Woodstock Hydro
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January 12, 2011

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

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: 2011 IRM Rate Application
EB-2010-0145
Interrogatory Responses

Enclosed please find Woodstock Hydro Services Inc. responses to the interrogatories filed by Board Staff in the above noted proceeding.

The Interrogatory Responses are being filed through the Board's web portal (PDF) and also sent by email and 2 paper copies.

Any confidential documents have been filed under separate cover.

Should there be any questions, please do not hesitate to contact me. Thank you.

Respectfully submitted,

Original Signed By:

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Woodstock Hydro Services Inc. (WHSI)
Response to

Board Staff Interrogatories
Woodstock Hydro Services Inc. (WHSI)
2011 Electricity Distribution Rates
EB-2010-0145
January 13, 2011

Interrogatory # 1 Responses to Letters of Comment

Following publication of the Notice of Application, has WHSI received any letters of comment? If so, please confirm that a reply was sent to the author of the letter, and file a copy of the reply with the Board. If not confirmed, please explain why a response was not sent and confirm whether the applicant intends to respond.

Response:

WHSI has not received any letters of comment following publication of the Notice of Application.

Interrogatory # 2 HST Input Tax Credit

Ref: Exhibit 1 / Tab 1 / Schedule 15

Please describe what has been recorded in the sub-account of account 1592 and describe how the tracking is done. What will be the approximate balance at the end of 2010?

Response:

In accordance with the Board Decision and Order for WHSI's May 1, 2010 Distribution Rate Approval, (EB-2009-0211) WHSI established deferral account 1592 (PILS and Taxes Variances, Sub-account HST/OVAT Input Tax Credits (ITCs)). A contra-sub-account HST/OVAT Input Tax Credits was also setup to offset the amounts posted and net the entry to zero, based on the regulatory accounting concept prescribed for account 1565 CDM Expenditures and Recoveries and account 1566 CDM Contra Account.

WHSI modified the tax codes and cost types within its financial IT system so that incremental ITC's on distribution revenue requirement items that were previously subject to PST and now subject to HST were posted to a separate sub ledger-account of OEB Account 2290, Commodity Taxes. As part of the month end closing, the total ITC amount recorded in this sub-ledger account 2290 Commodity Taxes during the month is the amount posted to the OEB Deferral accounts. An example of the accounting entry follows:

DR 1592 PILS and Taxes Variances, Sub-account HST/OVAT ITCs	$10,000	
CR 1592 Contra PILS and Taxes Variances, Sub-account HST/OVAT ITCs		$10,000

To record the incremental ITC on distribution revenue requirement items previously subject to PST

The approximate balance in the 1592 deferral accounts at the end of 2010 is expected to be:

1592 PILS and Taxes Variances, Sub-account HST/OVAT ITCs	DR $ 60,000
1592 Contra PILS and Taxes Variances, Sub-account HST/OVAT ITCs	CR ($60,000)

Interrogatory #3 International Financial Reporting Standards (IFRS)

Reference: Exhibit 1 / Tab 2 / Schedule 3

a. In what year does WHSI intend to begin reporting its (audited) actual results on an IFRS basis.

b. Has WHSI included an amount for IFRS transition costs in its 2011 revenue requirement. If yes, please identify the amount and provide a breakdown with a detailed explanation of each cost item. If no, is WHSI recording IFRS transition costs in the deferral account established by the Board in October 2009?

Response:

a) WHSI intends to begin reporting it (audited) actual results on an IFRS basis for 2012 fiscal year. WHSI's fiscal year is the 12 month period beginning January 1st and ending December 31st.

b) WHSI has not included an amount for IFRS transition costs in its 2011 revenue requirement. WHSI records one-time incremental IFRS transition costs in deferral 1508, Other Regulatory Assets, "Sub-account IFRS Transition Costs Variance" in the manner established by the Board in October 2009.

Interrogatory # 4 Prepaid Meters

Ref: Exhibit 2 / Tab 2 / Schedule 3 / p. 19, & Exhibit 9 / Tab 4 / Schedule 3 / p. 5

a. Please provide a description of when prepaid meters were acquired by WHSI, up to 2007 as noted in the reference, and explain when and why the decision was reached to discontinue and remove them.
b. Does WHSI have an estimate of the extent to which its current net book value of Stranded Meters is greater because of the Prepaid Meter initiative, compared to conventional "dumb" meters?
c. When will the prepaid meters become fully depreciated under the proposed plan for stranded meters?

Response:

a.

In 1988 WHSI introduced prepaid meters to WHSI customers as an alternative to conventional metering. Initially intended to be used for multi-unit residential buildings, prepaid meters gained popularity and installations in single family dwellings and some small commercial services became more common.

WHSI's final purchase of prepaid meters in 2005 was recognized in OEB Account 1330, Inventory. Prepaid meter costs were then transferred to OEB Account 1860, Meters, upon installation.

In 2006, WHSI recognised that the existing prepaid meters did not meet the OEB requirements for AMI capability and two-way communication features. In discussions with AMPY, WHSI's primary prepaid meter supplier, WHSI had been informed that neither the AMI capability nor two-way communication features would be available for the market from AMPY until some time in 2007, and at which time would still not be able to address vendor credential requirements.

During the London RFQ Committee process in 2007, WHSI requested prepay be included as a separate section within the RFQ. This was incorporated under section 6.2.10.7 of the RFQ Document issued August 14 2007 and is copied below:

"6.2.10.7 Prepayment Metering

Prepayment metering (also referred to as "pay-as-you-go" metering) in its simplest form refers to paying for electricity, gas or water before it is used. Although a lesser more limited residential service (that would likely have its own rate class), the advantages of prepayment metering to the customer include budget management, awareness and control of energy usage, no security deposits, and in the case of delinquent customers, no utility surcharges or waiting for reconnection.

The basic elements of a prepayment metering system include (but are not necessarily limited to) the following:

· *Prepayment meter – the prepayment meter replaces the customer's conventional meter and contains an internal means (wireless or power-line carrier over household wiring) for communications with the CIU, and an internal automatic disconnect switch that opens or closes as the meter depletes or recharges the energy credits respectively. The relay / switch shall be 200 A rated (both continuous and load-interrupting). The prepayment meter shall be a selfcontained, socket-style, energy meter available in both a single-phase style (240 V, 200A; ANSI Form 2S) for residential dwellings and a network style (120 V, 200 A; ANSI Form 12S) for apartment buildings.*

· *Consumer interface unit (CIU) – the CIU is a small wall-mounted or counter-top panel with a keypad and display (LCD or similar) that automatically communicates with its associated prepayment meter and enables the consumer to monitor consumption and view remaining credits to their meter.*
Note: It is presumed that with prepayment metering, the consumer interface unit and an in home energy use display (previously described in Section 6.2.10.5 on page 63 herein) are one in the same.

· *A two-way communications system between the prepayment meter and AMI master control computer.*

· *Host prepayment management software (which may be resident on the AMI Master Control Computer or another processor) that interacts with the Customer Information System (to obtain electricity tariffs), licensed energy retailers (to obtain commodity costs), and the prepayment stations within the community whereby consumers buy electricity in advance. Based on the incremental cost, product sophistication (i.e. means, robustness, and flexibility by which customer can procure electricity), and means of implementation, London Hydro may be interested in a selective deployment of prepayment metering.*

Desirable features of the prepayment subsystem include:

· *The prepayment meter shall predict the day on which credits will be exhausted based on existing rates of energy consumption. The CIU shall continuously blink and emit a regular "chirp" (e.g. hourly) when the credit remaining is than say five times the amount used on the previous day.*

· *Cold weather protections shall permit continued consumption with service limiter constraints. If, for example, during the designated winter months the electricity demand exceeds a designated level (e.g. 2,000 W) after the purchased consumption is exhausted, the CIU shall provide an audible warning and then cutoff power for a designated period of time. At the end of that time, the meter will check to determine whether the demand has been reduced below the permitted levels. Any electricity consumption after the credit has been depleted during the winter months shall accumulate as a negative amount on the meter and be subtracted from any new electricity procurements.*

· *A preferred option shall allow the utility to configure the system to provide a customer-friendly service disconnect option, i.e. in the event of zero credit during the evening or weekend, service continuity would be maintained until a time during normal weekday working hours.*

Bidders with available prepayment functionality that generally conforms to the design principles outlined above shall include literature or descriptions of their product, or a white paper outlining their plans if the product is still under development."

One vendor responded to section 6.10.2.7 of the RFQ request but was eliminated during the short-listing process. This process took place under the watchful eye of a Fairness commissioner to further support our efforts in finding the most suitable, cost effective smart meter solution for all WHSI customers.

In 2007, $79,905 was recognized in account 1860 for labour, vehicle and material costs to install prepaid meters. Material costs included amounts for prepaid meters had been included in Account 1330, Inventory until the meters were installed.

WHSI Management determined at it's December 5, 2007 Business Meeting that it would be prudent for WHSI to cease new installations of prepaid meters pending the outcome of the assessment of the smart meter RFP. Prepaid meter stock that was purchased in 2005 had depleted to low levels, and until such time WHSI was able to determine the future of prepaid meters, the remaining prepaid meter stock was to be held for repair and replacement of existing prepaid meter services. Effective February 1, 2008, WHSI issued a moratorium on the installation of new prepaid meter services. Advance notice provided to WHSI's Shareholder on January 3, 2008 is attached as Appendix A.

A public notice was published in the Sentinel Review on January 12th and 19th 2008, and posted at all 4 offsite prepay locations, the WHSI office, and on WHSI's webpage. A copy of this notice is attached as Appendix B.

In 2008 a vendor submitted a proposal to supply a prepaid metering solution to WHSI. Upon review WHSI Management determined that this option would be both cost prohibitive and have less functionality than its existing prepaid technology.

With the OEB deadline to install smart meters before December 31, 2010 on the horizon, and after more than 3 years of searching and unsuccessfully finding a cost-effective, viable solution to smart prepaid technology, WHSI Senior Management submitted a report to the WHSI Board of Directors that supported a recommendation to discontinue the prepaid meter program. As a result, the WHSI Board of Directors passed a resolution at their December 12, 2008 meeting to accept the recommendation of staff to eliminate pre-paid meters by December 31, 2009. To protect proprietary vendor information, a redacted copy of the report is included as Appendix C and unredacted copy of the report is filed in Confidence as Appendix C - unredacted.

A detailed project plan including shareholder and customer communication strategy for discontinuation of the prepaid meter program was presented at the WHSI Board Q1 2009 Board meeting and approved. The project plan is included in Appendix D.

b.

WHSI estimates that the 2010 net book value (NBV) of stranded meters is $706,322 greater because of the Prepaid Initiative compared to the conventional "dumb" meters and was determined in 3 steps:

Step 1

The NBV of stranded meters as of Dec 31, 2010 for conventional and prepaid meters are as follows:

NBV - Conventional meters	$	177,960
Proceeds on Disposal		($3,218)
	$	174,742
NBV - Prepaid meters	$	776,472
Proceeds on Disposal		($1,073)
	$	775,400
NBV Stranded Meters Dec 31 2010	$	950,142

Step 2

A comparison of meter costs indicated that the average price of a conventional meter was approximately 9% of the average price of a prepaid metering unit.

	Cost per Unit		Proportion of Prepaid Meter Cost
Prepaid Meter + Display Unit	$	449	100%
Conventional Meter	$	40	9%
Incremental Cost of Prepaid	$	409	91%

Step 3

Had conventional meters been installed instead of prepaid meters, the total NBV stranded meter costs would have been approximately $243,820. The following table shows that the incremental NBV of stranded meter assets for prepaid meters would be $706,322

NBV stranded conventional meters	$	174,742
9% of NBV stranded prepaid meters ($775,400)	$	69,078
Hypothetical NBV assuming no prepaid meters	$	243,820
Incremental NBV prepaid meters	$	706,322
NBV Stranded Meters Dec 31 2010	$	950,142

c. Prepaid meters are depreciated on a straight line basis over 15 years. The prepaid meters will become fully depreciated under the proposed plan for stranded meters in the year 2023 as indicated in the following schedule:

Gross Prepaid Meter Assets Dec 31 2010	$2,812,279
Proceeds on Disposal of Scrapped Meters	($1,073)
Subtotal - Prepaid Meter Assets net of Disposal	$2,811,206
Accumulated Depreciation Dec 31 2010	($2,035,806)
Net Book Value Dec 31 2010	$775,400

Amortization Schedule - Prepaid Meters			
Year	Depreciation Expense	Net Book Value	Accumulated Depreciation
2010			
2011	$157,292	$618,107	($2,193,099)
2012	$131,529	$486,578	($2,324,628)
2013	$110,567	$376,011	($2,435,195)
2014	$88,760	$287,251	($2,523,955)
2015	$70,211	$217,040	($2,594,166)
2016	$59,519	$157,522	($2,653,684)
2017	$43,013	$114,509	($2,696,697)
2018	$41,253	$73,256	($2,737,950)
2019	$22,911	$50,346	($2,760,860)
2020	$20,834	$29,512	($2,781,694)
2021	$13,902	$15,610	($2,795,596)
2022	$6,966	$8,644	($2,802,562)
2023	$8,644	$0	($2,811,206)

Interrogatory # 5 Capital Contribution for Hydro One Transformer Station

Ref: Exhibit 2 / Tab 2 / Schedule 3 / p. 40

a. Please provide a copy of the Letter of Agreement between Hydro One and WHSI. Please include any information on how WHSI's required contribution was established.
b. Please provide a rationale for why the capital contributions totalling $4,100,000 should be included in WHSI's rate base in 2011, considering that the in-service date is forecast to be the last day of 2011.

Response:

a. A copy of the Letter Agreement between Hydro One and WHSI has been filed in confidence as Appendix “E”.

   The required $4.1 million capital contribution was established based on an economic evaluation conducted by Hydro One. A copy of this evaluation has been filed in confidence as Appendix “F.”

b. It is WHSI's understanding that any capital that goes into service during the test year is allowed in the rate base for the test year no matter when the capital goes into service throughout the test year. The half year rule for depreciation and the average of the opening and closing fixed assets in the test year to determine the test year rate base implicitly assumes that capital is being put into service at different times during the year. The half year rule assumes that on average the total capital in the test year is in service for half a year. As a result, capital that is put in service on January 1, 2011 is depreciated and included in the 2011 rate base on a half year basis and the same applies to capital installed on the last day of 2011.

   Please refer to WHSI’s response to Energy Probe’s Interrogatory # 3 for further detail regarding the Hydro One Transformer Station.

Interrogatory # 6   Computer Hardware and Software Requirements

Ref: Exhibit 2 / Tab 2 / Schedule 3 / p. 54

The 2011 Capital Projects include $140,000 for computer hardware and $60,000 for software.

Has WHSI investigated any possibilities for sharing computer facilities with other distributors, for example by providing backup of information instead of building redundancy with WHSI itself? If so, please describe what possibilities there may be for cost savings of such a nature.

Response:

Yes, WHSI has investigated possibilities for sharing computer facilities with other distributors. In 2007 WHSI explored options for its conversion from Advanced Utility Systems to Harris Northstar, and requested a proposal from the ERTH group of companies (Erie-Thames) to host the new billing system. WHSI also obtained a quote from an independent company to host Northstar and to provided broader Disaster Recovery (DR) support. However, in both cases, a cost-benefit analysis revealed that an in-house solution was more economical for WHSI.

During the first phase of the disaster-recovery strategy, WHSI attempted to implement a low-cost solution through leveraging our Shareholder relationship and locating our DR equipment at one of the Shareholder's facilities. WHSI however, experienced difficulties in coordinating timely access to our equipment or remote technical assistance, which in the end severely compromised the overall effectiveness of the strategy.

Over the course of the past five years, WHSI has systematically implemented a best-practices network platform which includes VMWare and BackupExec software and a Dell Storage Area Network (SAN). A SAN provides for energy efficiency, ease of maintenance, troubleshooting and operation, strong performance, streamlined backup and recovery, built-in and hardware redundancy. Our DR site is housed more than 30 minutes from the WHSI office and would enable us to have our mission critical applications back up and running within a few days and able to process transactions.

Interrogatory # 7 Accounting Treatment of Smart Meters

Ref: Exhibit 2 / Tab 2 / Schedule 3 / p. 50; and Exhibit 2 / Tab 3 / Schedule 3 / p. 3

a. WHSI is proposing to include all smart meter capital as of December 31, 2009 into the 2011 rate base for the full year, an addition of $1,442,731. Please confirm that all of the equipment will be installed and in use by the end of 2010.
b. Will the status of all of the equipment have been audited as of the end of 2010?
c. Are all of the Smart Meters that are to be put into the Rate Base shown in Table 2-18 (2009 Capital Expenditures) or in a previous year?
d. Please explain whether the responses to the preceding questions are consistent with Capital Expenditures in Table 2-24, which shows an expenditure of $1,384,779 in 2011.

Response:

a. WHSI confirms that all smart meter capital equipment has been installed and will be in use by the end of 2010.

b. The accounting status for equipment and other smart meter costs will be audited as part of WHSI's 2010 year end financial audit.

c. All of the Smart Meters that are to be put into the Rate Base are shown in Table 2-24. The Capital Expenditures by Project shown in Table 2-18 are the expenditures charged to distribution capital accounts. Because Smart Meter capital expenditures were recorded in account 1555, they were excluded from Table 2-18.

d. The total Smart Meter Capital amount of $1,442,731 includes $1,384,779 for installed smart meters and collectors and is shown in distribution asset account 1860 Meters on Table 2-24. The remaining Smart Meter Capital costs include $10,697 for related computer hardware and $47,255 for related computer software. Table 2-20 also includes all 2009 Smart Meter capital costs of $1,442,731 allocated to the appropriate distribution and general capital accounts, namely, 1860 Meters, 1920 Computer Hardware, and 1925, Computer Software.

Interrogatory # 8 Asset Management

Ref: Exhibit 2 / Tab 3 / Schedule 2 / p. 2, and Appendix B-5

Is the document 'Facilities Replacement Schedule' complete as filed (Appendix B-5), or is the page in the pre-filed evidence an introductory sheet to a more extensive schedule? If the former, please explain how this sheet should be considered as ensuring that the general requirements of a formal asset management plan are being satisfied, as noted at p. 2. If the page that has been filed is an introduction, please provide a typical page in the replacement schedule.

Response:

The Facilities Replacement Schedule filed in Appendix B-5 is a guideline that includes key factors to consider as part of WHSI's asset management and replacement strategy. This an ongoing process that culminates in a 5 year capital and maintenance activity forecast. Subdivision replacements are prioritized based on age of asset, distribution voltage and outage statistics as maintained through our Work flow software. Please refer to our 5 year capital replacement forecast for more detail.

To ensure aging or prematurely failing equipment is identified and replaced, we base activity on the results of annual equipment inspection activity. For example, WHSI invited responses from qualified contractors in 2009 to complete a three year inspection program for all pole equipment and pad mount equipment. An external contract budget of $22k/year for pole inspection and $15k per year for pad mount equipment inspection through a three year contract was completed, with the first year of this activity beginning in 2010.

Our Pole Replacement budget is based on the expectation that an annual investment of approximately $150k per year is required to meet an end-of-life replacement strategy for all 4200 poles in our system. Similarly, pad mount inspections invariable spawn switch and transformer repair and replacement activity and this is covered through annual maintenance and or capital expenditures as required by the circumstance of the activity.

A sample vehicle replacement schedule form is attached as Appendix G.

Interrogatory # 9 Infrared Inspection

Ref: Exhibit 2 / Tab 3 / Schedule 2 / Appendix E

If possible, please provide an enlarged photograph of a facility that has been examined by the infrared technique, and/or a colour version of its infrared image – for example an intelligible version of the image and photograph on p. 4 of 27.

Response:

WHSI has received a colourized pdf of the above noted Infrared Inspection report which is included as Appendix “H” in its entirety.

Interrogatory # 10 Working Capital – Global Adjustment

Ref: Exhibit 2 / Tab 4 / Schedule 1 / Appendix F (p. 3)

Please explain the sequence and timing of payments involved in non-RPP Global Adjustment, as a rationale for including this item as a component of the conventional 15% formula for working capital.

Response:

When the IESO power bill is received on the 15th of the month following the month of purchase, the gross amount of the global adjustment and all other IESO charges are due and payable. WHSI must pay this invoice to the IESO within two business days. The largest portion of WHSI's non-RPP global adjustment applies to interval customers who are billed on a calendar monthly basis. The majority of WHSI's non-RPP customers (interval customers) are billed approximately 21 days following the last day of billed usage. The bill is generally due on the 12th of the following month. This results in a lag between the time WHSI pays the IESO and the time WHSI's Non-RPP customers pay their invoice approximately 25 to 28 days later. This delay may extend further should the customer pay their invoice to WHSI after their due date.

Other non-RPP customers are distributed throughout WHSI's other billing cycles, which may increase the lag in receiving payment from the customer even longer, as amounts billed in August could potentially include July and June quantities. The following example illustrates the delay for interval customers.

Aug 1 - 31 usage charges are paid to the IESO September 17thth.
Aug 1 - 31 usage charges are billed to WHSI's customer September 20th. The due date is October 12th

Sept 17th to October 12th = 25 calendar days between the time WHSI pays the IESO invoice and the time WHSI collects the amounts from it's interval customers.

In this example, WHSI must fund these amounts from it's own working capital for 25 days or until payment is received, and therefore the global adjustment amounts should be included as a component of the conventional 15% formula for working capital.

Interrogatory # 11 Load Forecast Regression Model

Ref: Exhibit 3 / Tab 2 / Schedule 1 / p. 8; and Appendix A

a. Please provide the units of measure, and an interpretation of the regression coefficients, for the variable 'CDM Savings' and 'Ontario Real GDP Index'.

b. The variable “Customer” is included in the Appendix but does not appear in the regression equation. Is this an omission or is it deliberate, and if the latter please describe why it is not included. Would the accuracy of the load forecast be enhanced by including a forecast of the customer count?

Response:

a. The variable referenced on Exhibit 3 / Tab 2 / Schedule 1 / p. 8 as 'CDM Savings' should have been referenced as 'OPA CDM Activity'. The unit of measure of the coefficients for the variables 'OPA CDM Activity’ and 'Ontario Real GDP Index' is kWh in both cases. The coefficient for the 'OPA CDM Activity' variable is negative 2 and the values for this variable used in the regression analysis are net kWh saved from OPA programs only. This suggests to WHSI that the coefficient of negative 2 is taking into account the free ridership associated with the OPA programs, the kWh saved from 'Third Tranche' programs initiated by WHSI as well as general sense of energy conservation in the City of Woodstock.

   In regards to the 'Ontario Real GDP Index' variable, the coefficient is 291,753 which suggests to WHSI that when the index increases by one the forecasted kWh will increase by 291,753 kWh.

b. The variable “Customer” is included in the Appendix but it was not used in the final regression analysis that supports the proposed load forecast. The "Customer" variable was tested as a possible variable to be included the regression analysis but the resulting T-stat on the variable was 0.35. As a result, it was not used in the final analysis as it was not statistically significant and did not improve the accuracy of the load forecast.

Interrogatory # 12 Accuracy of the Load Forecast Model

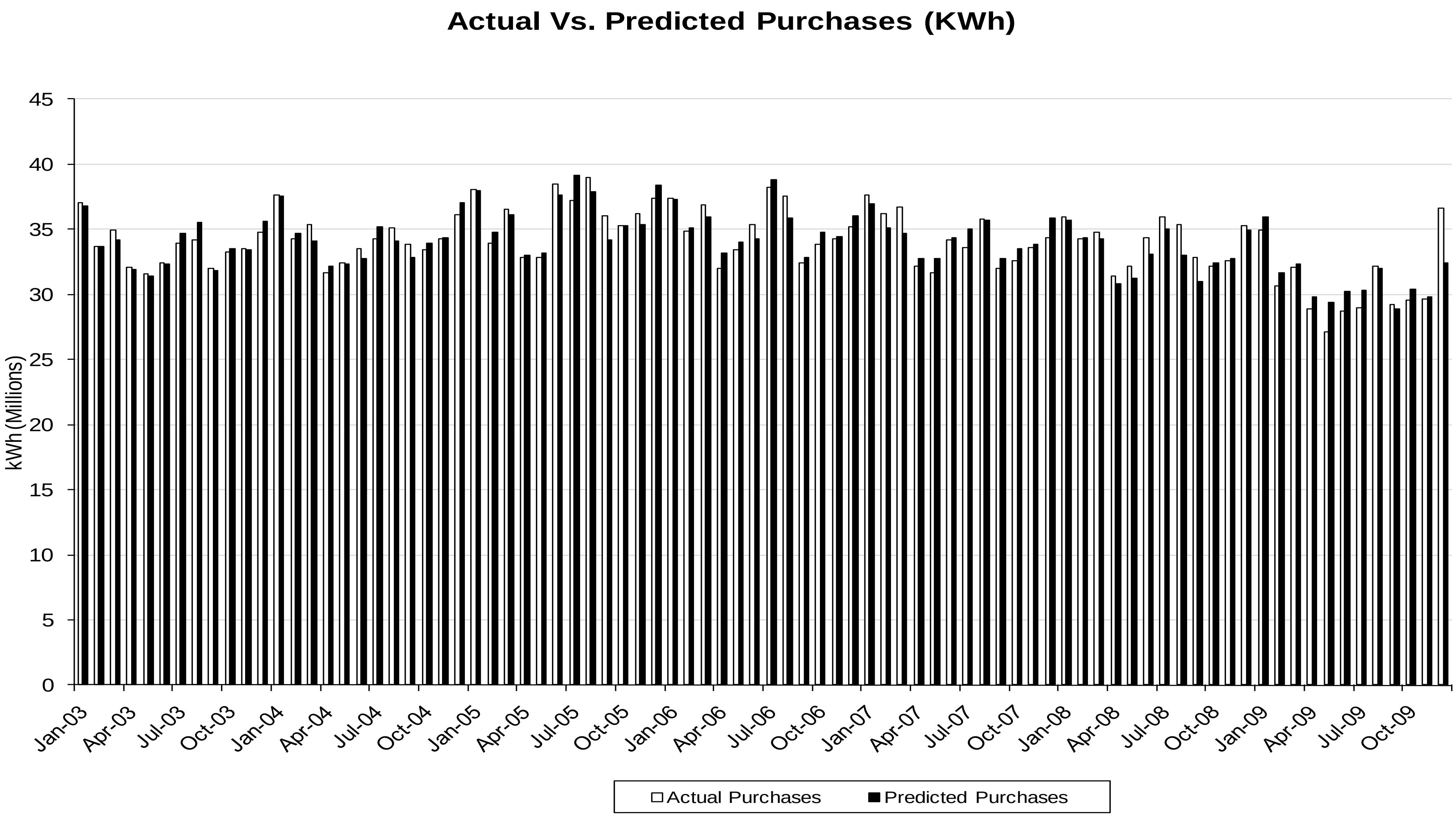
Ref: Exhibit 3 / Tab 2 / Schedule 1 / p. 9

a. Please confirm that the statistics in Table 3-4 are the result of a regression using monthly data.
b. Please provide a monthly version of the bar graph 'Actual vs. Predicted Purchases (kWh)

Response:

a. WHSI confirms that the statistics in Table 3-4 are the result of a regression using monthly data.

b. A monthly version of the bar graph “Actual vs. Predicted Purchases (kWh) is presented below, followed by the supporting data table.


Actual Vs. Predicted Purchases (KWh)
kWh (Millions)
45
40
35
30
25
20
15
10
5
0
Jan-03
Apr-03
Jul-03
Oct-03
Jan-04
Apr-04
Jul-04
Oct-04
Jan-05
Apr-05
Jul-05
Oct-05
Jan-06
Apr-06
Jul-06
Oct-06
Jan-07
Apr-07
Jul-07
Oct-07
Jan-08
Apr-08
Jul-08
Oct-08
Jan-09
Apr-09
Jul-09
Oct-09
Actual Purchases
Predicted Purchases

Monthly Data Table

	Actual Purchases	Predicted Purchases	% Difference
Jan-03	37,017,303	36,840,103	(0.5%)
Feb-03	33,678,639	33,661,419	(0.1%)
Mar-03	34,990,452	34,197,780	(2.3%)
Apr-03	32,097,231	31,914,949	(0.6%)
May-03	31,610,601	31,403,025	(0.7%)
Jun-03	32,441,307	32,312,549	(0.4%)
Jul-03	33,944,718	34,677,637	2.2%
Aug-03	34,152,834	35,569,319	4.1%
Sep-03	32,024,721	31,823,237	(0.6%)
Oct-03	33,294,540	33,523,779	0.7%
Nov-03	33,498,627	33,397,197	(0.3%)
Dec-03	34,797,805	35,635,283	2.4%
Jan-04	37,609,316	37,593,472	(0.0%)
Feb-04	34,240,547	34,664,241	1.2%
Mar-04	35,378,085	34,128,433	(3.5%)
Apr-04	31,708,884	32,183,339	1.5%
May-04	32,440,167	32,374,159	(0.2%)
Jun-04	33,560,716	32,775,745	(2.3%)
Jul-04	34,260,108	35,224,526	2.8%
Aug-04	35,099,601	34,066,370	(2.9%)
Sep-04	33,866,709	32,879,221	(2.9%)
Oct-04	33,459,472	33,946,202	1.5%
Nov-04	34,291,998	34,371,519	0.2%
Dec-04	36,127,448	37,060,978	2.6%
Jan-05	38,086,669	37,984,142	(0.3%)
Feb-05	33,948,283	34,749,662	2.4%
Mar-05	36,573,955	36,110,969	(1.3%)
Apr-05	32,869,336	33,036,366	0.5%
May-05	32,855,889	33,153,477	0.9%
Jun-05	38,447,266	37,610,828	(2.2%)
Jul-05	37,187,192	39,169,456	5.3%
Aug-05	38,980,568	37,892,808	(2.8%)
Sep-05	36,068,033	34,170,929	(5.3%)
Oct-05	35,298,516	35,304,939	0.0%
Nov-05	36,208,987	35,342,357	(2.4%)
Dec-05	37,375,907	38,412,963	2.8%
Jan-06	37,380,610	37,291,527	(0.2%)
Feb-06	34,858,034	35,141,824	0.8%
Mar-06	36,853,489	35,926,860	(2.5%)
Apr-06	32,012,005	33,206,307	3.7%

May-06	33,397,046	34,009,913	1.8%
	Actual Purchases	Predicted Purchases	% Difference
Jun-06	35,393,613	34,311,971	(3.1%)
Jul-06	38,211,550	38,836,682	1.6%
Aug-06	37,549,917	35,859,812	(4.5%)
Sep-06	32,409,216	32,809,029	1.2%
Oct-06	33,859,862	34,812,296	2.8%
Nov-06	34,256,645	34,411,554	0.5%
Dec-06	35,197,842	36,041,194	2.4%
Jan-07	37,602,510	36,951,332	(1.7%)
Feb-07	36,181,471	35,132,223	(2.9%)
Mar-07	36,692,690	34,730,418	(5.3%)
Apr-07	32,150,377	32,727,124	1.8%
May-07	31,697,554	32,777,030	3.4%
Jun-07	34,232,795	34,338,402	0.3%
Jul-07	33,640,750	35,036,409	4.1%
Aug-07	35,812,952	35,718,307	(0.3%)
Sep-07	31,962,853	32,755,593	2.5%
Oct-07	32,623,250	33,499,453	2.7%
Nov-07	33,638,403	33,869,306	0.7%
Dec-07	34,321,596	35,908,482	4.6%
Jan-08	35,970,167	35,692,357	(0.8%)
Feb-08	34,302,885	34,347,163	0.1%
Mar-08	34,743,679	34,303,070	(1.3%)
Apr-08	31,419,322	30,859,951	(1.8%)
May-08	32,204,384	31,284,354	(2.9%)
Jun-08	34,380,455	33,064,160	(3.8%)
Jul-08	35,999,969	35,005,330	(2.8%)
Aug-08	35,356,400	33,031,864	(6.6%)
Sep-08	32,807,025	31,027,066	(5.4%)
Oct-08	32,191,845	32,415,085	0.7%
Nov-08	32,580,912	32,781,660	0.6%
Dec-08	35,310,143	34,926,736	(1.1%)
Jan-09	34,949,268	35,987,640	3.0%
Feb-09	30,659,935	31,693,092	3.4%
Mar-09	32,101,565	32,309,242	0.6%
Apr-09	28,900,029	29,817,162	3.2%
May-09	27,144,412	29,387,225	8.3%
Jun-09	28,729,299	30,196,712	5.1%
Jul-09	28,970,065	30,346,243	4.8%
Aug-09	32,151,362	32,026,868	(0.4%)
Sep-09	29,194,423	28,914,303	(1.0%)

Oct-09	29,570,905	30,448,193	3.0%
Nov-09	29,683,922	29,835,056	0.5%
Dec-09	36,644,308	32,429,182	(11.5%)

Interrogatory # 13 Weather-related Variables in the Load Forecast

<u>Ref: Exhibit 3 / Tab 2 / Schedule 1 / p. 10</u>

Please provide monthly data of Heating and Cooling Degree Days of 20 years, if available for the relevant weather station, together with 10 and 20 year averages. Please show how these averages were used to calculate the weather-normal predictions in the last two rows of Table 3-5

Response:

Table 13-1 below provides the 20 year monthly data of Heating and Cooling Degree Days as well as the 7 year average, the 10 year average, and the 20 year trend.

Table 13-2 following Table 13-1 summarizes the variables used to calculate the weather-normal predictions in the last two rows of Table 3-5.

Calculation for Monthly Predicted Values =

Intercept Coefficient (30,859,526)
+ Heating Degree Days * Heating Degree Days Coefficient
+ Cooling Degree Days * Cooling Degree Days Coefficient
+ Spring Fall Flag * Spring Fall Flag Coefficient
+ Number of Days in Month * Number of Days in Month Coefficient
+ OPA CEM Activity * OPA CAM Activity Coefficient
+ Ont. Real GDP Monthly % + Ont. Real GDP Monthly % Coefficient
= Monthly Predicted Values

: The Sum of Monthly Predicted Values for each year 2010 and 2011 equal the weather-normal predictions in the last two rows of Table 3-5.

Table 13-1

Station Name:	London WS																					
Heating Degree Days	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	7 Year Avg	10 Year Avg	20 Trend
Jan	601	743	692	674	914	659.3	775	751	614	770	746	712	598	824	854	776	555	656	639	850	736	721	728
Feb	593	566	649	603	747	716	687	597	516	550	611	602	560	713	657	651	609	759	693	613	671	647	660
Mar	502	511	577	530	600	519	663	562	506	588	422	569	549	596	498	645	546	527	627	533	567	551	569
Apr	311	277	381	323	326	407.5	398	388	301	301	338	298	331	371	326	310	286	371	265	307	319	320	311
May	198	101	161	153	225	156.3	202	284	60	105	138	127	252	185	155	199	152	132	209	157	170	170	170
Jun	46	21	81	49	44	20.9	21	30	62	40	31	39	37	48	55	11	27	23	24	50	34	34	30
Jul	8	5	27	13	7	13.1	14	14	0	2	16	17	1	3	7	2	3	11	4	20	7	8	6
Aug	7	5	49	20	30	1.9	4	30	7	13	23	1	3	8	32	5	5	12	12	18	13	12	9
Sep	103	123	111	112	92	127.6	86	87	46	67	120	102	69	76	53	31	99	61	57	71	64	74	50
Oct	279	235	325	280	246	229.6	265	271	231	287	222	248	628	293	234	228	308	150	287	301	257	290	285
Nov	398	479	453	444	381	523.2	524	488	402	380	449	331	455	388	400	393	383	469	468	357	408	409	396
Dec	601	640	732	658	565	725.6	590	606	541	599	815	544	663	585	656	702	512	657	671	637	632	644	631
Cooling Degree Days	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	7 Year Avg	10 Year Avg	20 Trend
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	1	0	0	0
Apr	14.9	1	0	0	2	0	0	0	0	0	0	0	6	2	0	0	0	0	0	3	1	1	0
May	1	65	4	23	7	2	14	0	26	13	19	4	6	0	11	0	23	23	2	3	9	9	5
Jun	38.4	71	19	43	62	85	46	57	82	85	47	63	73	34	27	121	44	70	66	36	57	58	64
Jul	70.6	92	30	64	89	116	53	75	81	156	53	84	150	75	70	138	134	72	97	29	88	90	98
Aug	52.6	87	27	56	34	118	57	30	100	44	61	111	97	94	38	106	68	89	53	72	74	79	84
Sep	12.6	30	20	21	17	14	18	8	45	37	32	19	73	16	25	35	5	35	21	16	22	28	29
Oct	2.7	3	0	2	0	1	0	5	0	0	1	1	14	1	0	9	1	22	0	0	4	5	6
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 13-2

	Heating Degree Days	Cooling Degree Days	Spring Fall Flag	Number of Days in Month	OPA CDM Activity	Ontario Real GDP Monthly %	Predicted	2011Total Predicted
10 Year Average								
Jan-11	721	0	0	31	3,281,638	139	33,236,494	
Feb-11	647	0	0	28	3,316,909	139	30,306,267	
Mar-11	551	0	1	31	3,352,180	140	30,993,188	
Apr-11	320	1	1	30	3,387,451	140	28,635,771	
May-11	170	9	1	31	3,422,722	141	28,793,907	
Jun-11	34	58	0	30	3,457,992	141	30,361,619	
Jul-11	8	90	0	31	3,493,263	141	32,448,501	
Aug-11	12	79	0	31	3,528,534	142	32,014,016	
Sep-11	74	28	0	30	3,563,805	142	29,390,025	
Oct-11	290	5	0	31	3,599,076	142	30,737,258	
Nov-11	409	0	0	30	3,634,347	143	30,588,651	
Dec-11	644	0	0	31	3,669,618	143	33,086,571	370,592,268
20 Year Trend								
Jan-11	728	0	0	31	3,281,638	139	33,287,706	
Feb-11	660	0	0	28	3,316,909	139	30,401,187	
Mar-11	569	0	1	31	3,352,180	140	31,126,272	
Apr-11	311	0	1	30	3,387,451	140	28,526,151	
May-11	170	5	1	31	3,422,722	141	28,598,647	
Jun-11	30	64	0	30	3,457,992	141	30,606,974	
Jul-11	6	98	0	31	3,493,263	141	32,801,697	
Aug-11	9	84	0	31	3,528,534	142	32,205,524	
Sep-11	50	29	0	30	3,563,805	142	29,283,792	
Oct-11	285	6	0	31	3,599,076	142	30,760,445	
Nov-11	396	0	0	30	3,634,347	143	30,493,185	
Dec-11	631	0	0	31	3,669,618	143	32,994,889	371,086,470

	Coefficients
Intercept	(30,859,526)
Heating Degree Days	7,006
Cooling Degree Days	44,346
Spring Fall Flag	(1,127,294)
Number of Days in Month	814,988
OPA CDM Activity	(2)
Ontario Real GDP Monthly %	291,753

Interrogatory # 14 Residential Consumption per Customer

Ref: Exhibit 3 / Tab 2 / Schedule 1 / pp. 13-14

Annual consumption per customer forecast for 2011 (last row of Table 3-11) appears to be inconsistent with the trend in Table 3-9, being higher than actual consumption in all years except one since 2003.

Please explain how the 2011 forecast of consumption per residential customer was derived. If the forecast is in error, please make such adjustments as may be required.

Response:

Incorrect values were included in Table 3-11 due to a cell reference error. The Table should have been presented as follows:

Table 3-11: Forecast Annual kWh Usage per Customer/Connection

Year	Residential	GS < 50	General Service 50 to 999 kW	*General Service > 1000 kW	Streetlight	USL
Forecast Annual kWh Usage per Customers/Connection						
2010	7,664	35,197	605,502	10,687,187	584	4,735
2011	7,562	35,014	579,523	9,960,560	570	4,562

Interrogatory # 15 Harmonized Sales Tax

The impact of HST as a cost driver of OM&A is shown in Table 4-2 (Exhibit 4 / Tab 1 / Schedule 4). The comparable effect on capital expenditures is mentioned in percentage terms at Exhibit 2 / Tab 3 / Schedule 3 / p. 2.

What is the amount of saving from the HST on capital expenditures?

Response:

The estimated amount of total savings from the HST on capital expenditures is $41,918 for 2010 and $36,660 for 2011. The Board's Decision and Order EB-2009-0211 (page 7) stated that 50% of the confirmed balances in account 1592 shall be returnable to rate payers. Accordingly, the estimated proportion of total savings from the HST on capital expenditures returnable to rate payers would be $ 20,959 in 2010, and $18,330 in 2011.

Interrogatory # 16 Low Income Energy Assistance Program (LEAP)

Ref: Exhibit 4 / Tab 1 / Schedule 4 / p. 4

Has WHSI included in its 2011 revenue requirement for the LEAP initiative the precise amount of $9879, or a continuation of the previous year's donation $10,000, or an amount $5000 (shown in Table 4-2), or the amount of $500 shown for account 6205 in Exhibit 7 / Tab 1 / Schedule 2 / Appendix C (the cost allocation model)? What is the amount in the revenue requirement: in other words, are these various amounts inconsistent versions of the same thing, or are the respective amounts cumulative in the requested revenue requirement?

Response:

WHSI has forecast $10,000 in its 2011 revenue requirement for the LEAP initiative which is included in account 5410, Community Relations, Sundry. In light of the recent release of the OEB Accounting Procedures Handbook, WHSI confirms that it will include the these funds in Account 6205, Donations, "Sub account LEAP funding".

Table 4-2 shows the incremental change in costs over the previous year. The $5,000 amount referred to in Interrogatory question # 16 is an incremental increase of $5,000 over the 2009 donation amount of $5,000. The total donation amount forecasted for 2010 is $10,000.

The amount of $500 shown for account 6205 in Exhibit 7/Tab 1/Schedule 2/Appendix C is for an annual donation to WHSI's Social Committee which is used to help fund the social club events. This expense is recognized in account 6205 so that it is excluded from WHSI's operating expenses, the revenue requirement and cost allocation calculations.

Interrogatory # 17 Ontario Municipal Employees Retirement System Pension Costs

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

OMERS has announced a three-year contribution rate increase for its members and employers for the years 2011, 2012, and 2013. The forecast increase for 2011 is shown in Table 4-11 can be calculated at $33,693, or 18.8%.

What are the forecast increases for 2012 and 2013?

Response:

WHSI forecasts an increase of 15.3% in 2012 and 12.3% in 2013 based on the following assumptions:

	2011 Test Year	2012	2013
Annual Premiums	$ 213,126	$ 245,843	$ 276,096
$ Change		$ 32,717	$ 30,253
% Change		15.4%	12.3%

OMERS

Increases are based on OMERS publication Number 89, which states:

"*OMERS SC has announced a three-year contribution rate increase for members and employers: an average 1% of member's earning per side in 2011, 1% in 2012 and 0.9% in 2013… (The exact rates for 2012 and 2013 will be determined next year.)*"

OMERS*	**Rate 1** (on earnings up to CPP earnings limit)	**Rate 2** (on earnings over CPP earnings limit)	Actual/Estimated CPP earnings limit
2010 Rates	6.4%	9.7%	$ 47,200
2011 Rates	7.4%	10.7%	$ 48,200
2012 Rates	8.4%	11.7%	$ 49,300 ^^
2013 Rates	9.3%	12.6%	$ 50,400 ^^
**Normal retirement age 65*		*^^ based on historical average (2001-2011)*	

2012: Retirement of one FTE
Recruitment of one Lineperson Apprentice
3% wage adjustments

2013: Retirement of one Administrative FTE Dec 31 2012
Replacement of Administrative FTE
3% wage adjustments

Interrogatory # 18 Employee Benefits

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

Please describe the increase in the cost of benefits from $288,474 in 2010 to $326,839 in 2011, an increase of 13.3%. As there is no projected increase in employee FTEs, please show which benefits increase by more than 13.3%

Response:

The 13.3% increase was based on a combination of premium based adjustments and wage adjustments. Premium based adjustments are determined based on the recent cost trends for WHSI and the wage based adjustments are determined based on projected inflationary and progression increases for employees who are not at their target job rate. The following table provides allocation detail for each type of employee benefit expense:

	Dental	**Health**	**Life**	**LTD**	**Total**
2011 Test	$57,502	$223,688	$10,923	$ 34,727	$326,839
2010 Bridge	$49,913	$194,211	$ 9,698	$ 34,653	$288,474
Incremental Increase	**$ 7,589**	**$ 29,476**	**$ 1,225**	**$ 75**	**$ 38,365**
Increase as a %	15.2%	15.2%	12.6%	0.2%	13.3%
Attributable to:					
Wage Based Adjustments	5.2%	5.2%	7.6%	1.2%	36.0%
Premium Based Adjustments	10.0%	10.0%	5.0%	-1.0%	64.0%
Wage Based Adjustments	$ 2,598	$ 10,055	$ 740	$ 421	$ 13,814
Premium Based Adjustments	$ 4,991	$ 19,421	$ 485	-$ 347	$ 24,551
Incremental Increase	**$ 7,589**	**$ 29,476**	**$ 1,225**	**$ 75**	**$ 38,365**

Interrogatory # 19 Long-Term Debt

Ref: Exhibit 5 / Tab 1 / Schedules 1 & 3

The description of the promissory note with CIBC in Schedule 1 would indicate that the interest rate is 5.15% throughout 2011 and until April 2012, but a rate of 5.59% is used in the table in Schedule 3.

Please explain this apparent discrepancy, and if necessary please provide a corrected rate of return on the total rate base.

Response:

WHSI has secured two financial instruments with the CIBC. The promissory note described in Schedule 1 in the amount of $10,941,862 was originally held by the City of Woodstock. This was paid to the City of Woodstock in 2008 and replaced with a committed term instalment loan/interest rate swap facility with the CIBC. This debt instrument is listed on Schedule 3 with the description “Initial Debt Issue” and has a rate of 5.15%.

The second financing facility with CIBC is a demand instalment loan/interest rate swap facility in the total amount of $4,100,000 for the Hydro One Commerce Way TS Capital Contribution. A summary description of this facility is on Exhibit 5, Tab 1 Schedule 1 page 2, under the subheading ii) Capital Contribution – Commerce Way Hydro One TS $4,100,000. This committed facility has a rate of 5.59%. This debt instrument is listed in Schedule 3, with the descriptions “HONI TS Cap Cont #1, HONI TS Cap Cont #2, and HONI TS Cap Cont #3, to show the 3 scheduled fund advances for this facility.

Interrogatory # 20 Class Load Profiles in the Cost Allocation Model

Ref: Exhibit 7 / Tab 1 / Schedule 2 / Appendix C

a. Please confirm that for the GS 50 – 999 kW class, it is assumed that monthly consumption will be 583 kWh per coincident kW (i.e. row 49 in sheet I8) and 542 kWh per non-coincident kW (row 67), and confirm that these amounts are higher than for the GS > 1000 kW class.
b. Please describe how the separate load profiles for the two classes GS 50-999kW and GS > 1000 kW were constructed.

Response:

a. WHSI confirms that for the GS 50 – 999 kW class, the information provided in 2011 cost allocation model suggests that the monthly consumption will be 583 kWh per coincident kW (i.e. row 49 in sheet I8) and 542 kWh per non-coincident kW (row 67), and that these amounts are higher than for the GS > 1000 kW class

b. A description of how the separate load profiles for the two classes GS 50-999kW and GS > 1000 kW were constructed is provided in Exhibit 7, Tab 1, Schedule 2, Page 1 of 4 which is repeated below

   "For the General Service 50 to 999 kW rate class, the load profile for General Service > 50 kW used in the original information filing has been used and scaled to match the 2011 load forecast for the General Service 50 to 999 kW class. The scaling factor ***(i.e 50.8% added****) reflects that some of the load previously in the General Service > 50 kW class has moved to the General Service > 1000 kW class in this application. For the General Service > 1000 kW rate class the load profile for Large Use class used in the original information filing has been used and scaled to match the 2011 load forecast for the General Service > 1000 kW class. The scaling factor* ***(i.e 260.0%% added****) reflects that the customer that was previously a Large Use customer has moved in the General Service > 1000 kW class and been included with customers that were previously in the General Service > 50 kW class."*

Interrogatory # 21 Streetlight Connections in the Cost Allocation Model

<u>Ref: Exhibit 7 / Tab 1 / Schedule 2 / Appendix C; and Exhibit 8 / Tab 2 / Schedule 1 / p. 4 (Table 8-8)</u>

Please describe the assumptions that would reconcile the number of streetlight connections in the cost allocation model, which is 2509, with the annualized connections in Table 8-8, which is 52,432.

Response:

The annualized connections in Table 8-8 of 52,432 translates into 4,369 (i.e. 52,432/12) street light devices which WHSI proposes to charge a monthly connection charge. In the original cost allocation the number of street light connections was 2,160 which was a 2004 value. In 2004, WHSI had 3,762 street light devices. The ratio of connections to devices was 57.4% (i.e. 2,160/3,762) in 2004. In the 2011 cost allocation study this ratio was maintain which means the number of connections in the 2011 study is 57.4% of 4,369 devices or 2,509 connections.

Interrogatory # 22 Class Revenues in the Cost Allocation Model

Ref: Exhibit 7 / Tab 1 / Schedule 2 / p. 3 (Table 7-3); and Appendix C;

a. Please show the derivation of the revenue amounts in Sheet O1, $1,536,290 for the GS 50 – 999 kW class, and $292,607 for the GS > 1000 kW class.

b. Please provide calculations confirming that the proposed change in base revenue from the GS 50 – 999 kW class, from the hypothetical amount of $1,536,290 to the proposed amount $1,478,505 (Exhibit 8 / 2 / 1 / Table 8-8), is consistent with the proposed rebalanced revenue to cost ratios in Table 7-3, from 127.1% to 122.4%

Response:

a. The follow table shows the derivation of the revenue amounts in Sheet O1, $1,536,290 for the GS 50 – 999 kW class, and $292,607 for the GS > 1000 kW class as being the 2011 Base Revenue Requirement allocated to each rate class in the same proportion as the 2011 Base Revenue at existing rates.

Class	2011 Base Revenue at Existing Rates	2011 Base Revenue at Existing Rates Proportions	2011 Proposed Base Revenue Allocated at Existing Rates Proportion	2011 Proposed Base Revenue Proportions
Residential	$4,067,105	62.8%	$5,170,401	62.8%
GS < 50	$869,459	13.4%	$1,105,305	13.4%
General Service 50 to 999 kW	$1,208,481	18.7%	$1,536,290	18.7%

General Service > 1000 kW	$230,171	3.6%	$292,607	3.6%
Unmetered Scattered Load	$24,957	0.4%	$31,727	0.4%
MicroFIT	$252	0.0%	$252	0.0%
Streetlight	$75,431	1.2%	$95,892	1.2%
Total	$6,475,857	100.0%	$8,232,474	100.0%

b. The following table provides calculations confirming that the proposed change in base revenue from the GS 50 – 999 kW class, from the amount of $1,536,290 to the proposed amount $1,478,505 is consistent with the proposed rebalanced revenue to cost ratios in Table 7-3, from 127.1% to 122.4%

	General Service 50 to 999 kW
2011 Proposed Base Revenue Allocated at Existing Rates Proportion (A)	$1,536,290
Allocated Miscellaneous Rev (B)	$53,057
Total Revenue (C) = (A) + (B)	$1,589,347
Costs from Cost Allocation (D)	$1,250,871
Starting Point Rev/Cost Ratio (C)/(D)	127.1%
2011 Proposed Base Revenue (E)	$1,478,505
Revised Total Revenue (F) = (E) + (B)	$1,531,562
Proposed Rev/Cost Ratio (F)/(D)	122.4%

Interrogatory # 23 Bill Impacts due to Proposed GS > 1000 kW Rate Class

Ref: Exhibit 8 / Tab 1 / Schedule 2, & Exhibit 8 / Tab 10 / Schedule 1 / Appendix B

The evidence shows that one customer's load changed in May 2009 to the extent that it ceased to be a Large User. Table 8-2 shows bill impact calculations for hypothetical scenarios for customers that would be in the proposed GS > 1000 kW class

a. Does WHSI have other customers that will be in the proposed GS > 1000 kW class, other than the previous Large Use customer? If so, how many, and which of the scenarios in Appendix B is most nearly representative of these customers. Table 8-2

(Tab 1 reference) shows six scenarios for customers in the proposed GS > 1000 kW class.

b. Please show those scenarios in the level of detail found in Appendix B (Tab 10 reference), and explain any discrepancies that may appear between the percentage impacts shown in the final column of Table 8-2 and the 'Total Bill Before Taxes' row, second-from right column in Appendix B.

Response:

a. As noted in Exhibit 8, Tab WHSI has 7 customers that will be in the proposed GS>1000 kW class, including the previous Large Use customer. The scenarios in Appendix B represent an average range of kW and kWh usage for these customers. Of the 7 customers, 3 customers have an average monthly demand between 1,000kW and 2,000 kW; 2 customers have an average monthly demand between 2,500kW and 3,500 kW, and 2 customers have an average monthly demand above 3,500 kW.

   Table 8-2 (Tab 1 reference) compares the rate impact for existing GS>50 kW customers with the proposed 50 kW-999 kW and GS>1000 kW rates as well as a Test rate for a single GS>50 rate class. This table also provides a rate impact comparison of the proposed GS>1000 kW rate class with both the existing GS>50 rate class and the Large Use rate class using the same usage quantities.

   The primary purpose of Table 8-2 is to illustrate how 2 proposed rate classes would have a lower rate impact on 5 of the 6 scenarios compared to having only 1 >50 kW rate class.

b. Upon review it was found that some incorrect rates were used to calculate the values in Table 8-2. A revised rate Table 8-2 and comparison of the 6 scenarios in the same level of Appendix B is attached as Appendix I

   This comparison includes a reconciliation of the rate discrepancy in Table 8-2. Amendments to change the 5% GST for the 2010 bill amount to 13% HST from 5% GST; to change the 2010 loss factor adjustment for the existing Large Use rate to 1.01

from 1.0440; and changes to the Non-RPP Rate Riders for 2010 and 2011 to reflect the rate as per kW have been included in the revised Table 8-2 and Appendix B Bill Impact.

The amended Non-RPP Rate Riders for 2010 and 2011 are the same amounts presented in the Schedule of Proposed Rates and Charges, Exhibit 8 Tab 8 Schedule 3.

Interrogatory # 24 Revenue Requirement of microFIT class

Ref: Exhibit 8 / Tab 1 / Schedule 3 / Table 8-3

The microFIT class is shown as having a revenue requirement of $252.

While not a material amount in 2011, please explain what assumptions have been made to arrive at this amount.

Response:

Although immaterial in amount, WHSI included the microFIT class in the allocation of the base revenue requirement to avoid misallocation of costs associated with the micro FIT rate class to other rate classes. Costs, however small at this point in time, are attributable to microFIT customers and are included in WHSI's revenue requirement. In the absence of an allocated amount to the microFIT rate class, these costs would have been allocated among the other rate classes. Additionally, WHSI would collect an additional $252 in revenue over and above its base revenue requirement by billing microFIT rates to customers because the

Until further cost allocation methodologies are introduced, and in light of the immateriality of the amount, WHSI assumed that the projected revenue of $252 ($252 = 4 microFIT customers X $5.25/month X 12 months) was equal to the cost, or revenue requirement, to provide this service. WHSI currently has 3 active microFIT customers and projected 4 microFIT customers for 2011 in this calculation.

Interrogatory # 25 Rate Riders

Ref: Exhibit 8 / Tab 8 / Schedule 3

Three rate riders proposed for the GS < 50 kW class and one rate rider for the GS > 1000 kW class are shown to the fifth decimal place.

Is this level of precision intentional, and if so please confirm that WHSI's billing system has the capability to use this level of precision.

Response:

WHSI confirms that this level of precision is intentional as WHSI's billing system has the capacity to use this level of precision.

Interrogatory # 26 Wheeling Charges

WHSI's published Conditions of Service provide at section 2.4.2.1 for "Wheeling of Power", and the document directs the customer to contact WHSI for current applicable rates.

a. Does WHSI have any customers who use or have inquired about the applicable rates?
b. Please explain whether in the WHSI's view, rates or charges for Wheeling should be included on its tariff sheet.

Response:

a. WHSI does not have any customers who use or have inquired about the Wheeling of Power rates.

b. In WHSI's view, rates or charges for Wheeling should be excluded on its tariff sheet and its Conditions of Services amended to remove references to WHSI Wheeling of Power rates. Exhibit 8 Tab 3 Schedule 1 is repeated below:

"The 2006 EDR Decision and Order for WHSI's Distribution Rates included approval for an Embedded Rate Class and Low Voltage Wheeling Charge Rate of $0.11/kW. Hydro One is no longer an embedded distributor to WHSI and therefore requests removal of the Low Voltage

Wheeling Charge Rate."

27. Recovery of Late Payment Litigation Costs

Ref: Exhibit 9/Tab 2/Schedule 3

WHSI is requesting a new deferral account to record the payment and recovery of late payment litigation costs pertaining to the Municipal Electrical Utilities Late Payment Class Action proceeding. WHSI has stated that its share of this proceeding is $58,033.26.

a. Please provide evidence supporting the amount allocated to WHSI (e.g. the settlement agreement).
b. Is the amount allocated to WHSI subject to any further adjustments as a result of contingencies as described in paragraphs 4 and 5 (p. 3 of the reference)?

Response:

a. The settlement agreement is attached as Appendix J. As indicated in this Appendix, the final estimate of each LDC's share has been revised. WHSI's share is now $57,743.72.

b. The methodology of allocating total settlement costs amongst the LDCs, the proposed method of recovery are the subject of a proceeding that is currently in progress at the Board. The Electricity Distributors Association has submitted the required evidence on behalf of all affected LDC's. The amount allocated to WHSI would be subject to change based on Board's determination in that proceeding.

Interrogatory # 28 Ontario Smart Metering System Meter Data Management and Repository (MDM/R) Deferral Account

Ref: Exhibit 9/Tab 2/Schedule 3

WHSI is requesting a new account to record costs for the Ontario Smart Metering System Meter Data Management and Repository (MDM/R).

a. Given that, to date, there are no charges levied by the IESO with respect to the Smart Meter Entity (SME), and the Board has not yet received an SME application in relation to these charges, what is the justification for this account?
b. Please provide the regulatory precedent for this account.
c. What are the journal entries to be recorded in this account?
d. What account number is WHSI proposing to use for this account?
e. What new or additional information is available since the filing of the application that would improve the Board's ability to make a decision to approve the recording of these costs in a deferral account?

Response:

a. WHSI is aware that there is currently a proceeding before the Board (i.e. EB-2007-0750) which is an application by the IESO for a SME licence. WHSI understands that currently there are no charges levied by the IESO with respect to the Smart Meter Entity (SME), and the Board has not yet received an SME application in relation to these charges. However, once the licensing issue is resolved then an application for SME charges could follow. Approved SME charges could be put in place in the next four years when WHSI will be filing IRM rate applications. WHSI is concerned that it may not have an opportunity to collect these potential SME charges from its customers until its next cost of service rate application. As a result WHSI is requesting a deferral account to record possible SME charges which could occur over the next four years and to seek recover of the balance in the deferral account in the next cost of service rate application.

b. WHSI is not aware of any regulatory precedent for this account. However, WHSI suggests the requested account would be handled in a similar manner to the method used for Wholesale Market Service charges.

c. WHSI would propose to record incremental capital and operating costs directly related to the Ontario Smart Metering system MDM/R in the same manner in which the Smart Meter capital and operating costs are recorded in account 1555 and 1556.

d. WHSI is proposing to either create new Account numbers (1557 MDM/R Capital, 1558 MDM/R Expense) for the Ontario Smart Metering System Meter Data Management and Repository (MDM/R), or Sub-Account numbers of the Smart Meter Accounts .

e. WHSI is not aware of new or additional industry information available since the filing of the application that would improve the Board's ability to make a decision to approve the recording of these costs in a deferral account. WHSI also acknowledges that the extent of MDM/R costs in relation to the IESO system integration are unknown at this point. However, based on preliminary MDM/R budgets provided by WHSI's consulting firm, Utilassist, the estimated implementation costs exclusive of WHSI labour costs, are approximately $345,000. WHSI believes these costs are material and should be tracked in an OEB deferral account in the same manner as Smart Meter costs.

OEB Staff Interrogatories

Appendix A

2008 01 03 Shareholder re

Prepaid Moratorium

Woodstock Hydro Services Inc.
16 Graham Street
Box 245 Stn Main
Woodstock, ON N4S 7X4
Telephone: (519) 537-3488
Fax: (519) 537-5081

January 3, 2008

Attention: Louise Gartshore, City Clerk
City of Woodstock
P.O. Box 40, 500 Dundas Street
Woodstock, ON N4S 7W5

Dear Louise:

Re: Feb. 1, 2008 - Moratorium on Installation of Prepaid Meters

Please bring this correspondence to the attention of the Shareholder.

For almost twenty years, Woodstock Hydro Services Inc. (WHSI, previously Woodstock Public Utility Commission), has proudly supported prepaid meters (PowerStat and AMPY) as a convenient payment option for its electricity customers. Today, approximately twenty-five per cent of WHSI's residential customers purchase power in advance at any one of five locations around the City, update their payment at home, and then manage their consumption via the in-home display unit. Throughout the years, customers (and landlords) have confirmed their high level of satisfaction with this unique payment offering.

As you are aware, in 2004, the Government of Ontario announced the installation of smart electricity meters for all Ontario customers by December 31, 2010. The approved system is based on two-way communication, and will measure how much electricity a customer uses each hour of the day so that the customer can be charged a corresponding price. WHSI's prepaid metering technology is not compliant with these smart meter technology requirements.

Clause 53.18 of Bill 21 (Energy Conservation Leadership Act - March 28, 2006), stipulates that after November 3, 2005, no distributor shall conduct discretionary metering activities (i.e. meter installation, removal, replacement or repair). Within the sector, this has been interpreted to mean that local distribution companies (LDCs) shall not purchase any new meters, and many LDCs have continued to install, remove, replace or repair meters using existing inventory. Currently WHSI is participating in a consortium-based Smart Meter RFP along with approximately twenty other LDCs. It is possible that several of the submitting vendors will offer compliant, prepaid technologies. The assessment of the responses and vendor selection will take place over the course of the first half of 2008. I therefore anticipate a comprehensive understanding of the future of prepaid electricity in the City of Woodstock (if such a future exists) within the same timeline.

It is anticipated that the installation of smart meters within our service territory will commence in the second half of 2008. However, in order to start procuring and installing smart meters in the City of Woodstock, two additional hurdles must be overcome. First Woodstock Hydro Services

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Inc. must be named in regulation to allow us to proceed with procurement and installation. Secondly, if a prepaid technology can be sourced as a result of the above mentioned consortium RFQ, an application would need to be made to the Ontario Energy Board as pre-payment is considered optional functionality of a smart meter and not covered by the minimum functionality requirements of the regulations.

WHSI has not ordered prepaid meters since 2005. We have utilized in-stock meters and have continued with removals and installations based on customer requests. However, as 2007 drew to a close, our inventory of in-stock prepaid meters had been depleted. Therefore, **effective February 1, 2008, Woodstock Hydro Services Inc. is implementing a moratorium on the installation of prepaid meters within its service territory.** After February 1, 2008, all existing prepaid customers will be able to continue to utilize their meter and pre-purchase their electricity at their existing location and until such time as the meter is replaced with a smart meter. However, there will not be any new installations, transfers, major repairs or replacements of prepaid meters (i.e. legacy meters). For all new or moving customers, our security deposit requirements will apply and customers will be enrolled with post-paid status.

In mid-January, we will be placing advertisements in the local media and at off-site sales locations to inform our customers about this decision. It is regrettable that we are not in a position to communicate a forward-looking vision regarding prepaid electricity at this time. However, due to the legislative realities, we have no choice but to declare this moratorium in the short term. I encourage individual Council representatives who may be approached by constituents to educate those customers who come forward with the facts surrounding the moratorium, and to reassure them that we are investigating all of the avenues that are available to us towards locating a smart-meter compliant technology that efficiently addresses the needs of customers, legislators, the Shareholder and the corporation.

Sincerely,

Ross McMillan

Ross McMillan, B.A., C.M.A., F.C.I.
President & CEO
Woodstock Hydro Services Inc.

cc: Woodstock Hydro Services Inc. Board of Directors
Woodstock Hydro Holdings Inc. Board of Directors
Hon. Gerry Phillips – Minister of Energy
Ernie Hardeman – MPP for County of Oxford

OEB Staff Interrogatories

Appendix B

Prepaid Moratorium

Notice of Suspension

Woodstock Hydro Services Inc.
Telephone: (519) 537-3488
www.woodstockhydro.com

January 11, 2008

ATTENTION
WOODSTOCK HYDRO CUSTOMERS
USING PREPAID POWER (AMPY, POWERSTAT)

NOTICE OF SUSPENSION

Effective February 1, 2008, Woodstock Hydro Services Inc. will cease all installation, replacements and major repairs of prepaid meters.

THIS NOTICE AFFECTS YOU IF YOU ARE OR WILL BE:

- **A new customer who may have wished to have a prepaid meter installed -** New customers on or after February 1, 2008 will be a regular "post-paid" electricity customer. Our security deposit policies will apply.
- **An existing customer who, on or after February 1, 2008, has a broken PowerStat/AMPY unit that cannot be quickly repaired at your residence**. We will try to repair your unit at your address. If a repair is not possible, it will be replaced with a "regular" meter and you will then receive electricity bills as a regular "post-paid" customer. Any security deposit requirement will be waived but the security deposit policy will apply. Therefore, adhering to future payment deadlines will ensure the continuation of the security deposit waiver.
- **Customers Moving Within the City**
  - **AMPY Transfers** - Existing AMPY customers moving within the City must submit a request prior to moving for their unit to be transferred to their new service address.
  - **PowerStat Transfers** – Existing PowerStat customers moving within the City must request in advance for their unit to be transferred to their new service address. The new service address also must be pre-wired for PowerStat (i.e. it must have had an installed PowerStat in the past).

WHAT IF MY UNIT IS WORKING WELL?

You are not affected immediately by this change. You can still purchase power at all five sales locations.

WHY DOES WOODSTOCK HYDRO HAVE TO DO THIS?

For almost 20 years, Woodstock Hydro has proudly supported prepaid meters (PowerStat and AMPY) as a convenient payment option, which is used by approximately 25% of our residential customers. However, the Government of Ontario has mandated the installation of smart electricity meters for all Ontario customers by December 31, 2010. Woodstock Hydro's prepaid metering technology is not compliant with the smart meter technology requirements and legally, we are no longer allowed to install or replace meters with anything but a compliant smart meter. We are currently in the midst of assessing the various technology offerings that are available in accordance with the Ministry's timelines, and we intend to select a vendor in 2008. We are hopeful, but at this time we are not certain whether prepayment will continue to be an option for customers.

Have Questions? – Please visit our Website at www.woodstockhydro.com or call 519-537-3488

OEB Staff Interrogatories

Appendix C

Redacted 2008 12 12

Future of Prepaid Metering

Woodstock Hydro Services Inc.
16 Graham Street
Box 245 Stn Main
Woodstock, ON N4S 7X4
Telephone: (519) 537-3488
Fax: (519) 537-5081

TO: WHSI Board of Directors

FROM: Management Team

DATE: December 12, 2008

RE: Prepaid Metering - Decision

Executive Summary

The WHSI management team participated in a conference call to review the [redacted] pre-paid solution on Tuesday, December 9, 2008. The consensus reached was that the solution provides less functionality at a significantly higher cost, and that it should not be pursued. This is the sole market-ready solution that is offered in conjunction with our approved smart meter vendor (Elster). We regretfully recommend that the best course of action is for WHSI to proceed with the replacement / elimination of pre-paid meters by December 31, 2009.

1. **Cost to Customer Set to Double** – If WHSI were to pursue the [redacted] pre-paid model, the monthly fee for pre-paid would increase from **7.50 to 15.00** per customer, at a time when customers will also be expected to pay a monthly smart meter fee going forward.

2. **Diminished Functionality** – WHSI's prepaid customers are accustomed to a real-time in-home display unit that displays increments and decrements to their electricity balance on account, expressed in dollars and cents. The [redacted] solution would only update once every twenty-four hours, eliminating the customer's ability to monitor their balance and adjust consumption.

3. **Diminished Safety** – Today, the customer's card swipe to restore power necessitates there being someone home when power is restored. With the [redacted] system, power is restored when a payment is processed in the CIS system, which could occur before a customer even returns home or hours after their purchase, depending on our business processes.

4. **Dubiousness of $15.00 Rate Being Approved –** It is highly unlikely that the $15.00 monthly rate for pre-paid functionality would withstand the scrutiny of the 3rd-generation rate application process, and the effort required to defend the rate would be considerable.

5. **Diminished Disconnection Functionality –** Today, disconnection occurs instantaneously upon the expiry of funds. With the [redacted] solution, disconnection happens when WHSI personnel process disconnection routines on a daily basis. Not only does this introduce additional risk of arrears (up to 24 hours of consumption may have accrued before the disconnection), but savvy customers may soon learn to take advantage of timing windows leading to payment lineups (to prevent disconnection) at key times.

A detailed project plan, establishing education processes, customer outreach and enrolment, agency contacts, meter installation timing, security-deposit requirements, and transition to post-paid billing will be established in the coming weeks. The elimination of pre-paid prior to December 2009 also allows WHSI to proceed with a 2010 rate application model that does not include pre-paid.

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Current Generation Pre-Paid Technology

1. Woodstock Hydro has offered a pre-paid metering option to customers for almost 20 years.

2. We currently support two, similar technologies – PowerStat and AMPY. Neither supports the province's smart-meter requirements, particularly with respect to AMI, hourly reads and time-of-use pricing and therefore will need to be replaced no later than December 31, 2010.

3. There are approximately 2,850 WHSI customers are currently utilizing a prepayment system, and 12,372 receiving and paying a bill.

4. Both PowerStat and AMPY require an alternate meter (with auto-disconnect functionality along with communication to the in-home display unit). Historically, this has resulted in costs being incurred for meter changes and as required, customer support at their premises.

5. Both PowerStat and AMPY involve the installation, configuration, maintenance and support of a non-integrated billing client/server application. In recent years, considerable efforts have been made to integrate with both the CIS and GIS, leading to modest success. Asset-management and smart-grid applications require comprehensive, real-time visibility to actual customer loads.

6. Customers purchase power at WHSI and 4 off-site locations. Costs incurred include per-transaction fees paid to the offsite locations, IT infrastructure and support for the offsite locations, and back office efforts to balance, audit and reconcile transactions.

7. Customers utilizing the prepayment system are not required to pay security deposits, as they are paying for their electricity up front. WHSI benefits from a cash-flow perspective, earning interest on the pre-paid funds, and also enjoys very low write-off experience.

8. Customers report conservation and cash-management benefits, but some also report inconvenience with respect to disconnections and having to replenish funds. Through the customer survey and ongoing dialogue, we know that landlords appreciate the prepayment option.

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[redacted] Technology

1. **Field Service** – WHSI had envisioned a scenario whereby Elster's pricing for the remote disconnect would allow for all residential service addresses to be pre-installed with the remote disconnect, leading to the elimination of field visits where a service address was transitioning between pre and post-paid. Unfortunately, the remote-disconnect extension matches the cost of the meter, rendering across-the-board installation impossible. Further, the OEB has given direction that it desires LDCs to focus on core technologies in their smart-meter rate applications. Accordingly, with [redacted] solution, we would need to continue with current practices – namely, costly field visits for each transition and associated back office administration of the meter change event.

2. **Software** – [redacted]'s [redacted] system ([redacted]) is a web-based, hosted solution, eliminating the need for servers and IT support at WHSI. However, the software "footprint" continues to require configuration, maintenance and troubleshooting. Rates will continue to be required outside of the primary CIS system. The pass-through cost for the [redacted] solution alone is $6 per customer per month.

3. **Transaction Reconciliation** - Reconciliation issues are different, but equal in magnitude between the current and [redacted] solutions. With the current system, WHSI personnel reconcile counter-sale and offsite sale transactions weekly, and perform a complete reconciliation on an annual basis. The [redacted] system is designed to calculate an approximate bill for customers, and then performs a monthly true-up when the billing process occurs. It is expected that this true-up exercise will create a different, but potentially more complicating trueing-up process for the administrative staff.

4. **Offsite Sales** – WHSI had envisioned a scenario where the relationship with the offsite sales locations could be severed, as customers gain access to innovative and accessible approaches for incremental payments (internet, IVR, pre-authorized) from the comfort of their homes. While these services are available for a fee, none are integrated with [redacted] directly, as it is not designed to be a payment-processing system. In fact, payments are first processed through the primary CIS and then [redacted] is updated. Therefore, especially since many pre-paid customers utilize cash as their primary payment method, the [redacted] solution would require a continued involvement with 24/7 sales organizations. These organizations would also need secure access to our primary billing system to post payments directly to customer accounts. This introduces increased risk and higher training and support requirements than the levels required at this time.

5. **Fully Allocated Costs** – The OEB's directive is for LDCs to allocate costs for a particular service to the group of customers benefiting from that service. The $15/month rate represents a fully-allocated costing model, and therefore includes the contributions of personnel at WHSI as described more fully below.

The essential support elements of the current pre-paid technology – offsites, software, reconciliations, and ongoing field support – would continue with the [redacted] solution, so there are no efficiency savings to be had for WHSI. From the customer's perspective, they would be paying twice the price for diminished functionality. For many customers, they may be losing the most critical element – the ability to curtail consumption to match available funds, in real-time.

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Costing Summary

1. **Current Rate Covers Current, Direct Costs** - The OEB-approved, monthly rental fee of $7.50 per month generates revenue of approximately $240,000 per year. $225,000 in direct, incremental costs for the prepaid solution (offsite IT requirements and support, offsite transaction fees, overtime directly attributed to prepaid and most notably, depreciation expense for the prepaid meter infrastructure) essentially offsets the revenue (note: pre-paid meter depreciation expense for 2010 is $175,000).

2. **Stranded Asset Value** – The estimated value of the stranded pre-paid meter assets at December 31, 2009 is $860,000. The OEB has committed to implementing recovery methodologies for all LDCs affected by the smart-meter mandate.

3. **Sensitivity Analysis for 2009 Net Income** – As pre-paid accounts are converted to post-paid, rental revenues will decline. At the same time, the incremental costs (offsite transactions) will also decline, and the depreciation expense issues will presumably be resolved by the OEB as noted above.

4. **Increased Writeoffs** – It is prudent to expect and predict increased writeoffs due to the known profile of the pre-paid customer group. Security deposit initiatives implemented during the transition phase will assist in mitigating exposure. If ten percent (10%) of the customers in this group defaulted on three-months of electricity consumption, the result would be writeoffs of $75,000.

5. **Increased Collections and Disconnection Activity** – LDCs are permitted to collect allocated costs associated with collection and disconnect activities. WHSI will be pursuing appropriate rates for these activities in conjunction with the 2010 rate application. While the current tag charge of $4 covers the piece rate for disconnection services, going forward a tag charge will be significantly higher, and will present a much greater disincentive to all customers.

6. **Opportunity to Capitalize on Redirected Labour Hours** – In addition to direct costs, 3,720 hours (~2.5 FTEs) from WHSI personnel were directed to pre-paid (i.e. setup, troubleshooting, installation, meter changes, reconciliation, etc.). Therefore, commencing in 2010 3,720 hours could be allocated to alternative initiatives, projects and emerging needs and may contribute to lower overtime levels or diminished need for temporary staff or additional hires that may otherwise have been required. In the longer-term, particularly in the Meter and Internal Services departments, there is the possibility that attrition through retirement can be achieved as a direct result of the elimination of pre-paid.

7. **Impact on Rates for “Regular” (Non-Prepaid) Customers** – The 2009 cost of the 3,720 hours diverted to pre-paid activities is $180,000. However, $40,000 in expenses are avoided annually as pre-paid customers do not require a meter reading, bill, envelope, or postage stamp and do not call in with high-bill complaints. The net result ($140,000 /annum) equates to each customer paying, on average, $9 per year (through rates) to support the labour effort that goes into today’s prepaid solution. Since the hours expended have been included in rates in the past and will continue to be included in rates in the future, there is minimal impact for general rate levels. Increased costs associated with more post-paid customers (postage, etc.), will be included in the 2010 rate application. Further, the 2009 eBilling implementation (whereby a percentage of customers will take up WHSI’s offer to receive an electronic bill), will mitigate increased printing/mailing expenses.

OEB Staff Interrogatories

Appendix D

4.2.5 – Prepaid Project and

Communications Plan

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Woodstock, ON N4S 0A8
Telephone: (519) 537-3488
Fax: (519) 537-5081

TO: WHSI Board of Directors
FROM: Management Team
DATE: February 13, 2009
RE: Prepaid Transition Plan

Background

At the December 12, 2008 meeting of the Woodstock Hydro Services Inc. Board of Directors, the following resolution was passed:

IT WAS RESOLVED THAT THE WOODSTOCK HYDRO SERVICES INC. BOARD OF DIRECTORS ACCEPTS THE RECOMMENDATION OF STAFF TO ELIMINATE PRE-PAID METERS BY DECEMBER 31, 2009.

It was further agreed that a detailed project plan, including shareholder and customer communication strategy, would be presented at the next Board meeting.

Three Workgroups

There are three major workgroups who will play a pivotal role throughout 2009:

1. Customer Service
   a. Will liaise with Meter and Billing departments towards creating a "master schedule" of planned meter changes with regard to billing cycles
   b. Will perform customer outreach and enrolment in advance of the meter change, and will ensure that the appropriate security deposits have been obtained
   c. Will respond to customer questions
   d. Will assist with the upload/download of electronic service orders for the current batch of meter changes
   e. Will manage the prepaid customer database and prepare reports and updates as required

2. Meter Personnel
   a. Will change the meters, and take final reads etc. for billing purposes
   b. Will shut off meters where customer information / security deposit has not been obtained

3. Billing Personnel
   a. Will process final bills on prepaid accounts, transfer unused electricity balances to new accounts, and process first (and subsequent) post-paid bill

Project coordination, timing and workflow between these workgroups will be closely monitored to ensure timeliness of delivery of each element.

Project Timeline

The plan calls for 100-120 meter changes per week, over the course of up to 25 weeks between the months of May and November. In most cases, this will translate to 25-30 meter changes per day, with one day per week reserved for cleanup from the current week and preparation for the ensuing week.

Time Frame	Activity
January / February	Planning, Procedures, Resourcing, Communication Strategy
February / March	Communication to Shareholder and Customers • Correspondence • Sentinel / Oxford Review, Heart FM, Website • Off-sites, Front Counter • Word of mouth
March / April	“One-Off” Meter Changes Begin for Moves and Service Calls
April	Customer Service - Scheduling and Account Setup for May
May – December	Customer Service - Scheduling and Account Setup for “Next Month” Meter - Meter Changes for Current Month Billing –Final Bills / First Post-paid Bills for Recent Meter Changes

Resourcing

A Customer Service Representative (Smart Meters) has been hired for a one-year contract, and commenced their employment with WHSI on February 9, 2009. This individual will be the point person for the Customer Service tasks listed above, and will allow full-time, permanent personnel to continue with their normal duties. In any given week during the months of April through November, this individual will be handling hundreds of accounts – reaching out to upcoming customers to ensure that we have their information, assisting the Meter department with the current week’s activities, and assisting the Billing department with the billing of meters which have recently been changed.

A WHSI meter technician will head up each of two dedicated two-person crews. The meter technician will perform the actual meter change, and will be supported by a contract field worker who will assist with data collection etc.

The costs associated with contract personnel will be captured in smart-meter variance accounts, to be recouped through smart-meter rates.

Communication Plan

1. **Shareholder**

   A meeting with the Shareholder has been scheduled for Friday, February 13, 2009 from 1:00 to 2:00 pm, and a Powerpoint presentation prepared.

2. **Media / Postings**

   We intend to proceed with a one-time communication blitz which will include a number of radio spots on Heart FM, two consecutive Saturday advertisements in the Oxford Review (circulated free to all county residents) and a press release that will be released the day prior to the first Oxford Review advertisement. Postings will be erected at off-site sale locations and at WHSI, and information will be published on the WHSI website.

   The purpose of these communications is to ensure that every prepaid customer is made aware that they are affected by the smart meter plan, and further that they know which next steps to expect.

3. **Targeted Customer Outreach / Enrolment**

   Each individual customer may receive up to 3 levels of direct communication beyond the communication blitz phase.

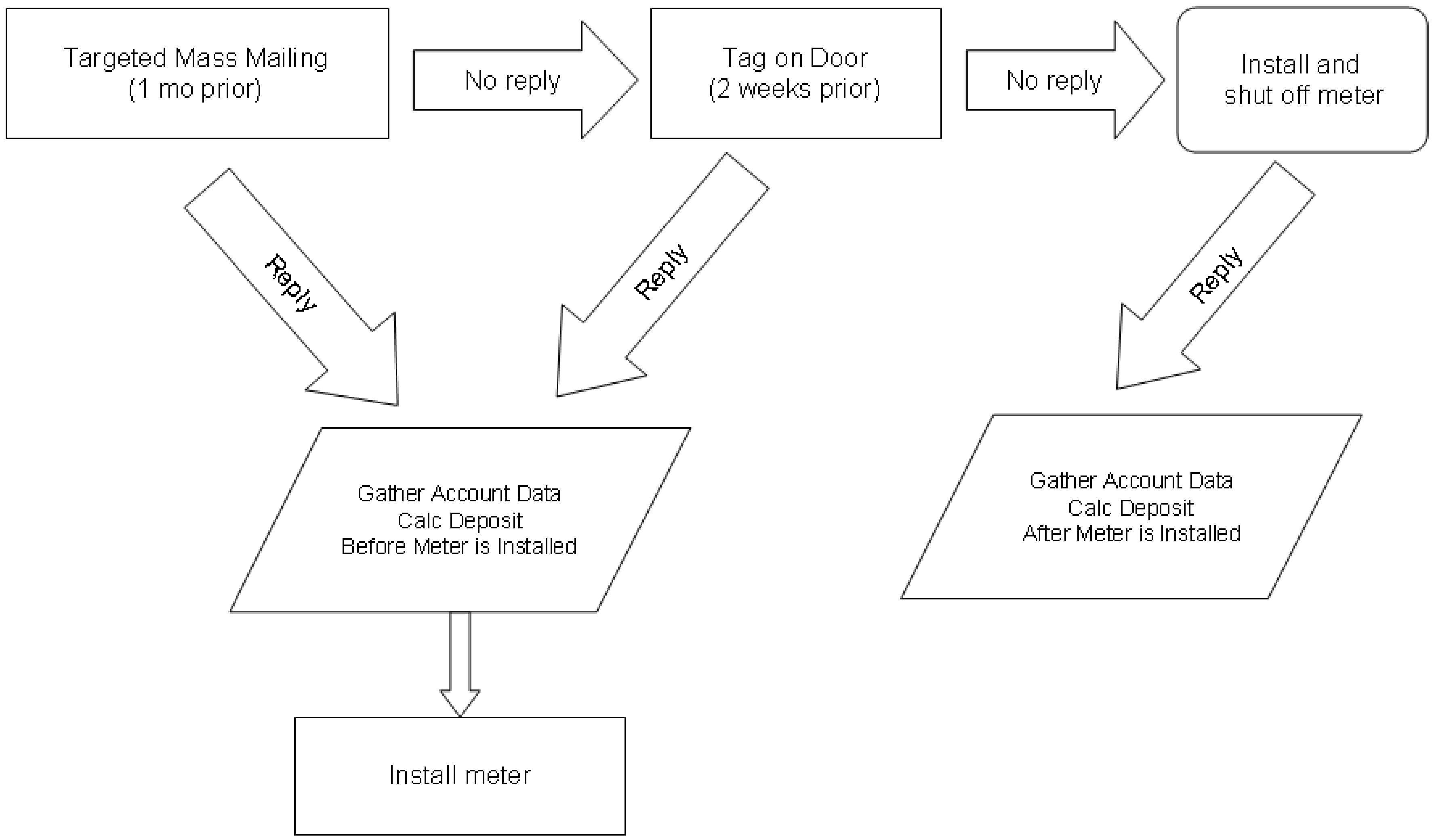
   Each week, a targeted mass mailing will be sent to the identified group of addresses whose meters will be changed one-month hence (i.e. "Current Occupant"). This will result in a certain percentage of customers responding to our correspondence and participating in the enrolment / deposit management process. Two weeks later, the remaining group of accounts who have not contacted us will receive a notification tag on their door, urging them to contact us within the next week in order to avoid disconnection of their electricity supply in conjunction with their smart meter being installed. Again, the hope is that the majority of the remaining group will respond leading to account setup and deposit management.

   Finally, if the customer never responds, their new smart meter will be installed and will be shut off immediately, and a third and final note will be left at the premises for the customer so that they know why they do not have electricity and can respond.

Security Deposits / Mitigating Risk of Writeoffs

WHSI's existing security deposit provisions will be utilized during the transition. Within the confines of the policy, customers can avoid the security deposit requirement by either providing a letter from another utility (e.g. Union Gas) confirming good payment history or providing a satisfactory credit check made at the customer's expense. Customers can reduce the deposit requirement from 2.5 times to 2.0 times the estimated monthly electricity bill by enrolling in the PAP (pre-authorized payment) program. Further, customers can pay their security deposit in up to 4 installments. Additionally, remaining prepaid balances will be transferred to fulfil deposit requirements. Finally, on a one-time basis in 2009 WHSI will be increasing its donation to the Salvation Army from $5,000 to $10,000 to provide additional access to funds for those most in need.

CUSTOMER SERVICE → METERING WORKFLOW



Heart FM Radio Spot - *Draft*

This is a message for Woodstock Hydro Powerstat and AMPY prepaid electricity customers. As directed by the Province of Ontario, over the next few years all Ontarians will be making the switch to being billed for electricity using time-of-use pricing. The price you will pay for electricity will depend on when it is used. A smart meter electronically tracks how much electricity is used **and when** it is used, paving the way for time-of-use pricing. Today's prepaid meter does not support time-of-use pricing, and therefore it must be replaced with a smart meter. Woodstock Hydro will be following the province's direction by converting all installed prepaid meters to smart meters before December 31 of this year. When your smart meter is installed, the way that you will pay for your electricity will change and you ***may*** be required to pay a security deposit. For now, you do not need to contact us. We will be contacting all affected customers by mail some time between April and October, closer to the time that we schedule your smart meter installation. If you would like more information immediately, a posting with additional information is available at all offsite locations as well as at Woodstock Hydro, or you can find out more at www.woodstockhydro.com or by calling our office.

Oxford Review Advertisement - *Draft*

IMPORTANT NOTICE

FOR

WOODSTOCK HYDRO PREPAID CUSTOMERS

As directed by the Province of Ontario, over the next few years all Ontarians will be making the switch to being billed for electricity using time-of-use pricing. The price you will pay for electricity will depend on when it is used. A smart meter electronically tracks how much electricity is used a**nd when** it is used, paving the way for time-of-use pricing.

Today's prepaid meter does not support time-of-use pricing, and therefore it must be replaced with a smart meter. As part of our broader smart-meter rollout plan, Woodstock Hydro will be following the province's direction by converting all installed prepaid meters to smart meters before December 31 of this year.

If you are a Powerstat and AMPY prepaid electricity customer, as soon as your smart meter is installed, you will start to receive a utility bill for electricity, water and sewer charges (if applicable), and you will be paying the bill monthly, as opposed to the current prepayment approach. The way that you will monitor consumption will also be changing, as your current in-home display unit will not work with the smart meter. You may be required to pay a security deposit as part of the move to being a post-paid customer.

For now, you do not need to contact us. We will be contacting all affected customers by mail some time between April and October, closer to the time that we schedule your smart meter installation.

If you would like more information immediately, a posting with additional information is available at all off-site prepaid sales locations as well as at Woodstock Hydro, or you can find out more at www.woodstockhydro.com or by calling our office at 519-537-3488.

The prepaid option has helped Woodstock Hydro customers conserve electricity and manage their expenses for almost 20 years. Woodstock Hydro sincerely regrets any inconvenience that customers may experience in the transition from the conservation tool of the past to the conservation tool of the future.

Smart Meter Update

Woodstock Hydro Services Inc.

February 13, 2009

Ontario’s Energy Needs

- Between now and 2025, Ontario will replace about 80 per cent of its current electricity system via building new generation, refurbishment of existing facilities and investing in conservation
- Conservation will help make the best use of our existing electricity resources and slow the growth in demand

Lowering "Peak" Demand

- Spikes of electricity demand:
  - **adds to electricity costs** because higher demand often means higher market prices
  - **is hard on the environment** because more of the less attractive forms of generation must be run to meet them
  - **adds to the amount Ontario needs to invest in the system** because meeting the peaks requires even more new generation and more transmission infrastructure

Culture of Conservation

- By 2010, every home and small business in Ontario will have a Smart Meter
- Customers will have new options for managing and reducing electricity consumption and costs
- Customers will each contribute to ensuring a positive impact on the environment and Ontario's energy system

Smart Meter Chronology

- April 2004 - provincial government announces the initiative of installing ‘smart’ meters in all Ontario homes by 2010
- January 2005 – Ontario Energy Board submits smart-meter implementation plan (including mandatory technical requirements)
- August 2006 – Final smart meter documents published. Woodstock prepaid meters will not be “grandfathered”
- 2007 - Woodstock Hydro commences detailed smart meter project, and remains committed to researching a next-generation prepaid technology in conjunction with smart-meter research and preparation

What is a Smart Meter?

- Old-style meters can only measure the total amount of electricity used over an entire billing period
- A Smart Meter will record total electricity consumption hour by hour
- Smart Meters make time-of-use (TOU) prices possible - different prices can apply at different times of the day

Benefits of Smart Meters

- **Manage electricity bills** - attention to how and when electricity is used
- **Feedback about electricity use** - electricity bills plus Internet views will show how much electricity was consumed within each TOU period

Time of Use Pricing

- Electricity prices will vary, based on when it is used - time of day, day of week (weekdays versus weekend), and by season (winter or summer)
- TOU pricing will be designed to encourage Ontarians to shift some electricity use to off-peak hours (demand drops overnight and on weekends so the price can be lower)

TOU Pricing Comparison

- Current TOU Pricing
  - Off-Peak – 4.0 cents / kWh
  - Mid-Peak – 7.2 cents / kWh
  - On-Peak – 8.8 cents / kWh
- RPP Pricing
  - 5.6 cents / kWh – lower tier
  - 6.5 cents / kWh – higher tier

Billing / Cost Recovery

- The cost for Smart Meters will be recovered through electricity rates paid by all customers just like costs for existing meters are recovered today
- TOU Pricing – Customers will be notified in advance regarding when they can start to take advantage of time-of-use rates

2008: Vendor Selection

- Participated in London Hydro RFP along with 30+ Ontario LDCs
- Facilitated by a “fairness commissioner”
- Selected vendor prescribed by process
- Prepaid functionality included in checklist
- Elster = Chosen Smart Meter Vendor for WHSI

Woodstock Prepaid Meters

- Woodstock prepaid program started in 1989
- Two current types - "PowerStat" (2,114) and AMPY (721)
- In-home display
- No security deposit required as no risk ($50 deposit for AMPY display)

Prepaid → Conservation

- Amount of power currently in use is displayed, allowing in-home behaviors to be modified
- Electricity costs can be monitored, controlled and budgeted
- 10-15% reduction in consumption

Current Prepaid

- Electricity rates preprogrammed for kWh consumption
- $7.50 / month “rental” charge
- “Real-time” (current balance, current consumption / hour) information on in-home display, expressed in dollars and cents..
- Power can be purchased at 4 variety stores + Hydro office
- Shutoff is instantaneous
- Only one way communication with meter

Future Prepaid?

- Elster meter + XXXXXXXX "bolt-on" technology; TOU pricing not yet available (future)
- No in-home display
- No real-time consumption information as only updated once/day and only kWh
- $15 / month rental fee (vs. $7.50) for same information all customers can access on the web (previous day's consumption information) – Expect rate application challenges from intervenors
- Cash purchases not easily supported
- Shutoffs would be daily, not immediate

End Result

- Woodstock Hydro must (at least for now) transition prepaid customers to post-paid smart meters
  - Must be installed by end of 2010
  - Elster = chosen vendor
  - XXXXXXXX = Elster’s prepaid option
  - XXXXXXXX functionality is costly, unproven and provides less than what customers currently enjoy

2009: Pre-paid Transition

- 2,800+ pre-paid customers
- February / March – Mass Communication blitz
- April → November
  - 100+ meters each week
  - Targeted Customer outreach – 2 “touches” (letter, tag);
  - Security Deposit Coordination
  - Meter Change
- Deposit Policy must be enforced to minimize writeoff exposure

Superior Customer Service

- $5,000 donation each year to Salvation Army
- Increasing in 2009 to $10,000
- Multi-step, multi-media communication strategy to inform customers at least 3 times
- Customers can have security deposit requirement waived if they can demonstrate good utility payment history (e.g. Union Gas)
- Deposits can be paid in installments (over 4 months)

2009: Other Smart Meter

- 2,500+ Additional meter changes
  - Small Commercial
  - Other “regular” post-paid residential
- Remaining meters will be transitioned in 2010

Questions?

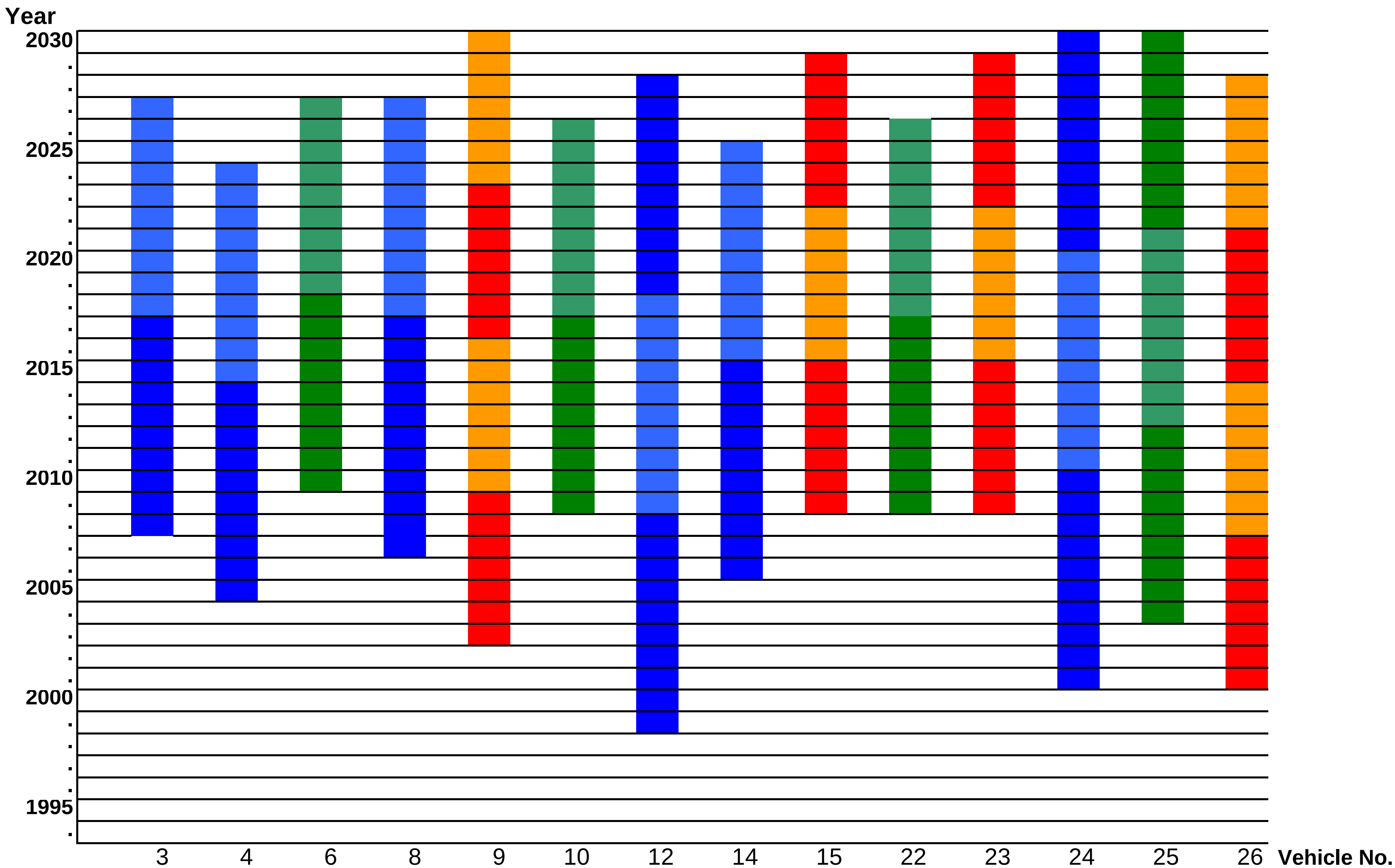
OEB Staff Interrogatories

Appendix G

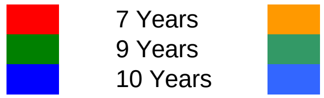
LForm-23

Vehicle Replacement Schedule

Vehicle Replacement Schedule



Note: this is a guide only, vehicle life may be extended



OEB Staff Interrogatories

Appendix H

Boldstar IR Report 2010

Boldstar
Infrared Services Inc.

Infrared Inspection
- Electrical Distribution System -

Woodstock Hydro

Date:

September 21st-23rd, 2010

Report Completed By:	
Boldstar Infrared Services Inc. 453 Crerar Avenue Oshawa ON L1H 2W6 Tel: 905-579-9264, 1-888-847-0517 Fax: 905-579-4678 **www.boldstarinfrared.com**	 Certification Stamp

Infrared Report Summary

Purpose: Infrared inspection to identify thermal anomaly conditions on electrical distribution equipment that suggest an unwanted condition exists and repairs are required.
Method: Complete infrared inspection of selected Woodstock Hydro distribution system equipment. Save infrared images of all noted anomaly conditions. Compile a report detailing findings.
Conditions: Equipment operating under normal daytime loading conditions.
Inspection Equipment: FLIR model PM695 thermal imaging systems, serial # 15210467.

Observations

Note: Boldstar Infrared Services Inc. is in no way responsible for any expenses resulting in actions or repair of reported anomalies. This report is not a warranty or guarantee of any equipment condition or reliability.

Numerous anomaly thermal patterns were noted during the infrared scanning. All noted conditions are detailed in this report.

All anomalies classified as follows:
HIGH Priority: Component temperature over 50 C rise over ambient.
Plan and execute repairs as soon as possible, within the next few days. Do not ignore.
MEDIUM Priority: Component temperature 25 to 50 C rise over ambient.
Plan and execute repairs at the next opportunity, within the next few weeks. Do not ignore.
LOW Priority: Component temperature below 25 C rise over ambient.
Plan and execute repairs at the next convenient opportunity. Do not ignore.
No Problems Noted (N/A): No anomalies noted. Condition good.

All reported condition should be investigated further as soon as possible to verify the reported condition. Use all safety procedures. Electrical hazards exist.

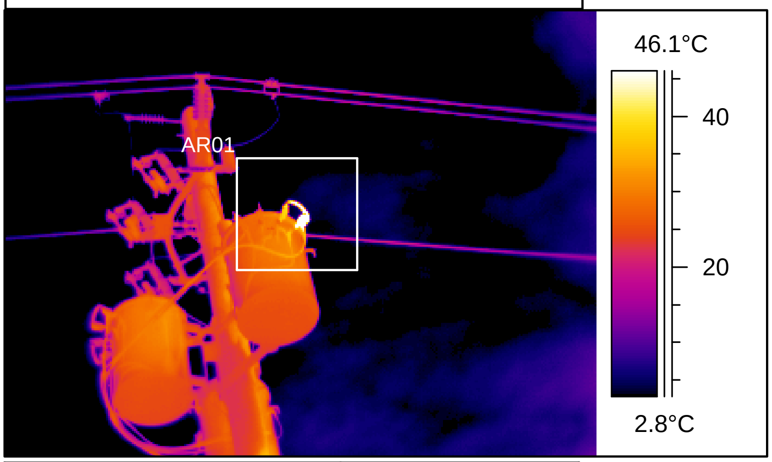
CONTENTS OF REPORT

Priority: ***H= High M= Medium L= Low N/A= Not Applicable***

Identification:	DATE
Pole W02399	21/09/2010

Description: **Transformer**

INFRARED IMAGE



PHOTO

Temperature rise: 59.74 °C
(over ambient)

IR information	Value
Date of creation	21/09/2010
Time of creation	11:08:01 AM
Object parameter	**Value**
Ambient temperature	13.0°C
Label	**Value**
AR01 : max	72.8°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of a 3-phase transformer bank.
Located on pole W02399 at the John Knox Christian School on Juliana Dr.
Heating noted at the indicated secondary connection.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

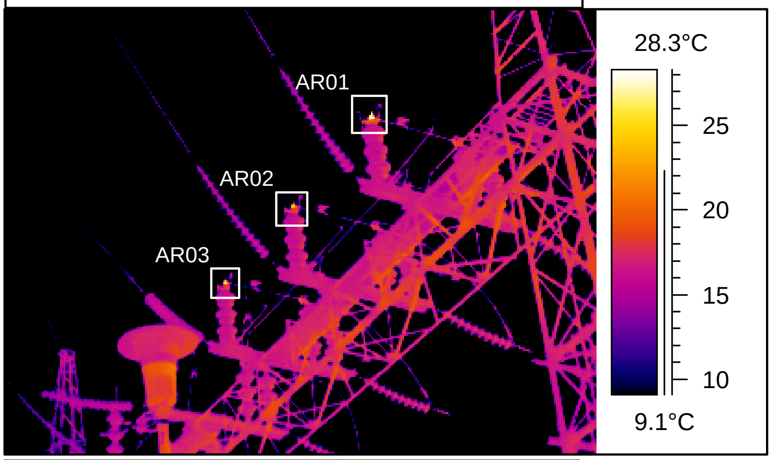
PRIORITY: **High** **Medium** **Low**

ANOMALY:	Heating connection

Identification:	DATE
115 Feed-In Lines	**21/09/2010**

Description: **Insulators**

INFRARED IMAGE



PHOTO

Temperature rise: 26.73 °C
(over ambient)

IR information	Value
Date of creation	21/09/2010
Time of creation	8:25:19 AM
Object parameter	**Value**
Ambient temperature	13.0°C
Label	**Value**
AR01 : max	39.8°C
AR02 : max	24.4°C
AR03 : max	26.2°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of the 115 feed-in lines substation structure.
Located at the Woodstock TS M-4 station.
Heating noted at the tops of the indicated insulators.
At arrows in photo.
See IR information chart above for maximum temperature inside area box (AR01).

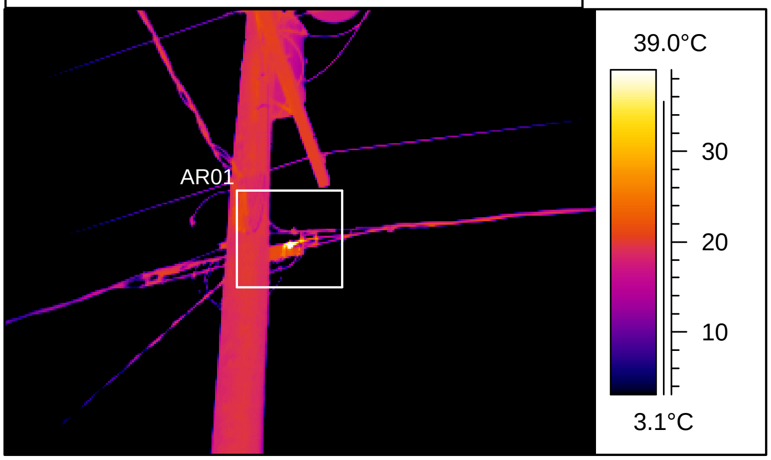
PRIORITY: High **Medium** Low

ANOMALY: Heating connections

Identification:	DATE
Pole W01606	21/09/2010

Description: **Secondary connection**

INFRARED IMAGE



PHOTO

Temperature rise: 44.22 °C
(over ambient)

IR information	Value
Date of creation	21/09/2010
Time of creation	10:25:58 AM
Object parameter	**Value**
Ambient temperature	13.0°C
Label	**Value**
AR01 : max	57.2°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of a secondary connection.
Located on pole W01606 at 566 Henry St.
Heating noted at the indicated secondary connection.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

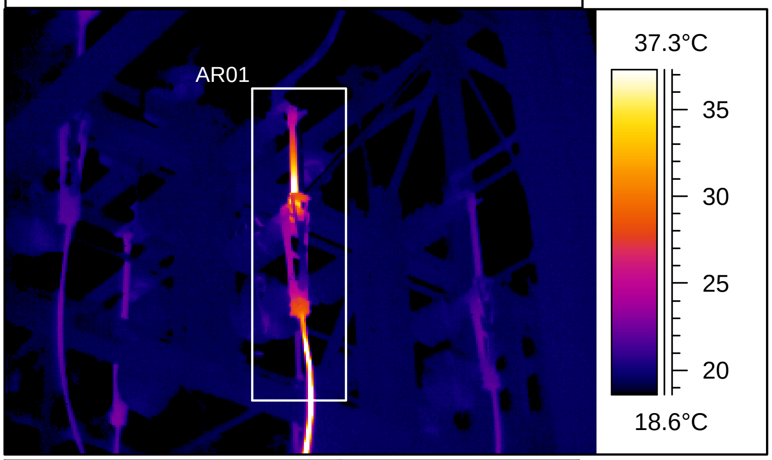
PRIORITY: High **Medium** Low

ANOMALY:	Heating connection

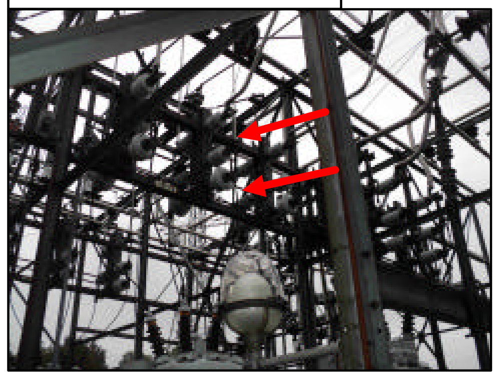
Identification:	DATE
M4 Station 10N3-B	22/09/2010

Description: **Red Phase Jaw**

INFRARED IMAGE



PHOTO



Temperature rise: 28.53 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	9:47:06 AM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	47.6°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of the red phase switch.
Located at the M4 station on 10N3-B.
Heating noted at the top of the switch and bottom cable.
At arrows in photo.
See IR information chart above for maximum temperature inside area box (AR01).

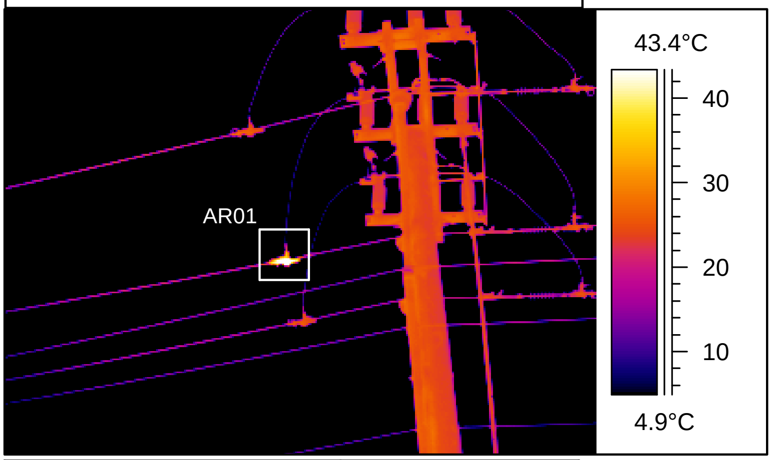
PRIORITY: High **Medium** Low

ANOMALY:	Heating connection

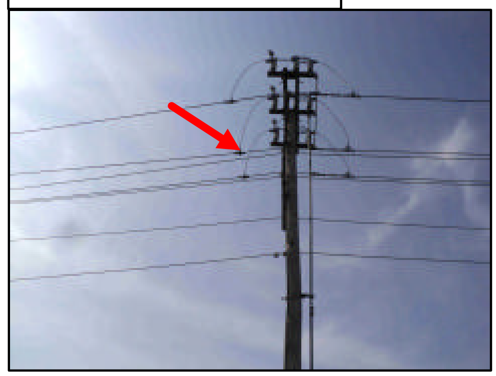
Identification:	DATE
Pole W02920	**21/09/2010**

Description: **Line Clamp**

INFRARED IMAGE



PHOTO



Temperature rise: 40.70 °C
(over ambient)

IR information	Value
Date of creation	21/09/2010
Time of creation	12:50:22 PM
Object parameter	**Value**
Ambient temperature	13.0°C
Label	**Value**
AR01 : max	53.7°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of a line clamp.
Located on pole W02920.
Heating noted at the middle phase line clamp.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

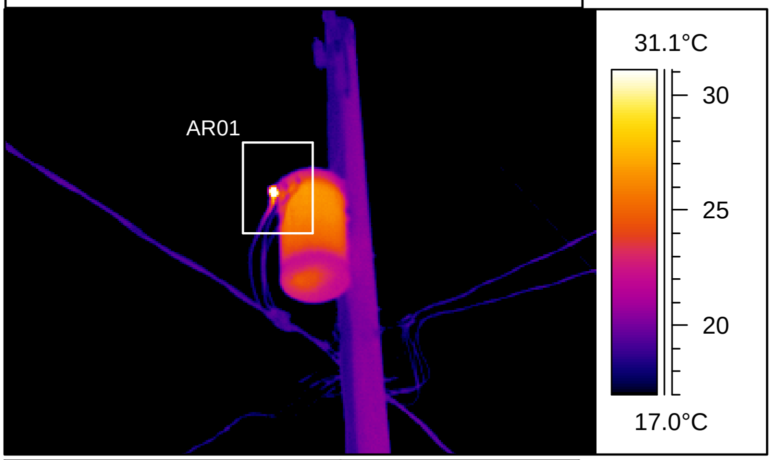
PRIORITY: High **Medium** Low

ANOMALY:	Heating line clamp

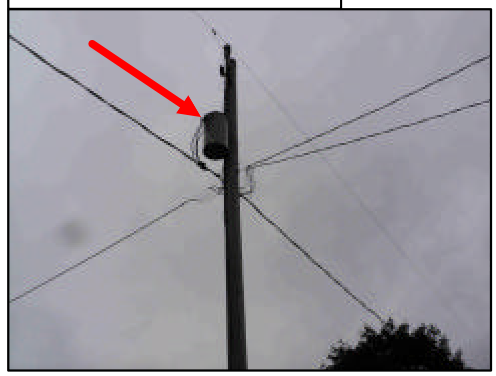
Identification:	DATE
Pole W00666	22/09/2010

Description: **Transformer**

INFRARED IMAGE



PHOTO



Temperature rise: 24.08 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	1:39:33 PM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	43.1°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of a transformer.
Located on pole W00666 at 543 Highland Dr.
Heating noted at the X1 connection.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

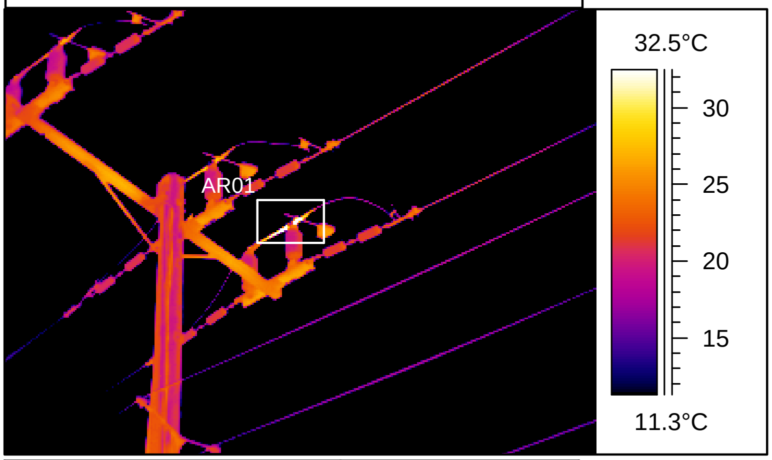
PRIORITY: High **Medium** Low

ANOMALY:	Heating connection

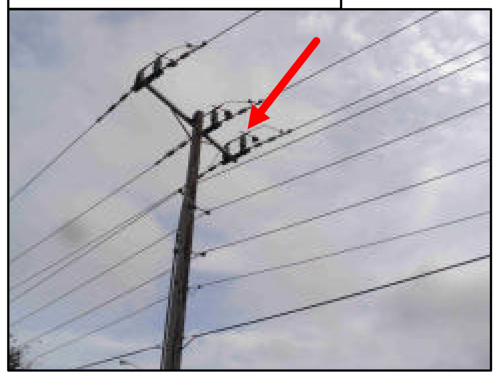
Identification:	DATE
Pole W04258	22/09/2010

Description: **Switch**

INFRARED IMAGE



PHOTO



Temperature rise: 27.51 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	2:32:32 PM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	46.5°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of a switch.
Located on pole W04258 at 1147 Dundas St. East.
Heating noted at the roadside switch.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

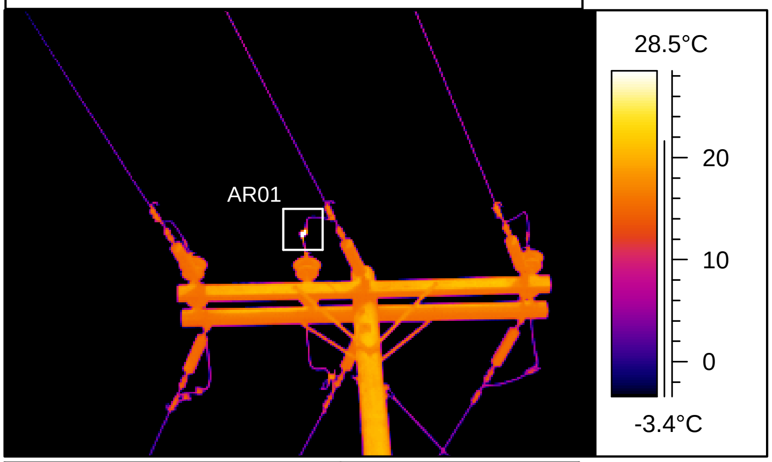
PRIORITY: High **Medium** Low

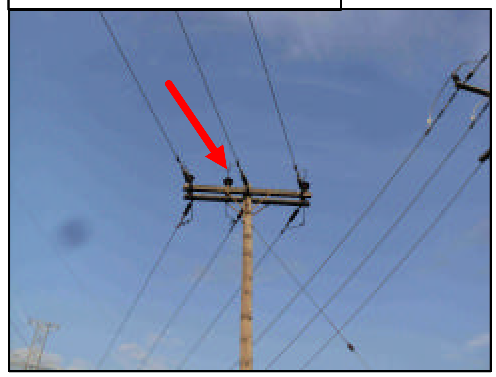
ANOMALY:	Heating connection

Identification:	DATE
Woodside TS - M4 First pole east of the bus	**21/09/2010**

Description: **Middle phase connection**

INFRARED IMAGE	PHOTO





Temperature rise: 30.59 °C
(over ambient)

IR information	Value
Date of creation	21/09/2010
Time of creation	8:19:20 AM
Object parameter	**Value**
Ambient temperature	13.0°C
Label	**Value**
AR01 : max	43.6°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of a direction change pole with jumpers.
Located at Woodstock TS M-4 on the first pole east of the bus.
Heating noted at the indicated middle phase ampact connection.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

PRIORITY: High **Medium** Low

ANOMALY:	Heating connection

Identification:	DATE
Pole W01824	22/09/2010

Description: **Line Clamp**

INFRARED IMAGE

PHOTO

Temperature rise: 12.71 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	8:41:54 AM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	31.7°C
AR02 : max	33.4°C
AR03 : max	32.8°C
AR04 : max	23.0°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of pole W01824.
Located on Athlone St.
Heating noted at the top line clamp and at the indicated secondary connections.
At arrows in photo.
See IR information chart above for maximum temperature inside area box (AR01).

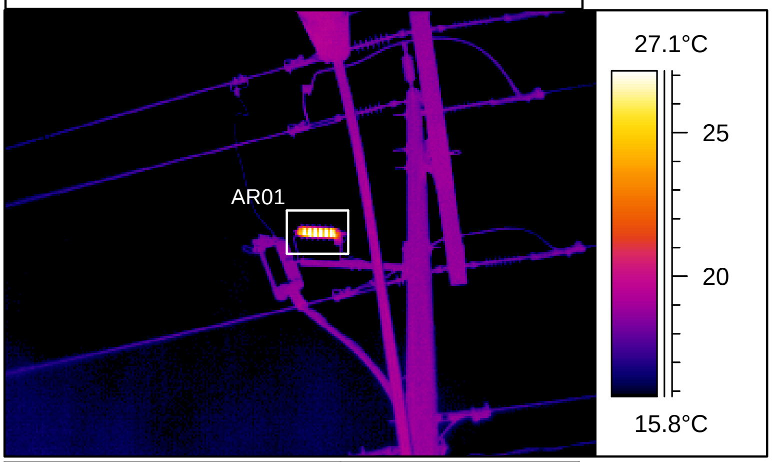
PRIORITY: High Medium **Low**

ANOMALY:	Heating connections

Identification:	DATE
Pole W01363	22/09/2010

Description: **Arrestor**

INFRARED IMAGE



PHOTO

Temperature rise: 11.06 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	8:56:54 AM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	30.1°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of a lightning arrestor.
Located on pole W01363 at the corner of Stonegate Dr. and Ferguson St.
Heating noted at the arrestor.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

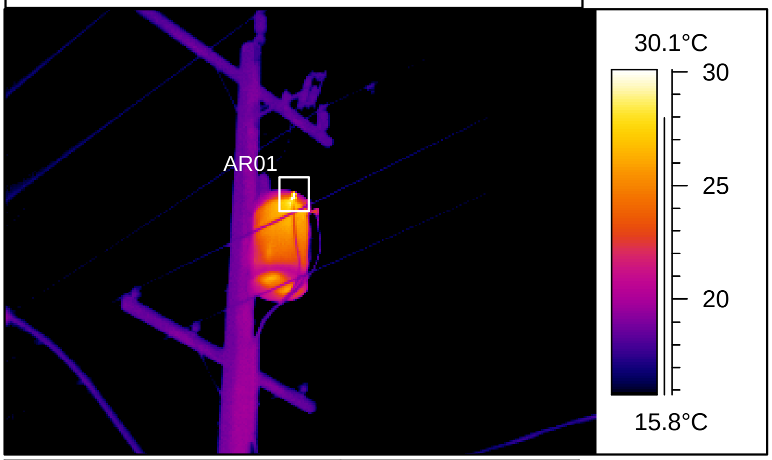
PRIORITY: High Medium **Low**

ANOMALY: Heating component

Identification:	DATE
Pole W02273	**22/09/2010**

Description: **Transformer**

INFRARED IMAGE



PHOTO

Temperature rise: 13.42 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	9:06:06 AM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	32.4°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of a transformer.
Located on pole W02273 at 817 Parkinson Rd.
Heating noted at the X1 connection.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

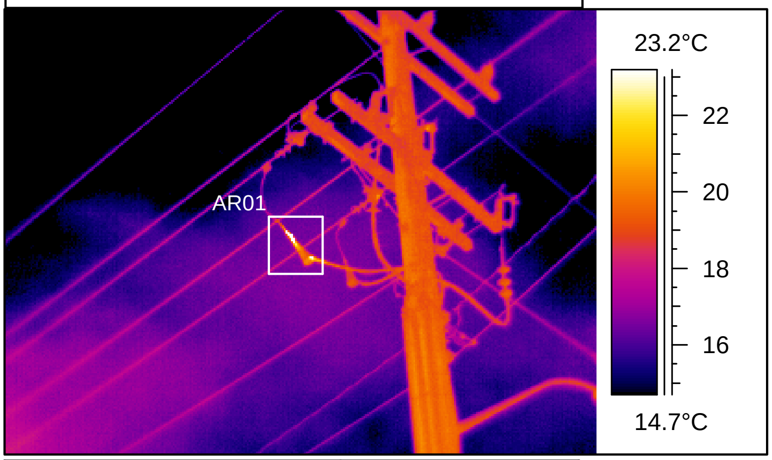
PRIORITY: High Medium **Low**

ANOMALY:	Heating connection

Identification:	DATE
Pole W02269	22/09/2010

Description: **Stress Cone**

INFRARED IMAGE



PHOTO

Temperature rise: 9.88 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	9:08:29 AM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	28.9°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of a stress cone termination.
Located on pole W02269 at the Mac's store at Parkinson Rd. and Norwich Ave.
Heating noted at the field side stress cone connection.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

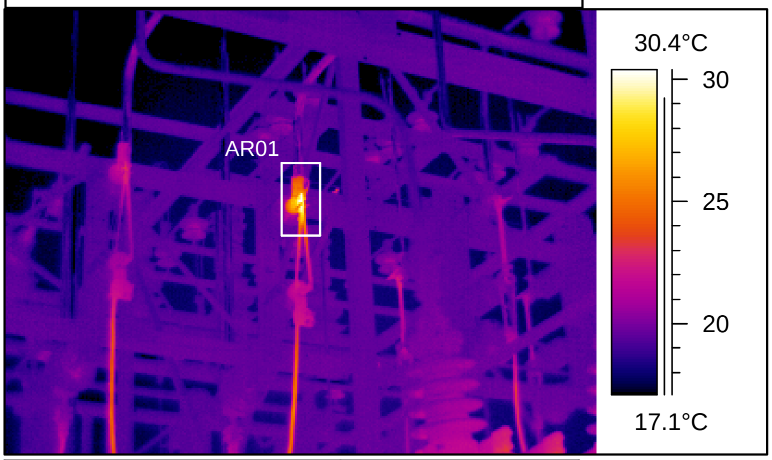
PRIORITY: High Medium **Low**

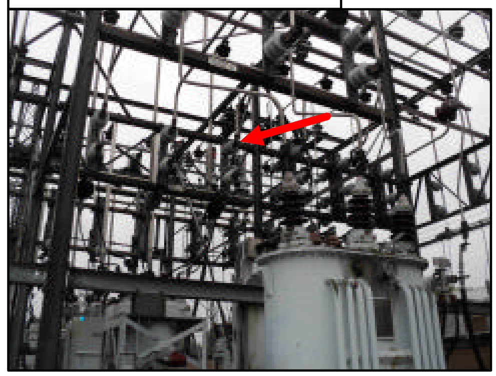
ANOMALY:	Heating connection

Identification:	DATE
M4 Station 10SC 1-Y	**22/09/2010**

Description: **White Phase Jaw**

INFRARED IMAGE	PHOTO





Temperature rise: 12.85 °C
(over ambient)

IR information	**Value**
Date of creation	22/09/2010
Time of creation	9:43:32 AM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	31.9°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of the white phase switch jaw.
Located at the M4 station on 10SC 1-Y.
Heating noted at the top of the indicated switch.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

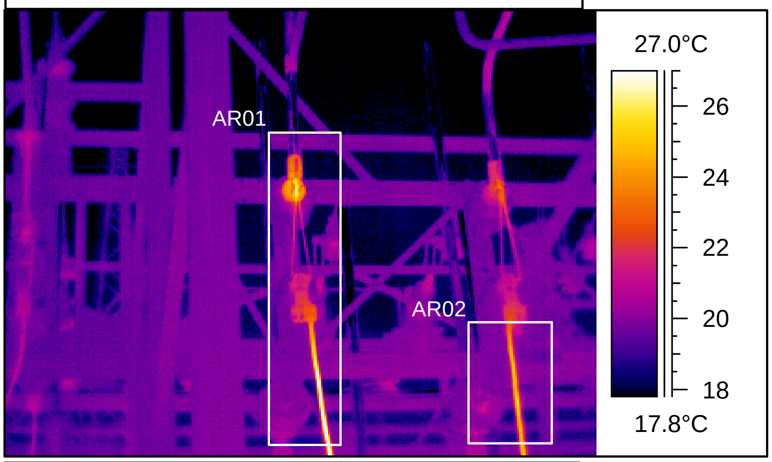
PRIORITY: **High** **Medium** **Low**

ANOMALY:	Heating switch

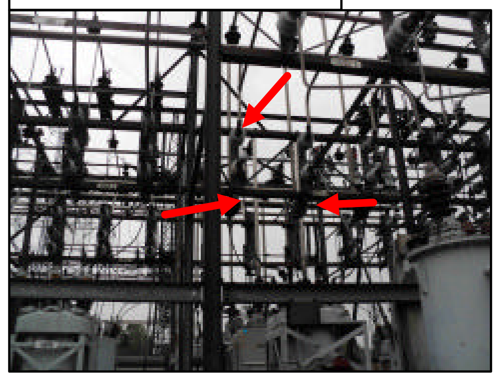
Identification:	DATE
M4 Station 10SC 1-Y	**22/09/2010**

Description: **Blue Phase Jaw**

INFRARED IMAGE



PHOTO



Temperature rise: 8.77 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	9:44:44 AM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	27.8°C
AR02 : max	25.7°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of the blue phase switch.
Located at the M4 station on 10SC 1-Y.
Heating noted at the top of the indicated switch and cables.
At arrows in photo.
See IR information chart above for maximum temperature inside area box (AR01).

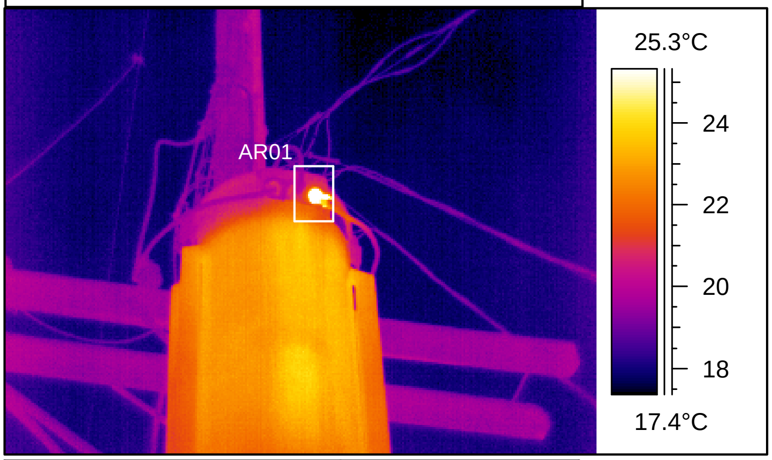
PRIORITY: **High** **Medium** **Low**

ANOMALY: Heating switch

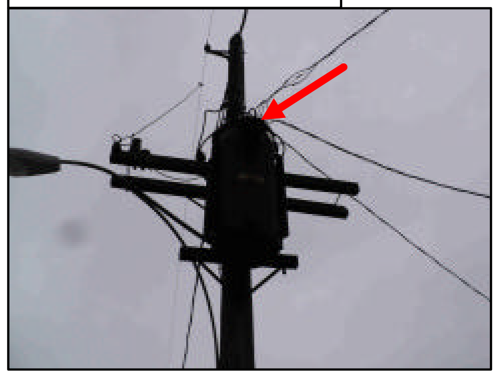
Identification:	DATE
Pole W00468	**22/09/2010**

Description: **Transformer**

INFRARED IMAGE



PHOTO



Temperature rise: 13.38 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	10:45:34 AM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	32.4°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of a transformer.
Located on pole W00468 at 290 Wellington St. North.
Heating noted at the X3 connection.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

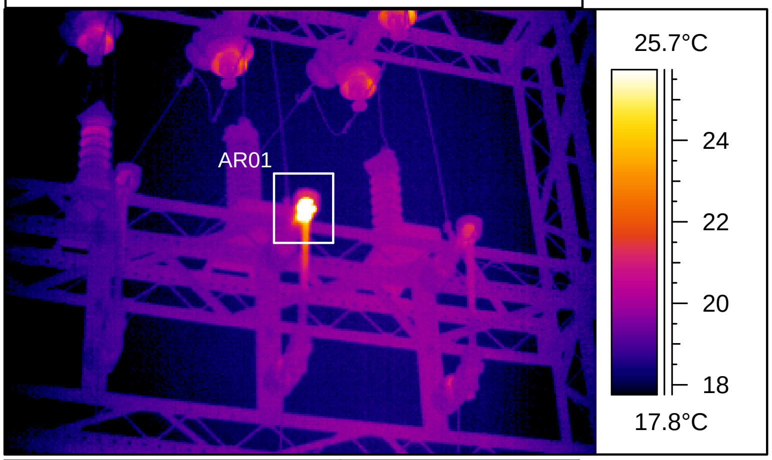
PRIORITY: High Medium Low

ANOMALY: Heating connection

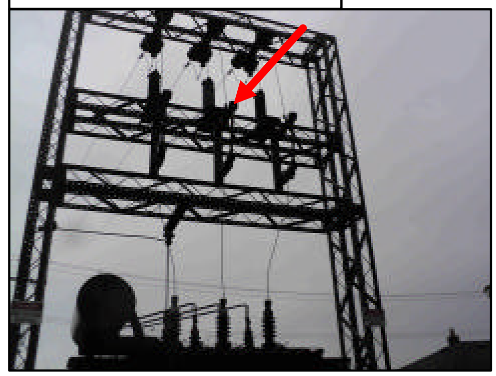
Identification:	DATE
MS9 Station	**22/09/2010**

Description: **Switch**

INFRARED IMAGE



PHOTO



Temperature rise: 18.89 °C
(over ambient)

IR information	**Value**
Date of creation	22/09/2010
Time of creation	10:58:50 AM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	37.9°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of a substation switch.
Located at MS9 station.
Heating noted at the top of the indicated switch connection.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

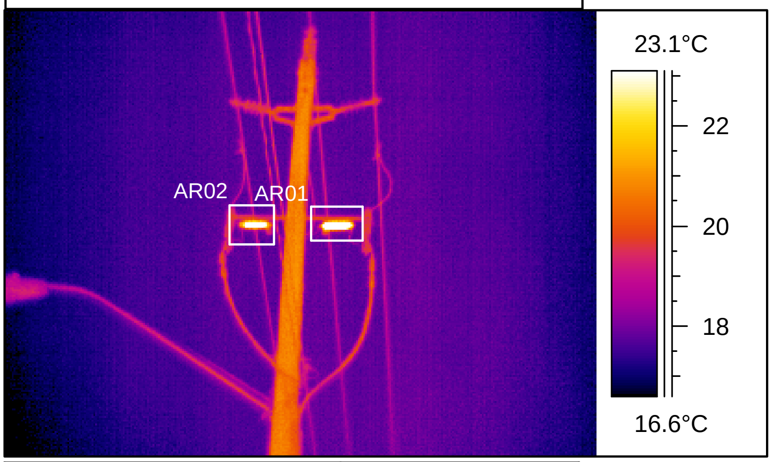
PRIORITY: **High** **Medium** **Low**

ANOMALY:	Heating switch

Identification:	DATE
Pole W02077	**22/09/2010**

Description: **Arrestors**

INFRARED IMAGE



PHOTO

Temperature rise: 12.09 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	12:28:36 PM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	31.1°C
AR02 : max	26.1°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of some arrestors.
Located on pole W02077 at 3 Bysham Park Drive.
Heating noted at the roadside and fieldside arrestors.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

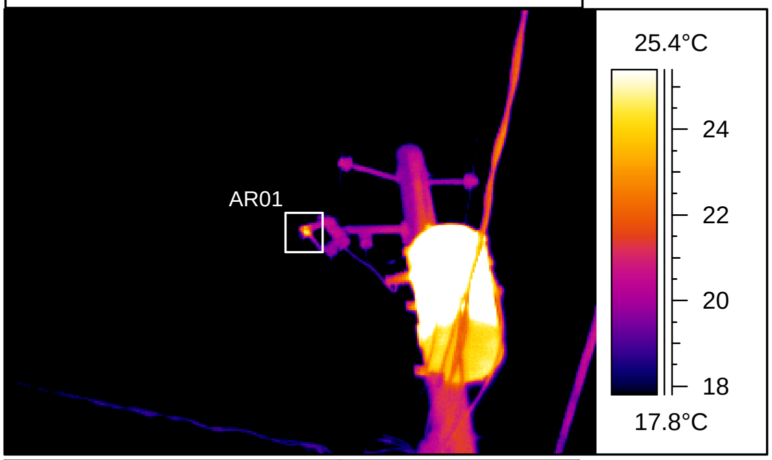
PRIORITY: High Medium **Low**

ANOMALY:	Heating arrestors

Identification:	DATE
Pole W03627	**22/09/2010**

Description: **Switch**

INFRARED IMAGE



PHOTO

Temperature rise: 5.80 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	1:14:39 PM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	24.8°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of a switch.
Located on pole W03627 at 776 Rathbourne St.
Heating noted at the top of the switch.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

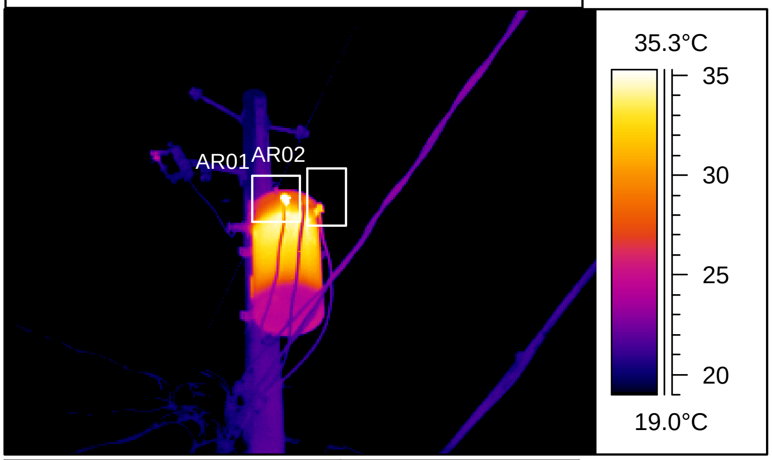
PRIORITY: High Medium **Low**

ANOMALY:	Heating switch

Identification:	DATE
Pole W03627	**22/09/2010**

Description: **Transformer**

INFRARED IMAGE



PHOTO

Temperature rise: 20.08 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	1:18:02 PM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	39.1°C
AR02 : max	35.0°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of the transformer.
Located on pole W03627 at 776 Rathbourne St.
Heating noted at the X1 and X3 connections.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

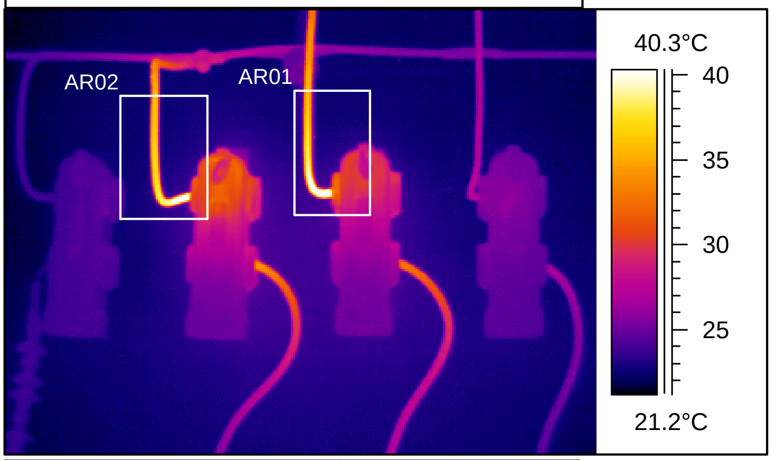
PRIORITY: High Medium **Low**

ANOMALY:	Heating connections

Identification:	DATE
Station MS-3B	23/09/2010

Description: **Switches**

INFRARED IMAGE



PHOTO

Temperature rise: 22.62 °C
(over ambient)

IR information	Value
Date of creation	23/09/2010
Time of creation	12:40:29 PM
Object parameter	**Value**
Ambient temperature	23.0°C
Label	**Value**
AR01 : max	45.6°C
AR02 : max	42.1°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of some indoor substation switches.
Located in the MS-3B station.
Heating noted at the blue and white phase top connections.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

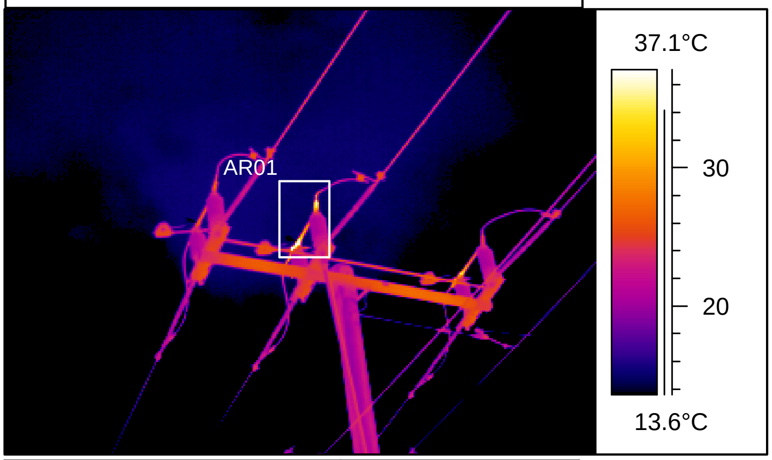
PRIORITY: High Medium **Low**

ANOMALY: Heating switches

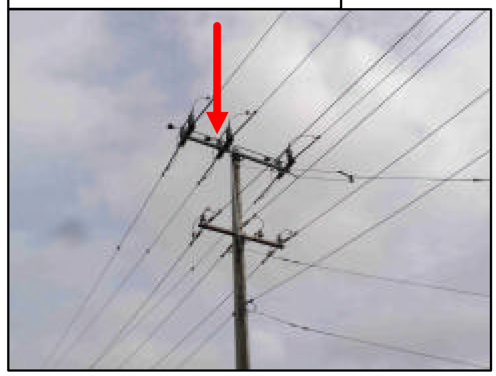
Identification:	DATE
Pole LB38	22/09/2010

Description: Switch

INFRARED IMAGE



PHOTO



Temperature rise: 23.38 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	2:39:59 PM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	42.4°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of a switch.
Located on pole LB 38 at Barney Printing Ltd. on Dundas St. East.
Heating noted at the middle phase switch.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

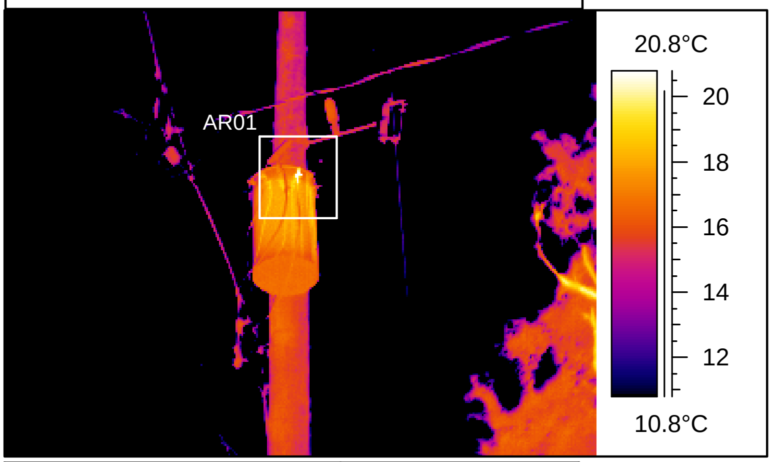
PRIORITY: High Medium **Low**

ANOMALY:	Heating connection

Identification:	DATE
Pole 3176	21/09/2010

Description: **Transformer**

INFRARED IMAGE



PHOTO

Temperature rise: 9.77 °C
(over ambient)

IR information	Value
Date of creation	21/09/2010
Time of creation	9:01:42 AM
Object parameter	**Value**
Ambient temperature	13.0°C
Label	**Value**
AR01 : max	22.8°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of the transformer.
Located on pole 3176 at 565077 Bower Hill.
Heating noted at the X3 field side connection.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

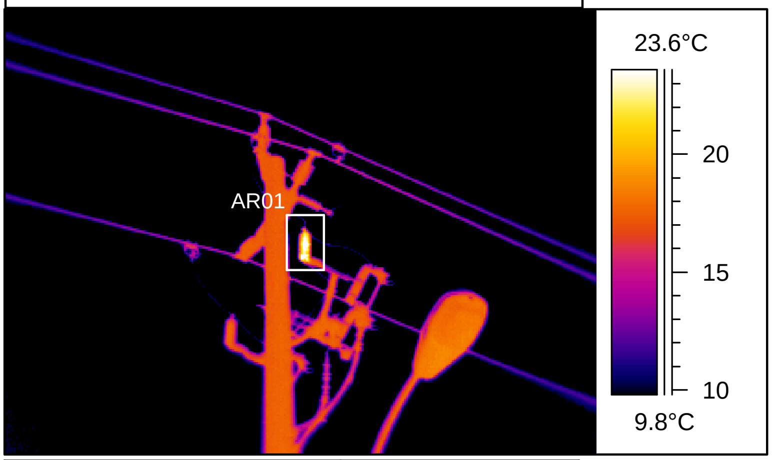
PRIORITY: High Medium Low

ANOMALY: Heating connection

Identification:	DATE
Pole W01416	22/09/2010

Description: **Arrestor**

INFRARED IMAGE



PHOTO

Temperature rise: 7.88 °C
(over ambient)

IR information	Value
Date of creation	22/09/2010
Time of creation	8:34:23 AM
Object parameter	**Value**
Ambient temperature	19.0°C
Label	**Value**
AR01 : max	26.9°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of an arrestor.
Located on pole W01416 at the corner of Stonegate Dr. and Athlone St.
Heating noted at the arrestor.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

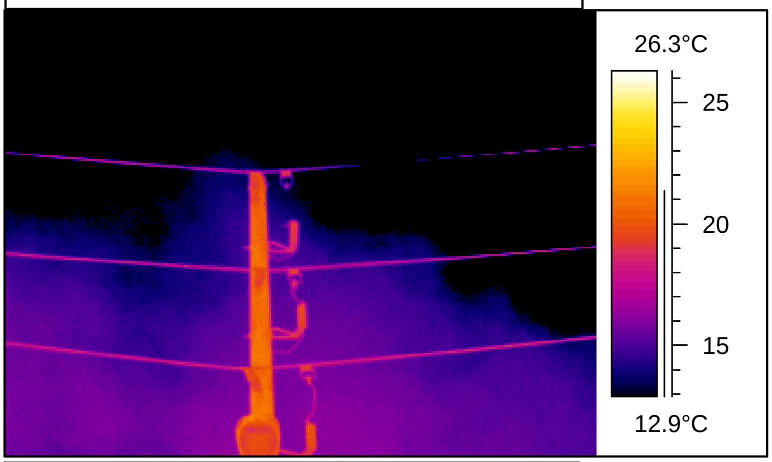
PRIORITY: High Medium **Low**

ANOMALY: Heating arrestor

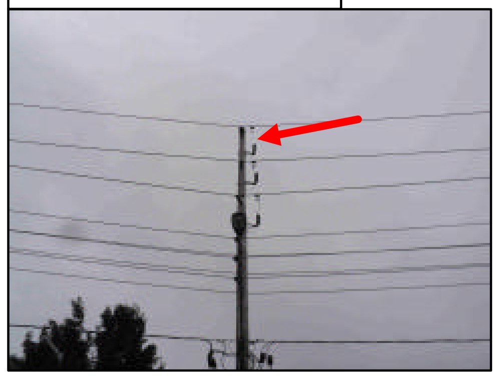
Identification:	DATE
Pole W02103	22/09/2010

Description: **Arrestor**

INFRARED IMAGE



PHOTO



IR information	Value
Date of creation	22/09/2010
Time of creation	11:15:24 AM
Object parameter	**Value**
Ambient temperature	19.0°C

Status:

Repaired Date:

Notes:

INFORMATION:

Infrared image of the top arrestor.
Located on pole W02103.
No thermal anomaly noted. The top arrestor wire is disconnected.
At arrow in photo.
See IR information chart above for maximum temperature inside area box (AR01).

PRIORITY: High Medium Low

ANOMALY:	Disconnected arrestor

OEB Staff Interrogatories

Appendix I

Bill Impacts

BILL IMPACTS *(Monthly Consumptions)*

GENERAL SERVICE 50 kW - 999 kW (Comparison to Existing GS>50 kW Rate)

Consumption
30,000 kWh
100 kW

	2010 BILL			2011 BILL			IMPACT			Table 8-2 Error Detail - 2011 Bill		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill	table input error	$ included	error (over)/under
Monthly Service Charge			294.82			360.69	65.87	22.34%	10.12%		360.69	0.00
Distribution (kW)	100	1.8048	180.48	100	2.1129	211.29	30.81	17.07%	5.93%		211.29	0.00
Smart Meter Adder (per month)			0.00			0.47	0.47		0.01%		0.47	0.00
Smart Meter Rider (per month)			1.63			1.20	(0.43)	(26.38%)	0.03%	0.92	0.92	0.28
LRAM & SSM Rider (kW)	100		0.00	100	0.0863	8.63	8.63		0.24%		8.63	0.00
Deferral and Variance Account Rider (2010) (kW)	100	(0.4471)	-44.71	100	(0.5422)	(54.22)	(9.51)	21.27%	(1.52%)	(0.3761)	(37.61)	(16.61)
Deferral and Variance Account Rider (2011) (kW)	100		0.00	100	(0.0487)	(4.87)	(4.87)		(0.14%)		0.00	(4.87)
Non-RPP Global Adjustment Rate Rider (2010) (kW)	100		0.00	100	0.1471	14.71	14.71		0.41%		0.00	14.71
Non-RPP Global Adjustment Rate Rider (2011) (kW)	100		0.00	100	0.0301	3.01	3.01		0.08%		0.00	3.01
Distribution Sub-Total			**432.22**			**540.91**	**108.69**	**25.15%**	**15.18%**	**Distribution**	**544.39**	**(3.47)**
Retail Transmisssion (kW)	100	4.2383	423.83	100	2.9046	290.46	(133.37)	(31.47%)	8.15%		290.46	
Delivery Sub-Total			**856.05**			**831.37**	**(24.68)**	**(2.88%)**	**23.33%**		**834.84**	**(3.47)**
Other Charges (kWh)	31,320	0.0135	422.82	31,293	0.0135	422.46	(0.36)	(0.09%)	11.85%		422.46	
Cost of Power Commodity (kWh)	31,320	0.0607	1,901.75	31,293	0.0607	1,900.11	(1.64)	(0.09%)	53.31%		1,900.11	
Total Bill Before Taxes			**3,180.62**			**3,153.94**	**(26.68)**	**(0.84%)**	**88.50%**	**Table 8-2 Total**	**3,157.41**	**(3.47)**
GST/HST		**13.00%**	413.48		13.00%	410.01	(3.47)	(0.84%)	11.50%			
Total Bill			**3,594.10**			**3,563.95**	**(30.15)**	**(0.84%)**	**100.00%**			

GENERAL SERVICE 50 kW - 999 kW (Comparison to Existing GS>50 kW Rate)

Consumption
200,000 kWh
500 kW

	2010 BILL			2011 BILL			IMPACT			Table 8-2 Error Detail - 2011 Bill		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill	table input error	$ included	error (over)/under
Monthly Service Charge			294.82			360.69	65.87	22.34%	1.75%		360.69	0.00
Distribution (kW)	500	1.8048	902.40	500	2.1129	1,056.45	154.05	17.07%	5.14%		1,056.45	0.00
Smart Meter Adder (per month)			0.00			0.47	0.47		0.00%		0.47	0.00
Smart Meter Rider (per month)			1.63			1.20	(0.43)	(26.38%)	0.01%	0.92	0.92	0.28
LRAM & SSM Rider (kW)	500		0.00	500	0.0863	43.15	43.15		0.21%		43.15	0.00
Deferral and Variance Account Rider (2010) (kW)	500	(0.4471)	-223.55	500	(0.5422)	(271.09)	(47.54)	21.27%	(1.32%)	(0.3761)	(188.06)	(83.03)
Deferral and Variance Account Rider (2011) (kW)	500		0.00	500	(0.0487)	(24.36)	(24.36)		(0.12%)	0.00	0.00	(24.36)
Non-RPP Global Adjustment Rate Rider (2010) (kW)	500		0.00	500	0.1471	73.55	73.55		0.36%	0.00	0.00	73.55
Non-RPP Global Adjustment Rate Rider (2011) (kW)	500		0.00	500	0.0301	15.07	15.07		0.07%	0.0000	0.00	15.07
Distribution Sub-Total			**975.30**			**1,255.13**	**279.83**	**28.69%**	**6.11%**	**Distribution**	**1,273.62**	**(18.49)**
Retail Transmisssion (kW)	500	4.2383	2,119.15	500	2.9046	1,452.28	(666.87)	(31.47%)	7.06%		1,452.28	
Delivery Sub-Total			**3,094.45**			**2,707.41**	**(387.04)**	**(12.51%)**	**13.17%**		**2,725.90**	**(18.49)**
Other Charges (kWh)	208,800	0.0135	2,818.80	208,620	0.0135	2,816.37	(2.43)	(0.09%)	13.70%		2,816.37	
Cost of Power Commodity (kWh)	208,800	0.0607	12,678.34	208,620	0.0607	12,667.41	(10.93)	(0.09%)	61.62%		12,667.41	
Total Bill Before Taxes			**18,591.59**			**18,191.19**	**(400.40)**	**(2.15%)**	**88.50%**	**Table 8-2 Total**	**18,209.68**	**(18.49)**
GST/HST		13.00%	2,416.91		13.00%	2,364.85	(52.05)	(2.15%)	11.50%			
Total Bill			**21,008.49**			**20,556.05**	**(452.45)**	**(2.15%)**	**100.00%**			

GENERAL SERVICE 50 kW - 999 kW (Comparison to Existing GS>50 kW Rate)

Consumption
300,000 kWh
750 kW

	2010 BILL			2011 BILL			IMPACT			Table 8-2 Error Detail - 2011 Bill		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill	table input error	$ included	error (over)/under
Monthly Service Charge			294.82			360.69	65.87	22.34%	1.18%		360.69	0.00
Distribution (kW)	750	1.8048	1,353.60	750	2.1129	1,584.68	231.08	17.07%	5.17%		1,584.68	0.00
Smart Meter Adder (per month)			0.00			0.47	0.47		0.00%		0.47	0.00
Smart Meter Rider (per month)			1.63			1.20	(0.43)	(26.38%)	0.00%	0.92	0.92	0.28
LRAM & SSM Rider (kW)	750		0.00	750	0.0863	64.73	64.73		0.21%		64.73	0.00
Deferral and Variance Account Rider (2010) (kW)	750	(0.4471)	-335.33	750	(0.5422)	(406.64)	(71.31)	21.27%	(1.33%)	(0.3761)	(282.09)	(124.55)
Deferral and Variance Account Rider (2011) (kW)	750		0.00	750	(0.0487)	(36.54)	(36.54)		(0.12%)	0.00	0.00	(36.54)
Non-RPP Global Adjustment Rate Rider (2010) (kW)	750		0.00	750	0.1471	110.32	110.32		0.36%	0.00	0.00	110.32
Non-RPP Global Adjustment Rate Rider (2011) (kW)	750		0.00	750	0.0301	22.61	22.61		0.07%	0.0000	0.00	22.61
Distribution Sub-Total			**1,314.73**			**1,701.52**	**386.79**	**29.42%**	**5.56%**	**Distribution**	**1,729.39**	**(27.87)**
Retail Transmisssion (kW)	750	4.2383	3,178.73	750	2.9046	2,178.42	(1,000.30)	(31.47%)	7.11%		2,178.42	
Delivery Sub-Total			**4,493.45**			**3,879.94**	**(613.51)**	**(13.65%)**	**12.67%**		**3,907.81**	**(27.87)**
Other Charges (kWh)	313,200	0.0135	4,228.20	312,930	0.0135	4,224.56	(3.64)	(0.09%)	13.79%		4,224.56	
Cost of Power Commodity (kWh)	313,200	0.0607	19,017.50	312,930	0.0607	19,001.11	(16.39)	(0.09%)	62.04%		19,001.11	
Total Bill Before Taxes			**27,739.15**			**27,105.61**	**(633.55)**	**(2.28%)**	**88.50%**	**Table 8-2 Total**	**27,133.48**	**(27.87)**
GST/HST		13.00%	3,606.09		13.00%	3,523.73	(82.36)	(2.28%)	11.50%			
Total Bill			**31,345.24**			**30,629.34**	**(715.91)**	**(2.28%)**	**100.00%**			

(2.28%)

GENERAL SERVICE >1000 kW (Comparison to Existing GS>50 kW Rate)

Consumption
750,000 kWh
1,500 kW

	2010 BILL			2011 BILL			IMPACT			Table 8-2 Error Detail - 2011 Bill		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill	table input error	$ included	error (over)/under
Monthly Service Charge			294.82			2,335.85	2,041.03	692.30%	2.98%		2,335.85	0.00
Distribution (kW)	1,500	1.8048	2,707.20	1,500	1.4400	2,160.00	(547.20)	(20.21%)	2.76%		2,160.00	0.00
Smart Meter Adder (per month)			0.00			0.47	0.47		0.00%		0.47	0.00
Smart Meter Rider (per month)			1.63			1.20	(0.43)	(26.38%)	0.00%	0.92	0.92	0.28
LRAM & SSM Rider (kW)	1,500		0.00	1,500	0.0863	129.45	129.45		0.17%		129.45	0.00
Deferral and Variance Account Rider (2010) (kW)	1,500	(0.4471)	-670.65	1,500	(0.6522)	(978.26)	(307.61)	45.87%	(1.25%)	(0.3400)	(509.94)	(468.32)
Deferral and Variance Account Rider (2011) (kW)	1,500		0.00	1,500	(0.2040)	(306.07)	(306.07)		(0.39%)	0.00	0.00	(306.07)
Non-RPP Global Adjustment Rate Rider (2010) (kW)	1,500		0.00	1,500	0.1771	265.62	265.62		0.34%	0.00	0.00	265.62
Non-RPP Global Adjustment Rate Rider (2011) (kW)	1,500		0.00	1,500	0.0301	45.21	45.21		0.06%	0.0000	0.00	45.21
Distribution Sub-Total			**2,333.00**			**3,653.49**	**1,320.49**	**56.60%**	**4.66%**	**Distribution**	**4,116.75**	**(463.27)**
Retail Transmisssion (kW)	1,500	4.2383	6,357.45	1,500	5.0741	7,611.18	1,253.73	19.72%	9.72%		7,611.18	
Delivery Sub-Total			**8,690.45**			**11,264.67**	**2,574.22**	**29.62%**	**14.38%**		**11,727.94**	**(463.27)**
Other Charges (kWh)	783,000	0.0135	10,570.50	782,325	0.0135	10,561.39	(9.11)	(0.09%)	13.48%		10,561.39	
Cost of Power Commodity (kWh)	783,000	0.0607	47,543.76	782,325	0.0607	47,502.77	(40.99)	(0.09%)	60.64%		47,502.77	
Total Bill Before Taxes			**66,804.71**			**69,328.83**	**2,524.12**	**3.78%**	**88.50%**	**Table 8-2 Total**	**69,792.10**	**(463.27)**
GST/HST		13.00%	8,684.61		13.00%	9,012.75	328.14	3.78%	11.50%			
Total Bill			**75,489.32**			**78,341.58**	**2,852.26**	**3.78%**	**100.00%**			

GENERAL SERVICE >1000 kW (Comparison to Existing GS>50 kW Rate)

Consumption
2,000,000 kWh
4,500 kW

	2010 BILL			2011 BILL			IMPACT			Table 8-2 Error Detail - 2011 Bill		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill	table input error	$ included	error (over)/under
Monthly Service Charge			294.82			2,335.85	2,041.03	692.30%	1.12%		2,335.85	0.00
Distribution (kW)	4,500	1.8048	8,121.60	4,500	1.4400	6,480.00	(1,641.60)	(20.21%)	3.12%		6,480.00	0.00
Smart Meter Adder (per month)			0.00			0.47	0.47		0.00%		0.47	0.00
Smart Meter Rider (per month)			1.63			1.20	(0.43)	(26.38%)	0.00%	0.92	0.92	0.28
LRAM & SSM Rider (kW)	4,500		0.00	4,500	0.0863	388.35	388.35		0.19%		388.35	0.00
Deferral and Variance Account Rider (2010) (kW)	4,500	(0.4471)	-2,011.95	4,500	(0.6522)	(2,934.77)	(922.82)	45.87%	(1.41%)	(0.3400)	(1,529.81)	(1,404.96)
Deferral and Variance Account Rider (2011) (kW)	4,500		0.00	4,500	(0.2040)	(918.20)	(918.20)		(0.44%)	0.00	0.00	(918.20)
Non-RPP Global Adjustment Rate Rider (2010) (kW)	4,500		0.00	4,500	0.1771	796.87	796.87		0.38%	0.00	0.00	796.87
Non-RPP Global Adjustment Rate Rider (2011) (kW)	4,500		0.00	4,500	0.0499	224.44	224.44		0.11%	0.0000	0.00	224.44
Distribution Sub-Total			**6,406.10**			**6,374.22**	**(31.88)**	**(0.50%)**	**3.06%**	**Distribution**	**7,675.78**	**(1,301.57)**
Retail Transmisssion (kW)	4,500	4.2383	19,072.35	4,500	5.0741	22,833.55	3,761.20	19.72%	10.98%		22,833.55	
Delivery Sub-Total			**25,478.45**			**29,207.77**	**3,729.32**	**14.64%**	**14.04%**		**30,509.34**	**(1,301.57)**
Other Charges (kWh)	2,088,000	0.0135	28,188.00	2,086,200	0.0135	28,163.70	(24.30)	(0.09%)	13.54%		28,163.70	
Cost of Power Commodity (kWh)	2,088,000	0.0607	126,783.36	2,086,200	0.0607	126,674.06	(109.30)	(0.09%)	60.91%		126,674.06	
Total Bill Before Taxes			**180,449.81**			**184,045.53**	**3,595.72**	**1.99%**	**88.50%**	**Table 8-2 Total**	**185,347.10**	**(1,301.57)**
GST/HST		13.00%	23,458.48		13.00%	23,925.92	467.44	1.99%	11.50%			
Total Bill			**203,908.29**			**207,971.45**	**4,063.17**	**1.99%**	**100.00%**			

GENERAL SERVICE >1000 kW (Comparison to Existing Large Use Rate)

Consumption
2,000,000 kWh
4,500 kW

	2010 BILL Large User Rate			2011 BILL GS>1000 kW Rate			IMPACT			Table 8-2 Error Detail - 2011 Bill		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill	table input error	$ included	error (over)/under
Monthly Service Charge			13,876.25			2,335.85	(11,540.40)	(83.17%)	1.12%		2,335.85	0.00
Distribution (kW)	4,500	2.4566	11,054.70	4,500	1.4400	6,480.00	(4,574.70)	(41.38%)	3.12%		6,480.00	0.00
Smart Meter Adder (per month)			0.00			0.47	0.47		0.00%		0.47	0.00
Smart Meter Rider (per month)			1.63			1.20	(0.43)	(26.38%)	0.00%	0.92	0.92	0.28
LRAM & SSM Rider (kW)	4,500		0.00	4,500	0.0863	388.35	388.35		0.19%		388.35	0.00
Deferral and Variance Account Rider (2010) (kW)	4,500	(0.4471)	-2,011.95	4,500	(0.6522)	(2,934.77)	(922.82)	45.87%	(1.41%)	(0.3400)	(1,529.81)	(1,404.96)
Deferral and Variance Account Rider (2011) (kW)	4,500		0.00	4,500	(0.2040)	(918.20)	(918.20)		(0.44%)	0.00	0.00	(918.20)
Non-RPP Global Adjustment Rate Rider (2010) (kW)	4,500		0.00	4,500	0.1771	796.87	796.87		0.38%	0.00	0.00	796.87
Non-RPP Global Adjustment Rate Rider (2011) (kW)	4,500		0.00	4,500	0.0499	224.44	224.44		0.11%	0.0000	0.00	224.44
Distribution Sub-Total			**22,920.63**			**6,374.22**	**(16,546.41)**	**(72.19%)**	**3.06%**	**Distribution**	**7,675.78**	**(1,301.57)**
Retail Transmisssion (kW)	4,500	4.2383	19,072.35	4,500	5.0741	22,833.55	3,761.20	19.72%	10.98%		22,833.55	
Delivery Sub-Total			**41,992.98**			**29,207.77**	**(12,785.21)**	**(30.45%)**	**14.04%**		**30,509.34**	**(1,301.57)**
Other Charges (kWh)*	2,020,000	0.0135	27,270.00	2,086,200	0.0135	28,163.70	893.70	3.28%	13.54%		28,163.70	
Cost of Power Commodity (kWh)*	2,020,000	0.0607	122,654.40	2,086,200	0.0607	126,674.06	4,019.66	3.28%	60.91%		126,674.06	
Total Bill Before Taxes			**191,917.38**			**184,045.53**	**(7,871.85)**	**(4.10%)**	**88.50%**	**Table 8-2 Total**	**185,347.10**	**(1,301.57)**
GST/HST		13.00%	24,949.26		13.00%	23,925.92	(1,023.34)	(4.10%)	11.50%			
Total Bill			**216,866.64**			**207,971.45**	**(8,895.19)**	**(4.10%)**	**100.00%**			

* loss adjustment factor corrected - should be 1.01% for 2010 large user rate.

BILL IMPACTS *(Monthly Consumptions)*

GENERAL SERVICE 50 kW - 999 kW (2010 GS>50kW Bill VS Hypothetical Test 2011 GS>50 kW Rate)

Consumption
30,000 kWh
100 kW

	2010 BILL			2011 Test GS>50 kW BILL			IMPACT			Table 8-2 Error Detail		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill	table input error	$ included	error (over)/under
Monthly Service Charge			294.82			374.21	79.39	26.93%	10.13%		374.21	0.00
Distribution (kW)	100	1.8048	180.48	100	2.1761	217.61	37.13	20.57%	5.89%		217.61	0.00
Smart Meter Adder (per month)			0.00			0.47	0.47		0.01%		0.47	0.00
Smart Meter Rider (per month)			1.63			1.20	(0.43)	(26.38%)	0.03%	0.92	0.92	0.28
LRAM & SSM Rider (kW)	100		0.00	100	0.0863	8.63	8.63		0.23%		8.63	0.00
Deferral and Variance Account Rider (2010) (kW)	100	(0.4471)	-44.71	100	(0.5815)	(58.15)	(13.44)	30.07%	(1.57%)	(0.3761)	(37.61)	(20.54)
Deferral and Variance Account Rider (2011) (kW)	100		0.00	100	(0.0924)	(9.24)	(9.24)		(0.25%)	0.00	0.00	(9.24)
Non-RPP Global Adjustment Rate Rider (2010) (kW)	100		0.00	100	0.1588	15.88	15.88		0.43%	0.00	0.00	15.88
Non-RPP Global Adjustment Rate Rider (2011) (kW)	100		0.00	100	0.0357	3.57	3.57		0.10%	0.0000	0.00	3.57
Distribution Sub-Total			**432.22**			**554.19**	**121.97**	**28.22%**	**15.01%**	**Distribution**	**564.23**	**(10.04)**
Retail Transmisssion (kW)	100	4.2383	423.83	100	3.9154	391.54	(32.29)	(7.62%)	10.60%		391.54	0.00
Delivery Sub-Total			**856.05**			**945.73**	**89.68**	**10.48%**	**25.61%**		**955.77**	**(10.04)**
Other Charges (kWh)	31,320	0.0135	422.82	31,293	0.0135	422.46	(0.36)	(0.09%)	11.44%		422.46	
Cost of Power Commodity (kWh)	31,320	0.0607	1,901.75	31,293	0.0607	1,900.11	(1.64)	(0.09%)	51.45%		1,900.11	
Total Bill Before Taxes			**3,180.62**			**3,268.29**	**87.67**	**2.76%**	**88.50%**	**Table 8-2 Total**	**3,278.33**	**(10.04)**
GST/HST		**13.00%**	413.48		13.00%	424.88	11.40	2.76%	11.50%			
Total Bill			**3,594.10**			**3,693.17**	**99.07**	**2.76%**	**100.00%**			

GENERAL SERVICE 50 kW - 999 kW (2010 GS>50kW Bill VS Hypothetical Test 2011 GS>50 kW Rate)

Consumption
200,000 kWh
500 kW

	2010 BILL			2011 Test GS>50 kW BILL			IMPACT			Table 8-2 Error Detail		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill	table input error	$ included	error (over)/under
Monthly Service Charge			294.82			374.21	79.39	26.93%	1.77%		374.21	0.00
Distribution (kW)	500	1.8048	902.40	500	2.1761	1,088.05	185.65	20.57%	5.15%		1,088.05	0.00
Smart Meter Adder (per month)			0.00			0.47	0.47		0.00%		0.47	0.00
Smart Meter Rider (per month)			1.63			1.20	(0.43)	(26.38%)	0.01%	0.92	0.92	0.28
LRAM & SSM Rider (kW)	500		0.00	500	0.0863	43.15	43.15		0.20%		43.15	0.00
Deferral and Variance Account Rider (2010) (kW)	500	(0.4471)	-223.55	500	(0.5815)	(290.76)	(67.21)	30.07%	(1.38%)	(0.3761)	(188.06)	(102.70)
Deferral and Variance Account Rider (2011) (kW)	500		0.00	500	(0.0924)	(46.18)	(46.18)		(0.22%)	0.00	0.00	(46.18)
Non-RPP Global Adjustment Rate Rider (2010) (kW)	500		0.00	500	0.1588	79.42	79.42		0.38%	0.00	0.00	79.42
Non-RPP Global Adjustment Rate Rider (2011) (kW)	500		0.00	500	0.0357	17.84	17.84		0.08%	0.0000	0.00	17.84
Distribution Sub-Total			**975.30**			**1,267.41**	**292.11**	**29.95%**	**6.00%**	**Distribution**	**1,318.74**	**(51.33)**
Retail Transmisssion (kW)	500	4.2383	2,119.15	500	3.9154	1,957.70	(161.45)	(7.62%)	9.26%		1,957.70	
Delivery Sub-Total			**3,094.45**			**3,225.11**	**130.66**	**4.22%**	**15.26%**		**3,276.44**	**(51.33)**
Other Charges (kWh)	208,800	0.0135	2,818.80	208,620	0.0135	2,816.37	(2.43)	(0.09%)	13.32%		2,816.37	
Cost of Power Commodity (kWh)	208,800	0.0607	12,678.34	208,620	0.0607	12,667.41	(10.93)	(0.09%)	59.92%		12,667.41	
Total Bill Before Taxes			**18,591.59**			**18,708.88**	**117.30**	**0.63%**	**88.50%**	**Table 8-2 Total**	**18,760.22**	**(51.33)**
GST/HST		13.00%	2,416.91		13.00%	2,432.15	15.25	0.63%	11.50%			
Total Bill			**21,008.49**			**21,141.04**	**132.55**	**0.63%**	**100.00%**			

GENERAL SERVICE 50 kW - 999 kW (2010 GS>50kW Bill VS Hypothetical Test 2011 GS>50 kW Rate)

Consumption: 300,000 kWh, 750 kW

	2010 BILL			2011 Test GS>50 kW BILL			IMPACT			Table 8-2 Error Detail		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill	table input error	$ included	error (over)/under
Monthly Service Charge			294.82			374.21	79.39	26.93%	1.19%		374.21	0.00
Distribution (kW)	750	1.8048	1,353.60	750	2.1761	1,632.08	278.48	20.57%	5.18%		1,632.08	0.00
Smart Meter Adder (per month)			0.00			0.47	0.47		0.00%		0.47	0.00
Smart Meter Rider (per month)			1.63			1.20	(0.43)	(26.38%)	0.00%	0.92	0.92	0.28
LRAM & SSM Rider (kW)	750		0.00	750	0.0863	64.73	64.73		0.21%		64.73	0.00
Deferral and Variance Account Rider (2010) (kW)	750	(0.4471)	-335.33	750	(0.5815)	(436.14)	(100.82)	30.07%	(1.38%)	(0.3761)	(282.09)	(154.05)
Deferral and Variance Account Rider (2011) (kW)	750		0.00	750	(0.0924)	(69.27)	(69.27)		(0.22%)	0.00	0.00	(69.27)
Non-RPP Global Adjustment Rate Rider (2010) (kW)	750		0.00	750	0.1588	119.13	119.13		0.38%	0.00	0.00	119.13
Non-RPP Global Adjustment Rate Rider (2011) (kW)	750		0.00	750	0.0357	26.77	26.77		0.08%	0.0000	0.00	26.77
Distribution Sub-Total			**1,314.73**			**1,713.17**	**398.45**	**30.31%**	**5.44%**	**Distribution**	**1,790.31**	**(77.14)**
Retail Transmisssion (kW)	750	4.2383	3,178.73	750	3.9154	2,936.55	(242.18)	(7.62%)	9.32%		2,936.55	
Delivery Sub-Total			**4,493.45**			**4,649.72**	**156.27**	**3.48%**	**14.76%**		**4,726.86**	**(77.14)**
Other Charges (kWh)	313,200	0.0135	4,228.20	312,930	0.0135	4,224.56	(3.64)	(0.09%)	13.41%		4,224.56	
Cost of Power Commodity (kWh)	313,200	0.0607	19,017.50	312,930	0.0607	19,001.11	(16.39)	(0.09%)	60.32%		19,001.11	
Total Bill Before Taxes			**27,739.15**			**27,875.39**	**136.23**	**0.49%**	**88.50%**	**Table 8-2 Total**	**27,952.52**	**(77.14)**
GST/HST		13.00%	3,606.09		13.00%	3,623.80	17.71	0.49%	11.50%			
Total Bill			**31,345.24**			**31,499.19**	**153.94**	**0.49%**	**100.00%**			

GENERAL SERVICE >1000 kW (2010 GS>50kW Bill VS Hypothetical Test 2011 GS>50 kW Rate)

Consumption: 750,000 kWh, 1,500 kW

	2010 BILL			2011 Test GS>50 kW BILL			IMPACT			Table 8-2 Error Detail		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill	table input error	$ included	error (over)/under
Monthly Service Charge			294.82			374.21	79.39	26.93%	0.49%		374.21	0.00
Distribution (kW)	1,500	1.8048	2,707.20	1,500	2.1761	3,264.15	556.95	20.57%	4.31%		3,264.15	0.00
Smart Meter Adder (per month)			0.00			0.47	0.47		0.00%		0.47	0.00
Smart Meter Rider (per month)			1.63			1.20	(0.43)	(26.38%)	0.00%	0.92	0.92	0.28
LRAM & SSM Rider (kW)	1,500		0.00	1,500	0.0863	129.45	129.45		0.17%		129.45	0.00
Deferral and Variance Account Rider (2010) (kW)	1,500	(0.4471)	-670.65	1,500	(0.5815)	(872.28)	(201.63)	30.07%	(1.15%)	(0.3400)	(509.94)	(362.35)
Deferral and Variance Account Rider (2011) (kW)	1,500		0.00	1,500	(0.0924)	(138.54)	(138.54)		(0.18%)	0.00	0.00	(138.54)
Non-RPP Global Adjustment Rate Rider (2010) (kW)	1,500		0.00	1,500	0.1588	238.27	238.27		0.31%	0.00	0.00	238.27
Non-RPP Global Adjustment Rate Rider (2011) (kW)	1,500		0.00	1,500	0.0357	53.53	53.53		0.07%	0.0000	0.00	53.53
Distribution Sub-Total			**2,333.00**			**3,050.46**	**717.46**	**30.75%**	**4.03%**	**Distribution**	**3,259.26**	**(208.80)**
Retail Transmisssion (kW)	1,500	4.2383	6,357.45	1,500	3.9154	5,873.10	(484.35)	(7.62%)	7.76%		5,873.10	
Delivery Sub-Total			**8,690.45**			**8,923.56**	**233.11**	**2.68%**	**11.79%**		**9,132.36**	**(208.80)**
Other Charges (kWh)	783,000	0.0135	10,570.50	782,325	0.0135	10,561.39	(9.11)	(0.09%)	13.95%		10,561.39	
Cost of Power Commodity (kWh)	783,000	0.0607	47,543.76	782,325	0.0607	47,502.77	(40.99)	(0.09%)	62.75%		47,502.77	
Total Bill Before Taxes			**66,804.71**			**66,987.72**	**183.01**	**0.27%**	**88.50%**	**Table 8-2 Total**	**67,196.53**	**(208.80)**
GST/HST		13.00%	8,684.61		13.00%	8,708.40	23.79	0.27%	11.50%			
Total Bill			**75,489.32**			**75,696.13**	**206.80**	**0.27%**	**100.00%**			

GENERAL SERVICE <1000 kW (2010 GS>50kW Bill VS Hypothetical Test 2011 GS>50 kW Rate)

Consumption
2,000,000 kWh
4,500 kW

	2010 BILL			2011 Test GS>50 kW BILL			IMPACT			Table 8-2 Error Detail		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill	table input error	$ included	error (over)/under
Monthly Service Charge			294.82			374.21	79.39	26.93%	0.18%		374.21	0.00
Distribution (kW)	4,500	1.8048	8,121.60	4,500	2.1761	9,792.45	1,670.85	20.57%	4.79%		9,792.45	0.00
Smart Meter Adder (per month)			0.00			0.47	0.47		0.00%		0.47	0.00
Smart Meter Rider (per month)			1.63			1.20	(0.43)	(26.38%)	0.00%	0.92	0.92	0.28
LRAM & SSM Rider (kW)	4,500		0.00	4,500	0.0863	388.35	388.35		0.19%		388.35	0.00
Deferral and Variance Account Rider (2010) (kW)	4,500	(0.4471)	-2,011.95	4,500	(0.5815)	(2,616.84)	(604.89)	30.07%	(1.28%)	(0.3400)	(1,529.81)	(1,087.04)
Deferral and Variance Account Rider (2011) (kW)	4,500		0.00	4,500	(0.0924)	(415.61)	(415.61)		(0.20%)	0.00	0.00	(415.61)
Non-RPP Global Adjustment Rate Rider (2010) (kW)	4,500		0.00	4,500	0.1588	714.80	714.80		0.35%	0.00	0.00	714.80
Non-RPP Global Adjustment Rate Rider (2011) (kW)	4,500		0.00	4,500	0.0357	160.59	160.59		0.08%	0.0000	0.00	160.59
Distribution Sub-Total			**6,406.10**			**8,399.62**	**1,993.52**	**31.12%**	**4.11%**	**Distribution**	**9,026.59**	**(626.97)**
Retail Transmisssion (kW)	4,500	4.2383	19,072.35	4,500	3.9154	17,619.30	(1,453.05)	(7.62%)	8.62%		17,619.30	
Delivery Sub-Total			**25,478.45**			**26,018.92**	**540.47**	**2.12%**	**12.73%**		**26,645.89**	**(626.97)**
Other Charges (kWh)	2,088,000	0.0135	28,188.00	2,086,200	0.0135	28,163.70	(24.30)	(0.09%)	13.78%		28,163.70	
Cost of Power Commodity (kWh)	2,088,000	0.0607	126,783.36	2,086,200	0.0607	126,674.06	(109.30)	(0.09%)	61.98%		126,674.06	
Total Bill Before Taxes			**180,449.81**			**180,856.69**	**406.88**	**0.23%**	**88.50%**	**Table 8-2 Total**	**181,483.66**	**(626.97)**
GST/HST		13.00%	23,458.48		13.00%	23,511.37	52.89	0.23%	11.50%			
Total Bill			**203,908.29**			**204,368.06**	**459.77**	**0.23%**	**100.00%**			

GENERAL SERVICE <1000 kW (2010 Large Use Bill VS Hypothetical Test 2011 GS>50 kW Rate)

Consumption
2,000,000 kWh
4,500 kW

	2010 BILL Large User Rate			2011 Test GS>50 kW BILL			IMPACT			Table 8-2 Error Detail		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill	table input error	$ included	error (over)/under
Monthly Service Charge			13,876.25			374.21	(13,502.04)	(97.30%)	0.18%		374.21	0.00
Distribution (kW)	4,500	2.4566	11,054.70	4,500	2.1761	9,792.45	(1,262.25)	(11.42%)	4.79%		9,792.45	0.00
Smart Meter Adder (per month)			0.00			0.47	0.47		0.00%		0.47	0.00
Smart Meter Rider (per month)			1.63			1.20	(0.43)	(26.38%)	0.00%	0.92	0.92	0.28
LRAM & SSM Rider (kW)	4,500		0.00	4,500	0.0863	388.35	388.35		0.19%		388.35	0.00
Deferral and Variance Account Rider (2010) (kW)	4,500	(0.4471)	-2,011.95	4,500	(0.5815)	(2,616.84)	(604.89)	30.07%	(1.28%)	(0.3400)	(1,529.81)	(1,087.04)
Deferral and Variance Account Rider (2011) (kW)	4,500		0.00	4,500	(0.0924)	(415.61)	(415.61)		(0.20%)	0.00	0.00	(415.61)
Non-RPP Global Adjustment Rate Rider (2010) (kW)	4,500		0.00	4,500	0.1588	714.80	714.80		0.35%	0.00	0.00	714.80
Non-RPP Global Adjustment Rate Rider (2011) (kW)	4,500		0.00	4,500	0.0357	160.59	160.59		0.08%	0.0000	0.00	160.59
Distribution Sub-Total			**22,920.63**			**8,399.62**	**(14,521.01)**	**(63.35%)**	**4.11%**	**Distribution**	**9,026.59**	**(626.97)**
Retail Transmisssion (kW)	4,500	4.2383	19,072.35	4,500	3.9154	17,619.30	(1,453.05)	(7.62%)	8.62%		17,619.30	
Delivery Sub-Total			**41,992.98**			**26,018.92**	**(15,974.06)**	**(38.04%)**	**12.73%**		**26,645.89**	**(626.97)**
Other Charges (kWh)*	2,020,000	0.0135	27,270.00	2,086,200	0.0135	28,163.70	893.70	3.28%	13.78%		28,163.70	
Cost of Power Commodity (kWh)*	2,020,000	0.0607	122,654.40	2,086,200	0.0607	126,674.06	4,019.66	3.28%	61.98%		126,674.06	
Total Bill Before Taxes			**191,917.38**			**180,856.69**	**(11,060.69)**	**(5.76%)**	**88.50%**	**Table 8-2 Total**	**181,483.66**	**(626.97)**
GST/HST		13.00%	24,949.26		13.00%	23,511.37	(1,437.89)	(5.76%)	11.50%			
Total Bill			**216,866.64**			**204,368.06**	**(12,498.58)**	**(5.76%)**	**100.00%**			

*** loss adjustment factor corrected - should be 1.01% for 2010 large user rate.**

Table 8-2 Revised - OEB Staff IR # 23

Rate	kWh	kW	Distribution	Other Charges	Total Charges Before HST	Distribution Variance 2010 to 2011	Distribution Variance % 2010 to 2011	Total Variance before HST	Total Variance as a %
2010 Approved >50 KW	30,000	100	$ 432.22	$ 2,748.40	$ 3,180.62				
2011 Test >50KW	30,000	100	$ 554.19	$ 2,714.11	$ 3,268.29	$ 121.97	28.2%	$ 87.67	2.8%
2011 Proposed 50KW-999KW	**30,000**	**100**	**$ 540.91**	**$ 2,613.02**	**$ 3,153.94**	**$ 108.69**	**25.1%**	**-$ 26.68**	**-0.8%**
2010 Approved >50 KW	200,000	500	$ 975.30	$ 17,616.29	$ 18,591.59				
2011 Test >50KW	200,000	500	$ 1,267.41	$ 17,441.48	$ 18,708.88	$ 292.11	30.0%	$ 117.30	0.6%
2011 Proposed 50KW-999KW	**200,000**	**500**	**$ 1,255.13**	**$ 16,936.06**	**$ 18,191.19**	**$ 279.83**	**28.7%**	**-$ 400.40**	**-2.2%**
2010 Approved >50 KW	300,000	750	$ 1,314.73	$ 26,424.43	$ 27,739.15				
2011 Test >50KW	300,000	750	$ 1,713.17	$ 26,162.21	$ 27,875.39	$ 398.45	30.3%	$ 136.23	0.5%
2011 Proposed 50KW-999KW	**300,000**	**750**	**$ 1,701.52**	**$ 25,404.09**	**$ 27,105.61**	**$ 386.79**	**29.4%**	**-$ 633.55**	**-2.3%**
2010 Approved >50 KW	750,000	1,500	$ 2,333.00	$ 64,471.71	$ 66,804.71				
2011 Test >50KW	750,000	1,500	$ 3,050.46	$ 63,937.26	$ 66,987.72	$ 717.46	30.8%	$ 183.01	0.3%
2011 Proposed >1000 kW	**750,000**	**1,500**	**$ 3,653.49**	**$ 65,675.35**	**$ 69,328.83**	**$ 1,320.49**	**56.6%**	**$ 2,524.12**	**3.8%**
2010 Approved >50 KW	2,000,000	4,500	$ 6,406.10	$ 174,043.71	$ 180,449.81				
2011 Test >50KW	2,000,000	4,500	$ 8,399.62	$ 172,457.06	$ 180,856.69	$ 1,993.52	31.1%	$ 406.88	0.2%
2011 Proposed >1000 kW	**2,000,000**	**4,500**	**$ 6,374.22**	**$ 177,671.32**	**$ 184,045.53**	**-$ 31.88**	**-0.5%**	**$ 3,595.72**	**2.0%**
2010 Approved Large Use	2,000,000	4,500	$ 22,920.63	$ 168,996.75	$ 191,917.38				
2011 Test >50KW	2,000,000	4,500	$ 8,399.62	$ 172,457.06	$ 180,856.69	-$ 14,521.01	-63.4%	-$ 11,060.69	-5.8%
2011 Proposed >1000 kW	**2,000,000**	**4,500**	**$ 6,374.22**	**$ 177,671.32**	**$ 184,045.53**	**-$ 16,546.41**	**-72.2%**	**-$ 7,871.85**	**-4.1%**

OEB Staff Interrogatories

Appendix J

EDA_IRR_201101101

Late Payment Litigation

EB-2010-0295

IN THE MATTER OF a proceeding initiated by the Ontario Energy Board to determine whether the costs and damages incurred by electricity distributors as a result of the April 21, 2010 Minutes of Settlement in the late payment penalty class action, as further described in the Notice of Proceeding, are recoverable from electricity distribution ratepayers, and if so, the form and timing of such recovery.

RESPONSES TO WRITTEN INTERROGATORIES SUBMITTED BY THE ELECTRICITY DISTRIBUTORS ASSOCIATION ON BEHALF OF AFFECTED ELECTRICITY DISTRIBUTORS

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Solicitors for the Electricity Distributors Association

TO: Board Secretary
Ontario Energy Board
27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Attn: Board Secretary, Kirsten Walli
Email: boardsec@oeb.gov.on.ca

EB-2010-0295

IN THE MATTER OF a proceeding initiated by the Ontario Energy Board to determine whether the costs and damages incurred by electricity distributors as a result of the April 21, 2010 Minutes of Settlement in the late payment penalty class action, as further described in the Notice of Proceeding, are recoverable from electricity distribution ratepayers, and if so, the form and timing of such recovery.

RESPONSES TO WRITTEN INTERROGATORIES SUBMITTED BY THE ELECTRICITY DISTRIBUTORS ASSOCIATION ON BEHALF OF AFFECTED ELECTRICITY DISTRIBUTORS

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Schedule 1 - EDA Response to SEC Interrogatory 1
Schedule 2 - EDA Response to SEC Interrogatory 2
Schedule 3 - EDA Response to SEC Interrogatory 3
Schedule 4 - EDA Response to SEC Interrogatory 4
Schedule 5 - EDA Response to SEC Interrogatory 5
Schedule 6 - EDA Response to SEC Interrogatory 6

Answer to Interrogatory from Board Staff

Question 1:

Reference(s): None provided.

Updates to Appendix A:

(i) Barrie Hydro is listed as a separate distributor in Appendix A. Please clarify if Barrie Hydro should be listed under PowerStream Inc. If it should, please restate Appendix A.

(ii) Appendix A includes distributors who have since received Board approval to withdraw from the proceeding. Please update Appendix A to exclude those distributors that are not seeking recovery of LPP Class Action costs. (The complete list of distributors who have withdrawn from the proceeding is available in Procedural Order No. 1)

(iii) Please update Appendix A to reflect the adjusted amount that THESL is seeking to recover in this proceeding.

Answer:

Please see the attached updated Appendix A which stipulates an updated recovery amount in the amount of $17,690,907.53 (the "Updated Recovery Amount") which excludes those distributors that are not seeking recovery of LPP Class Action costs (namely, Hydro One Networks Inc., Hydro One Remote Communities and Orillia Power Distribution), excludes the amounts payable by various municipalities, and reflects the adjusted amount that Toronto Hydro Electric System Limited ("THESL") is seeking to recover in this proceeding.

For greater clarity, the Updated Recovery Amount outlined above should be distinguished from the total Settlement Amount, namely $17,037,500, which should also be distinguished from the revised Allocated Amount as outlined in the EDA's December 16, 2010 letter (the "Revised Allocated Amount"), which reflects the participation of Port Colborne Hydro Inc. in the settlement (as well as distributors that are not seeking rate recovery through this Application) and reflects additional costs to LDCs including legal defence costs, taxes and notice programs (as outlined in IR #2 below).

The amounts sought to be recovered by individual LDCs (save for THESL) seeking recovery through this Application as specified in the Updated Recovery Amount remain unchanged from the amounts sought to be recovered by these LDCs as specified in the Revised Allocated Amount filed with the Board on December 16, 2010.

Appendix A

	LDC	1994	1995	1996	1997	1998	1999	2000	2001	Total LDC Service Revenue	Share of each LDC as a %	Recovery Amount by LDC
1	Atikokan Hydro Inc.						$ 3,760,905	$ 3,772,991	$ 3,786,408	9427100	0.042333989%	$7,567.85
2	Bluewater Power Distribution Corporation						$ 72,269,920	$ 73,358,371	$ 80,259,114	185757848	0.834177065%	$149,121.96
3	Brant County Power Inc.						$ 20,070,971	$ 20,670,202	$ 22,320,459	51901402.5	0.233072035%	$41,665.21
4	Brantford Power Inc.						$ 60,799,461	$ 62,263,210	$ 69,483,604	157804473	0.708647702%	$126,681.66
5	Burlington Hydro Inc.						$ 110,861,924	$ 112,916,087	$ 125,142,447	286349234.5	1.285899716%	$229,874.32
6	Cambridge & North Dumfries Hydro Inc.						$ 92,885,248	$ 95,260,000	$ 108,415,000	242352748	1.088326045%	$194,554.99
7	Centre Wellington Hydro Ltd.						$ 12,242,918	$ 12,668,481	$ 13,384,395	31603596.5	0.141921301%	$25,370.61
8	Chapleau Public Utilities Corp.						$ 2,577,279	$ 2,647,536	$ 2,789,979	6619804.5	0.029727353%	$5,314.22
9	Chatham-Kent Hydro Inc.						$ 65,949,051	$ 64,998,829	$ 68,980,937	165438348.5	0.742928913%	$132,809.95
	DUTTON HYDRO INC.						$ 614,349	$ 620,300	$ 655,177	1562237.5	0.007015492%	$1,254.13
10	Clinton Power Corp.						$ 2,285,528	$ 2,317,735	$ 2,508,620	5857573	0.026304423%	$4,702.32
11	COLLUS Power Corp.						$ 19,130,245	$ 22,505,518	$ 23,590,659	53431092.5	0.239941367%	$42,893.20
	CLEARVIEW TWP. HEC						$ 2,850,510			2850510	0.012800698%	$2,288.32
	THE BLUE MOUNTAINS ENERGY SERVICES						$ 1,624,498			1624498	0.007295083%	$1,304.11
12	Cooperative Hydro Embrum Inc.						$ 1,948,515	$ 2,343,721	$ 2,058,081	5321276.5	0.023896093%	$4,271.79
13	E.L.K. Energy Inc.						$ 13,958,465	$ 13,858,363	$ 15,090,151	35361903.5	0.158798614%	$28,387.69
14	Enersource Hydro Mississauga Inc.						$ 479,146,404	$ 497,908,000	$ 552,824,000	1253466404	5.628903099%	$1,006,252.86
15	Enwin Powerlines Inc. & Enwin Utilities						$ 208,949,512	$ 215,214,173	$ 234,023,622	541175496	2.430240186%	$434,442.75
16	Erie Thames Powerlines Corp.						$ 27,859,517	$ 27,953,506	$ 27,711,893	69668969.5	0.312860302%	$55,928.58
17	Espanola Regional Hydro Distribution Corp.						$ 4,791,569	$ 4,930,694	$ 5,233,494	12339010	0.055410413%	$9,905.46
18	Essex Power Lines Corp.						$ 36,183,707	$ 37,181,695	$ 41,660,155	94195479.5	0.423000748%	$75,617.88
19	Festival Hydro Inc.						$ 31,516,350	$ 43,036,898	$ 46,928,817	98017656.5	0.440164881%	$78,686.23
	BRUSSELS PUC						$ 678,741			678741	0.003048001%	$544.88
	DASHWOOD HS						$ 240,894			240894	0.001081775%	$193.38
	HENSALL PUC						$ 1,248,159			1248159	0.005605069%	$1,001.99
	SEAFORTH PUC						$ 1,727,061			1727061	0.007755660%	$1,386.44
	ST. MARYS PUC						$ 6,002,472			6002472	0.026955117%	$4,818.64
	ZURICH HS						$ 526,931			526931	0.002366273%	$423.01
20	Fort Frances Power Corp.						$ 4,415,003	$ 4,508,531	$ 4,766,034	11306551	0.050773981%	$9,076.63
21	Greater Sudbury Hydro Inc.						$ 68,808,597	$ 71,758,369	$ 69,731,529	175432730.5	0.787810377%	$140,833.20
	WEST NIPISSING ENERGY SERVICES LTD.						$ 4,408,547	$ 4,417,170	$ 4,666,640	11159037	0.050111545%	$8,958.21
22	Grimsby Power Inc.						$ 11,189,655	$ 11,436,130	$ 12,637,696	28944633	0.129980775%	$23,236.06
23	Guelph Hydro Electric						$ 98,122,338	$ 101,690,227	$ 110,962,000	255293565	1.146438975%	$204,943.57
	WELLINGTON ELECTRIC DIST. CO. INC.						$ 1,130,963	$ 1,192,305	$ 1,290,000	2968268	0.013329510%	$2,382.85
24	Haldimand County Hydro Inc.						$ 24,090,995	$ 26,213,328	$ 29,201,835	64905240.5	0.291467971%	$52,104.38
25	Halton Hills Hydro Inc.						$ 29,880,212	$ 31,052,579	$ 34,690,624	$ 78,278,103	0.351521074%	$62,839.79
26	Hearst Power Distribution Co. Ltd.						$ 7,117,359	$ 7,484,128	$ 7,891,600	18547287	0.083289732%	$14,889.32
27	Horizon Utilities Corporation									0	0.000000000%	$0.00
	HAMILTON HYDRO INC.						$ 439,679,959	$ 444,035,264	$ 469,615,000	1118522723	5.022915653%	$897,923.30
	ST. CATHARINES HYDRO UTILITY SERVICES INC.						$ 100,988,064	$ 100,273,443	$ 106,739,607	254631310.5	1.143465009%	$204,411.93
28	Hydro 2000 Inc.						$ 1,876,768	$ 1,947,687	$ 1,964,469	4806689.5	0.021585253%	$3,858.70
29	Hydro Hawkesbury Inc.						$ 13,142,475	$ 12,973,902	$ 13,590,626	32911690	0.147795516%	$26,420.72
30	Hydro One Brampton Networks						$ 211,616,814	$ 219,596,080	$ 245,929,228	554177508	2.488627922%	$444,880.45
31	Hydro Ottawa Ltd.						$ 492,188,449	$ 497,634,000	$ 555,435,000	1267539949	5.692102735%	$1,017,550.77
	CASSELMAN HYDRO INC.						$ 1,869,745	$ 2,247,545		4117290	0.018489388%	$3,305.26
32	Innisfil Hydro Distribution Systems Ltd.						$ 16,071,658	$ 16,646,336	$ 17,851,573	41643780.5	0.187008447%	$33,430.63
33	Kenora Hydro Electric Corp. Ltd.						$ 8,009,484	$ 8,036,090	$ 8,508,767	20299957.5	0.091160396%	$16,296.32
34	Kingston Electricity Distribution Ltd.142446 Ontario Ltd.						$ 50,815,126	$ 51,373,200	$ 54,801,706	129589179	0.581942148%	$104,031.09
35	Kitchener-Wilmot Hydro Inc.						$ 132,389,803	$ 133,446,201	$ 145,752,598	338712303	1.521044941%	$271,910.14
36	Lakefront Utilities Inc.						$ 18,118,456	$ 18,178,809	$ 19,267,108	45930819	0.206260119%	$36,872.16
37	Lakeland Power Dist. Ltd.						$ 13,903,045	$ 16,473,383	$ 17,670,630	39211743	0.176086970%	$31,478.25
38	London Hydro Utilities Services Inc.						$ 227,959,973	$ 227,741,005	$ 227,750,000	569575978	2.557777358%	$457,241.98
39	Middlesex						$ 12,319,590	$ 12,538,569	$ 14,512,510	32114414	0.144215213%	$25,780.68
	NEWBURY POWER INC.						$ 275,842	$ 275,842	$ 283,831	693599.5	0.003114726%	$556.81
40	Midland Power Utility Corp.						$ 15,234,248	$ 15,899,287	$ 16,849,200	39558135	0.177642502%	$31,756.33
41	Milton Hydro Dist. Inc.						$ 35,742,019	$ 37,126,399	$ 40,301,561	93019198.5	0.417718459%	$74,673.59
42	Newmarket- Tay Power Distribution Ltd.									0	0.000000000%	$0.00
	TAY HYDRO ELECTRIC DISTRIBUTION CO. INC.						$ 3,176,178	$ 3,756,707	$ 3,978,308	8922039	0.040065927%	$7,162.40
	NEWMARKET HYDRO LTD.						$ 41,805,112	$ 43,365,283	$ 49,304,284	109822536.8	0.493176695%	$88,162.91
43	Niagara on the Lake Hydro Inc.						$ 11,710,073	$ 12,262,419	$ 13,842,228	30893606	0.138732968%	$24,800.65
44	Niagara Peninsula Energy Inc. (Niagara Falls, PenWest)						$ 56,431,364	$ 57,159,876	$ 61,985,370	144583925	0.649278593%	$116,068.52
	PENINSULA WEST UTILITIES LTD.						$ 22,967,526	$ 26,773,214	$ 28,356,244	63918862	0.287038471%	$51,312.53

LDC	1994	1995	1996	1997	1998	1999	2000	2001	Total LDC Service Revenue	Share of each LDC as a %	Recovery Amount by LDC
45 Norfolk Power Distribution Co. Ltd.						$ 26,751,763	$ 28,310,654	$ 29,083,038	69603936	0.312568259%	$55,876.38
46 North Bay Hydro Distribution Ltd.						$ 43,161,195	$ 43,306,743	$ 45,188,718	109062297	0.489762709%	$87,552.60
47 Northern Ontario Wires Inc.						$ 6,889,275	$ 10,586,819	$ 10,970,997	22961592.5	0.103112919%	$18,433.02
KAPUSKASING PUC						$ 3,697,544			3697544	0.016604447%	$2,968.30
48 Oakville Hydro Electricity Distribution Inc.						$ 129,257,000	$ 131,673,000	$ 119,844,000	320852000	1.440840226%	$257,572.31
49 Orangeville Hydro Ltd.(Grand Valley)						$ 15,471,375	$ 16,480,009	$ 17,896,125	40899446.5	0.183665889%	$32,833.10
GRAND VALLEY ENERGY INC.						$ 783,655	$ 776,878	$ 840,236	1980651	0.008894449%	$1,590.02
50 Oshawa PUC Networks Inc.						$ 84,119,662	$ 85,010,531	$ 90,240,000	214250193	0.962126764%	$171,994.93
51 Ottawa River Power Corp						$ 11,503,009	$ 12,869,438	$ 15,947,733	32346313.5	0.145256597%	$25,966.85
KILLALOE HEC						$ 491,044			491044	0.002205116%	$394.20
MISSISSIPPI MILLS PUC						$ 2,564,398			2564398	0.011515863%	$2,058.64
52 Parry Sound Power Corp.						$ 6,145,491	$ 6,164,788	$ 6,308,951	15464754.5	0.069447098%	$12,414.74
53 Peterborough Distribution Inc.						$ 47,700,067	$ 52,480,650	$ 57,742,526	129051980	0.579529765%	$103,599.84
LAKEFIELD DIST. INC.						$ 2,261,146	$ 2,404,827	$ 2,508,679	5920312.5	0.026586166%	$4,752.69
ASPHODEL-NORWOOD DIST. INC.						$ 950,701	$ 950,701	$ 994,013	2398408.5	0.010770459%	$1,925.39
54 Port Colborne Hydro Inc.						$ 14,051,801	$ 14,387,329	$ 15,053,184	35965722	0.161510164%	$28,872.42
55 Powerstream Inc.									0	0.000000000%	$0.00
RICHMOND HILL HYDRO INC.						$ 68,628,176	$ 71,857,762	$ 79,859,067	180415471.5	0.810186219%	$144,833.23
AURORA HYDRO CONNECTIONS LTD.						$ 25,978,423	$ 26,947,940	$ 30,245,825	$ 68,049,275	0.305586790%	$54,628.33
HYDRO VAUGHAN DISTRIBUTION INC.						$ 167,506,781	$ 173,758,152	$ 196,894,414	$ 439,712,140	1.974601810%	$352,990.39
MARKHAM HYDRO DISTRIBUTION INC.						$ 129,946,387	$ 134,796,000	$ 152,863,000	$ 341,173,887	1.532099101%	$273,886.24
BARRIE HYDRO DIST. INC.						$ 64,871,271	$ 95,736,656	$ 103,789,371	212502612.5	0.954278958%	$170,592.02
BRADFORD-WEST GWILLIMBURY PUC						$ 7,753,794			7753794	0.034819725%	$6,224.56
ESSA TWP. HEC						$ 299,349			299349	0.001344277%	$240.31
NEW TECUMSETH HEC						$ 14,158,292			14158292	0.063580207%	$11,365.94
PENETANGUISHENE HEC						$ 5,681,037			5681037	0.025511658%	$4,560.60
56 PUC Distribution Inc.										0.000000000%	$0.00
57 Renfrew Hydro Inc.						$ 7,095,366	$ 7,144,775	$ 7,527,979	18004130.5	0.080850596%	$14,453.29
58 Rideau St. Lawrence Dist. Inc.						$ 9,085,095	$ 9,052,896	$ 9,544,949	22910465.5	0.102883324%	$18,391.97
59 Sioux Lookout Hydro Inc.						$ 6,243,486	$ 5,859,492	$ 6,744,085	15475020.5	0.069493199%	$12,422.98
60 St. Thomas Energy Inc.						$ 25,525,724	$ 26,408,283	$ 27,232,887	65550450.5	0.294365396%	$52,622.33
61 Thunder Bay Hydro Electricity Dist. Inc.						$ 78,676,751	$ 79,143,606	$ 83,572,003	199606358.5	0.896366146%	$160,239.21
62 Toronto Hydro-Electric S	$753,288,234	$744,553,612	$724,520,201	$721,743,898	$1,852,812,000	$ 1,877,651,730	$ 1,900,029,000	$ 2,062,179,000	$ 9,605,688,175	43.13597%	$7,525,588.82
63 Tillsonburg Hydro Inc.						$ 14,569,289	$ 14,793,988	$ 15,846,081	37286317.5	0.167440521%	$29,932.56
64 Veridian Connections Inc.						$ 102,487,053	$ 159,517,859	$ 175,514,124	349761974	1.570665359%	$280,780.55
1382154 ONTARIO LTD. [Brock HEC]						$ 3,822,493			3822493	0.017165552%	$3,068.61
BELLEVILLE ELECTRIC CORP.						$ 36,601,351			36601351	0.164364563%	$29,382.69
PORT HOPE HEC						$ 13,850,711			13850711	0.062198963%	$11,119.02
GRAVENHURST HYDRO ELECTRIC INC.						$ 5,622,103	$ 7,853,660	$ 8,090,606	17521066	0.078681313%	$14,065.49

Appendix A

	LDC	1994	1995	1996	1997	1998	1999	2000	2001	Total LDC Service Revenue	Share of each LDC as a %	Recovery Amount by LDC
	SCUGOG HYDRO ENERGY CORP.						$ 3,393,309	$ 3,429,935	$ 3,566,164	8606326	0.038648164%	$6,908.95
65	Wasaga Distribution Inc.						$ 7,018,252	$ 7,524,913	$ 8,139,796	18613063	0.083585111%	$14,942.12
66	Waterloo North Hydro Inc.						$ 83,316,810	$ 86,298,086	$ 92,968,505	216099148.5	0.970429812%	$173,479.23
67	Welland Hydro-Electric System Corp.						$ 36,404,835	$ 36,880,372	$ 39,114,111	92842262.5	0.416923898%	$74,531.55
68	Wellington North Power Inc.(Wellington)						$ 5,482,619	$ 5,682,162	$ 6,364,834	14347198	0.064428522%	$11,517.59
69	West Coast Huron Energy Inc.(Goderich Hydro)						$ 9,177,997	$ 8,268,144	$ 10,996,384	22944333	0.103035412%	$18,419.16
70	West Perth Power Inc.						$ 3,994,511	$ 4,267,606	$ 4,687,447	10605840.5	0.047627322%	$8,514.12
71	Westario Power Inc.						$ 24,369,218	$ 31,662,439	$ 33,274,531	72668922.5	0.326332099%	$58,336.87
	MINTO HYDRO INC.						$ 2,984,537			2984537	0.013402569%	$2,395.91
	WALKERTON PUC (including Elmwood HS)						$ 3,693,200			3693200	0.016584940%	$2,964.81
72	Whitby Hydro Electric Corp.						$ 59,902,609	$ 62,521,335	$ 65,436,281	155142084.5	0.696691796%	$124,544.36
73	Woodstock Hydro Services Inc.						$ 28,322,519	$ 28,483,803	$ 30,247,440	71930042	0.323014031%	$57,743.72
	Sub Total	$ 753,288,234	$ 744,553,612	$ 724,520,201	$ 721,743,898	$ 1,852,812,000	$ 6,790,070,748	$ 6,929,260,849	$ 7,504,291,902	22,268,395,493.00	100.000000000%	$17,690,907.53
	Updated Recovery Amount											$17,690,907.53

Total Recovered/Sought to be Recovered through Rates $17,876,535.53 (includes $185,628 recovered by THESL)

Answer to Interrogatory from
Board Staff

Question 2:

Reference(s): None provided.

The cost arising from the settlement of the LPP Class Action that the Affected Distributors are seeking to recover is $18,382,125 ("Allocated Amount"), as provided in paragraph 44. However, using the breakdown provided in paragraph 62 staff notes that the Allocated Amount appears to be $18,419,625. Please reconcile the amounts provided in paragraph 44 and 62. Please also provide a breakdown of the Allocated Amount using the categories provided in paragraph 62.

Answer:

For the purposes of calculating the Allocated Amount prior to the finalization of the settlement, the base amount of the settlement was estimated at $17 million (as opposed to the final quantum of $17,037,500) as outlined below:

Settlement item	$
Base amount	$17 million
Maximum applicable tax	$632,125
Notice Program	$50,000
Legal Fees	$700,000
	$18,382,125

As a consequence, there is a $37,500 difference between the amounts stipulated in paragraphs 44 and 62 of the evidence filed by the EDA on November 8, 2010. Given the legal fees and applicable taxes incurred to date, it is anticipated that no additional rate recovery will be required beyond the Updated Recovery Amount.

Answer to Interrogatory from
Board Staff

Question 3:

Reference(s): None provided.

Board staff notes that one of the reasons put forward by the Affected Distributors for seeking recovery from ratepayers of costs arising from the LPP Class Action is that LPP revenues were used to mitigate the rates of all customers". In order to complete the record and to provide Board staff with a comprehensive understanding of how that may be the case, please expand on the above statement explaining in detail, how LPP revenues that were collected from various rate classes were used to mitigate the rates for all customers. In your response please explain the basis upon which the LPP revenues reduced the revenue requirement by rate class and whether the reduction applied to all rate classes or intended customers only.

Answer:

LPPs reduced the revenue requirement for all customer classes. Specifically, historical or forecast LPP revenues were used as revenue offsets to reduce the base distribution revenue requirement, recoverable from all customers.

Answer to Interrogatory from
Board Staff

Question 4:

Reference(s): None provided.

Have any of the Affected Distributors received recovery of any costs arising from the LPP Class Action in a prior proceeding before the Board. If such costs have been recovered previously, please identify the distributor, the quantum of costs and indicate if costs that have already been recovered have been removed from the Allocated Amount.

Answer:

To the best of our knowledge, no other Affected Electricity Distributor has received recovery of any costs arising from the LPP Class Actions in a prior proceeding before the Board, other than THESL as outlined in footnote 17 of the evidence filed by the EDA on November 8, 2010 and as detailed in the supplementary evidence filed by THESL on November 12, 2010. As outlined in THESL's supplementary evidence, THESL has already notionally recovered the amount of $185,628 through rates. This amount has been removed from the Updated Recovery Amount as outlined in the revised Appendix A.

Answer to Interrogatory from Board Staff

Question 5:

Reference(s): None provided.

In paragraph 62, the EDA provides a breakdown of the Allocated Amount. The EDA estimates the legal costs to be $700,000 **"including this application"**. Please confirm if any Affected Distributor has sought recovery of legal costs in relation to the processing of this application in their Cost of Service application that is currently before the Board. If such a request has been made, please identify the distributor, provide the amount that has been sought for recovery and provide the rationale for requesting recovery of legal costs that are proposed to be recovered in this proceeding.

Answer:

To the best of our knowledge, no LDCs have separately sought recovery of legal fees associated to this application in any Cost of Service application currently before the Board, and no LDC seeks double recovery of any portion of its share of the Updated Recovery Amount. However, THESL, and possibly other LDCs, sought recovery of its portion of the Revised Allocated Amount in the context of its Cost of Service application prior to the Board's establishment of this proceeding, and in THESL's case this issue has been severed from its 2011 rate application for the purpose of determining the issues in this proceeding. The EDA presumes that the Board would follow a similar course in any other like proceeding.

Answer to Interrogatory from
Board Staff

Question 6:

Reference(s): None provided.

Please provide the following in relation to Appendix A:

(i) A copy of Appendix A in MS Excel format, keeping all formula's that are used to prepare the worksheet active.

(ii) Expand Appendix A to include three columns that provide the calculation of the rate rider as proposed in paragraph 70 - That is, a column that lists the total number of metered customers as per the most recent Yearbook of Electricity Distributors; A second column that provides the results of the division to calculate the per customer amount; And a third column that determines the monthly charge.

(iii) In addition to the information requested above, please add additional columns to Appendix A and provide the bill impact of the EDA's proposed recovery proposal on a residential customer consuming 800 kWh and a General Service customer consuming 2000kWh per month and having a monthly demand of less that 50 kW. Please provide this information for all Affected Distributors in Appendix A.

Answer:

a) (i) Please see the attached.

(ii) Please see the attached. The EDA cannot provide the bill impact of the EDA's proposed recovery proposal on a General Service customer consuming 2000 kWh per month with what is publicly available on the Board website.

(iii) Please see the attached. The EDA cannot provide a further breakdown of the bill impact of the EDA's proposed recovery proposal on a residential customer consuming 800 kWh per month or a general service customer consuming 2000 kWh per month with what is publicly available on the Board website.

Index		Used to:	Data Source
Tab 1	Distribution Revenue by Class	Calculate the % Distribution Revenue Allocated to each Cus	OEB 2009 Year Book for Electricity Distributors
Tab 2	Number of Customers by Class	|	OEB 2009 Year Book for Electricity Distributors
Tab 3	Allocation by Class Distribution Revenue	1.Calculate the LPP settlement amount allocated to each Customer Class based on the % of distribution revenue of each customer class. 2. Calculate the LPP settlement amount allocation per Customer. 3. Calculate the LPP settlement amount allocation per Customer per month over a period of 12 months	1. LPP Settlment Amount for Each LDC 2.Tab 1 and Tab 2
Tab 4	Allocation by Customer Numbers	1.Calculate the LPP settlement amount allocated to all metered customers based on the number of metered customers. 2. Calculate the LPP settlement amount allocated to all customers including unmetered customers. 3. Calculate the LPP settlement amount allocation per metered customer per month over a period of 12 months. 4. Calculate the LPP settlement amount allocation per Customer (including un-metered) per month over a period of 12 months	
Tab 5	Bill Impacts - Residential Customers	Residential Electricity Bill (May to October 2010) Excluding HST	OEB Website - Electricity Distribution Rates - Estimated Total Bill Impacts

Name of the LDC	Distribution Revenue from Residential Customers	Distribution Revenue from GS<50 kW Customers	Distribution Revenue from GS>50 kW Customers	Distribution Revenue from Unmetered Customers	Total Distribution Revenue	% of Revenue from Residential Customers	% of Revenue from GS<50 kW Customers	% of Revenue from GS>50 kW Customers	% of Revenue from Unmetered Load Customers
Algoma Power Inc.	$ 6,890,829	$ 311,540	$ 313,683	$ -	$ 7,516,052	91.68%	4.14%	4.17%	0.00%
Atikokan Hydro Inc.	$ 758,252	$ 278,858	$ 101,856	$ 26,290	$ 1,165,255	65.07%	23.93%	8.74%	2.26%
Bluewater Power Distribution Corporation	$ 9,157,764	$ 2,800,099	$ 4,441,480	$ 94,221	$ 16,493,564	55.52%	16.98%	26.93%	0.57%
Brant County Power Inc.	$ 2,804,327	$ 945,956	$ 1,817,161	$ 14,883	$ 5,582,327	50.24%	16.95%	32.55%	0.27%
Brantford Power Inc.	$ 8,301,363	$ 1,405,603	$ 5,056,916	$ 81,427	$ 14,845,309	55.92%	9.47%	34.06%	0.55%
Burlington Hydro Inc.	$ 16,289,521	$ 3,756,965	$ 6,186,875	$ 124,733	$ 26,358,094	61.80%	14.25%	23.47%	0.47%
Cambridge and North Dumfries Hydro Inc.	$ 9,579,085	$ 2,654,337	$ 7,224,560	$ 66,931	$ 19,524,913	49.06%	13.59%	37.00%	0.34%
Canadian Niagara Power Inc.	$ 4,526,265	$ 1,051,668	$ 2,778,279	$ -	$ 8,356,212	54.17%	12.59%	33.25%	0.00%
Centre Wellington Hydro Ltd.	$ 1,497,545	$ 471,110	$ 589,767	$ 9,627	$ 2,568,048	58.31%	18.35%	22.97%	0.37%
Chapleau Public Utilities Corporation	$ 425,335	$ 124,066	$ 68,389	$ 1,592	$ 619,381	68.67%	20.03%	11.04%	0.26%
Chatham-Kent Hydro Inc.	$ 7,985,703	$ 2,056,723	$ 2,860,875	$ 12,122	$ 12,915,423	61.83%	15.92%	22.15%	0.09%
Clinton Power Corporation	$ 280,150	$ 98,833	$ 116,242	$ 1,738	$ 496,963	56.37%	19.89%	23.39%	0.35%
COLLUS Power Corp.	$ 3,509,127	$ 824,192	$ 674,773	$ 8,261	$ 5,016,353	69.95%	16.43%	13.45%	0.16%
Cooperative Hydro Embrun Inc.	$ 435,106	$ 95,020	$ 67,223	$ -	$ 597,349	72.84%	15.91%	11.25%	0.00%
E.L.K. Energy Inc.	$ 843,320	$ 83,377	$ 589,701	$ -	$ 1,516,397	55.61%	5.50%	38.89%	0.00%
Eastern Ontario Power (CNP)	$ 938,784	$ 382,927	$ 497,048	$ -	$ 1,818,760	51.62%	21.05%	27.33%	0.00%
Enersource Hydro Mississauga Inc.	$ 44,995,913	$ 15,430,070	$ 52,663,450	$ 522,699	$ 113,612,132	39.60%	13.58%	46.35%	0.46%
ENWIN Powerlines Ltd.	$ 21,658,067	$ 5,636,594	$ 17,387,735	$ 150,546	$ 44,832,942	48.31%	12.57%	38.78%	0.34%
Erie Thames Powerlines Corporation	$ 3,219,337	$ 566,057	$ 1,671,758	$ 9,133	$ 5,466,285	58.89%	10.36%	30.58%	0.17%
Espanola Regional Hydro Distribution Corporation	$ 768,750	$ 298,677	$ 122,572	$ -	$ 1,189,999	64.60%	25.10%	10.30%	0.00%
Essex Powerlines Corporation	$ 6,786,809	$ 592,848	$ 2,012,993	$ 62,755	$ 9,455,404	71.78%	6.27%	21.29%	0.66%
Festival Hydro Inc.	$ 5,103,848	$ 1,619,721	$ 2,333,615	$ -	$ 9,057,184	56.35%	17.88%	25.77%	0.00%
Fort Frances Power Corporation	$ 833,635	$ 250,074	$ 360,752	$ 2,912	$ 1,447,372	57.60%	17.28%	24.92%	0.20%
Greater Sudbury Hydro Inc.	$ 12,627,666	$ 3,590,003	$ 5,182,403	$ 84,899	$ 21,484,970	58.77%	16.71%	24.12%	0.40%
Grimsby Power Incorporated	$ 2,414,963	$ 388,562	$ 472,269	$ 5,384	$ 3,281,178	73.60%	11.84%	14.39%	0.16%
Guelph Hydro Electric Systems Inc.	$ 13,114,938	$ 2,824,471	$ 7,236,902	$ 47,550	$ 23,223,860	56.47%	12.16%	31.16%	0.20%
Haldimand County Hydro Inc.	$ 7,584,891	$ 1,775,022	$ 1,773,198	$ 19,713	$ 11,152,824	68.01%	15.92%	15.90%	0.18%
Halton Hills Hydro Inc.	$ 5,365,267	$ 1,013,246	$ 2,474,220	$ 27,346	$ 8,880,079	60.42%	11.41%	27.86%	0.31%
Hearst Power Distribution Company Limited	$ 458,257	$ 134,006	$ 192,367	$ -	$ 784,630	58.40%	17.08%	24.52%	0.00%
Horizon Utilities Corporation	$ 55,192,117	$ 11,711,495	$ 19,998,502	$ -	$ 86,902,114	63.51%	13.48%	23.01%	0.00%
Hydro 2000 Inc.	$ 202,810	$ 80,448	$ 28,113	$ 1,007	$ 312,378	64.92%	25.75%	9.00%	0.32%
Hydro Hawkesbury Inc.	$ 459,030	$ 93,635	$ 158,413	$ 1,203	$ 712,281	64.45%	13.15%	22.24%	0.17%
Hydro One Brampton Networks Inc.	$ 35,076,490	$ 7,199,552	$ 18,585,172	$ -	$ 60,861,214	57.63%	11.83%	30.54%	0.00%
Hydro One Networks Inc.	$ 626,046,000	$ 263,006,000	$ 8,968,000	$ -	$ 898,020,000	69.71%	29.29%	1.00%	0.00%
Hydro Ottawa Limited	$ 80,607,007	$ 18,047,373	$ 44,019,818	$ 536,070	$ 143,210,268	56.29%	12.60%	30.74%	0.37%
Innisfil Hydro Distribution Systems Limited	$ 5,692,353	$ 639,448	$ 750,206	$ 34,074	$ 7,116,080	79.99%	8.99%	10.54%	0.48%
Kenora Hydro Electric Corporation Ltd.	$ 1,189,685	$ 327,550	$ 434,649	$ -	$ 1,951,883	60.95%	16.78%	22.27%	0.00%
Kingston Electricity Distribution Limited	$ 5,323,895	$ 1,849,197	$ 2,295,348	$ 47,426	$ 9,515,866	55.95%	19.43%	24.12%	0.50%
Kitchener-Wilmot Hydro Inc.	$ 16,684,101	$ 4,332,529	$ 10,459,518	$ 153,879	$ 31,630,027	52.75%	13.70%	33.07%	0.49%
Lakefront Utilities Inc.	$ 1,848,574	$ 576,899	$ 1,201,864	$ 31,864	$ 3,659,201	50.52%	15.77%	32.84%	0.87%
Lakeland Power Distribution Ltd.	$ 2,391,505	$ 968,457	$ 855,712	$ 10,568	$ 4,226,243	56.59%	22.92%	20.25%	0.25%
London Hydro Inc.	$ 33,503,321	$ 8,450,169	$ 10,248,092	$ 58,174	$ 52,259,756	64.11%	16.17%	19.61%	0.11%
Middlesex Power Distribution Corporation	$ 2,087,535	$ 282,773	$ 380,152	$ 7,091	$ 2,757,551	75.70%	10.25%	13.79%	0.26%

Name of the LDC	Distribution Revenue from Residential Customers	Distribution Revenue from GS<50 kW Customers	Distribution Revenue from GS>50 kW Customers	Distribution Revenue from Unmetered Customers	Total Distribution Revenue	% of Revenue from Residential Customers	% of Revenue from GS<50 kW Customers	% of Revenue from GS>50 kW Customers	% of Revenue from Unmetered Load Customers
Midland Power Utility Corporation	$ 1,808,381	$ 487,411	$ 766,955	$ 13,743	$ 3,076,490	58.78%	15.84%	24.93%	0.45%
Milton Hydro Distribution Inc.	$ 7,107,078	$ 1,570,851	$ 2,662,035	$ 36,889	$ 11,376,852	62.47%	13.81%	23.40%	0.32%
Newmarket Hydro Ltd.	$ 8,091,758	$ 2,310,777	$ 3,891,854	$ -	$ 14,294,389	56.61%	16.17%	27.23%	0.00%
Niagara Peninsula Energy Inc.	$ 13,491,773	$ 3,364,595	$ 8,581,980	$ 119,866	$ 25,558,213	52.79%	13.16%	33.58%	0.47%
Niagara-on-the-Lake Hydro Inc.	$ 2,214,849	$ 1,095,985	$ 1,115,534	$ 11,951	$ 4,438,318	49.90%	24.69%	25.13%	0.27%
Norfolk Power Distribution Inc.	$ 6,962,430	$ 2,114,481	$ 1,812,098	$ -	$ 10,889,009	63.94%	19.42%	16.64%	0.00%
North Bay Hydro Distribution Limited	$ 5,534,543	$ 1,892,314	$ 2,281,600	$ 9,587	$ 9,718,044	56.95%	19.47%	23.48%	0.10%
Northern Ontario Wires Inc.	$ 1,558,802	$ 427,800	$ 329,251	$ 4,204	$ 2,320,057	67.19%	18.44%	14.19%	0.18%
Oakville Hydro Electricity Distribution Inc.	$ 17,558,909	$ 3,985,324	$ 6,034,339	$ 119,036	$ 27,697,609	63.40%	14.39%	21.79%	0.43%
Orangeville Hydro Limited	$ 2,986,225	$ 705,587	$ 697,577	$ 12,798	$ 4,402,186	67.84%	16.03%	15.85%	0.29%
Orillia Power Distribution Corporation	$ 3,165,109	$ 1,167,744	$ 1,613,116	$ 40,790	$ 5,986,759	52.87%	19.51%	26.94%	0.68%
Oshawa PUC Networks Inc.	$ 10,503,425	$ 2,789,117	$ 4,550,193	$ 66,781	$ 17,909,516	58.65%	15.57%	25.41%	0.37%
Ottawa River Power Corporation	$ 2,025,174	$ 623,517	$ 820,651	$ 9,053	$ 3,478,395	58.22%	17.93%	23.59%	0.26%
Parry Sound Power Corporation	$ 937,164	$ 303,333	$ 418,864	$ 4,210	$ 1,663,572	56.33%	18.23%	25.18%	0.25%
Peterborough Distribution Incorporated	$ 7,729,832	$ 2,153,680	$ 2,860,209	$ 84,857	$ 12,828,578	60.25%	16.79%	22.30%	0.66%
Port Colborne (CNP)	$ 2,843,518	$ 674,350	$ 1,415,139	$ -	$ 4,933,006	57.64%	13.67%	28.69%	0.00%
PowerStream Inc.	$ 77,327,995	$ 21,418,543	$ 42,401,537	$ 438,584	$ 141,586,659	54.62%	15.13%	29.95%	0.31%
PUC Distribution Inc.	$ 8,375,415	$ 2,278,648	$ 3,630,937	$ 24,220	$ 14,309,220	58.53%	15.92%	25.37%	0.17%
Renfrew Hydro Inc.	$ 849,085	$ 247,632	$ 284,351	$ -	$ 1,381,068	61.48%	17.93%	20.59%	0.00%
Rideau St. Lawrence Distribution Inc.	$ 1,156,502	$ 375,059	$ 354,195	$ 16,617	$ 1,902,373	60.79%	19.72%	18.62%	0.87%
Sioux Lookout Hydro Inc.	$ 1,049,004	$ 339,855	$ 308,481	$ 3,620	$ 1,700,959	61.67%	19.98%	18.14%	0.21%
St. Thomas Energy Inc.	$ 742,203	$ 1,076,514	$ 3,861,714	$ 612	$ 5,681,043	13.06%	18.95%	67.98%	0.01%
Thunder Bay Hydro Electricity Distribution Inc.	$ 10,704,867	$ 2,675,518	$ 3,093,591	$ 134,844	$ 16,608,820	64.45%	16.11%	18.63%	0.81%
Tillsonburg Hydro Inc.	$ 1,653,970	$ 500,966	$ 495,519	$ 18,514	$ 2,668,968	61.97%	18.77%	18.57%	0.69%
Toronto Hydro-Electric System Limited	$ 193,430,604	$ 60,336,439	$ 201,544,335	$ 2,449,890	$ 457,761,268	42.26%	13.18%	44.03%	0.54%
Veridian Connections Inc.	$ 27,976,891	$ 6,464,083	$ 8,935,284	$ 181,472	$ 43,557,730	64.23%	14.84%	20.51%	0.42%
Wasaga Distribution Inc.	$ 2,752,651	$ 340,326	$ 275,966	$ 2,240	$ 3,371,183	81.65%	10.10%	8.19%	0.07%
Waterloo North Hydro Inc.	$ 13,521,851	$ 3,777,338	$ 7,382,623	$ 120,883	$ 24,802,695	54.52%	15.23%	29.77%	0.49%
Welland Hydro-Electric System Corp.	$ 5,402,478	$ 902,878	$ 1,441,330	$ 41,404	$ 7,788,090	69.37%	11.59%	18.51%	0.53%
Wellington North Power Inc.	$ 865,937	$ 297,891	$ 559,777	$ 218	$ 1,723,824	50.23%	17.28%	32.47%	0.01%
West Coast Huron Energy Inc.	$ 899,422	$ 313,302	$ 793,795	$ 3,352	$ 2,009,871	44.75%	15.59%	39.49%	0.17%
West Perth Power Inc.	$ 414,577	$ 138,361	$ 194,019	$ 68	$ 747,025	55.50%	18.52%	25.97%	0.01%
Westario Power Inc.	$ 4,543,177	$ 1,276,314	$ 1,886,930	$ 23,596	$ 7,730,017	58.77%	16.51%	24.41%	0.31%
Whitby Hydro Electric Corporation	$ 11,826,831	$ 1,715,967	$ 3,766,927	$ 123,686	$ 17,433,411	67.84%	9.84%	21.61%	0.71%
Woodstock Hydro Services Inc.	$ 3,851,591	$ 825,248	$ 1,585,466	$ 8,113	$ 6,270,417	61.42%	13.16%	25.28%	0.13%
Total	$ 1,527,323,258	$ 499,993,896	$ 568,300,791	$ 6,381,811	$ 2,601,999,756	58.70%	19.22%	21.84%	0.25%

Name of the LDC	Number of Residential Customers	Number of GS< 50kW Customers	Number of GS > 50kW Customers	Number of Large User Customers	Number of Sub Transmission	Total Number of > 50 kw; large user and sub transmission customers	Total Number of Metered Customers	Number of Connections (Unmetered class)	Total Number of All Customers including Unmetered
Algoma Power Inc.	10,630	1,010	47	1	0	48	11,688	0	11,688
Atikokan Hydro Inc.	1,415	225	22	0	0	22	1,662	8	1,670
Bluewater Power Distribution Corporation	31,420	3,505	395	3	0	398	35,323	257	35,580
Brant County Power Inc.	8,171	1,286	106	0	0	106	9,563	51	9,614
Brantford Power Inc.	34,089	2,721	413	0	0	413	37,223	445	37,668
Burlington Hydro Inc.	57,578	4,974	980	0	0	980	63,532	26	63,558
Cambridge and North Dumfries Hydro Inc.	44,805	4,620	709	2	0	711	50,136	65	50,201
Canadian Niagara Power Inc.	14,248	1,228	131	0	0	131	15,607	0	15,607
Centre Wellington Hydro Ltd.	5,603	714	63	0	0	63	6,380	2	6,382
Chapleau Public Utilities Corporation	1,144	162	14	0	0	14	1,320	6	1,326
Chatham-Kent Hydro Inc.	28,463	3,102	410	1	0	411	31,976	192	32,168
Clinton Power Corporation	1,411	221	17	0	0	17	1,649	11	1,660
COLLUS Power Corporation	13,152	1,609	116	1	0	117	14,878	30	14,908
Cooperative Hydro Embrun Inc.	1,757	172	12	0	0	12	1,941	0	1,941
E.L.K. Energy Inc.	9,843	1,148	121	0	0	121	11,112	0	11,112
Eastern Ontario Power Inc.	3,104	422	34	0	0	34	3,560	0	3,560
Enersource Hydro Mississauga Inc.	168,288	16,800	4,442	10	0	4,452	189,540	198	189,738
EnWin Utilities Ltd.	76,528	6,981	1,178	10	0	1,188	84,697	29	84,726
Erie Thames Powerlines Corporation	12,550	1,234	146	2	3	151	13,935	105	14,040
Espanola Regional Hydro Distribution Corporation	2,857	477	25	0	0	25	3,359	24	3,383
Essex Powerlines Corporation	25,817	2,015	222	0	0	222	28,054	148	28,202
Festival Hydro Inc.	17,311	2,009	209	2	0	211	19,531	0	19,531
Fort Frances Power Corporation	3,296	418	47	0	0	47	3,761	7	3,768
Greater Sudbury Hydro Inc.	41,926	3,911	512	0	0	512	46,349	190	46,539
Grimsby Power Incorporated	9,222	669	101	0	0	101	9,992	81	10,073
Guelph Hydro Electric Systems Inc.	45,023	3,650	582	4	0	586	49,259	40	49,299
Haldimand County Hydro Inc.	18,309	2,381	137	0	0	137	20,827	84	20,911
Halton Hills Hydro Inc.	18,924	1,913	207	0	0	207	21,044	140	21,184
Hearst Power Distribution Company Limited	2,332	388	44	0	0	44	2,764	0	2,764
Horizon Utilities Corporation	212,580	19,858	2,216	12	0	2,228	234,666	0	234,666
Hydro 2000 Inc.	1,027	140	11	0	0	11	1,178	6	1,184
Hydro Hawkesbury Inc.	4,781	586	81	1	0	82	5,449	4	5,453
Hydro One Brampton Networks Inc.	121,692	7,684	1,645	6	0	1,651	131,027	0	131,027
Hydro One Networks Inc.	1,084,186	109,208	0	0	373	373	1,193,767	0	1,193,767
Hydro Ottawa Limited	269,288	23,338	3,370	11	0	3,381	296,007	2,848	298,855
Innisfil Hydro Distribution Systems Limited	13,636	855	72	0	0	72	14,563	82	14,645
Kenora Hydro Electric Corporation Ltd.	4,777	733	69	0	0	69	5,579	0	5,579
Kingston Hydro Corporation	23,223	3,255	351	3	0	354	26,832	159	26,991
Kitchener-Wilmot Hydro Inc.	76,755	7,425	992	2	0	994	85,174	824	85,998
Lakefront Utilities Inc.	8,243	1,065	132	0	0	132	9,440	94	9,534
Lakeland Power Distribution Ltd.	7,697	1,547	100	0	0	100	9,344	43	9,387
London Hydro Inc.	131,734	11,914	1,647	3	0	1,650	145,298	1,489	146,787
Middlesex Power Distribution Corporation	6,984	780	95	1	0	96	7,860	51	7,911

Name of the LDC	Number of Residential Customers	Number of GS< 50kW Customers	Number of GS > 50kW Customers	Number of Large User Customers	Number of Sub Transmission	Total Number of > 50 kw; large user and sub transmission customers	Total Number of Metered Customers	Number of Connections (Unmetered class)	Total Number of All Customers including Unmetered
Midland Power Utility Corporation	6,052	729	112	0	0	112	6,893	12	6,905
Milton Hydro Distribution Inc.	24,832	2,203	286	2	0	288	27,323	183	27,506
Newmarket - Tay Power Distribution Ltd.	29,138	2,893	398	0	0	398	32,429	398	32,827
Niagara Peninsula Energy Inc.	45,167	4,389	847	0	0	847	50,403	420	50,823
Niagara-on-the-Lake Hydro Inc.	6,507	1,230	121	0	0	121	7,858	22	7,880
Norfolk Power Distribution Inc.	16,653	2,071	169	0	0	169	18,893	2	18,895
North Bay Hydro Distribution Limited	20,850	2,629	276	0	0	276	23,755	21	23,776
Northern Ontario Wires Inc.	5,179	798	73	0	0	73	6,050	19	6,069
Oakville Hydro Electricity Distribution Inc.	56,419	4,887	873	0	0	873	62,179	679	62,858
Orangeville Hydro Limited	9,814	1,148	129	0	0	129	11,091	35	11,126
Orillia Power Distribution Corporation	11,296	1,359	154	0	0	154	12,809	153	12,962
Oshawa PUC Networks Inc.	47,769	3,897	517	1	0	518	52,184	304	52,488
Ottawa River Power Corporation	8,851	1,394	144	0	0	144	10,389	73	10,462
Parry Sound Power Corporation	2,751	540	68	0	0	68	3,359	19	3,378
Peterborough Distribution Incorporated	30,680	3,609	363	2	0	365	34,654	383	35,037
Port Colborne Hydro Inc.	8,170	874	80	0	0	80	9,124	0	9,124
PowerStream Inc.	283,665	29,594	4,654	1	0	4,655	317,914	2,781	320,695
PUC Distribution Inc.	29,028	3,341	439	0	0	439	32,808	17	32,825
Renfrew Hydro Inc.	3,613	503	64	0	0	64	4,180	0	4,180
Rideau St. Lawrence Distribution Inc.	4,974	774	66	0	0	66	5,814	49	5,863
Sioux Lookout Hydro Inc.	2,296	392	39	0	0	39	2,727	13	2,740
St. Thomas Energy Inc.	14,374	1,672	192	0	0	192	16,238	5	16,243
Thunder Bay Hydro Electricity Distribution Inc.	44,443	4,486	524	0	0	524	49,453	469	49,922
Tillsonburg Hydro Inc.	5,907	675	87	0	0	87	6,669	69	6,738
Toronto Hydro-Electric System Limited	611,357	64,781	12,953	47	0	13,000	689,138	1,105	690,243
Veridian Connections Inc.	101,547	8,501	1,049	4	0	1,053	111,101	893	111,994
Wasaga Distribution Inc.	11,010	801	33	0	0	33	11,844	25	11,869
Waterloo North Hydro Inc.	45,113	5,300	661	1	0	662	51,075	14	51,089
Welland Hydro-Electric System Corp.	19,803	1,725	172	2	0	174	21,702	214	21,916
Wellington North Power Inc.	3,056	480	49	0	0	49	3,585	3	3,588
West Coast Huron Energy Inc.	3,231	474	53	1	0	54	3,759	4	3,763
West Perth Power Inc.	1,786	241	20	0	0	20	2,047	5	2,052
Westario Power Inc.	19,033	2,435	276	0	0	276	21,744	61	21,805
Whitby Hydro Electric Corporation	36,762	1,926	435	0	0	435	39,123	390	39,513
Woodstock Hydro Services Inc.	13,429	1,170	200	0	0	200	14,799	39	14,838
Total	4,260,374	422,274	48,799	136	376	49,311	4,731,959	16,618	4,748,577

Name of the LDC	Total Settlement Amount Allocation by LDC	Settlement Amount Allocation to each Class of Customers Based on Class Distribution Revenue				Settlement Amount Allocation per Customer				Allocation per Customer per month over a period of 12 months			
		Residential	GS<50KW	GS>50KW	Unmetered Class	Residential	GS<50KW	GS>50KW	Unmetered Class	Residential	GS<50KW	GS>50KW	Unmetered Class
Algoma Power Inc.	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Atikokan Hydro Inc.	$7,567.85	$4,924.53	$1,811.07	$661.51	$170.74	$3.48	$8.05	$30.07	$21.34	$0.29	$0.67	$2.51	$1.78
Bluewater Power Distribution Corporation	$149,121.96	$82,797.37	$25,316.31	$40,156.40	$851.87	$2.64	$7.22	$100.90	$3.31	$0.22	$0.60	$8.41	$0.28
Brant County Power Inc.	$41,665.21	$20,930.85	$7,060.40	$13,562.87	$111.08	$2.56	$5.49	$127.95	$2.18	$0.21	$0.46	$10.66	$0.18
Brantford Power Inc.	$126,681.66	$70,839.24	$11,994.64	$43,152.92	$694.85	$2.08	$4.41	$104.49	$1.56	$0.17	$0.37	$8.71	$0.13
Burlington Hydro Inc.	$229,874.32	$142,064.24	$32,765.26	$53,957.00	$1,087.82	$2.47	$6.59	$55.06	$41.84	$0.21	$0.55	$4.59	$3.49
Cambridge and North Dumfries Hydro Inc.	$194,554.99	$95,450.30	$26,449.00	$71,988.76	$666.93	$2.13	$5.72	$101.25	$10.26	$0.18	$0.48	$8.44	$0.86
Canadian Niagara Power Inc.	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Centre Wellington Hydro Ltd.	$25,370.61	$14,794.75	$4,654.25	$5,826.50	$95.11	$2.64	$6.52	$92.48	$47.55	$0.22	$0.54	$7.71	$3.96
Chapleau Public Utilities Corporation	$5,314.22	$3,649.33	$1,064.47	$586.77	$13.66	$3.19	$6.57	$41.91	$2.28	$0.27	$0.55	$3.49	$0.19
Chatham-Kent Hydro Inc.	$134,064.08	$82,892.83	$21,349.10	$29,696.32	$125.83	$2.91	$6.88	$72.25	$0.66	$0.24	$0.57	$6.02	$0.05
Clinton Power Corporation	$4,702.32	$2,650.81	$935.17	$1,099.90	$16.44	$1.88	$4.23	$64.70	$1.49	$0.16	$0.35	$5.39	$0.12
COLLUS Power Corporation	$46,485.63	$32,518.45	$7,637.64	$6,253.00	$76.55	$2.47	$4.75	$53.44	$2.55	$0.21	$0.40	$4.45	$0.21
Cooperative Hydro Embrun Inc.	$4,271.79	$3,111.55	$679.51	$480.73	$0.00	$1.77	$3.95	$40.06	$0.00	$0.15	$0.33	$3.34	$0.00
E.L.K. Energy Inc.	$28,387.69	$15,787.36	$1,560.85	$11,039.48	$0.00	$1.60	$1.36	$91.24	$0.00	$0.13	$0.11	$7.60	$0.00
Eastern Ontario Power Inc.	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Enersource Hydro Mississauga Inc.	$1,006,252.86	$398,524.92	$136,662.80	$466,435.64	$4,629.50	$2.37	$8.13	$104.77	$23.38	$0.20	$0.68	$8.73	$1.95
EnWin Utilities Ltd.	$434,442.75	$209,872.24	$54,620.05	$168,491.63	$1,458.83	$2.74	$7.82	$141.83	$50.30	$0.23	$0.65	$11.82	$4.19
Erie Thames Powerlines Corporation	$55,928.58	$32,938.82	$5,791.65	$17,104.68	$93.45	$2.62	$4.69	$113.28	$0.89	$0.22	$0.39	$9.44	$0.07
Espanola Regional Hydro Distribution Corporation	$9,905.46	$6,399.02	$2,486.17	$1,020.28	$0.00	$2.24	$5.21	$40.81	$0.00	$0.19	$0.43	$3.40	$0.00
Essex Powerlines Corporation	$75,617.88	$54,276.27	$4,741.19	$16,098.55	$501.87	$2.10	$2.35	$72.52	$3.39	$0.18	$0.20	$6.04	$0.28
Festival Hydro Inc.	$87,054.58	$49,056.45	$15,568.20	$22,429.92	$0.00	$2.83	$7.75	$106.30	$0.00	$0.24	$0.65	$8.86	$0.00
Fort Frances Power Corporation	$9,076.63	$5,227.81	$1,568.24	$2,262.31	$18.26	$1.59	$3.75	$48.13	$2.61	$0.13	$0.31	$4.01	$0.22
Greater Sudbury Hydro Inc.	$149,791.41	$88,039.03	$25,029.20	$36,131.28	$591.91	$2.10	$6.40	$70.57	$3.12	$0.17	$0.53	$5.88	$0.26
Grimsby Power Incorporated	$23,236.06	$17,101.85	$2,751.65	$3,344.43	$38.13	$1.85	$4.11	$33.11	$0.47	$0.15	$0.34	$2.76	$0.04
Guelph Hydro Electric Systems Inc.	$207,326.43	$117,081.02	$25,214.90	$64,606.02	$424.49	$2.60	$6.91	$110.25	$10.61	$0.22	$0.58	$9.19	$0.88
Haldimand County Hydro Inc.	$52,104.38	$35,435.51	$8,292.65	$8,284.12	$92.10	$1.94	$3.48	$60.47	$1.10	$0.16	$0.29	$5.04	$0.09
Halton Hills Hydro Inc.	$62,839.79	$37,967.26	$7,170.23	$17,508.79	$193.51	$2.01	$3.75	$84.58	$1.38	$0.17	$0.31	$7.05	$0.12
Hearst Power Distribution Company Limited	$14,889.32	$8,695.99	$2,542.93	$3,650.41	$0.00	$3.73	$6.55	$82.96	$0.00	$0.31	$0.55	$6.91	$0.00
Horizon Utilities Corporation	$1,102,335.23	$700,100.52	$148,557.87	$253,676.83	$0.00	$3.29	$7.48	$113.86	$0.00	$0.27	$0.62	$9.49	$0.00
Hydro 2000 Inc.	$3,858.70	$2,505.24	$993.75	$347.27	$12.44	$2.44	$7.10	$31.57	$2.07	$0.20	$0.59	$2.63	$0.17
Hydro Hawkesbury Inc.	$26,420.72	$17,026.85	$3,473.21	$5,876.03	$44.62	$3.56	$5.93	$71.66	$11.16	$0.30	$0.49	$5.97	$0.93
Hydro One Brampton Networks Inc.	$444,880.45	$256,400.49	$52,626.95	$135,853.02	$0.00	$2.11	$6.85	$82.29	$0.00	$0.18	$0.57	$6.86	$0.00
Hydro One Networks Inc.	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Hydro Ottawa Limited	$1,020,856.03	$574,596.71	$128,648.38	$313,789.63	$3,821.31	$2.13	$5.51	$92.81	$1.34	$0.18	$0.46	$7.73	$0.11
Innisfil Hydro Distribution Systems Limited	$33,430.63	$26,742.10	$3,004.06	$3,524.39	$160.08	$1.96	$3.51	$48.95	$1.95	$0.16	$0.29	$4.08	$0.16
Kenora Hydro Electric Corporation Ltd.	$16,296.32	$9,932.71	$2,734.72	$3,628.89	$0.00	$2.08	$3.73	$52.59	$0.00	$0.17	$0.31	$4.38	$0.00
Kingston Hydro Corporation	$104,031.09	$58,202.86	$20,216.13	$25,093.63	$518.48	$2.51	$6.21	$70.89	$3.26	$0.21	$0.52	$5.91	$0.27
Kitchener-Wilmot Hydro Inc.	$271,910.14	$143,426.25	$37,244.95	$89,916.11	$1,322.84	$1.87	$5.02	$90.46	$1.61	$0.16	$0.42	$7.54	$0.13
Lakefront Utilities Inc.	$36,872.16	$18,627.27	$5,813.16	$12,110.66	$321.08	$2.26	$5.46	$91.75	$3.42	$0.19	$0.45	$7.65	$0.28
Lakeland Power Distribution Ltd.	$31,478.25	$17,812.60	$7,213.34	$6,373.59	$78.72	$2.31	$4.66	$63.74	$1.83	$0.19	$0.39	$5.31	$0.15
London Hydro Inc.	$457,241.98	$293,134.26	$73,933.98	$89,664.75	$508.99	$2.23	$6.21	$54.34	$0.34	$0.19	$0.52	$4.53	$0.03
Middlesex Power Distribution Corporation	$26,337.49	$19,938.14	$2,700.78	$3,630.85	$67.73	$2.85	$3.46	$37.82	$1.33	$0.24	$0.29	$3.15	$0.11
Midland Power Utility Corporation	$31,756.33	$18,666.58	$5,031.18	$7,916.71	$141.86	$3.08	$6.90	$70.68	$11.82	$0.26	$0.58	$5.89	$0.99
Milton Hydro Distribution Inc.	$74,673.59	$46,648.32	$10,310.50	$17,472.64	$242.12	$1.88	$4.68	$60.67	$1.32	$0.16	$0.39	$5.06	$0.11
Newmarket - Tay Power Distribution Ltd.	$95,325.31	$53,961.68	$15,409.93	$25,953.69	$0.00	$1.85	$5.33	$65.21	$0.00	$0.15	$0.44	$5.43	$0.00
Niagara Peninsula Energy Inc.	$167,381.05	$88,357.79	$22,034.77	$56,203.49	$785.00	$1.96	$5.02	$66.36	$1.87	$0.16	$0.42	$5.53	$0.16
Niagara-on-the-Lake Hydro Inc.	$24,800.65	$12,376.24	$6,124.20	$6,233.43	$66.78	$1.90	$4.98	$51.52	$3.04	$0.16	$0.41	$4.29	$0.25
Norfolk Power Distribution Inc.	$55,876.38	$35,727.34	$10,850.35	$9,298.68	$0.00	$2.15	$5.24	$55.02	$0.00	$0.18	$0.44	$4.59	$0.00
North Bay Hydro Distribution Limited	$87,552.60	$49,862.26	$17,048.39	$20,555.58	$86.37	$2.39	$6.48	$74.48	$4.11	$0.20	$0.54	$6.21	$0.34
Northern Ontario Wires Inc.	$21,401.32	$14,379.14	$3,946.23	$3,037.17	$38.78	$2.78	$4.95	$41.61	$2.04	$0.23	$0.41	$3.47	$0.17
Oakville Hydro Electricity Distribution Inc.	$257,572.31	$163,288.06	$37,061.29	$56,115.99	$1,106.97	$2.89	$7.58	$64.28	$1.63	$0.24	$0.63	$5.36	$0.14
Orangeville Hydro Limited	$34,423.12	$23,350.94	$5,517.37	$5,454.74	$100.07	$2.38	$4.81	$42.28	$2.86	$0.20	$0.40	$3.52	$0.24
Orillia Power Distribution Corporation	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oshawa PUC Networks Inc.	$171,994.93	$100,870.17	$26,785.42	$43,698.01	$641.33	$2.11	$6.87	$84.36	$2.11	$0.18	$0.57	$7.03	$0.18
Ottawa River Power Corporation	$28,419.68	$16,546.37	$5,094.35	$6,705.00	$73.97	$1.87	$3.65	$46.56	$1.01	$0.16	$0.30	$3.88	$0.08
Parry Sound Power Corporation	$12,414.74	$6,993.77	$2,263.68	$3,125.86	$31.42	$2.54	$4.19	$45.97	$1.65	$0.21	$0.35	$3.83	$0.14
Peterborough Distribution Incorporated	$110,277.91	$66,447.72	$18,513.61	$24,587.13	$729.45	$2.17	$5.13	$67.36	$1.90	$0.18	$0.43	$5.61	$0.16
Port Colborne Hydro Inc.	$28,872.42	$16,642.84	$3,946.90	$8,282.67	$0.00	$2.04	$4.52	$103.53	$0.00	$0.17	$0.38	$8.63	$0.00
PowerStream Inc.	$1,019,321.62	$556,705.68	$154,198.03	$305,260.42	$3,157.49	$1.96	$5.21	$65.58	$1.14	$0.16	$0.43	$5.46	$0.09
PUC Distribution Inc.	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Renfrew Hydro Inc.	$14,453.29	$8,885.93	$2,591.54	$2,975.82	$0.00	$2.46	$5.15	$46.50	$0.00	$0.20	$0.43	$3.87	$0.00

Name of the LDC	Total Settlement Amount Allocation by LDC	Settlement Amount Allocation to each Class of Customers Based on Class Distribution Revenue				Settlement Amount Allocation per Customer				Allocation per Customer per month over a period of 12 months			
		Residential	GS<50KW	GS>50KW	Unmetered Class	Residential	GS<50KW	GS>50KW	Unmetered Class	Residential	GS<50KW	GS>50KW	Unmetered Class
Rideau St. Lawrence Distribution Inc.	$18,391.97	$11,180.96	$3,626.04	$3,424.32	$160.65	$2.25	$4.68	$51.88	$3.28	$0.19	$0.39	$4.32	$0.27
Sioux Lookout Hydro Inc.	$12,422.98	$7,661.41	$2,482.13	$2,252.99	$26.44	$3.34	$6.33	$57.77	$2.03	$0.28	$0.53	$4.81	$0.17
St. Thomas Energy Inc.	$52,622.33	$6,874.88	$9,971.53	$35,770.26	$5.66	$0.48	$5.96	$186.30	$1.13	$0.04	$0.50	$15.53	$0.09
Thunder Bay Hydro Electricity Distribution Inc.	$160,239.21	$103,278.83	$25,812.97	$29,846.46	$1,300.95	$2.32	$5.75	$56.96	$2.77	$0.19	$0.48	$4.75	$0.23
Tillsonburg Hydro Inc.	$29,932.56	$18,549.32	$5,618.35	$5,557.26	$207.63	$3.14	$8.32	$63.88	$3.01	$0.26	$0.69	$5.32	$0.25
Toronto Hydro-Electric System Limited	$7,525,588.82	$3,179,996.42	$991,930.21	$3,313,386.04	$40,276.16	$5.20	$15.31	$254.88	$36.45	$0.43	$1.28	$21.24	$3.04
Veridian Connections Inc.	$345,325.31	$221,800.55	$51,247.19	$70,838.86	$1,438.71	$2.18	$6.03	$67.27	$1.61	$0.18	$0.50	$5.61	$0.13
Wasaga Distribution Inc.	$14,942.12	$12,200.60	$1,508.43	$1,223.17	$9.93	$1.11	$1.88	$37.07	$0.40	$0.09	$0.16	$3.09	$0.03
Waterloo North Hydro Inc.	$173,479.23	$94,576.83	$26,420.10	$51,636.80	$845.50	$2.10	$4.98	$78.00	$60.39	$0.17	$0.42	$6.50	$5.03
Welland Hydro-Electric System Corp.	$74,531.55	$51,701.39	$8,640.49	$13,793.44	$396.23	$2.61	$5.01	$79.27	$1.85	$0.22	$0.42	$6.61	$0.15
Wellington North Power Inc.	$11,517.59	$5,785.69	$1,990.34	$3,740.11	$1.46	$1.89	$4.15	$76.33	$0.49	$0.16	$0.35	$6.36	$0.04
West Coast Huron Energy Inc.	$18,419.16	$8,242.62	$2,871.21	$7,274.61	$30.72	$2.55	$6.06	$134.72	$7.68	$0.21	$0.50	$11.23	$0.64
West Perth Power Inc.	$8,514.12	$4,725.08	$1,576.95	$2,211.31	$0.77	$2.65	$6.54	$110.57	$0.15	$0.22	$0.55	$9.21	$0.01
Westario Power Inc.	$63,697.60	$37,437.11	$10,517.20	$15,548.86	$194.44	$1.97	$4.32	$56.34	$3.19	$0.16	$0.36	$4.69	$0.27
Whitby Hydro Electric Corporation	$124,544.36	$84,490.93	$12,258.87	$26,910.94	$883.61	$2.30	$6.36	$61.86	$2.27	$0.19	$0.53	$5.16	$0.19
Woodstock Hydro Services Inc.	$57,743.72	$35,468.96	$7,599.63	$14,600.41	$74.71	$2.64	$6.50	$73.00	$1.92	$0.22	$0.54	$6.08	$0.16
Total or Average	$17,690,907.53	$8,935,156.18	$2,433,678.22	$6,250,208.75	$71,864.38	$2.20	$5.16	$69.82	$5.46	$0.18	$0.43	$5.82	$0.45

Name of the LDC	Residential Electricity Bill (May to October 2010) Excluding HST	Bill Impacts excluding HST (Allocation By Class Distribution Revenue)	Bill Impacts excluding HST (Allocation By Customer Numbers - All Metered customers)	Bill Impacts excluding HST (Allocation By Customer Numbers - Including Unmetered customers)
Algoma Power Inc.				
Atikokan Hydro Inc.	$116.75	0.25%	0.33%	0.32%
Bluewater Power Distribution Corporation	$104.31	0.21%	0.34%	0.33%
Brant County Power Inc.	$106.16	0.20%	0.34%	0.34%
Brantford Power Inc.	$100.00	0.17%	0.28%	0.28%
Burlington Hydro Inc.	$103.76	0.20%	0.29%	0.29%
Cambridge and North Dumfries Hydro Inc.	$94.29	0.19%	0.34%	0.34%
Canadian Niagara Power Inc.				
Centre Wellington Hydro Ltd.	$100.82	0.22%	0.33%	0.33%
Chapleau Public Utilities Corporation	$100.26	0.27%	0.33%	0.33%
Chatham-Kent Hydro Inc.	$101.01	0.24%	0.35%	0.34%
Clinton Power Corporation	$94.40	0.17%	0.25%	0.25%
COLLUS Power Corporation	$101.25	0.20%	0.26%	0.26%
Cooperative Hydro Embrun Inc.	$103.69	0.14%	0.18%	0.18%
E.L.K. Energy Inc.	$100.75	0.13%	0.21%	0.21%
Eastern Ontario Power Inc.				
Enersource Hydro Mississauga Inc.	$100.48	0.20%	0.44%	0.44%
EnWin Utilities Ltd.	$102.92	0.22%	0.42%	0.42%
Erie Thames Powerlines Corporation	$104.26	0.21%	0.32%	0.32%
Espanola Regional Hydro Distribution Corporation	$101.14	0.18%	0.24%	0.24%
Essex Powerlines Corporation	$105.06	0.17%	0.21%	0.21%
Festival Hydro Inc.	$104.16	0.23%	0.36%	0.36%
Fort Frances Power Corporation	$91.46	0.14%	0.22%	0.22%
Greater Sudbury Hydro Inc.	$103.01	0.17%	0.26%	0.26%
Grimsby Power Incorporated	$94.80	0.16%	0.20%	0.20%
Guelph Hydro Electric Systems Inc.	$103.37	0.21%	0.34%	0.34%
Haldimand County Hydro Inc.	$119.95	0.13%	0.17%	0.17%
Halton Hills Hydro Inc.	$101.67	0.16%	0.24%	0.24%

Name of the LDC	Residential Electricity Bill (May to October 2010) Excluding HST	Bill Impacts excluding HST (Allocation By Class Distribution Revenue)	Bill Impacts excluding HST (Allocation By Customer Numbers - All Metered customers)	Bill Impacts excluding HST (Allocation By Customer Numbers - Including Unmetered customers)
Hearst Power Distribution Company Limited	$92.89	0.33%	0.48%	0.48%
Horizon Utilities Corporation	$99.73	0.28%	0.39%	0.39%
Hydro 2000 Inc.	$101.50	0.20%	0.27%	0.27%
Hydro Hawkesbury Inc.	$86.84	0.34%	0.47%	0.46%
Hydro One Brampton Networks Inc.	$99.28	0.18%	0.28%	0.28%
Hydro One Networks Inc.				
Hydro Ottawa Limited	$103.47	0.17%	0.28%	0.28%
Innisfil Hydro Distribution Systems Limited	$118.98	0.14%	0.16%	0.16%
Kenora Hydro Electric Corporation Ltd.	$96.87	0.18%	0.25%	0.25%
Kingston Hydro Corporation	$94.96	0.22%	0.34%	0.34%
Kitchener-Wilmot Hydro Inc.	$95.50	0.16%	0.28%	0.28%
Lakefront Utilities Inc.	$100.54	0.19%	0.32%	0.32%
Lakeland Power Distribution Ltd.	$107.26	0.18%	0.26%	0.26%
London Hydro Inc.	$101.17	0.18%	0.26%	0.26%
Middlesex Power Distribution Corporation	$103.29	0.23%	0.27%	0.27%
Midland Power Utility Corporation	$107.67	0.24%	0.36%	0.36%
Milton Hydro Distribution Inc.	$99.66	0.16%	0.23%	0.23%
Newmarket - Tay Power Distribution Ltd.	$102.81	0.15%	0.24%	0.24%
Niagara Peninsula Energy Inc.	$103.09	0.16%	0.27%	0.27%
Niagara-on-the-Lake Hydro Inc.	$102.39	0.15%	0.26%	0.26%
Norfolk Power Distribution Inc.	$114.96	0.16%	0.21%	0.21%
North Bay Hydro Distribution Limited	$103.41	0.19%	0.30%	0.30%
Northern Ontario Wires Inc.	$105.65	0.22%	0.28%	0.28%
Oakville Hydro Electricity Distribution Inc.	$101.95	0.24%	0.34%	0.33%
Orangeville Hydro Limited	$103.49	0.19%	0.25%	0.25%
Orillia Power Distribution Corporation				
Oshawa PUC Networks Inc.	$96.98	0.18%	0.28%	0.28%
Ottawa River Power Corporation	$97.05	0.16%	0.23%	0.23%

Name of the LDC	Residential Electricity Bill (May to October 2010) Excluding HST	Bill Impacts excluding HST (Allocation By Class Distribution Revenue)	Bill Impacts excluding HST (Allocation By Customer Numbers - All Metered customers)	Bill Impacts excluding HST (Allocation By Customer Numbers - Including Unmetered customers)
Parry Sound Power Corporation	$103.73	0.20%	0.30%	0.30%
Peterborough Distribution Incorporated	$99.11	0.18%	0.27%	0.26%
Port Colborne Hydro Inc.	$116.47	0.15%	0.23%	0.23%
PowerStream Inc.	$96.76	0.17%	0.28%	0.27%
PUC Distribution Inc.				
Renfrew Hydro Inc.	$100.66	0.20%	0.29%	0.29%
Rideau St. Lawrence Distribution Inc.	$102.57	0.18%	0.26%	0.25%
Sioux Lookout Hydro Inc.	$111.59	0.25%	0.34%	0.34%
St. Thomas Energy Inc.	$100.00	0.04%	0.27%	0.27%
Thunder Bay Hydro Electricity Distribution Inc.	$97.48	0.20%	0.28%	0.27%
Tillsonburg Hydro Inc.	$102.23	0.26%	0.37%	0.36%
Toronto Hydro-Electric System Limited	$108.16	0.40%	0.84%	0.84%
Veridian Connections Inc.	$96.95	0.19%	0.27%	0.27%
Wasaga Distribution Inc.	$99.79	0.09%	0.11%	0.11%
Waterloo North Hydro Inc.	$99.18	0.18%	0.29%	0.29%
Welland Hydro-Electric System Corp.	$105.75	0.21%	0.27%	0.27%
Wellington North Power Inc.	$101.84	0.15%	0.26%	0.26%
West Coast Huron Energy Inc.	$101.72	0.21%	0.40%	0.40%
West Perth Power Inc.	$100.44	0.22%	0.35%	0.34%
Westario Power Inc.	$104.55	0.16%	0.23%	0.23%
Whitby Hydro Electric Corporation	$106.54	0.18%	0.25%	0.25%
Woodstock Hydro Services Inc.	$104.09	0.21%	0.31%	0.31%
Average		0.19%	0.30%	0.29%

Answer to Interrogatory from Board Staff

Question 7:

Reference(s): None provided.

In paragraph 70. the EDA states, "The LDCs propose that each LDCs portion of the Allocated Amount be divided by the LDCs total number of **metered customers as** set out in the Board's most recent Yearbook".

(i) Prior to 2001, was the Late Payment Penalty applied to and collected from all rate classes (i.e. metered and un-metered)?

(ii) Is the current (i.e. post 2001) Late Payment Penalty applied to and collected from all rate classes (i.e. metered and un-metered)?

(iii) Please provide the rationale for calculating the rate rider on the basis of only "metered customers". In your response please explain why rate classes such as un-metered scattered load, street lighting and sentinel lights should be excluded from the calculation of the rate rider?

(iv) Did the LDCs consider developing a rate rider on a rate class basis (such as the approach presented by THESL in its supplementary evidence)? - That is, by allocating to each rate class the Allocated Amount to be recovered and estimating the rate rider based on the customers in a specific rate class. If such an approach was considered please explain why it was not adopted. In your response please also explain why the proposed method of recovery is better than estimating the rate rider on a rate class specific basis.

Answer:

(i) Yes.

(ii) Yes.

(iii) To the best of our knowledge, LPP revenues from un-metered customer classes were nil or negligible, and customer counts in these classes are also small or negligible as proportions of total customers. In addition, un-metered classes represent a very small percentage of the allocation of LPP-related revenue offsets (in THESL's case, 1%). However, should the Board find that allocation of LPP allocated amounts should be proportional to either LPP revenues received or the allocation of the LPP revenue offset, the LDCs have no objection to the inclusion of un-metered classes if the amounts involved are material.

(iv) No, LDCs did not consider developing a rate rider on a rate class basis. The proposed method of recovery was put forward (as opposed to estimating the rate rider on a rate class specific basis) as it was a simple and straightforward way of allocating the Allocated Amount.

**Answer to Interrogatory from
Board Staff**

Question 8:

Reference(s): None provided.

Please prepare the following scenarios by updating Appendix A. Please provide the response in MS Excel format.

(i) Please calculate the rate rider for each Affected Distributor in Appendix A on a rate class basis as explained in Q7(iv). Please also provide the resultant bill impact on a residential customer consuming 800 kWh and a General Service customer consuming 2000kWh per month and having a monthly demand of less that 50 kW. For the purposes of completing the interrogatory please allocate the Allocated Amount to each rate class reflecting the historical proportions of Late Payment Revenue (similar to the approach used by THESL). If such an allocation cannot be undertaken, please explain why and propose an alternate method of allocation.

Answer:

(i) Please see the attached which calculates the rate rider using distribution revenues (as opposed to historical proportions of LPP revenues). The EDA is unable to complete the interrogatory allocating the Revised Allocated Amount or the Updated Recovery Amount to each rate class reflecting the historical proportions of LPP revenues as LPP revenues are not available. Furthermore, the difficulty in allocating the Revised Allocated Amount or the Updated Recovery Amount to each rate class is that the definition of "customers" versus "connections" for the unmetered class is not uniform across all LDCs. As such, data cannot be relied upon for this purpose. In addition, the general service greater than 50 kW was not further subdivided as this was the data available from the OEB Yearbook for Electricity Distributors. Finally, the EDA cannot provide a further breakdown of the resultant bill impact on a general service customer consuming 2000 kWh per month with what is publicly available on the Board website.

Index	Used to:	Data Source
Tab 1 Distribution Revenue by Class	Calculate the % Distribution Revenue Allocated to each Cus	OEB 2009 Year Book for Electricity Distributors
Tab 2 Number of Customers by Class	|	OEB 2009 Year Book for Electricity Distributors
Tab 3 Allocation by Class Distribution Revenue	1.Calculate the LPP settlement amount allocated to each Customer Class based on the % of distribution revenue of each customer class. 2. Calculate the LPP settlement amount allocation per Customer. 3. Calculate the LPP settlement amount allocation per Customer per month over a period of 12 months	1. LPP Settlment Amount for Each LDC 2.Tab 1 and Tab 2
Tab 4 Allocation by Customer Numbers	1.Calculate the LPP settlement amount allocated to all metered customers based on the number of metered customers. 2. Calculate the LPP settlement amount allocated to all customers including unmetered customers. 3. Calculate the LPP settlement amount allocation per metered customer per month over a period of 12 months. 4. Calculate the LPP settlement amount allocation per Customer (including un-metered) per month over a period of 12 months	
Tab 5 Bill Impacts - Residential Customers	Residential Electricity Bill (May to October 2010) Excluding HST	OEB Website - Electricity Distribution Rates - Estimated Total Bill Impacts

Name of the LDC	Distribution Revenue from Residential Customers	Distribution Revenue from GS<50 kW Customers	Distribution Revenue from GS>50 kW Customers	Distribution Revenue from Unmetered Customers	Total Distribution Revenue	% of Revenue from Residential Customers	% of Revenue from GS<50 kW Customers	% of Revenue from GS>50 kW Customers	% of Revenue from Unmetered Load Customers
Algoma Power Inc.	$ 6,890,829	$ 311,540	$ 313,683	$ -	$ 7,516,052	91.68%	4.14%	4.17%	0.00%
Atikokan Hydro Inc.	$ 758,252	$ 278,858	$ 101,856	$ 26,290	$ 1,165,255	65.07%	23.93%	8.74%	2.26%
Bluewater Power Distribution Corporation	$ 9,157,764	$ 2,800,099	$ 4,441,480	$ 94,221	$ 16,493,564	55.52%	16.98%	26.93%	0.57%
Brant County Power Inc.	$ 2,804,327	$ 945,956	$ 1,817,161	$ 14,883	$ 5,582,327	50.24%	16.95%	32.55%	0.27%
Brantford Power Inc.	$ 8,301,363	$ 1,405,603	$ 5,056,916	$ 81,427	$ 14,845,309	55.92%	9.47%	34.06%	0.55%
Burlington Hydro Inc.	$ 16,289,521	$ 3,756,965	$ 6,186,875	$ 124,733	$ 26,358,094	61.80%	14.25%	23.47%	0.47%
Cambridge and North Dumfries Hydro Inc.	$ 9,579,085	$ 2,654,337	$ 7,224,560	$ 66,931	$ 19,524,913	49.06%	13.59%	37.00%	0.34%
Canadian Niagara Power Inc.	$ 4,526,265	$ 1,051,668	$ 2,778,279	$ -	$ 8,356,212	54.17%	12.59%	33.25%	0.00%
Centre Wellington Hydro Ltd.	$ 1,497,545	$ 471,110	$ 589,767	$ 9,627	$ 2,568,048	58.31%	18.35%	22.97%	0.37%
Chapleau Public Utilities Corporation	$ 425,335	$ 124,066	$ 68,389	$ 1,592	$ 619,381	68.67%	20.03%	11.04%	0.26%
Chatham-Kent Hydro Inc.	$ 7,985,703	$ 2,056,723	$ 2,860,875	$ 12,122	$ 12,915,423	61.83%	15.92%	22.15%	0.09%
Clinton Power Corporation	$ 280,150	$ 98,833	$ 116,242	$ 1,738	$ 496,963	56.37%	19.89%	23.39%	0.35%
COLLUS Power Corp.	$ 3,509,127	$ 824,192	$ 674,773	$ 8,261	$ 5,016,353	69.95%	16.43%	13.45%	0.16%
Cooperative Hydro Embrun Inc.	$ 435,106	$ 95,020	$ 67,223	$ -	$ 597,349	72.84%	15.91%	11.25%	0.00%
E.L.K. Energy Inc.	$ 843,320	$ 83,377	$ 589,701	$ -	$ 1,516,397	55.61%	5.50%	38.89%	0.00%
Eastern Ontario Power (CNP)	$ 938,784	$ 382,927	$ 497,048	$ -	$ 1,818,760	51.62%	21.05%	27.33%	0.00%
Enersource Hydro Mississauga Inc.	$ 44,995,913	$ 15,430,070	$ 52,663,450	$ 522,699	$ 113,612,132	39.60%	13.58%	46.35%	0.46%
ENWIN Powerlines Ltd.	$ 21,658,067	$ 5,636,594	$ 17,387,735	$ 150,546	$ 44,832,942	48.31%	12.57%	38.78%	0.34%
Erie Thames Powerlines Corporation	$ 3,219,337	$ 566,057	$ 1,671,758	$ 9,133	$ 5,466,285	58.89%	10.36%	30.58%	0.17%
Espanola Regional Hydro Distribution Corporation	$ 768,750	$ 298,677	$ 122,572	$ -	$ 1,189,999	64.60%	25.10%	10.30%	0.00%
Essex Powerlines Corporation	$ 6,786,809	$ 592,848	$ 2,012,993	$ 62,755	$ 9,455,404	71.78%	6.27%	21.29%	0.66%
Festival Hydro Inc.	$ 5,103,848	$ 1,619,721	$ 2,333,615	$ -	$ 9,057,184	56.35%	17.88%	25.77%	0.00%
Fort Frances Power Corporation	$ 833,635	$ 250,074	$ 360,752	$ 2,912	$ 1,447,372	57.60%	17.28%	24.92%	0.20%
Greater Sudbury Hydro Inc.	$ 12,627,666	$ 3,590,003	$ 5,182,403	$ 84,899	$ 21,484,970	58.77%	16.71%	24.12%	0.40%
Grimsby Power Incorporated	$ 2,414,963	$ 388,562	$ 472,269	$ 5,384	$ 3,281,178	73.60%	11.84%	14.39%	0.16%
Guelph Hydro Electric Systems Inc.	$ 13,114,938	$ 2,824,471	$ 7,236,902	$ 47,550	$ 23,223,860	56.47%	12.16%	31.16%	0.20%
Haldimand County Hydro Inc.	$ 7,584,891	$ 1,775,022	$ 1,773,198	$ 19,713	$ 11,152,824	68.01%	15.92%	15.90%	0.18%
Halton Hills Hydro Inc.	$ 5,365,267	$ 1,013,246	$ 2,474,220	$ 27,346	$ 8,880,079	60.42%	11.41%	27.86%	0.31%
Hearst Power Distribution Company Limited	$ 458,257	$ 134,006	$ 192,367	$ -	$ 784,630	58.40%	17.08%	24.52%	0.00%
Horizon Utilities Corporation	$ 55,192,117	$ 11,711,495	$ 19,998,502	$ -	$ 86,902,114	63.51%	13.48%	23.01%	0.00%
Hydro 2000 Inc.	$ 202,810	$ 80,448	$ 28,113	$ 1,007	$ 312,378	64.92%	25.75%	9.00%	0.32%
Hydro Hawkesbury Inc.	$ 459,030	$ 93,635	$ 158,413	$ 1,203	$ 712,281	64.45%	13.15%	22.24%	0.17%
Hydro One Brampton Networks Inc.	$ 35,076,490	$ 7,199,552	$ 18,585,172	$ -	$ 60,861,214	57.63%	11.83%	30.54%	0.00%
Hydro One Networks Inc.	$ 626,046,000	$ 263,006,000	$ 8,968,000	$ -	$ 898,020,000	69.71%	29.29%	1.00%	0.00%
Hydro Ottawa Limited	$ 80,607,007	$ 18,047,373	$ 44,019,818	$ 536,070	$ 143,210,268	56.29%	12.60%	30.74%	0.37%
Innisfil Hydro Distribution Systems Limited	$ 5,692,353	$ 639,448	$ 750,206	$ 34,074	$ 7,116,080	79.99%	8.99%	10.54%	0.48%
Kenora Hydro Electric Corporation Ltd.	$ 1,189,685	$ 327,550	$ 434,649	$ -	$ 1,951,883	60.95%	16.78%	22.27%	0.00%
Kingston Electricity Distribution Limited	$ 5,323,895	$ 1,849,197	$ 2,295,348	$ 47,426	$ 9,515,866	55.95%	19.43%	24.12%	0.50%
Kitchener-Wilmot Hydro Inc.	$ 16,684,101	$ 4,332,529	$ 10,459,518	$ 153,879	$ 31,630,027	52.75%	13.70%	33.07%	0.49%
Lakefront Utilities Inc.	$ 1,848,574	$ 576,899	$ 1,201,864	$ 31,864	$ 3,659,201	50.52%	15.77%	32.84%	0.87%
Lakeland Power Distribution Ltd.	$ 2,391,505	$ 968,457	$ 855,712	$ 10,568	$ 4,226,243	56.59%	22.92%	20.25%	0.25%
London Hydro Inc.	$ 33,503,321	$ 8,450,169	$ 10,248,092	$ 58,174	$ 52,259,756	64.11%	16.17%	19.61%	0.11%
Middlesex Power Distribution Corporation	$ 2,087,535	$ 282,773	$ 380,152	$ 7,091	$ 2,757,551	75.70%	10.25%	13.79%	0.26%

Name of the LDC	Distribution Revenue from Residential Customers	Distribution Revenue from GS<50 kW Customers	Distribution Revenue from GS>50 kW Customers	Distribution Revenue from Unmetered Customers	Total Distribution Revenue	% of Revenue from Residential Customers	% of Revenue from GS<50 kW Customers	% of Revenue from GS>50 kW Customers	% of Revenue from Unmetered Load Customers
Midland Power Utility Corporation	$ 1,808,381	$ 487,411	$ 766,955	$ 13,743	$ 3,076,490	58.78%	15.84%	24.93%	0.45%
Milton Hydro Distribution Inc.	$ 7,107,078	$ 1,570,851	$ 2,662,035	$ 36,889	$ 11,376,852	62.47%	13.81%	23.40%	0.32%
Newmarket Hydro Ltd.	$ 8,091,758	$ 2,310,777	$ 3,891,854	$ -	$ 14,294,389	56.61%	16.17%	27.23%	0.00%
Niagara Peninsula Energy Inc.	$ 13,491,773	$ 3,364,595	$ 8,581,980	$ 119,866	$ 25,558,213	52.79%	13.16%	33.58%	0.47%
Niagara-on-the-Lake Hydro Inc.	$ 2,214,849	$ 1,095,985	$ 1,115,534	$ 11,951	$ 4,438,318	49.90%	24.69%	25.13%	0.27%
Norfolk Power Distribution Inc.	$ 6,962,430	$ 2,114,481	$ 1,812,098	$ -	$ 10,889,009	63.94%	19.42%	16.64%	0.00%
North Bay Hydro Distribution Limited	$ 5,534,543	$ 1,892,314	$ 2,281,600	$ 9,587	$ 9,718,044	56.95%	19.47%	23.48%	0.10%
Northern Ontario Wires Inc.	$ 1,558,802	$ 427,800	$ 329,251	$ 4,204	$ 2,320,057	67.19%	18.44%	14.19%	0.18%
Oakville Hydro Electricity Distribution Inc.	$ 17,558,909	$ 3,985,324	$ 6,034,339	$ 119,036	$ 27,697,609	63.40%	14.39%	21.79%	0.43%
Orangeville Hydro Limited	$ 2,986,225	$ 705,587	$ 697,577	$ 12,798	$ 4,402,186	67.84%	16.03%	15.85%	0.29%
Orillia Power Distribution Corporation	$ 3,165,109	$ 1,167,744	$ 1,613,116	$ 40,790	$ 5,986,759	52.87%	19.51%	26.94%	0.68%
Oshawa PUC Networks Inc.	$ 10,503,425	$ 2,789,117	$ 4,550,193	$ 66,781	$ 17,909,516	58.65%	15.57%	25.41%	0.37%
Ottawa River Power Corporation	$ 2,025,174	$ 623,517	$ 820,651	$ 9,053	$ 3,478,395	58.22%	17.93%	23.59%	0.26%
Parry Sound Power Corporation	$ 937,164	$ 303,333	$ 418,864	$ 4,210	$ 1,663,572	56.33%	18.23%	25.18%	0.25%
Peterborough Distribution Incorporated	$ 7,729,832	$ 2,153,680	$ 2,860,209	$ 84,857	$ 12,828,578	60.25%	16.79%	22.30%	0.66%
Port Colborne (CNP)	$ 2,843,518	$ 674,350	$ 1,415,139	$ -	$ 4,933,006	57.64%	13.67%	28.69%	0.00%
PowerStream Inc.	$ 77,327,995	$ 21,418,543	$ 42,401,537	$ 438,584	$ 141,586,659	54.62%	15.13%	29.95%	0.31%
PUC Distribution Inc.	$ 8,375,415	$ 2,278,648	$ 3,630,937	$ 24,220	$ 14,309,220	58.53%	15.92%	25.37%	0.17%
Renfrew Hydro Inc.	$ 849,085	$ 247,632	$ 284,351	$ -	$ 1,381,068	61.48%	17.93%	20.59%	0.00%
Rideau St. Lawrence Distribution Inc.	$ 1,156,502	$ 375,059	$ 354,195	$ 16,617	$ 1,902,373	60.79%	19.72%	18.62%	0.87%
Sioux Lookout Hydro Inc.	$ 1,049,004	$ 339,855	$ 308,481	$ 3,620	$ 1,700,959	61.67%	19.98%	18.14%	0.21%
St. Thomas Energy Inc.	$ 742,203	$ 1,076,514	$ 3,861,714	$ 612	$ 5,681,043	13.06%	18.95%	67.98%	0.01%
Thunder Bay Hydro Electricity Distribution Inc.	$ 10,704,867	$ 2,675,518	$ 3,093,591	$ 134,844	$ 16,608,820	64.45%	16.11%	18.63%	0.81%
Tillsonburg Hydro Inc.	$ 1,653,970	$ 500,966	$ 495,519	$ 18,514	$ 2,668,968	61.97%	18.77%	18.57%	0.69%
Toronto Hydro-Electric System Limited	$ 193,430,604	$ 60,336,439	$ 201,544,335	$ 2,449,890	$ 457,761,268	42.26%	13.18%	44.03%	0.54%
Veridian Connections Inc.	$ 27,976,891	$ 6,464,083	$ 8,935,284	$ 181,472	$ 43,557,730	64.23%	14.84%	20.51%	0.42%
Wasaga Distribution Inc.	$ 2,752,651	$ 340,326	$ 275,966	$ 2,240	$ 3,371,183	81.65%	10.10%	8.19%	0.07%
Waterloo North Hydro Inc.	$ 13,521,851	$ 3,777,338	$ 7,382,623	$ 120,883	$ 24,802,695	54.52%	15.23%	29.77%	0.49%
Welland Hydro-Electric System Corp.	$ 5,402,478	$ 902,878	$ 1,441,330	$ 41,404	$ 7,788,090	69.37%	11.59%	18.51%	0.53%
Wellington North Power Inc.	$ 865,937	$ 297,891	$ 559,777	$ 218	$ 1,723,824	50.23%	17.28%	32.47%	0.01%
West Coast Huron Energy Inc.	$ 899,422	$ 313,302	$ 793,795	$ 3,352	$ 2,009,871	44.75%	15.59%	39.49%	0.17%
West Perth Power Inc.	$ 414,577	$ 138,361	$ 194,019	$ 68	$ 747,025	55.50%	18.52%	25.97%	0.01%
Westario Power Inc.	$ 4,543,177	$ 1,276,314	$ 1,886,930	$ 23,596	$ 7,730,017	58.77%	16.51%	24.41%	0.31%
Whitby Hydro Electric Corporation	$ 11,826,831	$ 1,715,967	$ 3,766,927	$ 123,686	$ 17,433,411	67.84%	9.84%	21.61%	0.71%
Woodstock Hydro Services Inc.	$ 3,851,591	$ 825,248	$ 1,585,466	$ 8,113	$ 6,270,417	61.42%	13.16%	25.28%	0.13%
Total	$ 1,527,323,258	$ 499,993,896	$ 568,300,791	$ 6,381,811	$ 2,601,999,756	58.70%	19.22%	21.84%	0.25%

Name of the LDC	Number of Residential Customers	Number of GS< 50kW Customers	Number of GS > 50kW Customers	Number of Large User Customers	Number of Sub Transmission	Total Number of > 50 kw; large user and sub transmission customers	Total Number of Metered Customers	Number of Connections (Unmetered class)	Total Number of All Customers including Unmetered
Algoma Power Inc.	10,630	1,010	47	1	0	48	11,688	0	11,688
Atikokan Hydro Inc.	1,415	225	22	0	0	22	1,662	8	1,670
Bluewater Power Distribution Corporation	31,420	3,505	395	3	0	398	35,323	257	35,580
Brant County Power Inc.	8,171	1,286	106	0	0	106	9,563	51	9,614
Brantford Power Inc.	34,089	2,721	413	0	0	413	37,223	445	37,668
Burlington Hydro Inc.	57,578	4,974	980	0	0	980	63,532	26	63,558
Cambridge and North Dumfries Hydro Inc.	44,805	4,620	709	2	0	711	50,136	65	50,201
Canadian Niagara Power Inc.	14,248	1,228	131	0	0	131	15,607	0	15,607
Centre Wellington Hydro Ltd.	5,603	714	63	0	0	63	6,380	2	6,382
Chapleau Public Utilities Corporation	1,144	162	14	0	0	14	1,320	6	1,326
Chatham-Kent Hydro Inc.	28,463	3,102	410	1	0	411	31,976	192	32,168
Clinton Power Corporation	1,411	221	17	0	0	17	1,649	11	1,660
COLLUS Power Corporation	13,152	1,609	116	1	0	117	14,878	30	14,908
Cooperative Hydro Embrun Inc.	1,757	172	12	0	0	12	1,941	0	1,941
E.L.K. Energy Inc.	9,843	1,148	121	0	0	121	11,112	0	11,112
Eastern Ontario Power Inc.	3,104	422	34	0	0	34	3,560	0	3,560
Enersource Hydro Mississauga Inc.	168,288	16,800	4,442	10	0	4,452	189,540	198	189,738
EnWin Utilities Ltd.	76,528	6,981	1,178	10	0	1,188	84,697	29	84,726
Erie Thames Powerlines Corporation	12,550	1,234	146	2	3	151	13,935	105	14,040
Espanola Regional Hydro Distribution Corporation	2,857	477	25	0	0	25	3,359	24	3,383
Essex Powerlines Corporation	25,817	2,015	222	0	0	222	28,054	148	28,202
Festival Hydro Inc.	17,311	2,009	209	2	0	211	19,531	0	19,531
Fort Frances Power Corporation	3,296	418	47	0	0	47	3,761	7	3,768
Greater Sudbury Hydro Inc.	41,926	3,911	512	0	0	512	46,349	190	46,539
Grimsby Power Incorporated	9,222	669	101	0	0	101	9,992	81	10,073
Guelph Hydro Electric Systems Inc.	45,023	3,650	582	4	0	586	49,259	40	49,299
Haldimand County Hydro Inc.	18,309	2,381	137	0	0	137	20,827	84	20,911
Halton Hills Hydro Inc.	18,924	1,913	207	0	0	207	21,044	140	21,184
Hearst Power Distribution Company Limited	2,332	388	44	0	0	44	2,764	0	2,764
Horizon Utilities Corporation	212,580	19,858	2,216	12	0	2,228	234,666	0	234,666
Hydro 2000 Inc.	1,027	140	11	0	0	11	1,178	6	1,184
Hydro Hawkesbury Inc.	4,781	586	81	1	0	82	5,449	4	5,453
Hydro One Brampton Networks Inc.	121,692	7,684	1,645	6	0	1,651	131,027	0	131,027
Hydro One Networks Inc.	1,084,186	109,208	0	0	373	373	1,193,767	0	1,193,767
Hydro Ottawa Limited	269,288	23,338	3,370	11	0	3,381	296,007	2,848	298,855
Innisfil Hydro Distribution Systems Limited	13,636	855	72	0	0	72	14,563	82	14,645
Kenora Hydro Electric Corporation Ltd.	4,777	733	69	0	0	69	5,579	0	5,579
Kingston Hydro Corporation	23,223	3,255	351	3	0	354	26,832	159	26,991
Kitchener-Wilmot Hydro Inc.	76,755	7,425	992	2	0	994	85,174	824	85,998
Lakefront Utilities Inc.	8,243	1,065	132	0	0	132	9,440	94	9,534
Lakeland Power Distribution Ltd.	7,697	1,547	100	0	0	100	9,344	43	9,387
London Hydro Inc.	131,734	11,914	1,647	3	0	1,650	145,298	1,489	146,787
Middlesex Power Distribution Corporation	6,984	780	95	1	0	96	7,860	51	7,911

Name of the LDC	Number of Residential Customers	Number of GS< 50kW Customers	Number of GS > 50kW Customers	Number of Large User Customers	Number of Sub Transmission	Total Number of > 50 kw; large user and sub transmission customers	Total Number of Metered Customers	Number of Connections (Unmetered class)	Total Number of All Customers including Unmetered
Midland Power Utility Corporation	6,052	729	112	0	0	112	6,893	12	6,905
Milton Hydro Distribution Inc.	24,832	2,203	286	2	0	288	27,323	183	27,506
Newmarket - Tay Power Distribution Ltd.	29,138	2,893	398	0	0	398	32,429	398	32,827
Niagara Peninsula Energy Inc.	45,167	4,389	847	0	0	847	50,403	420	50,823
Niagara-on-the-Lake Hydro Inc.	6,507	1,230	121	0	0	121	7,858	22	7,880
Norfolk Power Distribution Inc.	16,653	2,071	169	0	0	169	18,893	2	18,895
North Bay Hydro Distribution Limited	20,850	2,629	276	0	0	276	23,755	21	23,776
Northern Ontario Wires Inc.	5,179	798	73	0	0	73	6,050	19	6,069
Oakville Hydro Electricity Distribution Inc.	56,419	4,887	873	0	0	873	62,179	679	62,858
Orangeville Hydro Limited	9,814	1,148	129	0	0	129	11,091	35	11,126
Orillia Power Distribution Corporation	11,296	1,359	154	0	0	154	12,809	153	12,962
Oshawa PUC Networks Inc.	47,769	3,897	517	1	0	518	52,184	304	52,488
Ottawa River Power Corporation	8,851	1,394	144	0	0	144	10,389	73	10,462
Parry Sound Power Corporation	2,751	540	68	0	0	68	3,359	19	3,378
Peterborough Distribution Incorporated	30,680	3,609	363	2	0	365	34,654	383	35,037
Port Colborne Hydro Inc.	8,170	874	80	0	0	80	9,124	0	9,124
PowerStream Inc.	283,665	29,594	4,654	1	0	4,655	317,914	2,781	320,695
PUC Distribution Inc.	29,028	3,341	439	0	0	439	32,808	17	32,825
Renfrew Hydro Inc.	3,613	503	64	0	0	64	4,180	0	4,180
Rideau St. Lawrence Distribution Inc.	4,974	774	66	0	0	66	5,814	49	5,863
Sioux Lookout Hydro Inc.	2,296	392	39	0	0	39	2,727	13	2,740
St. Thomas Energy Inc.	14,374	1,672	192	0	0	192	16,238	5	16,243
Thunder Bay Hydro Electricity Distribution Inc.	44,443	4,486	524	0	0	524	49,453	469	49,922
Tillsonburg Hydro Inc.	5,907	675	87	0	0	87	6,669	69	6,738
Toronto Hydro-Electric System Limited	611,357	64,781	12,953	47	0	13,000	689,138	1,105	690,243
Veridian Connections Inc.	101,547	8,501	1,049	4	0	1,053	111,101	893	111,994
Wasaga Distribution Inc.	11,010	801	33	0	0	33	11,844	25	11,869
Waterloo North Hydro Inc.	45,113	5,300	661	1	0	662	51,075	14	51,089
Welland Hydro-Electric System Corp.	19,803	1,725	172	2	0	174	21,702	214	21,916
Wellington North Power Inc.	3,056	480	49	0	0	49	3,585	3	3,588
West Coast Huron Energy Inc.	3,231	474	53	1	0	54	3,759	4	3,763
West Perth Power Inc.	1,786	241	20	0	0	20	2,047	5	2,052
Westario Power Inc.	19,033	2,435	276	0	0	276	21,744	61	21,805
Whitby Hydro Electric Corporation	36,762	1,926	435	0	0	435	39,123	390	39,513
Woodstock Hydro Services Inc.	13,429	1,170	200	0	0	200	14,799	39	14,838
Total	4,260,374	422,274	48,799	136	376	49,311	4,731,959	16,618	4,748,577

Name of the LDC	Total Settlement Amount Allocation by LDC	Settlement Amount Allocation to each Class of Customers Based on Class Distribution Revenue				Settlement Amount Allocation per Customer				Allocation per Customer per month over a period of 12 months			
		Residential	GS<50KW	GS>50KW	Unmetered Class	Residential	GS<50KW	GS>50KW	Unmetered Class	Residential	GS<50KW	GS>50KW	Unmetered Class
Algoma Power Inc.	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Atikokan Hydro Inc.	$7,567.85	$4,924.53	$1,811.07	$661.51	$170.74	$3.48	$8.05	$30.07	$21.34	$0.29	$0.67	$2.51	$1.78
Bluewater Power Distribution Corporation	$149,121.96	$82,797.37	$25,316.31	$40,156.40	$851.87	$2.64	$7.22	$100.90	$3.31	$0.22	$0.60	$8.41	$0.28
Brant County Power Inc.	$41,665.21	$20,930.85	$7,060.40	$13,562.87	$111.08	$2.56	$5.49	$127.95	$2.18	$0.21	$0.46	$10.66	$0.18
Brantford Power Inc.	$126,681.66	$70,839.24	$11,994.64	$43,152.92	$694.85	$2.08	$4.41	$104.49	$1.56	$0.17	$0.37	$8.71	$0.13
Burlington Hydro Inc.	$229,874.32	$142,064.24	$32,765.26	$53,957.00	$1,087.82	$2.47	$6.59	$55.06	$41.84	$0.21	$0.55	$4.59	$3.49
Cambridge and North Dumfries Hydro Inc.	$194,554.99	$95,450.30	$26,449.00	$71,988.76	$666.93	$2.13	$5.72	$101.25	$10.26	$0.18	$0.48	$8.44	$0.86
Canadian Niagara Power Inc.	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Centre Wellington Hydro Ltd.	$25,370.61	$14,794.75	$4,654.25	$5,826.50	$95.11	$2.64	$6.52	$92.48	$47.55	$0.22	$0.54	$7.71	$3.96
Chapleau Public Utilities Corporation	$5,314.22	$3,649.33	$1,064.47	$586.77	$13.66	$3.19	$6.57	$41.91	$2.28	$0.27	$0.55	$3.49	$0.19
Chatham-Kent Hydro Inc.	$134,064.08	$82,892.83	$21,349.10	$29,696.32	$125.83	$2.91	$6.88	$72.25	$0.66	$0.24	$0.57	$6.02	$0.05
Clinton Power Corporation	$4,702.32	$2,650.81	$935.17	$1,099.90	$16.44	$1.88	$4.23	$64.70	$1.49	$0.16	$0.35	$5.39	$0.12
COLLUS Power Corporation	$46,485.63	$32,518.45	$7,637.64	$6,253.00	$76.55	$2.47	$4.75	$53.44	$2.55	$0.21	$0.40	$4.45	$0.21
Cooperative Hydro Embrun Inc.	$4,271.79	$3,111.55	$679.51	$480.73	$0.00	$1.77	$3.95	$40.06	$0.00	$0.15	$0.33	$3.34	$0.00
E.L.K. Energy Inc.	$28,387.69	$15,787.36	$1,560.85	$11,039.48	$0.00	$1.60	$1.36	$91.24	$0.00	$0.13	$0.11	$7.60	$0.00
Eastern Ontario Power Inc.	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Enersource Hydro Mississauga Inc.	$1,006,252.86	$398,524.92	$136,662.80	$466,435.64	$4,629.50	$2.37	$8.13	$104.77	$23.38	$0.20	$0.68	$8.73	$1.95
EnWin Utilities Ltd.	$434,442.75	$209,872.24	$54,620.05	$168,491.63	$1,458.83	$2.74	$7.82	$141.83	$50.30	$0.23	$0.65	$11.82	$4.19
Erie Thames Powerlines Corporation	$55,928.58	$32,938.82	$5,791.65	$17,104.68	$93.45	$2.62	$4.69	$113.28	$0.89	$0.22	$0.39	$9.44	$0.07
Espanola Regional Hydro Distribution Corporation	$9,905.46	$6,399.02	$2,486.17	$1,020.28	$0.00	$2.24	$5.21	$40.81	$0.00	$0.19	$0.43	$3.40	$0.00
Essex Powerlines Corporation	$75,617.88	$54,276.27	$4,741.19	$16,098.55	$501.87	$2.10	$2.35	$72.52	$3.39	$0.18	$0.20	$6.04	$0.28
Festival Hydro Inc.	$87,054.58	$49,056.45	$15,568.20	$22,429.92	$0.00	$2.83	$7.75	$106.30	$0.00	$0.24	$0.65	$8.86	$0.00
Fort Frances Power Corporation	$9,076.63	$5,227.81	$1,568.24	$2,262.31	$18.26	$1.59	$3.75	$48.13	$2.61	$0.13	$0.31	$4.01	$0.22
Greater Sudbury Hydro Inc.	$149,791.41	$88,039.03	$25,029.20	$36,131.28	$591.91	$2.10	$6.40	$70.57	$3.12	$0.17	$0.53	$5.88	$0.26
Grimsby Power Incorporated	$23,236.06	$17,101.85	$2,751.65	$3,344.43	$38.13	$1.85	$4.11	$33.11	$0.47	$0.15	$0.34	$2.76	$0.04
Guelph Hydro Electric Systems Inc.	$207,326.43	$117,081.02	$25,214.90	$64,606.02	$424.49	$2.60	$6.91	$110.25	$10.61	$0.22	$0.58	$9.19	$0.88
Haldimand County Hydro Inc.	$52,104.38	$35,435.51	$8,292.65	$8,284.12	$92.10	$1.94	$3.48	$60.47	$1.10	$0.16	$0.29	$5.04	$0.09
Halton Hills Hydro Inc.	$62,839.79	$37,967.26	$7,170.23	$17,508.79	$193.51	$2.01	$3.75	$84.58	$1.38	$0.17	$0.31	$7.05	$0.12
Hearst Power Distribution Company Limited	$14,889.32	$8,695.99	$2,542.93	$3,650.41	$0.00	$3.73	$6.55	$82.96	$0.00	$0.31	$0.55	$6.91	$0.00
Horizon Utilities Corporation	$1,102,335.23	$700,100.52	$148,557.87	$253,676.83	$0.00	$3.29	$7.48	$113.86	$0.00	$0.27	$0.62	$9.49	$0.00
Hydro 2000 Inc.	$3,858.70	$2,505.24	$993.75	$347.27	$12.44	$2.44	$7.10	$31.57	$2.07	$0.20	$0.59	$2.63	$0.17
Hydro Hawkesbury Inc.	$26,420.72	$17,026.85	$3,473.21	$5,876.03	$44.62	$3.56	$5.93	$71.66	$11.16	$0.30	$0.49	$5.97	$0.93
Hydro One Brampton Networks Inc.	$444,880.45	$256,400.49	$52,626.95	$135,853.02	$0.00	$2.11	$6.85	$82.29	$0.00	$0.18	$0.57	$6.86	$0.00
Hydro One Networks Inc.	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Hydro Ottawa Limited	$1,020,856.03	$574,596.71	$128,648.38	$313,789.63	$3,821.31	$2.13	$5.51	$92.81	$1.34	$0.18	$0.46	$7.73	$0.11
Innisfil Hydro Distribution Systems Limited	$33,430.63	$26,742.10	$3,004.06	$3,524.39	$160.08	$1.96	$3.51	$48.95	$1.95	$0.16	$0.29	$4.08	$0.16
Kenora Hydro Electric Corporation Ltd.	$16,296.32	$9,932.71	$2,734.72	$3,628.89	$0.00	$2.08	$3.73	$52.59	$0.00	$0.17	$0.31	$4.38	$0.00
Kingston Hydro Corporation	$104,031.09	$58,202.86	$20,216.13	$25,093.63	$518.48	$2.51	$6.21	$70.89	$3.26	$0.21	$0.52	$5.91	$0.27
Kitchener-Wilmot Hydro Inc.	$271,910.14	$143,426.25	$37,244.95	$89,916.11	$1,322.84	$1.87	$5.02	$90.46	$1.61	$0.16	$0.42	$7.54	$0.13
Lakefront Utilities Inc.	$36,872.16	$18,627.27	$5,813.16	$12,110.66	$321.08	$2.26	$5.46	$91.75	$3.42	$0.19	$0.45	$7.65	$0.28
Lakeland Power Distribution Ltd.	$31,478.25	$17,812.60	$7,213.34	$6,373.59	$78.72	$2.31	$4.66	$63.74	$1.83	$0.19	$0.39	$5.31	$0.15
London Hydro Inc.	$457,241.98	$293,134.26	$73,933.98	$89,664.75	$508.99	$2.23	$6.21	$54.34	$0.34	$0.19	$0.52	$4.53	$0.03
Middlesex Power Distribution Corporation	$26,337.49	$19,938.14	$2,700.78	$3,630.85	$67.73	$2.85	$3.46	$37.82	$1.33	$0.24	$0.29	$3.15	$0.11
Midland Power Utility Corporation	$31,756.33	$18,666.58	$5,031.18	$7,916.71	$141.86	$3.08	$6.90	$70.68	$11.82	$0.26	$0.58	$5.89	$0.99
Milton Hydro Distribution Inc.	$74,673.59	$46,648.32	$10,310.50	$17,472.64	$242.12	$1.88	$4.68	$60.67	$1.32	$0.16	$0.39	$5.06	$0.11
Newmarket - Tay Power Distribution Ltd.	$95,325.31	$53,961.68	$15,409.93	$25,953.69	$0.00	$1.85	$5.33	$65.21	$0.00	$0.15	$0.44	$5.43	$0.00
Niagara Peninsula Energy Inc.	$167,381.05	$88,357.79	$22,034.77	$56,203.49	$785.00	$1.96	$5.02	$66.36	$1.87	$0.16	$0.42	$5.53	$0.16
Niagara-on-the-Lake Hydro Inc.	$24,800.65	$12,376.24	$6,124.20	$6,233.43	$66.78	$1.90	$4.98	$51.52	$3.04	$0.16	$0.41	$4.29	$0.25
Norfolk Power Distribution Inc.	$55,876.38	$35,727.34	$10,850.35	$9,298.68	$0.00	$2.15	$5.24	$55.02	$0.00	$0.18	$0.44	$4.59	$0.00
North Bay Hydro Distribution Limited	$87,552.60	$49,862.26	$17,048.39	$20,555.58	$86.37	$2.39	$6.48	$74.48	$4.11	$0.20	$0.54	$6.21	$0.34
Northern Ontario Wires Inc.	$21,401.32	$14,379.14	$3,946.23	$3,037.17	$38.78	$2.78	$4.95	$41.61	$2.04	$0.23	$0.41	$3.47	$0.17
Oakville Hydro Electricity Distribution Inc.	$257,572.31	$163,288.06	$37,061.29	$56,115.99	$1,106.97	$2.89	$7.58	$64.28	$1.63	$0.24	$0.63	$5.36	$0.14
Orangeville Hydro Limited	$34,423.12	$23,350.94	$5,517.37	$5,454.74	$100.07	$2.38	$4.81	$42.28	$2.86	$0.20	$0.40	$3.52	$0.24
Orillia Power Distribution Corporation	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oshawa PUC Networks Inc.	$171,994.93	$100,870.17	$26,785.42	$43,698.01	$641.33	$2.11	$6.87	$84.36	$2.11	$0.18	$0.57	$7.03	$0.18
Ottawa River Power Corporation	$28,419.68	$16,546.37	$5,094.35	$6,705.00	$73.97	$1.87	$3.65	$46.56	$1.01	$0.16	$0.30	$3.88	$0.08
Parry Sound Power Corporation	$12,414.74	$6,993.77	$2,263.68	$3,125.86	$31.42	$2.54	$4.19	$45.97	$1.65	$0.21	$0.35	$3.83	$0.14
Peterborough Distribution Incorporated	$110,277.91	$66,447.72	$18,513.61	$24,587.13	$729.45	$2.17	$5.13	$67.36	$1.90	$0.18	$0.43	$5.61	$0.16
Port Colborne Hydro Inc.	$28,872.42	$16,642.84	$3,946.90	$8,282.67	$0.00	$2.04	$4.52	$103.53	$0.00	$0.17	$0.38	$8.63	$0.00
PowerStream Inc.	$1,019,321.62	$556,705.68	$154,198.03	$305,260.42	$3,157.49	$1.96	$5.21	$65.58	$1.14	$0.16	$0.43	$5.46	$0.09
PUC Distribution Inc.	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Renfrew Hydro Inc.	$14,453.29	$8,885.93	$2,591.54	$2,975.82	$0.00	$2.46	$5.15	$46.50	$0.00	$0.20	$0.43	$3.87	$0.00

Name of the LDC	Total Settlement Amount Allocation by LDC	Settlement Amount Allocation to each Class of Customers Based on Class Distribution Revenue				Settlement Amount Allocation per Customer				Allocation per Customer per month over a period of 12 months			
		Residential	GS<50KW	GS>50KW	Unmetered Class	Residential	GS<50KW	GS>50KW	Unmetered Class	Residential	GS<50KW	GS>50KW	Unmetered Class
Rideau St. Lawrence Distribution Inc.	$18,391.97	$11,180.96	$3,626.04	$3,424.32	$160.65	$2.25	$4.68	$51.88	$3.28	$0.19	$0.39	$4.32	$0.27
Sioux Lookout Hydro Inc.	$12,422.98	$7,661.41	$2,482.13	$2,252.99	$26.44	$3.34	$6.33	$57.77	$2.03	$0.28	$0.53	$4.81	$0.17
St. Thomas Energy Inc.	$52,622.33	$6,874.88	$9,971.53	$35,770.26	$5.66	$0.48	$5.96	$186.30	$1.13	$0.04	$0.50	$15.53	$0.09
Thunder Bay Hydro Electricity Distribution Inc.	$160,239.21	$103,278.83	$25,812.97	$29,846.46	$1,300.95	$2.32	$5.75	$56.96	$2.77	$0.19	$0.48	$4.75	$0.23
Tillsonburg Hydro Inc.	$29,932.56	$18,549.32	$5,618.35	$5,557.26	$207.63	$3.14	$8.32	$63.88	$3.01	$0.26	$0.69	$5.32	$0.25
Toronto Hydro-Electric System Limited	$7,525,588.82	$3,179,996.42	$991,930.21	$3,313,386.04	$40,276.16	$5.20	$15.31	$254.88	$36.45	$0.43	$1.28	$21.24	$3.04
Veridian Connections Inc.	$345,325.31	$221,800.55	$51,247.19	$70,838.86	$1,438.71	$2.18	$6.03	$67.27	$1.61	$0.18	$0.50	$5.61	$0.13
Wasaga Distribution Inc.	$14,942.12	$12,200.60	$1,508.43	$1,223.17	$9.93	$1.11	$1.88	$37.07	$0.40	$0.09	$0.16	$3.09	$0.03
Waterloo North Hydro Inc.	$173,479.23	$94,576.83	$26,420.10	$51,636.80	$845.50	$2.10	$4.98	$78.00	$60.39	$0.17	$0.42	$6.50	$5.03
Welland Hydro-Electric System Corp.	$74,531.55	$51,701.39	$8,640.49	$13,793.44	$396.23	$2.61	$5.01	$79.27	$1.85	$0.22	$0.42	$6.61	$0.15
Wellington North Power Inc.	$11,517.59	$5,785.69	$1,990.34	$3,740.11	$1.46	$1.89	$4.15	$76.33	$0.49	$0.16	$0.35	$6.36	$0.04
West Coast Huron Energy Inc.	$18,419.16	$8,242.62	$2,871.21	$7,274.61	$30.72	$2.55	$6.06	$134.72	$7.68	$0.21	$0.50	$11.23	$0.64
West Perth Power Inc.	$8,514.12	$4,725.08	$1,576.95	$2,211.31	$0.77	$2.65	$6.54	$110.57	$0.15	$0.22	$0.55	$9.21	$0.01
Westario Power Inc.	$63,697.60	$37,437.11	$10,517.20	$15,548.86	$194.44	$1.97	$4.32	$56.34	$3.19	$0.16	$0.36	$4.69	$0.27
Whitby Hydro Electric Corporation	$124,544.36	$84,490.93	$12,258.87	$26,910.94	$883.61	$2.30	$6.36	$61.86	$2.27	$0.19	$0.53	$5.16	$0.19
Woodstock Hydro Services Inc.	$57,743.72	$35,468.96	$7,599.63	$14,600.41	$74.71	$2.64	$6.50	$73.00	$1.92	$0.22	$0.54	$6.08	$0.16
Total or Average	$17,690,907.53	$8,935,156.18	$2,433,678.22	$6,250,208.75	$71,864.38	$2.20	$5.16	$69.82	$5.46	$0.18	$0.43	$5.82	$0.45

Name of the LDC	Residential Electricity Bill (May to October 2010) Excluding HST	Bill Impacts excluding HST (Allocation By Class Distribution Revenue)	Bill Impacts excluding HST (Allocation By Customer Numbers - All Metered customers)	Bill Impacts excluding HST (Allocation By Customer Numbers - Including Unmetered customers)
Algoma Power Inc.				
Atikokan Hydro Inc.	$116.75	0.25%	0.33%	0.32%
Bluewater Power Distribution Corporation	$104.31	0.21%	0.34%	0.33%
Brant County Power Inc.	$106.16	0.20%	0.34%	0.34%
Brantford Power Inc.	$100.00	0.17%	0.28%	0.28%
Burlington Hydro Inc.	$103.76	0.20%	0.29%	0.29%
Cambridge and North Dumfries Hydro Inc.	$94.29	0.19%	0.34%	0.34%
Canadian Niagara Power Inc.				
Centre Wellington Hydro Ltd.	$100.82	0.22%	0.33%	0.33%
Chapleau Public Utilities Corporation	$100.26	0.27%	0.33%	0.33%
Chatham-Kent Hydro Inc.	$101.01	0.24%	0.35%	0.34%
Clinton Power Corporation	$94.40	0.17%	0.25%	0.25%
COLLUS Power Corporation	$101.25	0.20%	0.26%	0.26%
Cooperative Hydro Embrun Inc.	$103.69	0.14%	0.18%	0.18%
E.L.K. Energy Inc.	$100.75	0.13%	0.21%	0.21%
Eastern Ontario Power Inc.				
Enersource Hydro Mississauga Inc.	$100.48	0.20%	0.44%	0.44%
EnWin Utilities Ltd.	$102.92	0.22%	0.42%	0.42%
Erie Thames Powerlines Corporation	$104.26	0.21%	0.32%	0.32%
Espanola Regional Hydro Distribution Corporation	$101.14	0.18%	0.24%	0.24%
Essex Powerlines Corporation	$105.06	0.17%	0.21%	0.21%
Festival Hydro Inc.	$104.16	0.23%	0.36%	0.36%
Fort Frances Power Corporation	$91.46	0.14%	0.22%	0.22%
Greater Sudbury Hydro Inc.	$103.01	0.17%	0.26%	0.26%
Grimsby Power Incorporated	$94.80	0.16%	0.20%	0.20%
Guelph Hydro Electric Systems Inc.	$103.37	0.21%	0.34%	0.34%
Haldimand County Hydro Inc.	$119.95	0.13%	0.17%	0.17%
Halton Hills Hydro Inc.	$101.67	0.16%	0.24%	0.24%

Name of the LDC	Residential Electricity Bill (May to October 2010) Excluding HST	Bill Impacts excluding HST (Allocation By Class Distribution Revenue)	Bill Impacts excluding HST (Allocation By Customer Numbers - All Metered customers)	Bill Impacts excluding HST (Allocation By Customer Numbers - Including Unmetered customers)
Hearst Power Distribution Company Limited	$92.89	0.33%	0.48%	0.48%
Horizon Utilities Corporation	$99.73	0.28%	0.39%	0.39%
Hydro 2000 Inc.	$101.50	0.20%	0.27%	0.27%
Hydro Hawkesbury Inc.	$86.84	0.34%	0.47%	0.46%
Hydro One Brampton Networks Inc.	$99.28	0.18%	0.28%	0.28%
Hydro One Networks Inc.				
Hydro Ottawa Limited	$103.47	0.17%	0.28%	0.28%
Innisfil Hydro Distribution Systems Limited	$118.98	0.14%	0.16%	0.16%
Kenora Hydro Electric Corporation Ltd.	$96.87	0.18%	0.25%	0.25%
Kingston Hydro Corporation	$94.96	0.22%	0.34%	0.34%
Kitchener-Wilmot Hydro Inc.	$95.50	0.16%	0.28%	0.28%
Lakefront Utilities Inc.	$100.54	0.19%	0.32%	0.32%
Lakeland Power Distribution Ltd.	$107.26	0.18%	0.26%	0.26%
London Hydro Inc.	$101.17	0.18%	0.26%	0.26%
Middlesex Power Distribution Corporation	$103.29	0.23%	0.27%	0.27%
Midland Power Utility Corporation	$107.67	0.24%	0.36%	0.36%
Milton Hydro Distribution Inc.	$99.66	0.16%	0.23%	0.23%
Newmarket - Tay Power Distribution Ltd.	$102.81	0.15%	0.24%	0.24%
Niagara Peninsula Energy Inc.	$103.09	0.16%	0.27%	0.27%
Niagara-on-the-Lake Hydro Inc.	$102.39	0.15%	0.26%	0.26%
Norfolk Power Distribution Inc.	$114.96	0.16%	0.21%	0.21%
North Bay Hydro Distribution Limited	$103.41	0.19%	0.30%	0.30%
Northern Ontario Wires Inc.	$105.65	0.22%	0.28%	0.28%
Oakville Hydro Electricity Distribution Inc.	$101.95	0.24%	0.34%	0.33%
Orangeville Hydro Limited	$103.49	0.19%	0.25%	0.25%
Orillia Power Distribution Corporation				
Oshawa PUC Networks Inc.	$96.98	0.18%	0.28%	0.28%
Ottawa River Power Corporation	$97.05	0.16%	0.23%	0.23%

Name of the LDC	Residential Electricity Bill (May to October 2010) Excluding HST	Bill Impacts excluding HST (Allocation By Class Distribution Revenue)	Bill Impacts excluding HST (Allocation By Customer Numbers - All Metered customers)	Bill Impacts excluding HST (Allocation By Customer Numbers - Including Unmetered customers)
Parry Sound Power Corporation	$103.73	0.20%	0.30%	0.30%
Peterborough Distribution Incorporated	$99.11	0.18%	0.27%	0.26%
Port Colborne Hydro Inc.	$116.47	0.15%	0.23%	0.23%
PowerStream Inc.	$96.76	0.17%	0.28%	0.27%
PUC Distribution Inc.				
Renfrew Hydro Inc.	$100.66	0.20%	0.29%	0.29%
Rideau St. Lawrence Distribution Inc.	$102.57	0.18%	0.26%	0.25%
Sioux Lookout Hydro Inc.	$111.59	0.25%	0.34%	0.34%
St. Thomas Energy Inc.	$100.00	0.04%	0.27%	0.27%
Thunder Bay Hydro Electricity Distribution Inc.	$97.48	0.20%	0.28%	0.27%
Tillsonburg Hydro Inc.	$102.23	0.26%	0.37%	0.36%
Toronto Hydro-Electric System Limited	$108.16	0.40%	0.84%	0.84%
Veridian Connections Inc.	$96.95	0.19%	0.27%	0.27%
Wasaga Distribution Inc.	$99.79	0.09%	0.11%	0.11%
Waterloo North Hydro Inc.	$99.18	0.18%	0.29%	0.29%
Welland Hydro-Electric System Corp.	$105.75	0.21%	0.27%	0.27%
Wellington North Power Inc.	$101.84	0.15%	0.26%	0.26%
West Coast Huron Energy Inc.	$101.72	0.21%	0.40%	0.40%
West Perth Power Inc.	$100.44	0.22%	0.35%	0.34%
Westario Power Inc.	$104.55	0.16%	0.23%	0.23%
Whitby Hydro Electric Corporation	$106.54	0.18%	0.25%	0.25%
Woodstock Hydro Services Inc.	$104.09	0.21%	0.31%	0.31%
Average		0.19%	0.30%	0.29%

**Answer to Interrogatory from
Board Staff**

Question 9:

Reference(s): None provided.

In paragraph 67 the EDA states that the Allocated Amount should be recovered through a monthly fixed charge on distribution rates over 12 months from January 1, 2011 to December 31, 2011 for LDCs with distribution rates effective January 1, 2011 and from May 1, 2011 to April 30, 2012 for all LDCs

(i) Please identify the Affected Distributors in each category.

(ii) If the Board were to allow a recovery effective May 1, 2011 for both categories of distributors, please identify the EDA's concerns if any of such an approach.

Answer:

(i) The EDA is aware that some LDCs were seeking a January 1, 2011 rate year, but does not have accurate information in this regard.

(ii) The EDA appreciates that a single effective period would be a simpler approach for most utilities. However, for those utilities with rates commencing January 1, a May 1 implementation date would create two off-cycle, isolated rate changes, necessitating two additional customer notifications of rate changes and two additional issuances of tariffs by the Board for each such utility. This approach would be unnecessarily expensive and potentially irritating to customers. The EDA therefore recommends that the Board allow LDCs the option to have implementation (and termination) of rate riders coincide with the principal distribution rate change dates of each utility.

Answer to Interrogatory from
Board Staff

Question 10:

Reference(s): None provided.

In paragraph 69 the EDA states "A rate rider could be developed on a generic basis for all LDCs or each LDC could calculate the rate rider based upon a common methodology".

(i) It appears to staff that the approach proposed by the EDA is the latter - that is, "each LDC calculates a rate rider based on a common methodology". Is staffs' understanding correct? If not, please clarify.

(ii) Please clarify what is meant by "A rate rider could be developed on a generic basis for all LDCs". In your response please elaborate on how such an approach would be applied.

Answer:

(i) Staffs' understanding is correct, it is proposed that each LDC calculate a rate rider based upon a common methodology. For further clarification, the EDA did not understand from the Board's Procedural Order #1 or from the approved Issues List that rates *per se* would necessarily be determined for every Affected Electricity Distributor in the course of this proceeding. Both the EDA and THESL understand that the scope of this hearing is to determine the recoverability of the Updated Recovery Amount, and if found to be recoverable, the <u>methodology</u> under which recovery would be effected. Depending on the recovery methodology determined by the Board, establishment of the rate rider could occur within this proceeding or could take place within individual rate proceedings.

A range of recovery options is available to the Board. For example, the Board could determine a uniform rate rider for all LDCs. To accommodate the variation in the amounts to be recovered, the effective period for the rider could be allowed to vary. In all cases, LDCs would track actual recoveries opposite their actual Updated Recovery Amounts in the proposed variance account and any residual difference would be reserved for future disposition. Under this option, the Board could determine the rate rider in this proceeding.

Were the Board to find that the rate riders should vary between LDCs, then more information than is available in this proceeding would be required to determine the individual rate riders. In that case, determination of rate riders for individual LDCs would take place, according to the methodology determined in this proceeding, in the context of individual LDC rate applications.

(ii) A rate rider could be developed on a generic basis for all LDCs if a uniform rate per customer is applied. The uniform rate, applicable to customers of all Affected Electricity Distributors seeking recovery, would produce revenue that would be tracked in a variance account. Any variance between the actual Updated Recovery Amount paid by a utility and the revenue ultimately collected through the rate rider would be reserved and disposed of in a future proceeding. The uniform rate could be determined as the average rate necessary to recover the total Updated Recovery Amount from the sum of all customers of the Affected Electricity Distributors.

Answer to Interrogatory from
Donald D. Rennick

Question 1:

Reference(s): EDA Evidence, page 6 of Appendix "A" of the supplementary evidence letter dated December 16, 2010

The totals of the yearly LDC service revenues shown for the years 1994 - 2001 on do not cross add to the "Total LDC Service Revenue" total shown as $22,898,196,855.50. Please explain.

Answer:

The totals of the yearly LDC service revenues shown for the years 1994 – 2001 do not cross add to the "Total LDC Service Revenue" total shown as $22,898,196,855.50 as only 50 percent of service revenues for 2001 are included in the calculation because LDCs began to change their LPP billing practices in 2001.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition

Question 1:

Reference(s): EDA Evidence, pages 1-2, paragraphs 3 and 4
EDA Evidence, page 12, paragraph 64

d) Please explain how the revenues from late payment charges were used to "benefit" all customers. In doing so, please explain how the revenues were assigned to the various customer classes of the distributors.

Answer:

LPP revenues benefited all customers by mitigating the rates of all customers – LPPs were applied across all customer classes. Historical or forecast LPP revenues were used as revenue offsets to reduce the base distribution revenue requirement, recoverable from all customers.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition

Question 2

Reference(s): EDA Evidence, page 6, paragraphs 30 to 32

a) What was the period of recovery approved by the Board for Enbridge?

b) What was the period of recovery approved by the Board for Union?

Answer:

a) The period of recovery approved by the Board in the Enbridge case was 5 years, with an estimated impact of approximately $2.70 per year for 5 years.

b) In the Union Gas case, it is not clear that a recovery period has been approved. A LPP litigation deferral account was established until 2011.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition

Question 3:

Reference(s): EDA Evidence, page 8, paragraphs 44 and 62

a) Does the $700,000 in defendant's legal costs include any interest costs incurred by the EDA in financing (per footnote #17) legal fees for all LDCs other than Toronto Hydro? If yes, how much is included and how were the interest costs calculated?

b) Please break the $700,000 down as between the legal costs related to the late payment legal action/settlement process versus those associated with the current Application.

c) Does the $700,000 include the full legal costs paid for by Toronto Hydro? If yes, precisely how much has been paid for by Toronto Hydro already and when were the payments made?

d) Please explain what the "applicable taxes" include. If the applicable taxes include "HST" - how much does this represent? Also, if HST is included, will the LDCs be able to claim an input tax credit for their share of this 'cost'? If not, why not?

e) Has the EDA received any payments from LDCs other than Toronto Hydro related to the legal expenses incurred? If yes, please provide a schedule setting out the names of the LDCs, the amounts paid and the dates the payments were made.

f) In the determination of the fees charged to members has the EDA included any allowance for the legal fees related to either the class action/settlement or the current Application? If yes, please indicate the years and the amounts involved

Answer:

a) The estimated $700,000 in defendants' legal costs does not include any interest costs incurred by the EDA for financing legal fees for any LDCs.

b) The estimated $700,000 in legal costs can be broken down as follows:

1. LPP Class Actions settlement – approximately $650,000; and
2. rate recovery Application – approximately $50,000.

c) The $700,000 presents the total forecast defence legal costs of all LDCs. THESL has advised that it has not incurred any additional legal costs. For further detail regarding THESL's legal costs, refer to THESL's November 12, 2010 filing.

d) The "applicable taxes" include taxes on legal fees. Taxes are payable on the portion of the settlement which is allocated to the payment of plaintiffs' counsel's fee. In accordance with the settlement, each LDC has to pay its portion of the applicable tax on plaintiffs' counsel fee, unless for some reason it is not eligible to flow through that tax payment by obtaining a tax credit. The settlement is structured with $4,812,500 for plaintiffs' counsel's fee and $50,000 for plaintiffs' counsel's disbursements. Therefore, the HST contingency was $632,125. It has since been determined that GST (5%), and not HST, will be payable. As part of the settlement, it was negotiated that no LDC has to pay tax if it does not have a corresponding credit. The EDA agrees that any input tax credit applicable to the Updated Recovery Amount payable by any LDC should be deducted from that LDC's Updated Recovery Amount.

e) The EDA has not received any payments from LDCs other than THESL related to the legal expenses incurred.

f) In the determination of the fees charged to members, the EDA has not included any allowance for the legal fees related to either the late payment penalty class actions settlement or the current Application.

Answer to Interrogatory from Vulnerable Energy Consumers Coalition

Question 4:

Reference(s): EDA Evidence, page 13, paragraphs 68 – 70

a) Please confirm that in Enbridge's case the decision to allocate the recovery on a per customer basis was because that was the way the revenues received from late payment charges were allocated to customer classes per the Enbridge CASDA Application, Exhibit B/Tab 2/Schedule 6, page 1). If this is not confirmed, please provide the EDA's understanding as to rationale for using customers as the "allocator" and provide relevant references to the Enbridge proceeding.

b) If the revenue from late payment charges was used to benefit all customers (per paragraphs #3 and #64) why is the EDA proposing to only allocate it to metered customers?

Answer:

a) The Board's Decision in the Enbridge case speaks for itself and the EDA cannot comment further on the reasons for that Decision. In the Enbridge case, Enbridge sought recovery on the basis of the number of customers in each class, which was the methodology that the company used to allocate late payment revenues to the rate classes.

b) Please refer to the response to Board Staff IR #7(iii).

Answer to Interrogatory from The School Energy Coalition

Question 1:

Reference(s): EDA Evidence, page 9, paragraph 45

Please provide a table for each LDC claiming recovery showing the late payment penalties charged to customers for each calendar year.

Answer:

As indicated at paragraph 46 of the evidence filed by the EDA on behalf of Affected Electricity Distributors on November 8, 2010, given the significant difficulties, if not impossibility and cost associated with endeavouring to calculate the offending LPP revenue of any particular utility, service revenue was considered to be the best proxy for allocating the settlement amongst the LDCs. Providing a table for each LDC claiming recovery showing the LPPs charged to customers for each calendar year is simply not possible.

**Answer to Interrogatory from
The School Energy Coalition**

Question 2:

Reference(s): EDA Evidence, page 10, paragraphs 54-55.

Please provide a copy of the full transcript of the Fairness Hearing held on July 15, 2010.

Answer:

There is no transcript of the Fairness Hearing held on July 15, 2010.

Answer to Interrogatory from The School Energy Coalition

Question 3:

Reference(s): EDA Evidence, page 3, paragraph 10.

Please provide, for each LDC that was incorporated after the date the first impugned late payment penalties were charged to customers, a copy of the agreement by which the incorporated LDC became liable for the existing obligations, including liable claims, of the predecessor entity that carried on the electricity distribution business. To the extent, if any, that there w ere disclosures of existing claims at the time of the transfer of the electricity distribution business, please provide a copy of those disclosures.

Answer:

The information requested cannot be obtained within the timelines prescribed by the Board for responding to interrogatories. Furthermore, the requested information is not relevant to either of the Board approved issues.

Answer to Interrogatory from
The School Energy Coalition

Question 4:

Reference(s): EDA Evidence, page 3, paragraph 10.

Please provide, for each LDC that was acquired by, or amalgamated with, another LDC or entity after 1998, a copy of the agreement by which the successor LDC became liable for the existing obligations, including legal claims, of the predecessor entity that carried on the electricity distribution business. To the extent, if any, that there were disclosures of existing claims at the time of the acquisition or amalgamation, as the case may be, please provide a copy of those disclosures.

Answer:

The information requested cannot be obtained within the timelines prescribed by the Board for responding to interrogatories. Furthermore, the requested information is not relevant to either of the Board approved issues.

Answer to Interrogatory from
The School Energy Coalition

Question 5:

Reference(s): None provided.

Please provide, for each LDC claiming recovery, details of any insurance place at the time of incorporation or thereafter covering any form of third party claim against the distribution business.

Answer:

The information requested cannot be obtained within the timelines prescribed by the Board for responding to interrogatories. However, The MEARIE Group has advised that its general liability insurance policy, which applies to the vast majority of LDCs, does not provide coverage for the Revised Allocated Amounts owing by LDCs. Furthermore, the EDA is not aware that any LDC carried insurance covering its liability under the settlement of the LPP Class Actions, but agrees that any proceeds from any such insurance that may have existed in the case of a particular LDC should be deducted from its Updated Recovery Amount.

Answer to Interrogatory from
The School Energy Coalition

Question: 6:

Reference(s): None provided.

Please provide, for each LDC claiming recovery that, during the period of the impugned late payment penalties, billed charges for goods or services other than electricity and its distribution in the same bill, a breakdown of the billed charges, by year, between electricity and its distribution and all. other charges. Please provide details of any late payment penalty policies that differed between the components of the bill, e.g. different interest rates, grace or notice periods, order of disconnection rules, etc.

Answer:

The information requested cannot be obtained within the timelines prescribed by the Board for responding to interrogatories.