydro One).

b) Expenses (in two situations): i) the distributor's expenses associated with servicing the acquired wholesale meter, and ii) the distributor's expenses related to Hydro One's $6,200 per meter point annual charge for wholesale meter services in the case where the distributor did not acquire the wholesale meter point.

c) Rebates: the distributor's receipt of $5,700 per meter point annually up to October 31, 2008, for Hydro One's avoided cost for not providing service in the transition period where the distributor acquired a meter point.

A.15 The following are the answers in respect to each of the above-noted items:

a) Asset – meter acquisition at $5,200

Distributors will record acquired metering points based on a payment of $5,200 exit fee per wholesale meter in sub-accounts of the following accounts:

- 1815, Transformer Station Equipment- Normally Primary Above 50kV, if the meter operates at voltages above 50kV, or
- 1820, Distribution Station Equipment – Normally Primary Below 50kV, if the meter operates at voltages below 50kV.

The Hydro One wholesale meter point charge of $5,200 amount is the net book value of the wholesale meters approved by the Board.

b) Expenses – i) distributor service expenses for acquired meter point ii) distributor fees paid for meter point not yet acquired

i) If the acquired meter point (asset) is recorded in account 1815, the expenses associated with the wholesale meter are recorded in account 5014, Transformer Station Equipment – Operating Labour, 5015, Transformer Station Equipment – Operating Supplies and Expense, or 5112, Maintenance of Transformer Station Equipment, as applicable. If the acquired meter point (asset) is recorded in account 1820, the expenses associated with the wholesale meter are recorded in account 5016, Distribution Station Equipment – Operating Labour, 5017, Distribution Station Equipment – Operating Supplies and Expense, or 5114, Maintenance of Distribution Station, as applicable.

ii) Effective November 1, 2007, the Hydro One approved fee is $6,200 per wholesale meter point in respect to services rendered to metered market participants (distributors included) for a meter point not yet acquired from Hydro One. This charge was approved as part of Hydro One's transmission rate order effective November 1, 2007. There is no account that specifically captures this type of wholesale meter fee in the electricity USoA. Due to the transitional nature of the metering fee effective until the metering point is acquired, a sub-account of account 5085, Miscellaneous Distribution Expense, can be used.

c) Rebates – avoided cost for service in the transition period ($5,700/ meter point)

The rebates provided annually for each meter point up to October 31, 2007 are offsets to distributors' expenses for servicing the acquired wholesale meters. Since they are not revenues derived through distribution rates, a distributor can elect (optional) to record the rebates of $5,700 per meter point as a credit in expense account 5112, Maintenance of Transformer Station Equipment or 5114, Maintenance of Distribution Station Equipment, depending to which asset account the acquired meters are recorded (i.e. account 1815 or 1820).

This treatment allows the matching of the rebate amounts with the wholesale meter service expenses (new costs) within one account in the wholesale metering transitional arrangement period.

The rebate payments served as avoided costs to Hydro One, the benefit of which was passed to metered market participants that acquired and serviced metering points. Effective November 1, 2007, Hydro One's new rate order was adjusted to remove the recovery of these expenses from rates. With this rate adjustment, the rebate payments have ceased.

Q.16 Is the mid-term yield data used to set the prescribed accounting interest rates for the CWIP (construction work in progress) account publicly available?

A.16 The original source reference used to determine the prescribed interest rate for the CWIP account, the Scotia Capital Inc. All Corporates Average Weighted Yield Mid-Term, was publicly available on the Bank of Canada's website until July 2007. The Board currently obtains this yield data under a licence with PC-Bond, a business unit of TSX Inc. The mid-term yield data used for the CWIP account was renamed DEX Mid Term Corporate Bond Index Yield.

The Board is not authorized to publish the PC-Bond yield data under the terms of the licence. However, to accommodate interested parties wishing to view the yield data, a copy of the data obtained from PC-Bond is available for public viewing at the Information Resource Centre of the Board's Office. The photocopying of this material is prohibited.

Q.17 An APH update was issued in July 2007. Were there any minor adjustments or corrections identified after the update?

A.17 The following amendments will be required in a future revision of the APH (except item # 3 below, which has been adjusted).

1) Reference: Article 220, page 23; account 1550, Paragraph D is not applicable and will be removed.

2) Reference: Article 220, page 34; account 1586, Paragraph A refers to "transmission network services." This reference is incorrect and will be replaced with "transmission connection services."

3) Reference: Article 220, page 46; the page-numbering sequence after page 46 continues as page 30 instead of page 47. An adjustment was made to reflect the correct page numbering in the current version (July 2007) of the APH on the OEB website (www.oeb.gov.on.ca).

4) Reference: Article 220, pages 124 and 125; account descriptions for accounts 4375 and 4380 provide date references of up to or until “Dec 31, 2004” to record “water or sewage services” in these accounts. This date restriction no longer applies and therefore water or sewage service transactions should continue to be recorded in these accounts. The date references will be removed from these accounts.

5) Reference: Article 410, page 6; CICA Handbook section references 3461.04 and 3461.10 are incorrect and will be replaced with 3061.04 and 3061.10 respectively.

Appendix Is-6

7-AMPCO-38s

File Number:	EB-2012-0167
Exhibit:	1
Tab:	2
Schedule:	1
Page:	5
Date:	March 25, 2013

Appendix 2-W
Bill Impacts

Table 1-2.1: Bill Impact: Residential and General Service Less than 50kW

Customer Class: **Residential**

Consumption 800 **kWh** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 9.8500	1	$ 9.85	$ 13.6500	1	$ 13.65	$ 3.80	38.58%
Smart Meter Incremental Rev Req	Monthly	$ 1.8667	1	$ 1.87	$ -	1	$ -	$ (1.87)	(100.00%)
Distribution Volumetric Rate	per kWh	$ 0.0124	800	$ 9.92	$ 0.0131	800	$ 10.48	$ 0.56	5.65%
Smart Meter Disposition Rider	Monthly	$ (1.3167)	1	$ (1.32)	$ (1.3167)	1	$ (1.32)	$ -	0.00%
LRAM & SSM Rate Rider	per kWh	$ 0.00004	800	$ 0.03	$ -	800	$ -	$ (0.03)	(100.00%)
Stranded Asset Rate Rider	Monthly	$ -	1	$ -	$ 2.2700	1	$ 2.27	$ 2.27	
Sub-Total A				$ 20.35			$ 25.08	**$ 4.73**	**23.25%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0034)	800	$ (2.72)	$ (0.0028)	800	$ (2.24)	$ 0.48	(17.65%)
Tax Charge Rate Rider	per kWh	$ (0.0003)	800	$ (0.24)		800	$ -	$ 0.24	(100.00%)
GEA Funding Adder	Monthly				$ 0.0022	1	$ 0.00	$ 0.00	
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 17.39**			**$ 22.85**	**$ 5.45**	**31.36%**
RTSR - Network	per kWh	$ 0.0064	836	$ 5.35	$ 0.0064	827	$ 5.30	$ (0.05)	(1.01%)
RTSR - Line and Transformation Connection	per kWh	$ 0.0049	836	$ 4.10	$ 0.0048	827	$ 3.97	$ (0.12)	(3.03%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 26.84**			**$ 32.11**	**$ 5.27**	**19.66%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	836	$ 4.35	$ 0.0052	827	$ 4.30	$ (0.04)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	836	$ 0.92	$ 0.0011	827	$ 0.91	$ (0.01)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	836	$ 5.85	$ 0.0070	827	$ 5.79	$ (0.06)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	800	$ 59.20	$ 0.0740	800	$ 59.20	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	535	$ 33.70	$ 0.0630	530	$ 33.36	$ (0.34)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	150	$ 14.89	$ 0.0990	149	$ 14.74	$ (0.15)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	150	$ 17.75	$ 0.1180	149	$ 17.57	$ (0.18)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 97.40**			**$ 102.57**	**$ 5.16**	**5.30%**
HST		13%		$ 12.66	13%		$ 13.33	$ 0.67	5.30%
Total Bill (including HST)				$ 110.07			$ 115.90	$ 5.83	5.30%
Ontario Clean Energy Benefit [1]				$ (11.01)			$ (11.59)	$ (0.58)	5.27%
Total Bill on RPP (including OCEB)				**$ 99.06**			**$ 104.31**	**$ 5.25**	**5.30%**
Total Bill on TOU (before Taxes)				**$ 104.55**			**$ 109.04**	**$ 4.49**	**4.29%**
HST		13%		$ 13.59	13%		$ 14.18	$ 0.58	4.29%
Total Bill (including HST)				$ 118.14			$ 123.22	$ 5.07	4.29%
Ontario Clean Energy Benefit [1]				$ (11.81)			$ (12.32)	$ (0.51)	4.32%
Total Bill on TOU (including OCEB)				**$ 106.33**			**$ 110.90**	**$ 4.56**	**4.29%**
Loss Factor (%)		4.48%			3.42%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

File Number:	EB-2012-0167
Exhibit:	1
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Schedule:	1
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Date:	November 8, 2012

Appendix 2-W
Bill Impacts

Customer Class: **General Service Less Than 50 kW**

Consumption **2000** **kWh** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 3

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 17.8400	1	$ 17.84	$ 27.5800	1	$ 27.58	$ 9.74	54.60%
Smart Meter Incremental Rev Req	Monthly	$ 6.8417	1	$ 6.84	$ -	1	$ -	$ (6.84)	(100.00%)
Distribution Volumetric Rate	per kWh	$ 0.0130	2000	$ 26.00	$ 0.0139	2000	$ 27.80	$ 1.80	6.92%
Smart Meter Disposition Rider	Monthly	$ 3.4917	1	$ 3.49	$ 3.4917	1	$ 3.49	$ -	0.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0002	2000	$ 0.40	$ -	2000	$ -	$ (0.40)	(100.00%)
Stranded Asset Rate Rider	Monthly		1	$ -	$ 6.5200	1	$ 6.52	$ 6.52	
Sub-Total A				$ 54.57			$ 65.39	**$ 10.82**	**19.82%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0030)	2000	$ (6.00)	$ (0.0035)	2000	$ (7.00)	$ (1.00)	16.67%
Tax Charge Rate Rider	per kWh	$ (0.0002)	2000	$ (0.40)	$ -	2000	$ -	$ 0.40	(100.00%)
GEA Funding Adder	Monthly				$ 0.0022	1	$ 0.00	$ 0.00	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 48.17**			**$ 58.39**	**$ 10.22**	**21.22%**
RTSR - Network	per kWh	$ 0.0061	2090	$ 12.75	$ 0.0061	2068	$ 12.62	$ (0.13)	(1.01%)
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	2090	$ 9.61	$ 0.0046	2068	$ 9.51	$ (0.10)	(1.01%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 70.53**			**$ 80.53**	**$ 9.99**	**14.17%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2090	$ 10.87	$ 0.0052	2068	$ 10.76	$ (0.11)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2090	$ 2.30	$ 0.0011	2068	$ 2.28	$ (0.02)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2090	$ 14.63	$ 0.0070	2068	$ 14.48	$ (0.15)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	1000	$ 87.00	$ 0.0870	1000	$ 87.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0630	1337	$ 84.25	$ 0.0630	1324	$ 83.40	$ (0.85)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	376	$ 37.24	$ 0.0990	372	$ 36.86	$ (0.38)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	376	$ 44.38	$ 0.1180	372	$ 43.93	$ (0.45)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 259.57**			**$ 269.29**	**$ 9.71**	**3.74%**
HST		13%		$ 33.74	13%		$ 35.01	$ 1.26	3.74%
Total Bill (including HST)				$ 293.32			$ 304.29	$ 10.97	3.74%
Ontario Clean Energy Benefit [1]				$ (29.33)			$ (30.43)	$ (1.10)	3.75%
Total Bill on RPP (including OCEB)				**$ 263.99**			**$ 273.86**	**$ 9.87**	**3.74%**
Total Bill on TOU (before Taxes)				**$ 264.45**			**$ 272.48**	**$ 8.03**	**3.04%**
HST		13%		$ 34.38	13%		$ 35.42	$ 1.04	3.04%
Total Bill (including HST)				$ 298.82			$ 307.90	$ 9.07	3.04%
Ontario Clean Energy Benefit [1]				$ (29.88)			$ (30.79)	$ (0.91)	3.05%
Total Bill on TOU (including OCEB)				**$ 268.94**			**$ 277.11**	**$ 8.16**	**3.04%**
Loss Factor (%)		4.48%			3.42%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **General Service 50 to to 999 kW**

Consumption 100 **kW** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 241.7800	1	$ 241.78	$ 286.4500	1	$ 286.45	$ 44.67	18.48%
Distribution Volumetric Rate	per kW	$ 1.3603	100	$ 136.03	$ 1.5948	100	$ 159.48	$ 23.45	17.24%
LRAM & SSM Rate Rider	per kW	$ 0.00011			$ -			$ -	
Sub-Total A				$ 377.81			$ 445.93	**$ 68.12**	**18.03%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (0.9127)	100	$ (91.27)	$ (1.4580)	100	$ (145.80)	$ (54.53)	59.75%
Global Adjustment Rate Rider	per kW	$ (0.1051)	100	$ (10.51)	$ 0.7802	100	$ 78.02	$ 88.53	(842.34%)
Tax Charge Rate Rider	per kW	$ (0.0410)	100	$ (4.10)	$ -	100	$ -	$ 4.10	(100.00%)
GEA Funding Adder	Monthly				$ 0.0022	1	$ 0.00	$ 0.00	
Smart Meter Entity Charge					$ -	100	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 271.93**			**$ 378.15**	**$ 106.22**	**39.06%**
RTSR - Network	per kW	$ 2.4300	104	$ 253.89	$ 2.4130	103	$ 249.55	$ (4.33)	(1.71%)
RTSR - Line and Transformation Connection	per kW	$ 1.7458	104	$ 182.40	$ 1.7275	103	$ 178.66	$ (3.74)	(2.05%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 708.22**			**$ 806.36**	**$ 98.15**	**13.86%**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	104	$ 0.54	$ 0.0052	103	$ 0.54	$ (0.01)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	104	$ 0.11	$ 0.0011	103	$ 0.11	$ (0.00)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	104	$ 0.73	$ 0.0070	103	$ 0.72	$ (0.01)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	100	$ 7.40	$ 0.0740	100	$ 7.40	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kW	$ 0.0630	67	$ 4.21	$ 0.0630	66	$ 4.17	$ (0.04)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	19	$ 1.86	$ 0.0990	19	$ 1.84	$ (0.02)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	19	$ 2.22	$ 0.1180	19	$ 2.20	$ (0.02)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 717.26**			**$ 815.39**	**$ 98.13**	**13.68%**
HST		13%		$ 93.24	13%		$ 106.00	$ 12.76	13.68%
Total Bill (including HST)				$ 810.50			$ 921.39	$ 110.89	13.68%
Ontario Clean Energy Benefit [1]				$ (81.05)			$ (92.14)	$ (11.09)	13.68%
Total Bill on RPP (including OCEB)				**$ 729.45**			**$ 829.25**	**$ 99.80**	**13.68%**
Total Bill on TOU (before Taxes)				**$ 718.15**			**$ 816.20**	**$ 98.05**	**13.65%**
HST		13%		$ 93.36	13%		$ 106.11	$ 12.75	13.65%
Total Bill (including HST)				$ 811.51			$ 922.30	$ 110.79	13.65%
Ontario Clean Energy Benefit [1]				$ (81.15)			$ (92.23)	$ (11.08)	13.65%
Total Bill on TOU (including OCEB)				**$ 730.36**			**$ 830.07**	**$ 99.71**	**13.65%**

Loss Factor (%) Current: 4.48% Proposed: 3.42%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: General Service 50 to to 999 kW Interval Metered

Consumption 100 kW ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 241.7800	1	$ 241.78	$ 286.4500	1	$ 286.45	$ 44.67	18.48%
Distribution Volumetric Rate	per kW	$ 1.3603	100	$ 136.03	$ 1.5948	100	$ 159.48	$ 23.45	17.24%
LRAM & SSM Rate Rider	per kW	$ 0.00011			$ -			$ -	
Sub-Total A				$ 377.81			$ 445.93	**$ 68.12**	**18.03%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (0.9127)	100	$ (91.27)	$ (1.4580)	100	$ (145.80)	$ (54.53)	59.75%
Global Adjustment Rate Rider	per kW	$ (0.1051)	100	$ (10.51)	$ 0.7802	100	$ 78.02	$ 88.53	(842.34%)
Tax Charge Rate Rider	per kW	$ (0.0410)	100	$ (4.10)	$ -	100	$ -	$ 4.10	(100.00%)
GEA Funding Adder	Monthly				$ 0.0022	1	$ 0.00	$ 0.00	
Smart Meter Entity Charge					$ -	100	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 271.93**			**$ 378.15**	**$ 106.22**	**39.06%**
RTSR - Network	per kW	$ 2.5777	104	$ 269.32	$ 2.5597	103	$ 264.72	$ (4.59)	(1.71%)
RTSR - Line and Transformation Connection	per kW	$ 1.9295	104	$ 201.59	$ 1.9093	103	$ 197.46	$ (4.13)	(2.05%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 742.84**			**$ 840.34**	**$ 97.49**	**13.12%**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	104	$ 0.54	$ 0.0052	103	$ 0.54	$ (0.01)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	104	$ 0.11	$ 0.0011	103	$ 0.11	$ (0.00)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	104	$ 0.73	$ 0.0070	103	$ 0.72	$ (0.01)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	100	$ 7.40	$ 0.0740	100	$ 7.40	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kW	$ 0.0630	67	$ 4.21	$ 0.0630	66	$ 4.17	$ (0.04)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	19	$ 1.86	$ 0.0990	19	$ 1.84	$ (0.02)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	19	$ 2.22	$ 0.1180	19	$ 2.20	$ (0.02)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 751.88**			**$ 849.36**	**$ 97.48**	**12.96%**
HST		13%		$ 97.74	13%		$ 110.42	$ 12.67	12.96%
Total Bill (including HST)				$ 849.63			$ 959.78	$ 110.15	12.96%
Ontario Clean Energy Benefit [1]				$ (84.96)			$ (95.98)	$ (11.02)	12.97%
Total Bill on RPP (including OCEB)				**$ 764.67**			**$ 863.80**	**$ 99.13**	**12.96%**
Total Bill on TOU (before Taxes)				**$ 752.78**			**$ 850.17**	**$ 97.40**	**12.94%**
HST		13%		$ 97.86	13%		$ 110.52	$ 12.66	12.94%
Total Bill (including HST)				$ 850.64			$ 960.69	$ 110.06	12.94%
Ontario Clean Energy Benefit [1]				$ (85.06)			$ (96.07)	$ (11.01)	12.94%
Total Bill on TOU (including OCEB)				**$ 765.58**			**$ 864.62**	**$ 99.05**	**12.94%**

	Current	Proposed
Loss Factor (%)	4.48%	3.42%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **General Service 1,000 to 4,999 kW**

Consumption 2000 **kW** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 2,794.5500	1	$ 2,794.55	$ 1,845.4100	1	$ 1,845.41	$ (949.14)	(33.96%)
Distribution Volumetric Rate	per kW	$ 2.2314	2000	$ 4,462.80	$ 1.6725	2000	$ 3,345.00	$ (1,117.80)	(25.05%)
Sub-Total A				$ 7,257.35			$ 5,190.41	**$ (2,066.94)**	**(28.48%)**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (0.7755)	2000	$ (1,551.00)	$ (1.3230)	2000	$ (2,646.00)	$ (1,095.00)	70.60%
Global Adjustment Rate Rider	per kW	$ (0.0924)	2000	$ (184.80)	$ 0.7057	2000	$ 1,411.40	$ 1,596.20	(863.74%)
Tax Charge Rate Rider	per kW	$ (0.0371)	2000	$ (74.20)	$ -	2000	$ -	$ 74.20	(100.00%)
GEA Funding Adder	Monthly				$ 0.0022	1	$ 0.00	$ 0.00	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 5,447.35**			**$ 3,955.81**	**$ (1,491.54)**	**(27.38%)**
RTSR - Network	per kW	$ 2.5777	2090	$ 5,386.36	$ 2.5597	2068	$ 5,294.48	$ (91.88)	(1.71%)
RTSR - Line and Transformation Connection	per kW	$ 1.9295	2090	$ 4,031.88	$ 1.9093	2068	$ 3,949.20	$ (82.69)	(2.05%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 14,865.60**			**$ 13,199.49**	**$ (1,666.10)**	**(11.21%)**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	2090	$ 10.87	$ 0.0052	2068	$ 10.76	$ (0.11)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	2090	$ 2.30	$ 0.0011	2068	$ 2.28	$ (0.02)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	2090	$ 14.63	$ 0.0070	2068	$ 14.48	$ (0.15)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	1000	$ 87.00	$ 0.0870	1000	$ 87.00	$ -	0.00%
TOU - Off Peak	per kW	$ 0.0630	1337	$ 84.25	$ 0.0630	1324	$ 83.40	$ (0.85)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	376	$ 37.24	$ 0.0990	372	$ 36.86	$ (0.38)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	376	$ 44.38	$ 0.1180	372	$ 43.93	$ (0.45)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 15,054.64**			**$ 13,388.25**	**$ (1,666.39)**	**(11.07%)**
HST		13%		$ 1,957.10	13%		$ 1,740.47	$ (216.63)	(11.07%)
Total Bill (including HST)				$ 17,011.74			$ 15,128.72	$ (1,883.02)	(11.07%)
Ontario Clean Energy Benefit [1]				$ (1,701.17)			$ (1,512.87)	$ 188.30	(11.07%)
Total Bill on RPP (including OCEB)				**$ 15,310.57**			**$ 13,615.85**	**$ (1,694.72)**	**(11.07%)**
Total Bill on TOU (before Taxes)				**$ 15,059.51**			**$ 13,391.44**	**$ (1,668.07)**	**(11.08%)**
HST		13%		$ 1,957.74	13%		$ 1,740.89	$ (216.85)	(11.08%)
Total Bill (including HST)				$ 17,017.25			$ 15,132.33	$ (1,884.92)	(11.08%)
Ontario Clean Energy Benefit [1]				$ (1,701.72)			$ (1,513.23)	$ 188.49	(11.08%)
Total Bill on TOU (including OCEB)				**$ 15,315.53**			**$ 13,619.10**	**$ (1,696.43)**	**(11.08%)**

Loss Factor (%) 4.48% 3.42%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Umetered Scattered Load**

Consumption 150 **kWh** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 8.9100	1	$ 8.91	$ 9.6700	1	$ 9.67	$ 0.76	8.53%
Distribution Volumetric Rate	per kWh	$ 0.0130	150	$ 1.95	$ 0.0141	150	$ 2.12	$ 0.17	8.46%
Sub-Total A				$ 10.86			$ 11.79	**$ 0.93**	**8.52%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0044)	150	$ (0.66)	$ (0.0036)	150	$ (0.54)	$ 0.12	(18.18%)
Tax Charge Rate Rider	per kWh	$ (0.0005)	150	$ (0.08)	$ -	150	$ -	$ 0.08	(100.00%)
Smart Meter Entity Charge					$ -	150	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 10.13**			**$ 11.25**	**$ 1.12**	**11.06%**
RTSR - Network	per kWh	$ 0.0061	157	$ 0.96	$ 0.0061	155	$ 0.95	$ (0.01)	(1.01%)
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	157	$ 0.72	$ 0.0046	155	$ 0.71	$ (0.01)	(1.01%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 11.80**			**$ 12.90**	**$ 1.10**	**9.35%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	157	$ 0.81	$ 0.0052	155	$ 0.81	$ (0.01)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	157	$ 0.17	$ 0.0011	155	$ 0.17	$ (0.00)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	157	$ 1.10	$ 0.0070	155	$ 1.09	$ (0.01)	(1.01%)
Energy - RPP - Tier 1	per kWh	$ 0.0740	150	$ 11.10	$ 0.0740	150	$ 11.10	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	100	$ 6.32	$ 0.0630	99	$ 6.25	$ (0.06)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	28	$ 2.79	$ 0.0990	28	$ 2.76	$ (0.03)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	28	$ 3.33	$ 0.1180	28	$ 3.29	$ (0.03)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 25.24**			**$ 26.32**	**$ 1.08**	**4.29%**
HST		13%		$ 3.28	13%		$ 3.42	$ 0.14	4.29%
Total Bill (including HST)				$ 28.52			$ 29.74	$ 1.22	4.29%
Ontario Clean Energy Benefit [1]				$ (2.85)			$ (2.97)	$ (0.12)	4.21%
Total Bill on RPP (including OCEB)				**$ 25.67**			**$ 26.77**	**$ 1.10**	**4.30%**
Total Bill on TOU (before Taxes)				**$ 26.58**			**$ 27.53**	**$ 0.96**	**3.60%**
HST		13%		$ 3.45	13%		$ 3.58	$ 0.12	3.60%
Total Bill (including HST)				$ 30.03			$ 31.11	$ 1.08	3.60%
Ontario Clean Energy Benefit [1]				$ (3.00)			$ (3.11)	$ (0.11)	3.67%
Total Bill on TOU (including OCEB)				**$ 27.03**			**$ 28.00**	**$ 0.97**	**3.59%**
Loss Factor (%)		4.48%			3.42%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Sentinel Lighting**

Consumption 0.2 **kW** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 6.4000	1	$ 6.40	$ 6.9400	1	$ 6.94	$ 0.54	8.44%
Distribution Volumetric Rate	per kW	$ 5.1350	0.2	$ 1.03	$ 5.5716	0.2	$ 1.11	$ 0.09	8.50%
Sub-Total A				$ 7.43			$ 8.05	**$ 0.63**	**8.45%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (2.4061)	0.2	$ (0.48)	$ 1.6015	0.2	$ 0.32	$ 0.80	(166.56%)
Tax Charge Rate Rider	per kW	$ (0.4698)	0.2	$ (0.09)		0.2	$ -	$ 0.09	(100.00%)
Smart Meter Entity Charge						0.2	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6.85**			**$ 8.37**	**$ 1.52**	**22.22%**
RTSR - Network	per kW	$ 1.8420	0	$ 0.38	$ 1.8291	0	$ 0.38	$ (0.01)	(1.71%)
RTSR - Line and Transformation Connection	per kW	$ 1.3779	0	$ 0.29	$ 1.3635	0	$ 0.28	$ (0.01)	(2.05%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 7.52**			**$ 9.03**	**$ 1.51**	**20.07%**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	0	$ 0.00	$ 0.0052	0	$ 0.00	$ (0.00)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	0	$ 0.00	$ 0.0011	0	$ 0.00	$ (0.00)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	0	$ 0.00	$ 0.0070	0	$ 0.00	$ (0.00)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	0	$ 0.01	$ 0.0740	0	$ 0.01	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kW	$ 0.0630	0	$ 0.01	$ 0.0630	0	$ 0.01	$ (0.00)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	0	$ 0.00	$ 0.0990	0	$ 0.00	$ (0.00)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	0	$ 0.00	$ 0.1180	0	$ 0.00	$ (0.00)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 7.79**			**$ 9.30**	**$ 1.51**	**19.38%**
HST		13%		$ 1.01	13%		$ 1.21	$ 0.20	19.38%
Total Bill (including HST)				$ 8.81			$ 10.51	$ 1.71	19.38%
Ontario Clean Energy Benefit [1]				$ (0.88)			$ (1.05)	$ (0.17)	19.32%
Total Bill on RPP (including OCEB)				**$ 7.93**			**$ 9.46**	**$ 1.54**	**19.39%**
Total Bill on TOU (before Taxes)				**$ 7.79**			**$ 9.30**	**$ 1.51**	**19.38%**
HST		13%		$ 1.01	13%		$ 1.21	$ 0.20	19.38%
Total Bill (including HST)				$ 8.81			$ 10.51	$ 1.71	19.38%
Ontario Clean Energy Benefit [1]				$ (0.88)			$ (1.05)	$ (0.17)	19.32%
Total Bill on TOU (including OCEB)				**$ 7.93**			**$ 9.46**	**$ 1.54**	**19.38%**
Loss Factor (%)		4.48%			3.42%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

Consumption 2400 **kW** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 2.1600	1	$ 2.16	$ 2.3400	1	$ 2.34	$ 0.18	8.33%
Distribution Volumetric Rate	per kW	$ 13.0610	2400	$ 31,346.40	$ 14.1714	2400	$ 34,011.36	$ 2,664.96	8.50%
Sub-Total A				$ 31,348.56			$ 34,013.70	**$ 2,665.14**	**8.50%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (1.5474)	2400	$ (3,713.76)	$ (1.3308)	2400	$ (3,193.92)	$ 519.84	(14.00%)
Tax Charge Rate Rider	per kW	$ (0.2863)	2400	$ (687.12)	$ -	2400	$ -	$ 687.12	(100.00%)
Smart Meter Entity Charge						2400	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26,947.68**			**$ 30,819.78**	**$ 3,872.10**	**14.37%**
RTSR - Network	per kW	$ 1.8325	2508	$ 4,595.03	$ 1.8197	2482	$ 4,516.64	$ (78.39)	(1.71%)
RTSR - Line and Transformation Connection	per kW	$ 1.3496	2508	$ 3,384.15	$ 1.3354	2482	$ 3,314.57	$ (69.58)	(2.06%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 34,926.86**			**$ 38,650.99**	**$ 3,724.13**	**10.66%**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	2508	$ 13.04	$ 0.0052	2482	$ 12.91	$ (0.13)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	2508	$ 2.76	$ 0.0011	2482	$ 2.73	$ (0.03)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	2508	$ 17.55	$ 0.0070	2482	$ 17.37	$ (0.18)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	1400	$ 121.80	$ 0.0870	1400	$ 121.80	$ -	0.00%
TOU - Off Peak	per kW	$ 0.0630	1605	$ 101.10	$ 0.0630	1589	$ 100.08	$ (1.03)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	451	$ 44.68	$ 0.0990	447	$ 44.23	$ (0.45)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	451	$ 53.26	$ 0.1180	447	$ 52.72	$ (0.54)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 35,156.26**			**$ 38,880.05**	**$ 3,723.79**	**10.59%**
HST		13%		$ 4,570.31	13%		$ 5,054.41	$ 484.09	10.59%
Total Bill (including HST)				$ 39,726.57			$ 43,934.46	$ 4,207.89	10.59%
Ontario Clean Energy Benefit [1]				$ (3,972.66)			$ (4,393.45)	$ (420.79)	10.59%
Total Bill on RPP (including OCEB)				**$ 35,753.91**			**$ 39,541.01**	**$ 3,787.10**	**10.59%**
Total Bill on TOU (before Taxes)				**$ 35,159.51**			**$ 38,881.28**	**$ 3,721.77**	**10.59%**
HST		13%		$ 4,570.74	13%		$ 5,054.57	$ 483.83	10.59%
Total Bill (including HST)				$ 39,730.24			$ 43,935.85	$ 4,205.60	10.59%
Ontario Clean Energy Benefit [1]				$ (3,973.02)			$ (4,393.58)	$ (420.56)	10.59%
Total Bill on TOU (including OCEB)				**$ 35,757.22**			**$ 39,542.27**	**$ 3,785.04**	**10.59%**

Loss Factor (%) Current: 4.48% Proposed: 3.42%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

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GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.