October 22, 2012

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700, P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: An Application by Algoma Power Inc. to Adjust Electricity Distribution Rates & Rural and Remote Rate Protection Funding, Effective January 1, 2013; EB-2012-0104

Please find accompanying this letter, two copies of an Application by Algoma Power Inc. to adjust Electricity Distribution Rates & Rural and Remote Rate Protection Funding, effective January 1, 2013. The Board has assigned case number EB-2012-0104 to this Application.

As per the Board's letter dated July 19, 2012, API has attached its Smart Meter application (EB-2012-0285), which was being held in abeyance to combine with this IRM application.

Electronic copies of the Application have been submitted via the Board's Regulatory Electronic Submission System and a CD containing electronic media accompany this submission.

Yours truly,

Original Signed by

Douglas Bradbury
Director Regulatory Affairs

An Application

By

Algoma Power Inc.

To Adjust

Electricity Distribution Rates

&

Rural and Remote Rate Protection Funding

Effective January 1, 2013

EB-2012-0104

Submitted: October 22, 2012

Index

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, C. S.O. 1998, c.15 (Sched. B);

AND IN THE MATTER OF an Application by Algoma Power Inc. for an Order or Orders pursuant to Section 78 of the *Ontario Energy Board Act, 1998* approving or fixing just and reasonable rates, Rural and Remote Rate Protection funding and other service charges for the distribution of electricity.

Application

1. The applicant is Algoma Power Inc. ("API" or the "Applicant"), a wholly-owned subsidiary of FortisOntario Inc. ("FortisOntario"). The Applicant, an Ontario corporation with its head office in Sault Ste. Marie, Ontario carries on the business of owning and operating electricity distribution facilities in the Algoma District of Ontario.

2. In the matter of EB-2009-0278, a Cost of Service Application, and EB-2010-0400, the Ontario Energy Board (the "Board" or the "OEB") approved electricity distribution rates for API effective December 1, 2010.

3. In the matter of EB-2011-0152, an Incentive Regulation Application, the Board approved electricity distribution rates for API effective January 1, 2012.

4. API hereby applies to the Board, pursuant to section 78 of the Ontario Energy Board Act, 1998 as amended (the "OEB Act") for an Order or Orders approving its proposed electricity distribution rates and other charges, effective January 1, 2013.

5. The Ontario Energy Board issued file number EB-2012-0104 to API in respect of a 2013 Incentive Regulation Application.

6. This application has been prepared in a manner to facilitate the Board's expectation expressed in its Order and Decision in the matter of EB-2009-0278 in respect of the Rural and Remote Rate Protection ("RRRP") factor with an annual change in distribution rates and RRRP funding. And, to apply the principles of incentive regulation. The application of the principles of incentive regulation is the same as those approved by the Board in the matter of EB-2011-0152.

7. In a letter from the Board dated July 19, 2012, the Board granted permission for API's Smart Meter Cost Recovery application to be held in abeyance until such time as API files this 2013 IRM rate application, at which time both the Smart Meter Cost Recovery application and the 2013 IRM3 application will be combined.
   In this Application, API is proposing a methodology to recover its Smart Meter Costs.

8. The persons affected by this Application are the ratepayers of API's service territory. It is impractical to set out their names and addresses because they are too numerous.

API's contact information for this Application is as follows:

The Applicant:

Mr. Douglas R. Bradbury
Director Regulatory Affairs
Algoma Power Inc.

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Telephone:	(905) 994-3634
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Email Address:	doug.bradbury@fortisontario.com

The Applicant's counsel:

Mr. R. Scott Hawkes
Vice President, Corporate Services and General Counsel
Algoma Power Inc.

Mailing Address:	1130 Bertie Street P. O. Box 1218 Fort Erie, Ontario L2A 5Y2
Telephone:	(905) 994-3642
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Email Address:	scott.hawkes@fortisontario.com

DATED at Fort Erie, Ontario this 22nd day of October, 2012.

ALGOMA POWER INC.

Douglas Bradbury, P.Eng.

Preamble

On November 11, 2010, the Ontario Energy Board (the "Board") issued its Decision and Order in the matter of EB-2009-0278; an application by Algoma Power Inc. ("API") for an order approving just and reasonable rates and other charges for the distribution of electricity to be effective July 1, 2010 and January 1, 2011. This Decision and Order was based on a 2011 Test Year.

On December 13, 2010, the Board issued its Rate Order with a Tariff of Rates and Charges effective and implemented on December 1, 2010. The Tariff of Rates and Charges was later amended on January 28, 2011 in EB-2010-0400, amending the Residential R – 2 customer class Rate Rider for the Deferral/Variance Account Disposition.

A key aspect of the Decision and Order in EB-2009-0278 was the Board's stated intention to calculate a Rural and Remote Rate Protection factor annually for API in order to calculate the annual change in distribution rates and RRRP funding. In its findings the Board stated,

> *"The Board intends to calculate an RRRP adjustment factor annually for Algoma Power, with rates and the RRRP amount for the rate year affected accordingly. Every year the Board will communicate the RRRP adjustment factor to Algoma Power to ensure that it is reflected in Algoma Power's rates application. Should Algoma Power not file either an IRM or a cost of service application, the Board will on its own motion initiate a proceeding in this regard."*[1]

In that context, API filed an incentive regulation ("IR") application, EB-2011-0152, which proposed a form of incentive regulation ("IR") that combines aspects of the Incentive Regulation Mechanism ("IRM") with the adjustment of electricity distribution rates contemplated in O. Reg. 442/01. The Board issued its final Decision and Order in the matter of EB-2011-0152 on March 6, 2012. The Board Approved Tariff of Rates and Charges, EB-2011-0152, is provided in Schedule "A".

This application is consistent with the Board's Decision and Order in the matter of EB-2011-0152 dated January 20, 2012.

API has four customer classifications:

i. Residential Service Classification

For the purposes of rates and charges, a residential service is defined in two ways:
i) a dwelling occupied as a residence continuously for at least eight months of the year and, where the residential premises is located on a farm, includes other farm premises associated with the residential electricity meter, and
ii) consumers who are treated as residential-rate class customers under Ontario Regulation 445/07 (Reclassifying Certain Classes of Consumers as Residential-Rate Class Customers: Section 78 of the *Ontario Energy Board Act, 1998*) made under the *Ontario Energy Board Act, 1998*.

[1] Decision and Order, EB-2009-0278, dated November 11, 2010, page 8

RESIDENTIAL – R1

- This classification refers to a Residential service with a demand of less than, or is forecast to be less than, 50 kilowatts, and which is billed on an energy basis.

RESIDENTIAL – R2

- This classification refers to a Residential service with a demand equal to or greater than, or is forecast to be equal to or greater than, 50 kilowatts, and which is billed on a demand basis.

ii. Seasonal Customer Service Classification

This classification includes all services supplied to single-family dwelling units for domestic purposes, which are occupied on a seasonal/intermittent basis. A service is defined as Seasonal if occupancy is for a period of less than eight months of the year.

iii. Street Lighting Service Classification

This classification refers to an account for roadway lighting. The consumption for these unmetered accounts will be based on the calculated connection load times the calculated hours of use established in the approved OEB street lighting load shape template.

iv. microFIT Generator Service Classification

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

Price cap adjustment and the adjustment of electricity distribution rates contemplated in O. Reg. 442/01 do not apply to the microFIT Generator Service Classification.

API's electricity distribution rates for Residential Service Classification (both Residential R – 1 and Residential R – 2) are adjusted in accordance with O. Reg. 442/01. The electricity distribution rates for these classes are adjusted in line with the average of rate adjustments of select rate classes of other distributors in the most recent rate orders, as calculated by the Board; the RRRP adjustment Factor. In this Application, API has assumed the RRRP adjustment factor to be 2.81 per cent. API acknowledges that the Board will update the RRRP adjustment factor at a later date.

The electricity distribution rates for the Seasonal Customer Service Classification and the Street Lighting Service Classification are not subject to the restrictions of O. Reg. 442/01 and may be determined in a manner consistent with a price cap form of incentive regulation. In this Application, API has assumed that the annual percent change in the Implicit Price Index for National Gross Domestic Product (GDP-IPI) for Final Domestic Demand is 2.0 per cent. API acknowledges that upon publication by Statistics Canada, the Board will issue a letter establishing the updated GDP-IPI.

Manager's Summary

In determining a price cap adjustment for the customer classes at API, two governing principles have to be considered:

1. The rates for Residential Service Classification (both Residential R – 1 and Residential R – 2) are adjusted in accordance with O. Reg. 442/01, as

determined by the Board. The adjustment will be applied to the Monthly Service Charge and Distribution Volumetric Rate.

2. The rates for customer classifications that are not adjusted in accordance with O. Reg. 442/01 (Seasonal and Street Light customer classifications) are adjusted by the price cap adjustment index determined as the annual percentage change in inflation less the X-Factor.

API's 2012 rate adjustment application has to accommodate both of these considerations and therefore the conventional rate generating models produced by the Board are not suitable. API has used a series of electronic models in EXCEL format to generate 2013 electricity distribution rates; these models accompany this Application.

The following is a discussion of API's Application.

1. Price Cap Index Adjustment

API is making this Application consistent with the Board's findings in its December 20, 2006 *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, the Board will use the annual percent change in the Implicit Price Index for National Gross Domestic Product (GDP-IPI) for Final Domestic Demand. API acknowledges that upon publication by Statistics Canada, the Board will issue a letter establishing the updated GDP-IPI. Board staff will update the GDP-IPI in each distributor's rate application model in order to calculate the price cap index adjustment for distribution rates for all applicants. API is applying, for distribution rates to be effective January 1 of the rate year; API acknowledges that the Board will use the appropriate measure of GDP-IPI in the final rate application model.

The price cap index adjustment is determined as the annual percentage change in the GDP-IPI less the X-Factor. The X-factor is 0.72% plus a stretch factor. The value of the stretch factor is specific to each distributor for each rate year, and will be one of the following values: 0.2%; 0.4%; or 0.6%.

In the Board's Decision and Order in the matter of EB-2011-0152 dated January 20, 2012, the Board decided that a stretch factor of 0.6% will apply to API.

API is unique in the way its distribution rates are set by the Board. Pursuant to O. Reg. 442/01, and with the exception of the Seasonal and Street Lighting Service Classifications, API's rates are to be adjusted in line with the average of any adjustment to rates approved by the Board for other distributors for the same rate year. Any remaining revenue deficiency related to the revenue requirement of the Residential Class is recovered by API on behalf of its customers through the Rural and Remote Rate Protection ("RRRP"). The rates for the Residential – R1 and Residential – R2 will be determined using the RRRP Adjustment Factor for 2012 as determined by the Board and rates for the Seasonal and Street Light customer classes will be set by an IR adjustment factor as determined by the Board.

The methodology proposed to accomplish the price cap adjustment and rates is explained in detail and are provided in Schedule "C" attached.

2. Changes in Provincial and Federal Income Tax Rates

In its Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors dated September 17, 2008, the Board determined that a 50/50 sharing of the impact of currently known legislated changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate.

In API's most recent cost of service electricity distribution rate application, EB-2009-0278, the Board approved recovery of $499,851 for federal and provincial income taxes in the rate requirement. There was no capital tax component and the corporate tax rate used in this determination was 28.25%. In this Application for a rate adjustment, API has determined the grossed up tax liability at the forecasted 2013 corporate tax rate of 26.5%.

API proposes that a 50/50 sharing of the impact of changes from the tax level reflected in the Board-approved base rates of 28.25% to the currently known legislated tax level for 2013 of 26.5%. API has calculated that the grossed up income taxes for the 2012 rate year is $457,723; a reduction of $42,128. Fifty per cent of this savings will be credited to the consumers in the form of a rate rider.

The details of the Tax Change Rate Rider are provided in Schedule "D" attached and are provided in an EXCEL spreadsheet accompanying this Application. API's 2013 combined income tax rate of 26.5% does not reflect the Ontario Small Business Deduction ("OSBD") and therefore API has used an unlocked version of the Board's Tax Savings Workform. API is a wholly-owned subsidiary of FortisOntario which is a wholly-owned by Fortis Inc. Fortis Inc.'s shares are listed on the Toronto Stock Exchange and traded under the symbol FTS and thus, Fortis Inc. is considered a public corporation under the Income Tax Act. API is considered a corporation controlled by a public corporation under the Income Tax Act. API is not considered a Canadian-controlled private corporation (CCPC) because it is owned indirectly by a public corporation. To be eligible for the OSBD a corporation must be a CCPC. Algoma Power Inc. does not qualify for the OSBD.

API proposes a one year income tax rate rider with a sunset date of December 31, 2013; the rate riders are shown in the table below.

Rate Class	Revenue by Rate Class	Total Revenue by %	Tax Changes by Rate Class	Rate Rider
Residential – R1	$14,427,317	72.76 %	($15,326)	($0.0001)
Residential – R2	$2,859,067	14.42 %	($3,037)	($0.0200)
Seasonal	$2,408,452	12.15 %	($2,558)	($0.0002)
Street Lighting	$133,847	0.68 %	($142)	($0.0002)

3. Smart Meter Funding Adder

Chapter 3 of the Filing Requirements for Transmission and Distribution Applications dated June 22, 2011 stated that with deployment of smart meters nearing completion, that it expects distributors to file for a final prudence review at the earliest possible opportunity following the availability of audited costs. The Board also approved a sunset date of April 30, 2012 for the Smart Meter Funding Adder ("SMFA") for most distributors in their 2011 rate application. In the matter of EB-2011-0152, the Board approved a SMFA of $1.00 per metered customer with a sunset date of December 31, 2012.

The SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board (G-2008-0002). The SMFA was not intended to be compensatory (return on and of capital) on a cumulative basis over the term the SMFA was in effect. The SMFA was initially designed to fund future investment, not fully fund prior capital investment.

The API service territory is recognized to be a high cost low revenue area. Substantiation of API's cost characteristics are found in the Board's Decision in the matter of EB-2007-0744, an application by Great Lakes Power Limited (the predecessor to API) for an Order or Orders approving just and reasonable rates and other service charges for the distribution of electricity. In that Decision the Board wrote;

> *"GLPL presents a unique challenge for the Board. In reviewing the record for this case and examining the history of this applicant before the Board it has become clear that conventional ratemaking practice cannot address the issues presented by this applicant. Conventional ratemaking cannot result in a rate that will cover the Company's costs, provide for a reasonable return on investment, while being reasonable from a ratepayer's point of view. This circumstance arises directly out of the characteristics of the Applicant's service area. The Applicant's service area is more than twice the area of the greater Toronto area. It has less than 12,000 customers and has the lowest customer/kilometer ratio in Ontario with only 6.7 customers per kilometer on average. 99.9% of its service area is rugged and sparsely populated wilderness. Its service area is characterized by long runs of distribution wire between customers. This is a high cost, low revenue service area."*

The same is true also for the delivery of Smart Meter Infrastructure ("SMI"). Due to its large geographic service area and low density customer dispersion, API has a significant per customer cost for its SMI.

Installing the SMI offered the same challenges to API as it did for other LDCs; the large scale implementation of new technology, the mass changes out of metering assets and the fundamental changes to business processes. However, API's vast geographic service territory and low customer density offered other unique challenges. As is discussed in greater detail in the "Smart Meter Funding and Cost Recovery – Final Disposition Application", provided as Schedule "B" attached, API required a much more significant investment in communication infrastructure than that of the typical LDC utilizing Sensus technology. In order to provide adequate communications for the SMI, API required a significant investment in Regional Collectors to collect data from Smart Meters and transmit to centralized collector. There are several types of Regional Collector used in the API service territory – Tower Gateway Basestation ("TGB"), FlexNet Network Portal ("FNP"), and FlexNet Regional Portal ("FRP"). The TGBs are the most powerful collectors and are strategically located to collect data from thousands of meters. The TGBs consist of a computerized collector with an associated antenna that must be mounted on a tall structure like a tower or pole for optimal communication (hence the term tower-based system). FNPs and FRPs are less powerful and are typically used in more remote areas to reach meters that cannot communicate with the TGBs. FNPs and FRPs also need to be mounted on tall structures, but do not require as much height as TGB antennae. All Regional Collectors are owned by API.

Legislation governs how electricity distribution rates are set at API. Pursuant to O. Reg. 442/01, and with the exception of the Seasonal and Street Lighting Service Classifications, API's rates are to be adjusted in line with the average of any adjustment to rates approved by the Board for other distributors for the same rate year (the "RRRP Adjustment Factor"). Any remaining revenue deficiency related to the revenue requirement of the Residential Class is recovered by API on behalf of its customers through the Rural and Remote Rate Protection ("RRRP"). This methodology is consistent for both cost of service regulation and incentive regulation.

API's current electricity distribution rates are based on API's 2011 revenue requirement approved by the Board in the matter of EB-2009-0278. This revenue requirement was by default indexed through incentive regulation, EB-2011-0152, using the Board's 3rd Generation Incentive Regulatory Mechanism ("3IRM"). The application of the RRRP Adjustment Factor to Residential R1 and R2 customer classes and the 3IRM adjustment to the Seasonal and Street Lighting customer classes together with a compensating adjustment to the RRRP funding amount keeps distribution revenue recovery in line with the 2012 revenue requirement.

The SMI is essentially a capital project which will be included in rate base and will contribute to API's revenue requirement. Recovery through rates of this capital addition to rate base is governed by regulation. At API there are two customer classes that are impacted by SMI; the Residential R1 customer class and the Seasonal customer class. The revenue requirement allocated to the Residential R1 customer class are partially funded by RRRP funding, the revenue requirement allocated to the Seasonal customer class is fully recovered through rates.

In this 2013 IR Application, EB-2012-0104, the Residential R1 distribution rates are being indexed using the Board's RRRP Adjustment Factor; that stipulated in O. Reg. 442/01 and the Board's Decision and Order in the matter of EB-2009-0278. As a consequence of indexing the Residential R1 distribution rates (and Residential R2) the amount of RRRP funding required to keep the revenue requirement whole will be adjusted downward.

The additional revenue requirement arising from the SMI project, if collected in Residential – R1 distribution rates, will result two adverse effects on the rate payers in API's service territory. First, the distribution rates developed and implemented to recover this marginal increase in revenue requirement will increase rates beyond the average of other utilities' increases in the most recent year as stipulated in O. Reg. 442/01. Second, the Residential R1 customer class will, in effect, pay for SMI twice; once by default by having distribution rates indexed by the average of other LDC's that will have had increases to recover SMI costs embedded in the distribution rates and again in an API SMI rate rider.

In this Application, API proposes that distribution rates be designed in the following manner;

- Incentive rates for 2013 for all rate classes determined as approved in API's 2012 IR, EB-2011-0152,
- the marginal revenue requirement associated with the SMI project be allocated to the effected customer classes, Residential R1 and Seasonal,

- the marginal revenue requirement allocated to the Residential R1 customer class will be allocated the revenue requirement of that customer class. That portion of the revenue requirement not adsorbed by the RRRP Adjustment factor will be funded by the RRRP, and

- the marginal revenue requirement allocated to the Seasonal customer class will be recovered in rates. Two rate riders will be determined with a proposed sunset date of December 31, 2013:

    - Net Deferred Revenue Requirement Rate Rider, and
    - Incremental Revenue Requirement Rate Rider.

Determination of the NDRRRR & IRRRR is shown in Schedule C, API 2013 DRIM.

4. Revenue-to-Cost Ratios

In the matter of EB-2010-0278, the Board did not direct API to make changes to the revenue to cost ratios in its future IRM applications. API has not requested a change in the revenue to cost ratios in this Application.

5. Retail Transmission Service Rates

API has proposed Retail Transmission Service Rates ("RTSR") compliant with the Board's Guideline G-2008-0001, Revision 4.0, and dated June 28, 2012. The RTSR Adjustment Workform Version 3 .0 accompanies this Application; a print version of the Workform is provided in Schedule "D" to this Application.

The proposed RTSR effective January 1, 2013 are shown below.

Service Classification	Board Approved	2013 Proposed	UOM
Residential - R1			
Retail Transmission Rate - Network Service Rate	0.0071	0.0068	per kWh
Retail Transmission Rate - Line and Conection Service Rate	0.0051	0.0050	per kWh
Residential - R2			
Retail Transmission Rate - Network Service Rate	2.6396	2.5209	per kW
Retail Transmission Rate - Line and Conection Service Rate	1.8099	1.7696	per kW
Retail Transmission Rate - Network Service Rate - Interval metered > 1,000 kW	2.8001	2.6742	per kW
Retail Transmission Rate - Line and Conection Service Rate - Interval metered > 1,000 kW	2.0003	1.9558	per kW
Seasonal Customers			
Retail Transmission Rate - Network Service Rate	0.0071	0.0068	per kWh
Retail Transmission Rate - Line and Conection Service Rate	0.0051	0.0050	per kWh
Street Lighting			
Retail Transmission Rate - Network Service Rate	1.9907	1.9012	per kW
Retail Transmission Rate - Line and Conection Service Rate	1.3992	1.3680	per kW

6. Review and Disposition of Group 1 Deferral and Variance Accounts

API is requesting disposition of its audited Group 1 Deferral and Variance Accounts as at December 31, 2011 with interest projected to December 31, 2012. The Group 1 accounts, excluding Power Global Adjustment, with projected interest are in a credit balance of $88,192. The resultant threshold test is $0.000466/kWh; not exceeding the threshold amount of $0.001/kWh.

Account 1588 – (*Retail Settlement Variance Account – Global Adjustment ("RSVA$_{GA}$")*) is the account used to record the net differences between the global adjustment amount billed, to non-RPP consumers and the global adjustment charge to a distributor for non-RPP consumers, using the settlement invoice received from the IESO, host distributor or embedded generator. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this RSVA account. API is requesting disposition of the balance of the RSVA$_{GA}$ account as at December 31, 2011, plus forecasted interest to December 31, 2012, as part of this Application. The resultant threshold test is $0.001087/kWh; exceeding the threshold amount of $0.001/kWh.

API is proposing to include account balances from Group 1 Deferral and Variance Accounts and the Global Adjustment Sub-Account in order to offset and minimize rate volatility.

Details of the account balances are provided in the Deferral / Variance Workform for 2013 electricity distribution rate applications, dated October 16, 2012. The class specific rate riders have been determined using the Board approved model used in API's last cost of service rate application, EB-2009-0278. API is requesting a sunset set date of December 31, 2013 therefore permitting disposition over a twelve month period. This sunset date will coincide with the current rate rider arising from EB-2011-0152 through to May 31, 2013.

Both of these models are provided in Schedules "F" and "G", Deferral and Variance Account Continuity Schedule and Deferral and Variance Account Disposition. Excel versions of the models accompany this Application.

In summary, the requested class specific rate riders are shown below:

Rate Rider for Deferral/Variance Account Disposition (2013) – effective until December 31, 2013	
Residential – R1	$(0.0012)/kWh
Residential – R2	$0.1096/kW
Seasonal	$(0.0015)/kWh
Street Lighting	$(0.0007)/kWh

Rate Rider for Global Adjustment Sub-Account Disposition (2013) - effective until December 31, 2013	
Residential – R1	$0.0011/kWh
Residential – R2	$0.4645/kW
Seasonal	$0.0011/kWh
Street Lighting	$0.0011/kWh

7. Update to Fixed Monthly Charge for microFIT Generator Service Classification

API is requesting, per the Board's letter dated September 20, 2012, that the fixed monthly charge related to the microFIT Generator Service Classification be updated to the province-wide fixed monthly charge of $5.40.

Proposed Tariff of Rates and Charges
Effective January 1, 2013

RESIDENTIAL SERVICE CLASSIFICATION

For the purposes of rates and charges, a residential service is defined in two ways:

i) a dwelling occupied as a residence continuously for at least eight months of the year and, where the residential premises is located on a farm, includes other farm premises associated with the residential electricity meter, and
ii) consumers who are treated as residential-rate class customers under Ontario Regulation 445/07 (Reclassifying Certain Classes of Consumers as Residential-Rate Class Customers: Section 78 of the *Ontario Energy Board Act, 1998*) made under the *Ontario Energy Board Act, 1998*.

RESIDENTIAL – R1

This classification refers to a Residential service with a demand of less than, or is forecast to be less than, 50 kilowatts, and which is billed on an energy basis.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	22.11
Distribution Volumetric Rate	$/kWh	0.0310
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until May31, 2013	$/kWh	0.0046
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until May31, 2013	$/kWh	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until December 31, 2013	$/kWh	(0.0012)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until December 31, 2013	$/kWh	0.0011
Rate Rider for Tax Change – effective until December 31, 2013	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0068
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administration Charge (if applicable)	$	0.25

RESIDENTIAL – R2

This classification refers to a Residential service with a demand equal to or greater than, or is forecast to be equal to or greater than, 50 kilowatts, and which is billed on a demand basis.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	596.12
Distribution Volumetric Rate	$/kW	2.8482
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until May 31, 2013	$/kW	2.2664
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until May31, 2013	$/kW	(2.8219)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until December 31, 2013	$/kW	0.1096
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until December 31, 2013	$/kWh	0.4645
Rate Rider for Tax Change – effective until December 31, 2013	$/kW	(0.0200)
Retail Transmission Rate – Network Service Rate	$/kW	2.5209
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7696
Retail Transmission Rate – Network Service Rate – Interval Metered > 1,000 kW	$/kW	2.6742
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered > 1,000 kW	$/kW	1.9558

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administration Charge (if applicable)	$	0.25

SEASONAL CUSTOMERS SERVICE CLASSIFICATION

This classification includes all services supplied to single-family dwelling units for domestic purposes, which are occupied on a seasonal/intermittent basis. A service is defined as Seasonal if occupancy is for a period of less than eight months of the year.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	26.38
Distribution Volumetric Rate	$/kWh	0.1015
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until May 31, 2013	$/kWh	0.0046
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until May31, 2013	$/kWh	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until November 30, 2015	$/kWh	0.0307
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until December 31, 2013	$/kWh	(0.0015)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until December 31, 2013	$/kWh	0.0011
Smart Meter Cost Recovery Rate Rider – Net Deferred Revenue Requirement – effective until December 31, 2013	$/kWh	0.0411
Smart Meter Cost Recovery Rate Rider – Incremental Revenue Requirement – effective until December 31, 2013	$/kWh	0.0174
Rate Rider for Tax Change – effective until December 31, 2013	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0068
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administration Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting. The consumption for these unmetered accounts will be based on the calculated connection load times the calculated hours of use established in the approved OEB street lighting load shape template.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	0.97
Distribution Volumetric Rate	$/kWh	0.1557
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until May 31, 2013	$/kWh	0.0048
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until May31, 2013	$/kWh	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until May31, 2013	$/kWh	(0.0007)
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until December 31, 2013	$/kWh	0.0011
Rate Rider for Tax Change – effective until December 31, 2013	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate	$/kW	1.9012
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3680

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administration Charge (if applicable)	$	0.25

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES – Delivery Component – effective January 1, 2013

Service Charge	$	5.40

Bill Impacts

The table shown below summarizes the bill impacts arising from the methodology and assumptions used in this Application.

Rate Impacts Summary Arising from the Rate Design Proposal								
Customer Class	Usage Profile		Delivery Charges			Total Bill		
	kWh	kW	Current	Proposed	% Chg.	Current	Proposed	% Chg.
Residential R1	800	-	56.15	54.93	-2.2%	132.42	131.18	-0.9%
Residential R1	2,000	-	106.62	104.15	-2.3%	311.22	308.70	-0.8%
Residential R2	90,000	225	2,169.18	2,180.91	0.5%	13,062.75	13,076.00	0.1%
Seasonal	287	-	61.36	75.48	23.0%	95.95	111.92	16.6%
Street Lighting	25,000	71	4,496.55	4,506.46	0.2%	8,141.64	8,152.84	0.1%

Schedule “A”

Board Approved Tariff of Rates and Charges
EB-2011-0152

APPENDIX A

TO RATE ORDER

EB-2011-0152

Algoma Power Inc.

DATED: March 6, 2012

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective Date January 1, 2012
Implementation Date March 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0152

RESIDENTIAL SERVICE CLASSIFICATION

For the purposes of rates and charges, a residential service is defined in two ways:
i) a dwelling occupied as a residence continuously for at least eight months of the year and, where the residential premises is located on a farm, includes other farm premises associated with the residential electricity meter, and
ii) consumers who are treated as residential-rate class customers under Ontario Regulation 445/07 (Reclassifying Certain Classes of Consumers as Residential-Rate Class Customers: Section 78 of the *Ontario Energy Board Act, 1998*) made under the *Ontario Energy Board Act, 1998*.

RESIDENTIAL – R1

This classification refers to a Residential service with a demand of less than, or is forecast to be less than, 50 kilowatts, and which is billed on an energy basis. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	21.51
Smart Meter Funding Adder – effective until December 31, 2012	$	1.00
Distribution Volumetric Rate	$/kWh	0.0302
Rate Rider for Foregone Revenue Recovery – effective until December 31, 2012	$/kWh	0.0003
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until May 31, 2013	$/kWh	0.0046
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until May 31, 2013	$/kWh	(0.0061)
Rate Rider for Tax Changes – effective until December 31, 2012	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0071
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge – effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge – effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service – Administration Charge (if applicable)	$	0.25

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective Date January 1, 2012
Implementation Date March 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0152

RESIDENTIAL – R2

This classification refers to a Residential service with a demand equal to or greater than, or is forecast to be equal to or greater than, 50 kilowatts, and which is billed on a demand basis. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	596.12
Smart Meter Funding Adder– effective until December 31, 2012	$	1.00
Distribution Volumetric Rate	$/kW	2.7086
Rate Rider for Foregone Revenue Recovery – effective until December 31, 2012	$/kW	0.0272
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until May 31, 2013	$/kW	2.2664
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until May 31, 2013	$/kW	(2.8219)
Rate Rider for Tax Changes – effective until December 31, 2012	$/kW	(0.0273)
Retail Transmission Rate – Network Service Rate	$/kW	2.6396
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8099
Retail Transmission Rate – Network Service Rate – Interval Metered > 1,000 kW	$/kW	2.8001
Retail Transmission Rate – Line and Trans. Connection Service Rate – Interval Metered > 1,000 kW	$/kW	2.0003

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge – effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge – effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service – Administration Charge (if applicable)	$	0.25

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective Date January 1, 2012
Implementation Date March 1, 2012

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EB-2011-0152

SEASONAL CUSTOMERS SERVICE CLASSIFICATION

This classification includes all services supplied to single-family dwelling units for domestic purposes, which are occupied on a seasonal/intermittent basis. A service is defined as Seasonal if occupancy is for a period of less than eight months of the year. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	26.15
Smart Meter Funding Adder – effective until December 31, 2012	$	1.00
Distribution Volumetric Rate	$/kWh	0.1006
Rate Rider for Foregone Revenue Recovery – effective until December 31, 2012	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until May 31, 2013	$/kWh	0.0046
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until May 31, 2013	$/kWh	(0.0061)
Rate Rider for Deferral/Variance Account Disposition – effective until November 30, 2015	$/kWh	0.0307
Rate Rider for Tax Changes – effective until December 31, 2012	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0071
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge – effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge – effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service – Administration Charge (if applicable)	$	0.25

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective Date January 1, 2012
Implementation Date March 1, 2012

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EB-2011-0152

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting. The consumption for these unmetered accounts will be based on the calculated connection load times the calculated hours of use established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.96
Distribution Volumetric Rate	$/kWh	0.1543
Rate Rider for Foregone Revenue Recovery – effective until December 31, 2012	$/kWh	0.0001
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until May 31, 2013	$/kWh	0.0048
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until May 31, 2013	$/kWh	(0.0061)
Rate Rider for Tax Changes – effective until December 31, 2012	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate	$/kW	1.9907
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3992

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge – effective until April 30, 2012	$/kWh	0.0013
Rural Rate Protection Charge – effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service – Administration Charge (if applicable)	$	0.25

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
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Implementation Date March 1, 2012

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EB-2011-0152

microFIT GENERATOR SERVICE CLASSIFICATION

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APPLICATION

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

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TARIFF OF RATES AND CHARGES
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EB-2011-0152

ALLOWANCES

Transformer Allowance for Ownership – per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

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Customer Administration		
Arrears certificate (credit reference)	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Notification charge	$	15.00
Account History	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheques	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection - during regular business hours	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect Charges - at meter during regular hours	$	65.00
Disconnect/Reconnect Charges - at meter after regular hours	$	185.00
Disconnect/Reconnect Charges at Pole - during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Service Call - customer owned equipment	$	30.00
Service Call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1000.00

Algoma Power Inc.
TARIFF OF RATES AND CHARGES
Effective Date January 1, 2012
Implementation Date March 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0152

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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Retail Service Charges refer to services provided by Algoma Power Inc. to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer	1.0864
Total Loss Factor – Primary Metered Customer	1.0755

Schedule “B”

Copy of Smart Meter Funding and Cost Recovery Final Disposition Application

Algoma Power Inc.
A FORTIS ONTARIO Company

June 15, 2012

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

Dear Ms. Walli,

RE: Algoma Power Inc.; Smart Meter Funding and Cost Recovery – Final Disposition – Amended June 15, 2012

Pursuant to the Board's Decision in the matter of EB-2011-0152, an application by Algoma Power Inc. for 2012 electricity distribution rates, please find attached an amended application in the above captioned matter. A typing error was made on the costs related to the true-up of revenue requirement on pages 1 and 32. The figure has now been corrected from $4,740,361 to $1,740,361.

Yours truly,

Original Signed by

Douglas R. Bradbury
Director, Regulatory Affairs

2 Sackville Road, Suite A, Sault Ste. Marie, Ontario P6B 6J6

Tel: 705-256-3850 • Fax: 705-253-6476 • **www.algomapower.com**

Contact Information

(a) The Applicant:

Mr. Douglas R. Bradbury
Director – Regulatory Affairs
Algoma Power Inc.

Address for personal service:	1130 Bertie Street P. O. Box 1218 Fort Erie, Ontario L2A 5Y2
Mailing Address:	1130 Bertie Street P. O. Box 1218 Fort Erie, Ontario L2A 5Y2
Telephone:	(905) 994-3634
Fax:	(905) 994-2207
Email Address:	doug.bradbury@cnpower.com

BACKGROUND

On December 15, 2011, the OEB issued Guideline G-2011-0001 "Smart Meter Funding and Cost Recovery – Final Disposition". This guideline included filing instructions related to the funding of, and recovery of costs associated with Smart Metering activities conducted by electricity distributors. The OEB's guideline states: "For those distributors that are scheduled to remain on IRM, the Board expects those distributors to file a stand–alone application with the Board seeking final approval for Smart Meter related costs".

In this application, Algoma Power Inc. ("API") requests that the Board approve the recovery of costs related to the true-up of revenue requirement up to December 31, 2012 in the amount of $1,740,361, and incremental revenue requirement from an effective date of January 1, 2013 to December 31, 2013 in the amount of $733,567. In addition, API requests Board approval for the recovery of costs related to stranded meters in the amount of $331,640.

Further, API is requesting an exemption from the requirements of Time of Use billing for 47 remote customers that are beyond the reach of conventional communications infrastructure.

SMART METER PROJECT OVERVIEW

API is a participant in the provincial mandate to install Advanced Metering Infrastructure ("AMI") Systems and implement Time-of-Use ("TOU") billing to Residential and General Service Less Than 50 kW customer classifications; specific to API these are Residential – R1 class customers. This project was a significant undertaking for API, as it involved the large-scale implementation of new technology, the mass change out of the vast majority of API's meter population, upgrades and modifications to the Customer Information System ("CIS"), and fundamental business process changes in terms of how meter data is acquired and processed for billing purposes. With conventional (electromechanical) meters, meters were read manually and only one "spot" reading per billing period was required. With Smart Meters, the collection and processing of meter data is almost entirely an automated process where data is collected on a "real time" basis by the AMI system and then transmitted to a centralized Meter Data Management/Repository ("MDMR"). In turn, the MDMR processes billing data and sends it to the LDC in TOU "buckets" for the LDC to invoice its consumers.

The mandatory provincial Smart Meter Initiative ("SMI") posed significant challenges to API. The Project would affect various functional areas and systems across API, including metering, customer service, and information technology. API accepted the goal of the mandate, which was to create a culture of electricity energy conservation in Ontario using the price signals inherent in TOU rates. API also recognized that Smart Meter systems could yield operational benefits because of the billing and operational data that would become available. Examples of such benefits would be the elimination of manual meter reading, the utilization of loading data for system planning purposes, and the acquisition of data – such as outage and voltage alarms – to enhance operations functions. Smart Metering also presented a unique opportunity for API to achieve further efficiencies, both in undertaking the project itself as well as subsequent day-to-day operations. For example, the automation of billing data collection and processing will allow the billing functions for API to be centralized at Canadian Niagara Power Inc. ("CNPI"); API's affiliate. Because API and CNPI both have AMI systems supplied by the same vendor, the management of the AMI network and associated data flows can also be centralized at the CNPI's Fort Erie office. Ultimately, the efficiencies gained from the implementation of Smart Metering systems will be to the benefit of API consumers.

API, therefore, embarked upon its Smart Metering Project (the "Project") with the mission of implementing AMI systems and TOU billing. API set the following key goals for the Project:

1. To conform to all regulatory and legislative requirements;
2. To leverage the information that will be available from Smart Meters to achieve operational improvements;

3. To accomplish the project in a cost-effective manner to protect the interests of ratepayers; and
4. To make best efforts to educate customers and provide them with tools to allow them to better manage their electricity consumption.

At various stages of the project, API also pursued a collaborative approach with its affiliate company, CNPI, which in turn collaborated with its associate LDCs Westario Power Inc. ("WPI") and Grimsby Power Inc. ("GPI"). This collaborative effort allowed API and the above-named LDCs to benefit from sharing the costs of specific aspects of the project, such as Information Technology ("IT") development costs. This common approach was facilitated by the fact that the above-named LDCs all share a common CIS; namely, the SAP system that is hosted by CNPI.

The API Smart Metering Project can generally be subdivided into the following distinct phases, although there was some overlap between the timing of some phases:

1. Planning
2. Procurement
3. AMI System Deployment
4. MDMR integration and TOU billing

These project phases are described in greater detail in the following text.

1. Planning

Because the Provincial SMI required the large-scale implementation of a technology that was mostly unfamiliar to Ontario LDCs, the Planning phase of the process was of critical importance for API. This project phase was necessary for API to prepare for the selection and deployment of Smart Meter technology. This phase of the Project included tasks such as understanding the technical and regulatory requirements of the Smart Meter initiative, researching available AMI systems and liaising with potential suppliers and installation contractors, and developing project plans. API is a part of the District 9 (D9) group, a consortium comprising seven utilities in Northeastern Ontario. The D9 utilities have enjoyed long-standing positive working relationships and successfully collaborated on various initiatives in the past.

Early in the planning process, the D9 utilities recognized that there would be great value in pursuing a collective approach to implementing AMI systems. This allowed the D9 LDCs to benefit from working collaboratively with a single project plan, a single AMI solution, and with a single vendor for each critical phase of the project. Working together also enabled the D9 utilities to pool resources to engage in educational and research activities.

D9 engaged the services of Util-Assist Inc., to manage its Smart Meter implementation project and provide guidance and direction through the initiative. Util-Assist also provided this service to other utility consortiums in Ontario working towards AMI implementation. Util-Assist also maintained close links with regulatory entities and AMI suppliers to remain abreast of developing regulatory and technical requirements pertaining to the Smart Meter Initiative. Because of its expertise, experience, and links to various stakeholder groups, therefore, Util-Assist was able to provide valuable project management and advisory services to the D9 utilities. Util-Assist worked with the D9 utilities to develop a comprehensive project plan that covered all aspects of Smart Meter implementation in order to meet regulatory timelines. Quite apart from significant tasks such as selecting and installing AMI infrastructure, D9 also had to consider issues such as the technical and resource implications of maintaining an AMI network, how to balance technical requirements against economic considerations, and even the environmentally friendly disposal of redundant meters. Some of the major considerations of the project were as follows:

- Conformance to regulatory requirements
- Strategic planning for AMI acquisition and deployment and the implementation of TOU billing
- Change management
- AMI security
- Web presentment
- Meter disposal
- CIS development and integration with the Meter Data Management/Repository
- Budgeting and project planning

- Rate recovery

2. ***Procurement***

The next significant phase of the Project entailed the selection and procurement of the AMI system. Guided by Util-Assist, D9 continued to gather information on AMI vendors in the North American market. Util-Assist organized presentations by potential AMI vendors so that member utilities could become familiar with the technical aspects of their meters and associated communication systems.

Between August 2007 and July 2008, D9 participated in the London Hydro Phase Two Request for Proposal (RFP) process, as authorized by the Ministry of Energy in O. Reg. 427/06. In this phase, London Hydro issued an RFP for AMI procurement, acting on behalf of a consortium of another 63 LDCs. Pursuant to O. Reg. 427/06, the other LDCs, including the D9 utilities, "piggybacked" on the London Hydro AMI RFP process. The evaluation process was facilitated by London Hydro and determined the #1 and #2 ranked bidders (or Proponents) for each participating LDC or consortium. The evaluation process was overseen by a Fairness Commissioner appointed by the Ontario Ministry of Energy. Each participating LDC was provided with their evaluation results along with an Attestation Letter from the Fairness Commissioner supporting the rankings. A copy of this letter appears in Appendix A. As a result of this process, KTI/Sensus Technologies (Sensus) was ranked as the #1 Proponent for D9, which enabled D9 to enter into contract negotiations with Sensus. Util-Assist then facilitated contract negotiations between D9 and Sensus. After an exhaustive negotiations process that also included a legal review, API signed a contract with Sensus in October of 2009.

The Sensus AMI system (marketed as the FlexNet system by Sensus) is a tower-based wireless communication system, the principle being that data is transmitted from the Smart Meter to regional collectors, then from the regional collectors to a remote, centralized collector. In some instances, an individual Smart Meter can be programmed to act as a collector for data from a nearby meter. This is a useful feature in areas where a meter may not communicate effectively with a regional collector. The major components of the Sensus AMI system deployed at API are as follows:

- Smart Meters – collect billing data (kWhr, kW) and operational data (voltage, outage, etc). Smart Meters are owned by API.
- Regional Collectors – collect data from Smart Meters and transmit to centralized collector. There are several types of Regional Collector used in the API service territory – Tower Gateway Basestation ("TGB"), FlexNet Network Portal ("FNP"), and FlexNet Regional Portal ("FRP"). The TGBs are the most powerful collectors and are strategically located to collect data from thousands of meters. The TGBs consist of a computerized collector with an associated antenna that must be mounted on a tall structure like a tower or pole for optimal communication (hence the term tower-based system). FNPs and FRPs are less powerful and are typically used in more remote areas to reach meters that cannot communicate with the TGBs. FNPs and FRPs also need to be mounted on tall structures, but do not require as much height as TGB antennae. All Regional Collectors are owned by API.
- Regional Network Interface ("RNI") – collects data from the Regional Collectors and forwards billing data to the MDMR. The D9 utilities share a single RNI. Sensus provided various RNI ownership and maintenance options to D9. After assessing the various options, D9 decided to collectively lease the RNI from Sensus, who would own the RNI and be responsible for its operation and maintenance. The D9 utilities felt that this was the best option at the time, because of the utilities' unfamiliarity with the technology. The option to own the RNI is available for future consideration, either to D9 collectively or its individual member utilities.

3. ***AMI System Deployment***

The next key phase in the Project was the deployment of the AMI system. This phase comprised the following key activities:

- Sensus propagation study and deployment of communications infrastructure
- Selection of meter installation contractor

- Installation of meters and removal of redundant conventional meters

The first stage in the deployment process was for Sensus to perform a propagation study to determine the optimal locations for Regional Collectors in the Algoma area. As part of submitting their proposal for the London Hydro RFP process, Sensus estimated the communications infrastructure that would be required by each LDC. The contract between API and Sensus defined the quantity of Collectors that would be required. After several iterations of the Propagation Study, the following communications infrastructure was agreed to in the contract:

- 8 TGBs
- 16 FNPs
- 19 FRPs

In deploying its AMI communications infrastructure, API proactively sought opportunities to save on installation and ongoing maintenance costs. Following the initial installation of the 8 TGB's, Sensus performed a 'drive test' to verify actual network coverage in certain portions of API's service territory. The results of the drive test, combined with preliminary Read Interval Success (RIS) statistics available from the RNI showed that the actual network coverage in many areas was better than predicted by the original Propagation Study. Based on this better than expected coverage, API decided to perform more detailed evaluations of whether certain FNP's and FRP's specified in the Propagation Study would actually be required. As a result of this effort, API is forecasting that the combined FNP/FRP count will be reduced from the initial estimate of 35 installations to 30 or less. Where FRPs or FNPs were required, they were often installed on API distribution poles, thereby avoiding the cost of building separate structures upon which to mount this equipment.

In addition to seeking opportunities to save on installation costs, API also undertook initiatives to save on operating and maintenance costs. API supplied electrical power to TGB, FRP, and FNP sites, thereby obtaining a discount from Sensus on monthly maintenance fees.

In parallel with preparing for an undertaking the deployment of the AMI communications infrastructure, API also worked on the selection of a meter installation contractor to undertake the mass meter change out. Facilitated by Util-Assist, D9 prepared an RFP for installation services. D9 also prepared a comprehensive RFP evaluation model that considered operational as well as pricing factors. Operational considerations included factors such as the vendor's experience with similar projects, safety standards, and project management system. Weightings were applied to each factor so that each prospective vendor could be objectively rated based on their submitted proposal. Overall, operational considerations accounted for about 40% of the evaluation weighting, while the remaining 60% was based on the price. The weighting structure was chosen to closely match that used in the 2006 Coalition of Large Distributors RFP for installation services, which was found prudent by the regulator.

Working with Util-Assist, D9 performed extensive research to identify potential vendors with the qualifications, ability, and experience to successfully undertake the change out of the approximately 80,000 meters served cumulatively by the D9 LDCs. D9 eventually identified a number of vendors that were considered most qualified and capable to successfully complete this aspect of the project. In the third quarter of 2008, the D9 RFP for meter installation services was released and four vendors indicated intent to bid. After the evaluation process, it was determined that Trilliant was the winning proponent. Trilliant submitted a proposal that most closely matched D9's operational requirements at the lowest overall cost. Shortly after the selection, D9 was informed that Olameter Inc. had acquired Trilliant and would provide the meter change services to D9, honouring the prices submitted in the Trilliant proposal. Since Olameter was known in Ontario to be a reputable firm and already provided meter reading services to many LDCs, D9 was confident that Olameter would be able to accomplish the project successfully. Led by Util-Assist, D9 then engaged in contract negotiations with Olameter for the meter change out services. This process also included a legal review. API signed a contract with Olameter in April 2010.

API commenced deploying Smart Meters in its service territory in May of 2010. Olameter installed approximately 84% of single-phase meters, while API internal resources installed the balance of single-phase meters and all three-phase meters. The single-phase meters installed by API internal resources were either not assigned to Olameter or were skipped by Olameter due to technical, safety, or access issues. In order to facilitate Olameter's change out of almost 10,000 meters, API had to make modifications to its SunGard CIS system to integrate with Olameter's OnSuite mobile workforce management system. This enabled the automated downloading of meter change orders from the CIS to handheld units that were then used by Olameter field crews to capture relevant information at each location about the changed meter and the new Smart Meter. At each location, Olameter took a picture of the existing electromechanical meter and its register read, and also recorded GPS co-ordinates of the meter location. The photograph of the legacy meter's register reads was retained in case disputes arose with the consumer regarding said reads. Olameter would then remove the existing electromechanical meter, install a Smart Meter, initialize the Smart Meter and ensure that it was communicating, and return to API the electromechanical meter for disposal. At the end of each day, all digital information was automatically uploaded into the SunGard CIS so meter records could be automatically updated.

By the end of 2011, API had deployed Smart Meters to all of its RPP-eligible consumers.

4. ***MDMR Integration***

This final, key phase of the Project involved proceeding through the process of registering with the SME to commence the process of MDMR integration, developing the CIS to achieve MDMR integration and facilitate TOU billing, testing business processes with the MDMR, and implementing TOU rates. The Meter Data Management/Repository (MDMR), which is the centralized system that receives and processes all billing data from Smart Meters in Ontario, and provides that data to LDCs in TOU "buckets" so that LDCs can bill their customers. Ontario Regulation 393/07 designated the Independent Electricity System Operator (the "IESO") as the

Smart Metering Entity (SME) that was responsible for operating the MDMR. The API AMI network would send billing data directly to the MDMR via the RNI. However, API would have to configure its CIS system to be able to communicate with the MDMR in order to perform tasks such as sending billing requests and receiving billing data. The CIS would also have to be configured to incorporate new business processes to facilitate functioning in an automated billing environment with a centralized MDMR. Because the MDMR has to digitally recognize every individual Smart Meter for which it receives data, all new meter installations and removals, for example, must be communicated to the MDMR via SME-established protocols. Therefore, new business processes had to be developed within the CIS to allow API to operate in a new metering environment where billing data is transferred and processed automatically amongst the AMI network, the MDMR, and the CIS. This was a critical aspect of this phase of the Project.

Along with Smart Meters and AMI networks, the concepts of the MDMR and TOU billing were also new to Ontario LDCs and represented major challenges to achieve the regulatory mandate. Given the success of the collaborative approach adopted in previous phases of the Project, the D9 utilities recognized that there would be value in undertaking a common approach to preparing for MDMR integration. Therefore, D9 continued to work together with Util-Assist to prepare for this critical step on the path to TOU billing. Util-Assist developed and hosted a series of MDMR Education sessions, in which D9 members were educated about the MDMR and the business process changes that would be required to successfully implement and maintain TOU billing. In addition to these Education Sessions, many LDCs, including API, also attended MDMR Information Sessions that were hosted by the SME. The Util-Assist and SME sessions were valuable in terms of imparting to API important knowledge about the MDMR and required business processes. However, because each D9 LDC had its own CIS and internal business processes, logically the D9 collaboration for this phase of the Project could only extend to educational functions and the sharing of information. Each LDC would have to undertake the processes of CIS development, MDMR integration and testing, and TOU billing implementation on their own.

For this phase of the Project, however, API was able to undertake a collaborative approach with its affiliate CNPI and associates WPI and GPI. This was a logical approach because GPI and WPI both use the SAP CIS hosted by CNPI, while API is in the process of migrating its Customer Information functions into SAP. By adopting common business processes, these four utilities could utilize a single SAP development solution that was implemented by CNPI's IT personnel. This allowed for the sharing of SAP development costs among CNPI, API, GPI, and WPI (collectively referred to hereafter as the "Group"). Acting on behalf of API, GPI, and WPI, CNPI also negotiated with Util-Assist an agreement for Util-Assist to provide specific additional services during this phase of the Project, namely:

- Performing in-depth analyses of existing business processes and leading the development of new common, specific business processes for operating the SAP CIS in an AMI/MDMR environment
- Providing general support through this phase in developing project plans, liaising with the SME, and assisting during the MDMR Testing phase

Assisted by Util-Assist, the Group proceeded to plan for this final phase of the Project. During this phase, CNPI liaised with Util-Assist and the SME on behalf of the Group, and also provided IT support to GPI and WPI during their Testing process. CNPI also hosted training sessions for its own personnel as well as GPI and WPI to roll out and explain the new business processes and provide training on using the SAP TOU tools. Util-Assist and CNPI led the development of a single, comprehensive project plan for the Group, detailing the various tasks that each utility had to undergo in order to implement TOU billing. CNPI registered with the SME in September 2010, and registered as a single entity encompassing CNPI's service areas in Fort Erie, Port Colborne and Gananoque, and API. This was possible because of the fact that the CNPI companies and API all deployed the Sensus AMI system and will share the same SAP CIS. As described earlier, this will enable CNPI and API to consolidate billing and meter data management functions at the Fort Erie office. Essentially, this will allow CNPI and API to operate as a single entity as far as interactions with the SME and MDMR are concerned. GPI and WPI registered separately with the SME. After registration, the Group's common project plan was formally submitted to the SME, which accepted the plan.

In terms of the SAP CIS development itself, the first critical stage was for CNPI to implement a technical upgrade to its SAP CIS. This upgrade was required because it would enable SAP to be more readily configured for MDMR connectivity and TOU billing. The reasons for this upgrade were explained in detail in the CNPI 2009 EDR Cost of Service Application, EB-2008-0223. This upgrade was successfully completed in March 2011.

Following the completion of the SAP technical upgrade, the CIS was then developed to achieve connectivity with the MDMR and implement new business processes to facilitate TOU billing. This development was carried out by CNPI IT resources with assistance from skilled consultants who also had experience in developing SAP TOU solutions for other LDCs. As described earlier, CNPI successfully developed a solution that was common to the Group and allowed the four utilities to derive the economic benefit of sharing the costs. Early on in the development process, CNPI decided to develop the SAP CIS solution to perform TOU billing functions only in the MDMR Version R7.2 operating environment. Version R7.2 is the MDMR upgrade that will allow the MDMR to transmit to LDCs meter register reads along with kWhr data in TOU "buckets", allowing LDCs to display register reads on their consumer invoices. The current MDMR operating environment, Version R7.0, does not have the functionality to process register reads, so LDCs who have implemented TOU billing are currently unable to display register reads on consumer invoices. This is not in accordance with Measurement Canada requirements. CNPI, therefore, decided to develop its CIS solution only for Version 7.2 billing functionality for the following reasons:

1. CNPI would be compliant with Measurement Canada requirements when it implemented TOU billing
2. CNPI considered it imprudent to develop a solution to perform billing in Version R7.0 and then incur costs later to make modifications to the CIS to bill in Version R7.2 once the SME promoted R7.2 to Production. CNPI felt

that incurring these extra costs would not be in the best interests of its ratepayers.

3. At the time, the SME timelines for the upgrade to R7.2 indicated that it would be completed before CNPI was ready to implement TOU billing.

CNPI proceeded with developing its CIS solution and preparing for MDMR integration and subsequent testing process. Throughout these stages of the Project, CNPI continued to work closely with Util-Assist and also SME project personnel, who provided valuable insight and assistance throughout the process. The SAP CIS successfully passed its MDMR Connectivity Testing in July 2011. The Group was now ready to proceed with the MDMR Testing phase of the process.

The MDMR Testing process required by the SME was a rigorous, structured process designed to ensure that LDCs had in place AMI network, customer information systems, and business processes required to effectively function in a TOU billing environment with the MDMR playing a central role. At each stage of the testing process, CNPI was required to provide evidence that SME requirements were met. There were three key stages in the MDMR Testing process:

1. *Unit Testing*, in which CNPI internally tested its new AMI and CIS business processes to verify that they met functional requirements. CNPI completed this stage in November 2011, and submitted its Self-Certification for Enrollment Testing on November 21, 2011. This qualified CNPI to enter the MDMR Enrollment Testing phase.
2. *System Integration Testing (SIT)*. In this stage, CNPI tested its interfaces to ensure that the AMI and CIS could operate with the MDMR and effectively handle the entire meter-to-bill process. CNPI successfully completed the SIT stage in December 2011.
3. *Qualification Testing (QT)*. This testing phase entailed “end-to-end” testing, in which CNPI had to demonstrate that its business processes could support the entire meter-to-bill process. CNPI successfully completed this stage in February 2012, and submitted its Self-Certification for Cutover on February 21, 2012.

On February 21, 2012, the SME formally informed CNPI that it had successfully completed Enrollment Testing and was ready to cutover to the MDMR Production environment. CNPI commenced cutting over its meter population to the MDMR production environment, which meant that CNPI meters were flowing "live" data to the MDMR. By March 2012, CNPI's entire Smart Meter population was cutover to the MDMR. At this point in time, Version R7.2 had not been promoted to MDMR Production. Therefore, CNPI could not proceed with TOU billing immediately. The SME promoted R7.2 to Production in April 2012. CNPI will begin converting its consumers to TOU billing in May 2012 (that is, invoices will be sent out in July for June consumption on TOU rates). Following successful implementation of TOU billing for CNPI consumers, CNPI's IT staff will begin the significant undertaking of migrating all of API's existing CIS data into CNPI's SAP CIS system. Following this migration and further testing, API expects to begin converting its consumers to TOU billing in January 2013 (that is, invoices will be sent out in February for January consumption on TOU rates).

Other significant issues pertinent to the Project are described in the following.

Minimum Functionality

The minimum functionality for AMI systems was set out on O. Reg. 425/06, *Criteria and Requirements for Meters and Metering Equipment, Systems and Technology* and the associated document Functional *Specification of an Advanced Metering Infrastructure, Version 2,* issued July 5, 2007 (the "Functional Specification"). These documents defined minimum functionality to include the significant components of the AMI system, namely:

- The Advanced Meter Communication Device (AMCD), or Smart Meter;
- The Advanced Regional Metering Collector (AMRC). In the case of the API Sensus AMI system, these devices are the TGB, FRP, and FNP.
- The Advanced Metering Central Computer (AMCC). This is the RNI in the Sensus AMI system.

The AMI system deployed by API did not exceed the minimum functionality requirements. However, there were two aspects of the Project where minimum functionality was exceeded, namely:

1. MDMR integration and TOU rate implementation, and
2. Operational Data Storage (ODS) implementation.

In terms of MDMR integration and TOU rate implementation, O. Reg. 393/07, Designation of Smart Metering Entity, defined the IESO as the Smart Metering Entity (SME) responsible for processing all meter read interval data to provide billing data to Ontario LDCs. Meter data processing is performed at the centralized MDMR. In order to achieve the objective of implementing TOU billing, it was necessary for meter data to flow to the MDMR from API's AMI system, and also for CNPI to configure its SAP CIS to achieve real-time integration with the MDMR to successfully function in a TOU billing environment. CNPI, on behalf of the Group, implemented a number of new business processes to support MDMR and TOU functionality, and these business processes had to be configured within the SAP system. Costs were also incurred for CNPI to progress through the formal, systematic enrolment testing phase required by the SME. Without undertaking the activities above, API would not have been able to comply with the mandate to implement TOU billing. Therefore, the activities and associated costs to achieve MDMR integration and implement TOU billing were justified. Costs were incurred for the following:

- SAP consultants were contracted to perform SAP development and assist through the testing phase
- Software and licensing, such as for the AS2 client required to achieve CIS-MDMR connectivity
- CNPI labour costs associated with SAP development, testing with the MDMR, and project co-ordination.
- Util-Assist was contracted to provide project management services, lead the development of new business processes, and provide support through the testing phase.

The above costs, therefore, were incremental to API normal day-to-day operations, and the recovery of these costs is justified.

In terms of the implementation of the ODS, this aspect of the project was necessary to support data management functionality. The ODS was required for the following reasons:

1. The ODS is used to audit the quality of data from the AMI system. While the AMI system will indicate that meters are communicating, the ODS can verify the quality of the data and identify any gaps in communication to facilitate troubleshooting efforts. The ODS, therefore, is an important tool for assessing the performance of the AMI network and ensuring that Service Level Agreement (SLA) performance metrics are maintained.
2. According to the Ministry of Energy's Functional Specification, the AMCC (that is, the Sensus RNI) is limited to storing AMI data for a maximum of sixty days. The ODS can store unlimited data and allows for archiving of data for comprehensive analysis by API.
3. The ODS can be used to analyze new rate structures to assess the possible impact to consumers. This analysis would allow API to understand which consumers would be most affected by new rate structures, thereby facilitating the forecasting of customer call volumes and the focusing of Demand-Side Management (DSM) efforts on consumers that would benefit most from changing their energy consumption patterns.
4. The MDMR presently handles only billing (kWhr) data, and does not process operational data such as power quality (e.g., low voltage alarms) and outage notifications. The ODS can process this data and allow API to utilize it to enhance operational functions. Moreover, the ODS allows for the processing of billing data (kWh, kW) to be used for system planning functions. The ODS, therefore, plays a key role in allowing API to use data from its AMI system to achieve operational benefits.

For the reasons listed above, the ODS is an integral tool for meter data and AMI system management. The intent of the ODS was not to duplicate functions to be performed by the MDMR, but rather to complement the AMI and MDMR to provide an efficient data management system. Moreover, once the majority of its Smart Meters were deployed, API commenced using the ODS to remotely read meters in late 2010 to save on the costs of manual meter reading. Thus, the ODS also led to economic benefit for API. The implementation of an ODS by API was, therefore, justified. Working with D9 and Util-Assist, API pursued a prudent approach to ODS implementation. D9 conducted research on systems available on the marketplace and prepared an RFP and comprehensive evaluation model that assessed both technical and financial factors. The weighting was 60% for technical factors and 40% for financial. Because D9 did not wish the ODS to duplicate MDMR functionality, and also because the MDMR may have the capability in future to process operational data, D9 decided to procure and ODS solution that was an Application Service Provider (ASP) model. This would allow the system to grow with the needs of each individual D9 utility, while providing flexibility with regards to contract term.

After a comprehensive RFP, bidding, and evaluation process, Harris was selected as the winning bidder. The D9 group entered into contract negotiations with Harris and API entered into a contract with Harris to provide ODS services.

Costs for ODS implementation and operation are incremental to API's normal day-to-day operational costs. ODS costs include the setup costs and monthly fees. Recovery of these costs is justified because of the necessity of the ODS to allow API to successfully manage its AMI system and meter data and utilize AMI data to achieve operational efficiencies.

TOU billing timelines

This section provides an overview of regulatory timelines associated with TOU billing implementation and API activities with regard to meeting said timelines. On June 24, 2010, the OEB issued a proposed determinant under Section 1.2.1 of the Standard Service Supply Code to mandate deadlines for each LDC to implement TOU billing for RPP consumers. CNPI responded to the proposed determinant on July 7, 2010, and commented that CNPI needed to implement upgrades to its SAP CIS to facilitate integration with the MDMR and TOU billing. In addition to the CNPI SAP CIS upgrade, API would have to transition to the CNPI SAP CIS system in order to avoid duplicating its own MDMR integration efforts. On August 4, 2010, the Board issued its final determination that mandated specific dates for each LDC to implement TOU billing. API was mandated to implement TOU billing by June 2011.

CNPI and its affiliates and associates initially set out to meet the mandated TOU billing dates, but it became evident that more time would be required to successfully complete the SAP technical upgrade, the SAP development for TOU billing, and the testing process with the SME. Therefore, on November 25, 2010, CNPI, API, GPI, and WPI formally submitted to the Board an Application for Exemption from Mandated Time-of-Use Pricing (Board File EB-2010-0307). In this Application, API described the reasons for the exemption and requested an extension to the mandatory TOU billing date, from June 2011 to July 2012.

After a written hearing on the Application, the Board issued its Decision on March 29, 2011, granting the requested extensions to TOU dates.

Led by CNPI, the Group continued to work towards MDMR integration and the Testing process. These activities were detailed in the previous sections. In accordance with Board requirements, API filed monthly reports with the Board summarizing progress with Smart Meter installation and implementing TOU billing. Because of delays in the implementation Version R7.2 of the MDMR Operating environment, CNPI IT resources continued to be involved with the CNPI TOU aspect of the project for a longer period of time than originally expected. Consequently, CNPI IT resources were unable to be deployed to the API SAP migration project until CNPI was ready to move to TOU billing. It is presently anticipated that the SAP CIS implementation at API will be complete by November 2012, and API will be ready to implement TOU billing by January 2013. API is presently preparing a formal Application to the OEB for an extension to its TOU billing implementation dates.

API's Unique Aspects

In terms of the Smart Metering Initiative, API faced several challenges that arose due to the unique nature of its service territory:

- An expansive service territory covering approximately 14,200 square kilometers.
- Rural and rugged terrain with dense vegetation. Less than 0.1% of API's service territory could be considered urban.
- Low customer density – 6.3 customers per km of line, or 0.8 customers per square kilometer of geographical area.

The combination of the above aspects contributes to API's higher per customer cost required to deliver safe and reliable distribution services, to the point where API must rely on the availability of Rural or Remote Rate Protection (RRRP) funding to prevent significant and unsustainable rate increases to the local populace. These unique aspects have had a similar effect on the costs associated with API's Smart Meter Project, as described in more detail below.

Progression through a propagation study and the subsequent deployment of the AMI communication infrastructure became a significant undertaking at API. For most Ontario LDC's, Sensus took the approach of providing essentially complete coverage of the service territory, primarily using TGB's situated at existing LDC or 3rd-party radio towers. Given that certain areas of API's service territory are essentially uninhabited, and many others are extremely low-density, API decided that a similar approach would not be prudent from an economic perspective. API and Sensus agreed to a modified approach as the basis for the initial Propagation Study. This approach would provide coverage using TGB's for areas with higher population density and would use lower-cost FNP's or FRP's to extend coverage to lower-density areas. Coverage would not be provided for areas that were completely uninhabited.

Through late 2008 and early 2009, Sensus completed several iterations of the Propagation Study, based upon discussions with API. The final result was a requirement for 8 TGB's, 16 FNP's and 19 FRP's - far less than the infrastructure that would have been required to cover API's service territory in its entirety.

The next significant challenge faced by API was obtaining optimal locations for the actual siting of the 8 TGB's. For 7 of the 8 locations, Sensus and API identified existing 3rd-party radio tower sites that would be suitable for installing the TGB's. For the other location, API planned to install its own antenna structure, as there was no suitable existing structure close to the preferred location. Of the 7 locations planned for 3rd party radio towers:

- 4 of the negotiations for tower leases were successful on the original tower
- 1 negotiation was unsuccessful; however there was an alternate tower site nearby at which Sensus was able to successfully negotiate a lease

Two negotiations were unsuccessful and with no other options in the area, API had to install its own structure. All of the above negotiations required considerable involvement of API's project management resources, as well as expenses for drafting and legal review of the lease agreements. The two ultimately unsuccessful negotiations increased the total number of antenna structures to be installed by API to three. In order to achieve the coverage areas identified in the Propagation Study, API had to install antenna structures between 20 and 30 meters in height. The installation of new antenna structure of this height required API to undertake an in-depth public consultation process to meet Industry Canada requirements for installation of a new antenna system. In two of the three locations, API also had to negotiate easements with landowners as API did not own any property in the area.

API also faced challenges with the actual installation of the TGB's. At all but one location, there was no suitable building in which API could place the TGB equipment. As a result, API had to order seven outdoor versions of the TGB and have suitable foundations designed and constructed for placement of this equipment.

API's rural, low-density service area also resulted in higher meter installation costs as compared to other LDC's. These additional costs are primarily related to the following:

- The installation contractor's RFP response included different rates for urban, semi-urban and rural installations. Approximately 76% of API's installs fell into the highest rate rural category.
- Meter changes carried out by API internal crews required significant travel time between sites.

Risk Mitigation

As mentioned earlier, the Smart Meter Project was a major undertaking for API. The Project entailed significant risks for API because of its large scale, the installation and ongoing operation of new, largely unknown AMI technology, the new concept of integrating with a centralized meter data management system, the implementation of new rate structures, the development of new business processes to support operating in an AMI/TOU environment, ensuring compliance with regulatory requirements, and the large costs involved. API undertook to mitigate risks by adopting a prudent, systematic, thorough approach to managing and executing the project. While the various stages of the Project were all of significant importance, API placed great emphasis on the Planning stage of the Project to ensure that API was well prepared to undertake the various tasks required for successful completion of the project. API also leveraged various relationships to form partnerships that supported the efficient and effective execution of various aspects of the project. Some of the initiatives undertaken by API to mitigate risk are as follows:

- Partnering with the D9 utilities through the Planning, Procurement, and Deployment phases of the Project. This partnership allowed D9 utilities to benefit from shared resources and the operational and pricing efficiencies inherent in a group approach. These benefits would not have been possible had API undertaken the Project on its own.
- D9 mitigated the risk of owning and maintaining a significant component of the AMI network by opting to collectively lease the Sensus RNI (AMCC), with Sensus being responsible for its operation and maintenance. API also entered into an escrow agreement with Iron Mountain for that company to hold the Sensus

software to ensure its availability to API should Sensus become insolvent in future.

- Working with D9 to engage the services of Util-Assist, who because of their experience and expertise provided valuable guidance and support throughout the Project. CNPI (on behalf of the Group that includes API) also engaged Util-Assist to provide services in the MDMR Integration phase of the Project. Without the benefit of Util-Assist's expertise and assistance, the Project would have been a much more difficult undertaking.
- Partnering with CNPI and its associate companies – Grimsby Power, and Westario Power – to undertake a collaborative approach to MDMR integration and TOU billing. This partnership allowed API to benefit from sharing in the costs of this aspect of the project.
- AMI system security – API mitigated the risk of operating an unsecure AMI network by participating in a Sensus AMI system security audit in partnership with other Ontario LDCs who deployed the Sensus FlexNet system. The audit was undertaken by Bell Wurldtech. Partnering with other LDCs allowed API to share the costs of this initiative.
- AMI system upgrades – there is a risk that future software and firmware upgrades to the Sensus FlexNet system may not function appropriately. CNPI (on behalf of API) mitigated this risk by participating with other Sensus LDCs in the PowerStream testing service, where PowerStream tests future releases of Sensus software before they are deployed. The participating LDCs share the cost of this initiative.

SMART METER PROGRAM COSTS

API installed 7,040 Residential, 3,548 Seasonal and 947 General Service less than 50 kW ("GS < 50 kW") Smart Meters in its service area between 2009 and 2011 representing 100% installation to applicable customers as at the end of 2011.

Cumulative audited Smart Meter capital costs incurred as at December 31, 2011, was \$4,272,096. An additional \$227,700 is forecasted to be incurred in 2012, with total capital costs forecasted of $4,499,796. See Table 1-1 below for summary of Smart Meter installations, funding adder recoveries and capital costs audited to December 31, 2011, as well as 2012 and 2013 forecast information. Schedule 1 in this application shows a more detailed analysis for API. Included in the Smart Meter capital costs is $103,369 ($43,369 in 2011 audited costs and $60,000 in 2012 forecasted costs) for functionality beyond the minimum functionality adopted in O.Reg. 425/06 in 2010 in relation to integrating with the MDM/R. API has not included in the Smart Meter Program Costs aspect of this application costs associated with the installation of Smart Meters in the General Service over 50 kW rate class. Instead, these costs were tracked separately for accounting purposes as the majority of these meters that were installed, replaced meters that were due for exchange in accordance with Measurement Canada's seal expiration dates.

Cumulative audited Smart Meter OM&A costs incurred as at December, 31, 2011, was $99,868. API has included in these costs only those that were deemed to be incremental in implementing the Smart Meter program (i.e. AMI and ODS service costs), less any cost savings that resulted from the implementation of the Smart Meter program (i.e. meter reading services).

Table 1-1: Summary of Smart Meter Costs – API

	2006 Audited	2007 Audited	2008 Audited	2009 Audited	2010 Audited	2011 Audited	2012 Forecast	2013 Forecast	Total
Total number of Smart Meters installed (Residential and GS < 50 kW only)	0	0	0	408	10,667	460	0	0	11,535
Cummulative number of Smart Meters installed (Residential and GS < 50 kW only)	0	0	0	408	11,075	11,535	11,535	11,535	
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed	0.00%	0.00%	0.00%	3.54%	96.01%	100.00%	100.00%	100.00%	
Recovery through Smart Meter Funding Adder	0	0	0	0	0	-128,873	-142,147	0	-271,020
Capital Costs									
1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	$ -	$ -	$ -	$ 114,840	$ 1,307,503	$ 307,525	$ -	$ -	$ 1,729,868
1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	$ -	$ -	$ -	$ 1,260,310	$ 230,423	$ 164,997	$ 144,000	$ -	$ 1,799,730
1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	$ -	$ -	$ -	$ 950	$ -	$ -	$ -	$ -	$ 950
1.4 WIDE AREA NETWORK (WAN)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY	$ -	$ 31,428	$ 78,920	$ 409,018	$ 230,023	$ 92,790	$ 23,700	$ -	$ 865,879
1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY	$ -	$ -	$ -	$ -	$ -	$ 43,369	$ 60,000	$ -	$ 103,369
Total Smart Meter Capital Costs	$ -	$ 31,428	$ 78,920	$ 1,785,118	$ 1,767,949	$ 608,681	$ 227,700	$ -	$ 4,499,796
Total Capital Costs per Smart Meter Installed									390.10
OM&A Expenses									
2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	$ -	$ -	$ -	$ -	$ 99,059	$ -	$ -	$ -	$ 99,059
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.4 WIDE AREA NETWORK (WAN)	$ -	$ -	$ -	$ -	$ 809	$ -	$ -	$ -	$ 809
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter OM&A Costs	$ -	$ -	$ -	$ -	$ 99,868	$ -	$ -	$ -	$ 99,868
Total OM&A Costs per Smart Meter Installed									8.66

Smart Meter Funding Adders Collected

API began recovery of the Smart Meter Funding Adders ("SMFAs"), in the amount of $1.00 per month per metered customer, per the 2010 Decision and Order (EB -2010-

0400 & EB-2009-0278). Rates were effective December 1, 2010 and the amounts collected have been tracked in an OEB sub account 1555. API's accounting system records all SMFAs collected in one account. Therefore, the SMFAs collected have been allocated to customer classes based on the percentage of meters installed for each class. See Schedule 2 of this application for allocation of rate adder collections between Residential, Seasonal and GS < 50 kW rate classes. The continuation of the rate adder of $1.00 per month per metered customer was approved as part of the 2011 Decision and Order (EB-2011-0152) for rates effective January 1, 2012, with an implementation date of February 1, 2012. This rate adder is effective until December 31, 2012.

For a detailed month-by-month tracking of the SMFAs collected since December 2010 and a forecast from May 1, 2012 to December 31, 2012 refer to Schedule 1 in this application.

Smart Meter Incremental Revenue Requirement

See Schedule 1 of this application for calculation of the Smart Meter Incremental Revenue Requirement ("SMIRR") per the Smart Meter model released by the Board. API recognizes the fact that certain Smart Meter program costs were more specific to a rate class and as such have calculated SMIRRs by class in Schedule 3 of this application.

STRANDED METERS

In this Application, API is requesting to recover its stranded meter costs in the amount of $331,640.

Replacement of Smart Meters

As part of the SMI, API began replacing conventional meters with Smart Meters in 2009 for Residential, Seasonal and GS < 50 rate class customers. At the beginning of the project API disposed of all meters in inventory. In 2009, in recording the disposal, the net book value of the meters in inventory of $39,718 was recorded in OEB 1555 as shown in Table 1 below. No further depreciation was recorded on these meters. If depreciation had been recorded in the 2010 to 2012 period, additional depreciation of $9,956 would have been recorded.

Table 1 - Stranded Meter Treatment (Appendix 2 - R-A of Filing Requirements)

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$ -		$ -
2007					$ -		$ -
2008					$ -		$ -
2009		$ 105,156	$ 65,438		$ 39,718		$ 39,718
2010					$ -		$ -
2011					$ -		$ -

As meters that were in service were replaced with Smart Meters, they continued to be depreciated in API's accounting records, with depreciation expense included in OEB 5705 and accumulated depreciation recorded in OEB 2105. The original capital costs of these stranded meters remained in OEB 1860. For 2012, depreciation expense has also been calculated to allow for a forecasted residual net book value balance as at December 31, 2012. As shown in Table 2 below, the residual net book value of the stranded meters that were taken out of service has been forecasted to be $291,922 as at December 31, 2012.

Table 2 - Stranded Meter Treatment (Appendix 2 - R-B of Filing Requirements)

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$ -		$ -
2007					$ -		$ -
2008					$ -		$ -
2009					$ -		$ -
2010					$ -		$ -
2011					$ -		$ -
2012		$ 890,529	$ 598,607		$ 291,922		$ 291,922

API will start to calculate interest on the effective date of the rate order, which will be recorded separately in the sub-account.

EXEMPTIONS REQUESTED

The Provincial Smart Meter Functional Specification imposes a very high standard related to Smart Meter data retrieval and availability of that data for processing and customer use. The implementation of a workable solution is a significant challenge for urban and more densely populated rural areas but the existing technologies have proven to have a limit in their reach to support Smart Meter requirements in the very rural and very sparsely populated portions of Algoma Power Inc. service territory.

API continues to work with the industry and vendors to accelerate the development of technology enhancements that will extend the "smart meter reach" to these customers. Based on anticipated progress, a solution that adequately addresses this gap is not expected anytime soon at a reasonable cost.

API is in a position similar to Hydro One with regards to being able to collect interval data from smart meters in extremely remote areas and subsequently being able to bill these customers on TOU rates.

- Key similarities between API and Hydro One's smart meter challenges in remote areas:
  - API serves a vast service area in Northeastern Ontario with low population density.
  - Much of API's service area is beyond the reach of 3rd party cellular networks.
- Key differences between API and Hydro One's smart meter challenges in remote areas:
  - API's AMI network does not rely on cellular coverage to the same extent that Hydro One's network does.
  - API's "hard to reach" meters represent less than 1% of total meter population, as opposed to ~11% for Hydro One.
  - API's network uses licensed radio frequency (RF) coverage in the 900 MHz range for communication between Tower Gateway Basestations

(TGB's) and thousands of meters. This coverage is supplemented by FlexNet Network Portals (FNP's), and FlexNet Regional Portal (FRP's). FNP's do not require backhaul communications, but rather act as a RF repeater to extend TGB RF coverage into "blind spots". FRP's essentially act as a "mini-TGB" to collect data from a small number of meters in areas beyond the limits of TGB coverage. FRP's require a separate communications backhaul.

The timelines related to implementation of the AMI, and associated challenges in extremely remote areas are as follows:

- API signed a contract with its AMI provider (Sensus) in October 2009 and subsequently completed detailed propagation studies and AMI system deployment.
- API completed installation of 8 TGB's in 2010 and the first half of 2011.
- By October 31, 2010, API had completed approximately 90% of meter exchanges.
- Installation of FNP's and most FRP's occurred throughout 2011 and into 2012 to improve and extend RF coverage. The backhaul selected for FRP's was a mixture of ordinary telephone lines and cellular modems.
- In combination with a very low number of customers, API found that a few of the extremely remote areas requiring FRP's did not have access to either ordinary telephone lines or cellular modems. API began investigating alternative backhaul communications.
- API initiated a 'network tuning' process in 2012 to improve performance for meters that were unheard or that had low read interval success (RIS) levels. This is a process where communication modes of individual meters are reviewed and changed if necessary to ensure optimum communication with infrastructure in the area (TGB vs FNP/FRP).

The timelines related to TOU billing at API are as follows:

- June 24, 2010: OEB issued a proposed determinant on TOU billing.

- July 7, 2010: CNPI commented that API would have to transition to the CNPI SAP CIS system in order to avoid duplicating MDMR integration efforts.
- August 4, 2010: OEB final determination mandated API to implement TOU billing by June 2011.
- September 2010: API became aware of Hydro One's application for an exemption from mandated TOU pricing for certain RPP customers in remote areas. API realized that it was facing similar challenges, but elected not to file a similar application for the following reasons:
  - API had focused its efforts to date on installation of TGB's and the mass deployment of smart meters. Remote repeaters had yet to be installed and meters had yet to be exchanged in some of API's most remote areas.
  - API would be part of a FortisOntario application for exemption for mandated TOU pricing due to the above-mentioned CIS migration issue.
  - If approved, the FortisOntario request would result in a new mandatory TOU date of July 2012.
  - In reviewing expansion plans for local cellular service providers, it became apparent that coverage would be expanding in API's service area during the 2010-2012 period.
  - API believed that significant progress could be made in the September 2010 to July 2012 period and an application similar to the Hydro One application could be made in advance of July 2012, if required.

The following is a summary of remote areas where technical and/or cost challenges remain a barrier to being able to read meters via the AMI system. All of these areas are far enough from TGB coverage that an FRP would be required. The estimated cost to install a FRP at each location is in the $10-20k range, depending on whether or not a new pole and cellular amplifiers are required. The estimated incremental O&M costs per site is $300 per month for Industry Canada licensing and $100 per month for communication, if cellular backhaul or phone lines are available. Where cellular or telephone backhaul is not available, API currently does not have a realistic means of remotely reading these meters.

The vast majority of customers in these areas fall into the following categories:

- Seasonal – typically low-consumption summer usage
- Small Commercial
    - Lodges – typically a number of campsites or cabins behind a single meter (seasonal service)
    - Government Ministries and Contractors – park campsites, radio towers, highway maintenance
    - Telecommunications Companies (Telco) and Railways – towers, equipment buildings, signaling
    - Station Service – backup station service for transformer and generating stations – typically 0 consumption

Location	Cell	Phone	# Meters	Customer Notes
Anjigami	No	No	8	6 Seasonal, 2 Small Commercial
Catfish Lake	No	No	3	3 Small Commercial
Fungus Lake	No	No	2	2 Small Commercial
Hammer Lake	No	No	1	1 Small Commercial
Hwy 101 East	No	No	9	5 Seasonal, 1 Residential, 2 Small Commercial, 1 Temp Service
Lake Sup Prov Park (North)	No	No	1	1 Small Commercial
Lake Sup Prov Park (South)	Yes	No	10	10 Small Commercial
Lochalsh	No	No	1	1 Residential
Missanabie Outlying	No	No	6	6 Small Commercial
Montreal River – Canoe Rd	Yes	No	3	2 Seasonal, 1 Small Commercial
Steephill	No	No	1	1 Small Commercial
Trembley-Magpie	No	No	2	2 Small Commercial

RELIEF SOUGHT

Recovery through electricity distribution rates of API's prudently incurred Smart Metering Initiative costs is a unique challenge for API and its regulator, the OEB. The setting of electricity distribution rates for API's Residential R-1 and R-2 classes is subject to the RRRP Regulation, Ontario Regulation 442/01, in particular, section 4 subsections 3.1 and 3.2:

> (3.1) For each year, in respect of the rates for a distributor serving consumers described in paragraph 5 of section 2, the Board shall calculate the amount by which the distributor's forecasted revenue requirement for the year, as approved by the Board, exceeds the distributor's forecasted consumer revenues for the year, as approved by the Board. O. Reg. 335/07, s. 1 (2).
>
> (3.2) For the purpose of subsection (3.1), the distributor's forecasted consumer revenues for a year shall be based on the rate classes and on the rates set out for those classes in the most recent rate order made by the Board and shall be adjusted in line with the average, as calculated by the Board, of any adjustment to rates approved by the Board for other distributors for the same rate year. O. Reg. 335/07, s. 1 (2).

A copy of O. Reg. 442/01 is provided in Appendix B.

The rates for the Seasonal customer classification is not subject to the RRRP Regulation and therefore Smart Metering Initiative costs will likely be dealt with differently but nevertheless require attention.

In its Decision on API's 2012 Incentive Regulation ("IR") Application, EB-2011-0152, dated January 20, 2012, the Board approved a methodology to calculate the annual increment to electricity distribution rates in a non cost of service rate year. The approved IR methodology is summarized below:

- rates for API's Residential R-1 and R-2 classes are adjusted annually by the RRRP Adjustment Factor, determined annual by the Board,

- the revenues generated by the R-1 and R-2 rate classes using the RRRP Adjustment are compared to the revenue requirement of the R-1 and R-2 rate classes adjusted by the price cap adjustment index,
- the difference in these two amounts is used to determine the level of RRRP funding for the rate year, and
- the Street Lighting and Seasonal classes' rates are indexed by the price cap adjustment index.

Smart Meter Initiative cost recovery will not be allocated to the Residential R – 2 customer class, these customers are demand billed customers as they equate to the General Service Greater Than 50 to 4,999 kW customer classification.

API requests that the Board approve:

- Smart Meter Disposition for the recovery of costs related to the true-up of revenue requirement up to December 31, 2012 in the amount of $1,740,361,
- Smart Meter Incremental Revenue Requirement from an effective date of January 1, 2013 to December 31, 2013 in the amount of $733,567, and
- recovery of the stranded meter costs in the amount of $331,640

all on a final basis.

API will design and propose rates in its 2013 IR application to dispose of the balances in a manner consistent with the Board's Decision in the matter of EB-2011-0152 and compliant with O.Reg. 442/01. API will comply with the Board's schedule with respect to the submission of 2013 Incentive based rate applications.

In a letter to all Ontario electricity distributors dated August 4, 2010, the OEB provided its determination of mandatory dates by which each distributor must bill those of its RPP customers that have eligible time-of-use meters using time-of-use pricing. The Board's determination was made pursuant to sections 3.4 and 3.5 of the Standard Supply Service Code for Electricity Distributors, which requires time-of-use pricing for RPP consumers with eligible time-of-use meters, as of the mandatory date. Compliance with this Code is a condition of licence for nearly all licensed electricity distributors in Ontario.

API is requesting an exemption from this requirement for the 47 metered customers described in the Exemptions Requested section of the Application. API is requesting this exemption because of the unique challenges in serving these remote areas with the existing technologies. This exemption would remain in place until such time there is a viable and economic solution available.

Appendix A

PRP International, Inc.

Fairness Advisory Services

August 1, 2008

Mr. Greg Beharriel
Great Lakes Power Limited
2 Sackville Road
Sault Ste. Marie, ON P6B 6J6

Dear Mr. Beharriel:

Subject: Attestation of the Fairness Commissioner
Advanced Metering Infrastructure RFP, August-July 2008
London Hydro, Consortium & Add-On LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its letter report of the Fairness Commissioner for the noted Request for Proposal (RFP) evaluation and selection phase. This judgment is being provided for the information and use of each Add-On LDC Sponsor, in their consideration of the report from the Evaluation Phase, for this competitive transaction.

"It is the judgment of PRP International, Inc., as the Fairness Commissioner, that the determinations of the two (2) highest ranked Proponents for the ***District 9 Collective of LDCs (Chapleau Public Utilities Corporation, Espanola Regional Hydro Distribution Corp., Great Lakes Power Limited, Hearst Power Distribution Co. Ltd., North Bay Hydro Distribution Ltd., Northern Ontario Wires Inc. – Cochrane, and PUC Distribution Inc. (Sault Ste. Marie))*** *requirements are:*

- *KTI/ Sensus Limited, as the recommended Preferred Proponent, based on its highest ranking, and*
- *Elster Metering being the second ranked Proponent.*

These determinations were made in a fair (objective and competent) manner and consistent with the evaluation and selection processes set out in the RFP, issued August 14, 2007."

A detailed report for your records will be submitted to you, by August 31, 2008. Should you have any questions or require clarification of any matter contained in this letter report, please contact the undersigned.

Yours truly,

Peter Sorensen
President
cc: Mr. Gary Rains, RFP Project Director

203 - 8 QUEEN STREET, SUMMERSIDE, PEI C1N 0A6
TELEPHONE: 902.436.3930 FAX: 604-677-5409
EMAIL: fairness@telus.net

PRP International, Inc.

Fairness Advisory Services

August 15, 2009

Mr. Greg Beharriel
Great Lakes Power Limited
2 Sackville Road
Sault Ste. Marie, ON P6B 6J6

Dear Mr. Beharriel:

Subject: Confirmation of the Fairness Commissioner
Great Lakes Power Limited
- KTI/Sensus Limited Contract Award
Advanced Metering Infrastructure RFP, August 2007
London Hydro & Consortium of LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its Confirming Letter of the Fairness Commissioner for the noted negotiations and contracting phase of the LH AMI Request for Proposal (RFP) procurement. This judgment is being provided for the information and use of Great Lakes Power Limited ("GLPL"), in its administration of the contract awarded to its #1 ranked Proponent, KTI/Sensus Limited.

"It is the judgment of PRP International, Inc., as the Fairness Commissioner engaged by GLPL *for the phase of negotiations and contract award pursuant to the Fairness Protocols issued August 2008, that the successful conclusion of negotiations and contract between* Great Lakes Power Limited *and* KTI/Sensus Limited, *were undertaken in accordance with the principle for such negotiations and contract award set out in the RFP, issued August 14, 2007."*

A backgrounder and summary of the Fairness Protocols is attached and forms part of this Confirming Letter.

Yours truly,

Peter Sorensen
President

Attachment: Negotiations and Contract Phase Backgrounder

203 - 8 Queen Street, Summerside, PEI C1N 0A6
Direct telephone: 902.436.3930 Fax: 604-677-5409
Email: fairness@telus.net

BACKGROUNDER TO FAIRNESS CONFIRMATION / ATTESTATION
Advanced Metering Infrastructure Procurement

TO WHOM IT MAY CONCERN:

Background:

- A Request for Proposal procurement transaction was conducted by London Hydro Inc., as the lead sponsoring Local Distribution Company (LDC) and with a consortia of another 63 LDCs, during the period August 2007 to July, 2008;
- The evaluation and selection phase of the RFP provided for the determination of the #1 and #2 ranked Proponents for each LDC;
- RFP Provision 7.5.14[1] provides the framework (principle) for negotiations and contracting based on the principle of "first right to negotiation and execution of a contract" being accorded to the ranked order of Proponents commencing with the highest ranked Proponent and proceeding in a consecutive order thereafter; and
- Each LDC was provided the evaluation results for their #1 and #2 ranked Proponents supported by the Attestation Letter of the Fairness Commissioner as to those rankings.

Fairness Coverage Objective:

Normally, fairness coverage terminates with the determination of the ranked Proponents following the evaluation and selection phase of the RFP; however, certain LDCs expressed a wish to secure additional fairness coverage during the subsequent phase of negotiations and contract award. The objective for this second phase fairness coverage is to assure that LDCs undertook a phase of negotiations and contracting that meets the RFP provisions of consecutive negotiations where required, e.g. with their top two ranked Proponents and in the event of unsuccessful negotiations with the #1 ranked Proponent, a subsequent contract award to the next ranked Proponent would be on an equitable basis as was the requirements in the negotiations with the #1 ranked Proponent.

---

[1]

7.5.14 **Final Contract Negotiations**

Any conditions and provisions that a bidder seeks shall be a part of this proposal. Notwithstanding, nothing herein shall be interpreted to prohibit London Hydro from introducing or modifying contract terms and conditions during negotiation of the final contract.

London Hydro has scheduled no more than two weeks for contract negotiations (if necessary), and expects the successful bidder to maintain a prompt and responsive negotiation to accomplish and complete final contract agreement within that time period. If contract negotiations exceed an interval acceptable to London Hydro, London Hydro retains the option to terminate negotiations and continue to the next apparent successful bidder, at the sole discretion of London Hydro. Said interval shall in no event be less than three weeks.

BACKGROUNDER TO FAIRNESS CONFIRMATION / ATTESTATION
Advanced Metering Infrastructure Procurement

Fairness Protocols:

- A Fairness Protocol was developed and issued to all LDCs, in August 2008 that set forth the best practices for fair consecutive-based negotiations and contract award.
  - The fundamental principle of the Protocol was the requirement for the LDC to establish the negotiations agenda for their top ranked Proponents and submit a copy to the Fairness Commissioner prior to engagement of their #1 ranked Proponent, i.e. the agenda would demonstrate a common statement of work, a LDC standard for pass/fail in their negotiations and the negotiation issues would only differ to the extent of the respective Proponent's technical solution being offered.

Form of Fairness Confirmation / Attestation[2]:

1. A confirmation of fair negotiations and contract award would be issued if the LDC's #1 ranked Proponent was awarded a contract; the original Attestation Letter remains in effect.

2. An Attestation of fair negotiations and contract award would be issued if the LDC determined that their #1 Proponent was to be set aside and the LDC successfully contracted with their next ranked Proponent, e.g. their #2; the original Attestation Letter is thus superseded by the Negotiations and Contract Award Attestation Letter.

Local Distribution Company:

Great Lakes Power Limited

Mr. Greg Beharriel
Great Lakes Power Limited
2 Sackville Road
Sault Ste. Marie, ON P6B 6J6

---

[2] **Conditions on the rendering of this Confirmation / Attestation.**

- The two Negotiations Agenda were provided by GLPL, via its agent Util-Assist;
- Fairness Commissioner undertook no direct participation or oversight in the negotiations between GLPL and their #1 ranked Proponent;
- The successful contract award was based on the GLPL criteria and no independent analysis nor any comparison with the evaluation results of the RFP process was carried out by the Fairness Commissioner; and
- The confirmation of the Fairness Commissioner was based on the progress report(s) provided by GLPL, via its agent Util-Assist.

Appendix B

Rural or Remote Electricity Rate Protection, O. Reg. 442/01

Current version: in force since Oct 8, 2009

Link to the latest version : http://www.canlii.org/en/on/laws/regu/o-reg-442-01/latest/
Stable link to this version : http://www.canlii.org/en/on/laws/regu/o-reg-442-01/76257/
Currency: Last updated from the e-Laws site on 2011-04-22

Ontario Energy Board Act, 1998
Loi de 1998 sur la commission de l'énergie de l'Ontario

ONTARIO REGULATION 442/01

RURAL OR REMOTE ELECTRICITY RATE PROTECTION

Consolidation Period: From October 8, 2009 to the e-Laws currency date.

Last amendment: O. Reg. 391/09.

This Regulation is made in English only.

Definitions

1. (1) In this Regulation,

"government premises" means premises occupied by the Crown in right of Canada or Ontario or a facility that is funded in whole or in part by the Crown in right of Canada or Ontario, but does not include premises occupied by,

(a) Canada Post Corporation, the Services Corporation or a subsidiary of the Services Corporation, or

(b) social housing, a library, a recreational or sports facility, or a radio, television or cable television facility;

"IESO" and "IESO-controlled grid" have the same meaning as in the *Electricity Act, 1998*;

"market participant" means a market participant under the *Electricity Act, 1998*;

"rate protection" means rate protection under section 79 of the Act;

"remote area" means a part of Ontario not connected to the IESO-controlled grid that receives electricity from Hydro One Remote Communities Inc.;

"residential premises" means a dwelling occupied as a residence continuously for at least eight months of the year and, where the residential premises is located on a farm, includes other farm premises associated with the residential electricity meter;

"rural area" means those parts of Ontario connected to the IESO-controlled grid that, before March 31, 1999, received electricity from Ontario Hydro and, at the time subsection 26 (1) of the *Electricity Act, 1998* comes into force, are receiving electricity from Hydro One Networks Inc.;

"Services Corporation" has the same meaning as in the *Electricity Act, 1998*. O. Reg. 442/01, s. 1 (1); O. Reg. 383/04, s. 1 (1); O. Reg. 391/09, s. 1.

(2) Revoked: O. Reg. 383/04, s. 1 (2).

Eligibility for rate protection

2. In addition to the persons described in subsection 79 (2) of the Act, the following classes of consumers in Ontario are eligible for rate protection:

1. Revoked: O. Reg. 383/04, s. 2.
2. Consumers who occupy residential premises in a rural area and who, if section 108 of the *Power Corporation Act* had not been repealed by section 28 of Schedule E to the *Energy Competition Act, 1998* and electricity had continued to be distributed by Ontario Hydro, would have been entitled, pursuant to section 108 of the *Power Corporation Act* as it read on March 31, 1999, to pay Ontario Hydro a discounted rate for the electricity they consumed.
3. Consumers who occupy residential premises in an area referred to in Schedule 16, if Ontario Hydro distributed electricity in the area before December 16, 1997 and electricity in the area is now distributed by a distributor connected to the IESO-controlled grid, other than a subsidiary of Hydro One Networks Inc.
4. Consumers who occupy premises, other than government premises, in a remote area.
5. Consumers,

    i. who are treated as residential-rate class customers under Ontario Regulation 445/07 (Reclassifying Certain Classes of Consumers as Residential-Rate Class Customers: Section 78 of the Act) made under the Act, or

    ii. who occupy residential premises in an area served by a distributor where,

        A. the distributor is licensed to serve the consumers,

        B. the area is not less than 10,000 square kilometres in size, and

        C. the average customer density for the distributor is less than seven customers per kilometre of distribution line. O. Reg. 442/01, s. 2; O. Reg. 262/03, s. 1; O. Reg. 383/04, s. 2; O. Reg. 446/07, s. 1; O. Reg. 391/09, s. 2.

3. Revoked: O. Reg. 383/04, s. 3.

Amount of rate protection: 2004 and 2005

4. (1) The total amount of rate protection available for eligible consumers in each of the years 2004 and 2005 is $127 million, plus the amount calculated under subsection (2) for the year. O. Reg. 442/01, s. 4 (1); O. Reg. 383/04, s. 4 (1).

(1.1) The total amount of rate protection for eligible consumers in each year after 2005 shall not exceed $127 million plus the amount calculated under subsections (2) and (3.1) and shall be based on the amount of rate protection provided by the distributor to eligible consumers for the previous year. O. Reg. 335/07, s. 1 (1).

(2) For each year, the Board shall calculate the amount by which Hydro One Remote Communities Inc.'s forecasted revenue requirement for the year, as approved by the Board, exceeds Hydro One Remote Communities Inc.'s forecasted consumer revenues for the year, as approved by the Board. O. Reg. 442/01, s. 4 (2); O. Reg. 383/04, s. 4 (3).

(3) For the purpose of subsection (2), Hydro One Remote Communities Inc.'s forecasted consumer revenues for a year shall be based on the rate classes set out in Transitional Rate Order RP-1998-0001 made by the Board and on the rates set out for those classes in the most recent rate order made by the Board. O. Reg. 442/01, s. 4 (3).

(3.1) For each year, in respect of the rates for a distributor serving consumers described in paragraph 5 of section 2, the Board shall calculate the amount by which the distributor's forecasted revenue requirement for the year, as approved by the Board, exceeds the distributor’s forecasted consumer revenues for the year, as approved by the Board. O. Reg. 335/07, s. 1 (2).

(3.2) For the purpose of subsection (3.1), the distributor’s forecasted consumer revenues for a year shall be based on the rate classes and on the rates set out for those classes in the most recent rate order made by the Board and shall be adjusted in line with the average, as calculated by the Board, of any adjustment to rates approved by the Board for other distributors for the same rate year. O. Reg. 335/07, s. 1 (2).

(4) For each year, the Board shall calculate the amount of rate protection for individual consumers referred to in subsection 79 (2) of the Act and in section 2 of this Regulation in a manner that ensures that the total amount of rate protection for those consumers is equal to the total amount of rate protection available for the year under subsection (1) or (1.1), according to the following rules:

1. Revoked: O. Reg. 383/04, s. 4 (5).
2. For each of the areas referred to in Schedule 16, the Board shall take reasonable steps to ensure that, for each month, the total amount of rate protection for consumers in the area who are in the class described in paragraph 3 of section 2 is the total monthly amount set out for that area in Schedule 16.
3. The Board shall take reasonable steps to ensure that an amount equal to the amount calculated under subsections (2) and (3.1) for the year is used to provide rate protection to consumers who are in the class described in paragraphs 4 and 5 of section 2.
4. After paragraphs 2 and 3 are complied with, the Board shall take reasonable steps to ensure that the remainder of the total amount of rate protection available under subsections (1) and (2) is used to provide rate protection to,
   i. the persons described in subsection 79 (2) of the Act, and
   ii. the consumers who are in the class described by paragraph 2 of section 2. O. Reg. 442/01, s. 4 (4); O. Reg. 262/03, s. 2; O. Reg. 383/04, s. 4 (4-6); O. Reg. 335/07, s. 1 (3).

(5) Any distributor that distributes electricity to eligible consumers shall provide, on a quarterly basis, such information relating to this Regulation as the Board may require, in a form specified by the Board. O. Reg. 383/04, s. 4 (7).

Compensation for distributors

5. (1) The Board shall calculate the amount of the charge to be collected by the IESO under subsection (5) for each kilowatt hour of electricity that is withdrawn from the IESO-controlled grid, as determined in accordance with the market rules, for use by consumers in Ontario, so that the total amount forecast to be collected is equal to the total amount of rate protection to be provided. O. Reg. 383/04, s. 5 (1); O. Reg. 391/09, s. 3 (1).

(2) At least 60 days before the end of each calendar year, the IESO shall submit to the Board,

(a) a forecast of the number of kilowatt hours of electricity that will be withdrawn from the IESO-controlled grid, as determined in accordance with the market rules, for use by consumers in Ontario during the next calendar year; and

(b) supporting documentation for the forecast. O. Reg. 442/01, s. 5 (2); O. Reg. 391/09, s. 3 (2, 3).

(3) The forecast shall be derived from information submitted to the Board under section 19 of the *Electricity Act, 1998* in respect of the next fiscal year O. Reg. 442/01, s. 5 (3).

(4) The IESO shall give a copy of the forecast and supporting documentation to Hydro One Networks Inc. O. Reg. 442/01, s. 5 (4); O. Reg. 391/09, s. 3 (4).

(5) The IESO shall collect the charge calculated by the Board under subsection (1) from market participants and any other person who, with the approval of the IESO, withdraws electricity from the IESO-controlled grid for use by consumers in Ontario. O. Reg. 442/01, s. 5 (5); O. Reg. 391/09, s. 3 (5).

(6) A distributor or retailer who bills a consumer for electricity shall aggregate the amount that the consumer is required to contribute to the compensation required by subsection 79 (3) of the Act with the wholesale market service rate described in the Electricity Distribution Rate Handbook issued by the Board, as it read on October 31, 2001. O. Reg. 442/01, s. 5 (6).

(7) Each month, the IESO shall pay the charges it collected under subsection (5) in the preceding month to Hydro One Networks Inc. O. Reg. 442/01, s. 5 (7); O. Reg. 391/09, s. 3 (6).

(8) Hydro One Networks Inc. shall pay the amounts it receives under subsection (7) into a separate account. O. Reg. 442/01, s. 5 (8).

(9) Each month, Hydro One Networks Inc. shall, from the account referred to in subsection (8), pay distributors the compensation to which they are entitled under subsection 79 (3) of the Act. O. Reg. 442/01, s. 5 (9).

(10), (11) Revoked: O. Reg. 383/04, s. 5 (2).

(12) If the amount collected under subsection (5) in a year exceeds the total amount of rate protection available for eligible consumers under subsection 4 (1) or (1.1) in the year, the excess less the amount used to provide rate protection under subparagraph 4 iii of subsection 4 (4) shall be applied against the amount necessary to compensate distributors who are entitled to compensation under subsection 79 (3) of the Act for the following year. O. Reg. 383/04, s. 5 (3).

(13) If the amount collected under subsection (5) in a year is less than the total amount of rate protection available for eligible consumers under subsection 4 (1) or (1.1) in the year, the difference plus the amount used to provide rate protection under subparagraph 4 iii of subsection 4 (4) shall be added to the amount necessary to compensate distributors who are entitled to compensation under subsection 79 (3) of the Act for the following year. O. Reg. 383/04, s. 5 (4).

(14) Any interest or other income earned on the account referred to in subsection (8) shall be held in the account and shall be used for the purpose of subsection (9). O. Reg. 442/01, s. 5 (14).

6. Revoked: O. Reg. 383/04, s. 6.

7. Omitted (revokes other Regulations). O. Reg. 442/01, s. 7.

8. Omitted (provides for coming into force of provisions of this Regulation). O. Reg. 442/01, s. 8.

SCHEDULES 1-15 Revoked: O. Reg. 383/04, s. 7.

SCHEDULE 16
OTHER AREAS

Area	Total Monthly Amount of Rate Protection
Attawapiskat	$53,333.33
Fort Albany	30,000.00
Kaschechewan	50,000.00

O. Reg. 442/01, Sched. 16.

Schedule 1

V 2.21

Ontario Energy Board

Smart Meter Model
(for 2013 Rates Applications)

Choose Your Utility:

Algoma Power Inc.
Atikokan Hydro Inc.

Application Contact Information

Name:	Douglas R. Bradbury
Title:	Director, Regulatory Affairs
Phone Number:	905-994-3634
Email Address:	doug.bradbury@fortisontario.com
We are applying for rates effective:	January 1, 2013
Last COS Re-based Year	2010

Legend

DROP-DOWN MENU

INPUT FIELD

CALCULATION FIELD

Copyright

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results. The use of any models and spreadsheets does not automatically imply Board approval. The onus is on the distributor to prepare, document and support its application. Board-issued Excel models and spreadsheets are offered to assist parties in providing the necessary information so as to facilitate an expeditious review of an application. The onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Smart Meter Model

Algoma Power Inc.

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2012, distributors that have completed their deployments by the end of 2011 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2012, distributors should enter the forecasted OM&A for 2012 for all smart meters in service.

Smart Meter Capital Cost and Operational Expense Data

Smart Meter Installation Plan

	2006	2007	2008	2009	2010	2011	2012	2013	Total
	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
Actual/Planned number of Smart Meters installed during the Calendar Year									
Residential				363	9,978	247			10588
General Service < 50 kW				45	689	213			947
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)	0	0	0	408	10667	460	0	0	11535
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed	0.00%	0.00%	0.00%	3.54%	96.01%	100.00%	0.00%	100.00%	100.00%
Actual/Planned number of GS > 50 kW meters installed						34			34
Other (please identify)									0
Total Number of Smart Meters installed or planned to be installed	0	0	0	408	10667	494	0	0	11569

1 Capital Costs

1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	Asset Type (Asset type must be selected to enable calculations)	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	Total
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter				99,526	886,374	63,315			$ 1,049,215
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter				15,314	421,129	244,210			$ 680,653
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hardware, etc.)*	Computer Hardware									$ -
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardware, etc.)*	Computer Software									$ -
Total Advanced Metering Communications Devices (AMCD)		$ -	$ -	$ -	$ 114,840	$ 1,307,503	$ 307,525	$ -	$ -	$ 1,729,868

1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.2.1 Collectors	Smart Meter				1,039,887					$ 1,039,887
1.2.2 Repeaters *(may include radio licence, etc.)*	Smart Meter				32,810	90,327		50,000		$ 173,137
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*	Smart Meter				187,613	140,096	164,997	94,000		$ 586,706
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		$ -	$ -	$ -	$ 1,260,310	$ 230,423	$ 164,997	$ 144,000	$ -	$ 1,799,730

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.3.1 Computer Hardware	Computer Hardware									$ -
1.3.2 Computer Software	Computer Software				950					$ 950
1.3.3 Computer Software Licences & Installation (includes hardware and software) *(may include AS/400 disk space, backup and recovery computer, UPS, etc.)*	Computer Software									$ -
Total Advanced Metering Control Computer (AMCC)		$ -	$ -	$ -	$ 950	$ -	$ -	$ -	$ -	$ 950

1.4 WIDE AREA NETWORK (WAN)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.4.1 Activiation Fees	Tools & Equipment									$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.5.1 Customer Equipment *(including repair of damaged equipment)*	Other Equipment				123,690	47,681	22,692			$ 194,063
1.5.2 AMI Interface to CIS	Computer Software				710	8,805	1,164			$ 10,679
1.5.3 Professional Fees	Computer Software		19,914	33,572	48,351	34,739	14,709	3,500		$ 154,785
1.5.4 Integration	Computer Software					4,988				$ 4,988
1.5.5 Program Management	Computer Software		11,514	45,348	236,267	117,015	52,725	20,200		$ 483,069
1.5.6 Other AMI Capital	Computer Software					16,795	1,500			$ 18,295
Total Other AMI Capital Costs Related to Minimum Functionality		$ -	$ 31,428	$ 78,920	$ 409,018	$ 230,023	$ 92,790	$ 23,700	$ -	$ 865,879
Total Capital Costs Related to Minimum Functionality		$ -	$ 31,428	$ 78,920	$ 1,785,118	$ 1,767,949	$ 565,312	$ 167,700	$ -	$ 4,396,427

1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06										$ -

1.6.2 Costs for deployment of smart meters to customers other than residential and small general service										$ -
1.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.	Computer Software						43,369	60,000		$ 103,369
Total Capital Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ 43,369	$ 60,000	$ -	$ 103,369
Total Smart Meter Capital Costs		$ -	$ 31,428	$ 78,920	$ 1,785,118	$ 1,767,949	$ 608,681	$ 227,700	$ -	$ 4,499,796

2 OM&A Expenses

		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)										
2.1.1 Maintenance *(may include meter reverification costs, etc.)*										$ -
2.1.2 Other *(please specifiy)*										$ -
Total Incremental AMCD OM&A Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)										
2.2.1 Maintenance						99,059	0	0		$ 99,059
2.2.2 Other *(please specifiy)*										$ -
Total Incremental AMRC OM&A Costs		$ -	$ -	$ -	$ -	$ 99,059	$ -	$ -	$ -	$ 99,059
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)										
2.3.1 Hardware Maintenance *(may include server support, etc.)*								0		$ -
2.3.2 Software Maintenance *(may include maintenance support, etc.)*										$ -
2.3.2 Other *(please specifiy)*										$ -
Total Incremental AMCC OM&A Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.4 WIDE AREA NETWORK (WAN)										
2.4.1 WAN Maintenance						809	0	0		$ 809
2.4.2 Other *(please specifiy)*										$ -
Total Incremental AMRC OM&A Costs		$ -	$ -	$ -	$ -	$ 809	$ -	$ -	$ -	$ 809
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY										
2.5.1 Business Process Redesign										$ -
2.5.2 Customer Communication (may include project communication, etc.)										$ -
2.5.3 Program Management								0		$ -
2.5.4 Change Management (may include training, etc.)										$ -
2.5.5 Administration Costs										$ -
2.5.6 Other AMI Expenses *(please specify)*							0	0		$ -

Total Other AMI OM&A Costs Related to Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY		$ -	$ -	$ -	$ -	$ 99,868	$ -	$ -	$ -	$ 99,868
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual			
2.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06										$ -
2.6.2 Costs for deployment of smart meters to customers other than residential and small general service										$ -
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.										$ -
Total OM&A Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter OM&A Costs		$ -	$ -	$ -	$ -	$ 99,868	$ -	$ -	$ -	$ 99,868

3 Aggregate Smart Meter Costs by Category

3.1	**Capital**									
3.1.1	Smart Meter	$ -	$ -	$ -	$ 1,375,150	$ 1,537,926	$ 472,522	$ 144,000	$ -	$ 3,529,598
3.1.2	Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.3	Computer Software	$ -	$ 31,428	$ 78,920	$ 286,278	$ 182,342	$ 113,467	$ 83,700	$ -	$ 776,135
3.1.4	Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.5	Other Equipment	$ -	$ -	$ -	$ 123,690	$ 47,681	$ 22,692	$ -	$ -	$ 194,063
3.1.6	Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.7	**Total Capital Costs**	**$ -**	**$ 31,428**	**$ 78,920**	**$ 1,785,118**	**$ 1,767,949**	**$ 608,681**	**$ 227,700**	**$ -**	**$ 4,499,796**
3.2	**OM&A Costs**									
3.2.1	**Total OM&A Costs**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 99,868**	**$ -**	**$ -**	**$ -**	**$ 99,868**

Ontario Energy Board

Smart Meter Model

Algoma Power Inc.

	2006	2007	2008	2009	2010	2011	2012	2013
Cost of Capital								
Capital Structure[1]								
Deemed Short-term Debt Capitalization			4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Deemed Long-term Debt Capitalization		0.0%	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%
Deemed Equity Capitalization	100.0%	100.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Preferred Shares								
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters								
Deemed Short-term Debt Rate			4.47%	1.13%	2.07%	2.07%	2.07%	2.07%
Long-term Debt Rate (actual/embedded/deemed) [2]	5.80%	5.80%			5.87%	5.87%	5.87%	5.87%
Target Return on Equity (ROE)	9.0%	9.00%	8.57%	8.01%	9.85%	9.85%	9.85%	9.85%
Return on Preferred Shares								
WACC	9.00%	9.00%	3.61%	3.25%	7.31%	7.31%	7.31%	7.31%
Working Capital Allowance								
Working Capital Allowance Rate	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	13.0%
(% of the sum of Cost of Power + controllable expenses)								
Taxes/PILs								
Aggregate Corporate Income Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	25.50%
Capital Tax (until July 1st, 2010)	0.30%	0.225%	0.225%	0.225%	0.075%	0.00%	0.00%	0.00%

Depreciation Rates

(expressed as expected useful life in years)

Smart Meters - years	15	15	15	15	15	15	15	15
- rate (%)	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Computer Hardware - years	5	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Computer Software - years	5	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Tools & Equipment - years	10	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Other Equipment - years	10	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

CCA Rates

Smart Meters - CCA Class	47	47	47	47	47	47	47	47
Smart Meters - CCA Rate	8%	8%	8%	8%	8%	8%	8%	8%
Computer Equipment - CCA Class	45	50	50	50	50	50	50	50
Computer Equipment - CCA Rate	45%	55%	55%	55%	55%	55%	55%	55%
General Equipment - CCA Class	8	8	8	8	8	8	8	8
General Equipment - CCA Rate	20%	20%	20%	20%	20%	20%	20%	20%
Applications Software - CCA Class								
Applications Software - CCA Rate								

Assumptions

[1] *Planned smart meter installations occur evenly throughout the year.*

[2] *Fiscal calendar year (January 1 to December 31) used.*

3 *Amortization is done on a striaght line basis and has the "half-year" rule applied.*

Ontario Energy Board

Smart Meter Model

Algoma Power Inc.

	2006	2007	2008	2009	2010	2011	2012	2013
Net Fixed Assets - Smart Meters								
Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ 1,375,150	$ 2,913,076	$ 3,385,598	$ 3,529,598
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 1,375,150	$ 1,537,926	$ 472,522	$ 144,000	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ 1,375,150	$ 2,913,076	$ 3,385,598	$ 3,529,598	$ 3,529,598
Accumulated Depreciation								
Opening Balance		$ -	$ -	$ -	-$ 45,838	-$ 188,779	-$ 398,735	-$ 629,242
Amortization expense during year	$ -	$ -	$ -	-$ 45,838	-$ 142,941	-$ 209,956	-$ 230,507	-$ 235,307
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	-$ 45,838	-$ 188,779	-$ 398,735	-$ 629,242	-$ 864,548
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ 1,329,312	$ 2,724,297	$ 2,986,863	$ 2,900,356
Closing Balance	$ -	$ -	$ -	$ 1,329,312	$ 2,724,297	$ 2,986,863	$ 2,900,356	$ 2,665,050
Average Net Book Value	$ -	$ -	$ -	$ 664,656	$ 2,026,804	$ 2,855,580	$ 2,943,610	$ 2,782,703
Net Fixed Assets - Computer Hardware								
Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets - Computer Software (including Applications Software)

Gross Book Value								
Opening Balance		$ -	$ 31,428	$ 110,348	$ 396,626	$ 578,968	$ 692,435	$ 776,135
Capital Additions during year (from Smart Meter Costs)	$ -	$ 31,428	$ 78,920	$ 286,278	$ 182,342	$ 113,467	$ 83,700	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ 31,428	$ 110,348	$ 396,626	$ 578,968	$ 692,435	$ 776,135	$ 776,135
Accumulated Depreciation								
Opening Balance	$ -	$ -	-$ 3,143	-$ 17,320	-$ 68,018	-$ 165,577	-$ 292,717	-$ 439,574
Amortization expense during year	$ -	-$ 3,143	-$ 14,178	-$ 50,697	-$ 97,559	-$ 127,140	-$ 146,857	-$ 155,227
Retirements/Removals (if applicable)								
Closing Balance	$ -	-$ 3,143	-$ 17,320	-$ 68,018	-$ 165,577	-$ 292,717	-$ 439,574	-$ 594,801
Net Book Value								
Opening Balance	$ -	$ -	$ 28,285	$ 93,028	$ 328,608	$ 413,391	$ 399,717	$ 336,560
Closing Balance	$ -	$ 28,285	$ 93,028	$ 328,608	$ 413,391	$ 399,717	$ 336,560	$ 181,333
Average Net Book Value	$ -	$ 14,143	$ 60,656	$ 210,818	$ 371,000	$ 406,554	$ 368,139	$ 258,947

Net Fixed Assets - Tools and Equipment

Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets - Other Equipment

Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ 123,690	$ 171,371	$ 194,063	$ 194,063
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ 123,690	$ 47,681	$ 22,692	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ 123,690	$ 171,371	$ 194,063	$ 194,063	$ 194,063
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	-$ 6,185	-$ 20,938	-$ 39,209	-$ 58,616
Amortization expense during year	$ -	$ -	$ -	-$ 6,185	-$ 14,753	-$ 18,272	-$ 19,406	-$ 19,406
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	-$ 6,185	-$ 20,938	-$ 39,209	-$ 58,616	-$ 78,022
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ 117,506	$ 150,433	$ 154,854	$ 135,447
Closing Balance	$ -	$ -	$ -	$ 117,506	$ 150,433	$ 154,854	$ 135,447	$ 116,041
Average Net Book Value	$ -	$ -	$ -	$ 58,753	$ 133,969	$ 152,644	$ 145,151	$ 125,744

	2006	2007	2008	2009	2010	2011	2012	2013
Average Net Fixed Asset Values (from Sheet 4)								
Smart Meters	$ -	$ -	$ -	$ 664,656	$ 2,026,804	$ 2,855,580	$ 2,943,610	$ 2,782,703
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software	$ -	$ 14,143	$ 60,656	$ 210,818	$ 371,000	$ 406,554	$ 368,139	$ 258,947
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ 58,753	$ 133,969	$ 152,644	$ 145,151	$ 125,744
Total Net Fixed Assets	**$ -**	**$ 14,143**	**$ 60,656**	**$ 934,226**	**$ 2,531,773**	**$ 3,414,778**	**$ 3,456,899**	**$ 3,167,394**
Working Capital								
Operating Expenses (from Sheet 2)	$ -	$ -	$ -	$ -	$ 99,868	$ -	$ -	$ -
Working Capital Factor (from Sheet 3)	15%	15%	15%	15%	15%	15%	15%	13%
Working Capital Allowance	$ -	$ -	$ -	$ -	$ 14,980	$ -	$ -	$ -
Incremental Smart Meter Rate Base	**$ -**	**$ 14,143**	**$ 60,656**	**$ 934,226**	**$ 2,546,753**	**$ 3,414,778**	**$ 3,456,899**	**$ 3,167,394**
Return on Rate Base								
Capital Structure								
Deemed Short Term Debt	$ -	$ -	$ 2,426	$ 37,369	$ 101,870	$ 136,591	$ 138,276	$ 126,696
Deemed Long Term Debt	$ -	$ -	$ 33,968	$ 523,167	$ 1,426,182	$ 1,912,275	$ 1,935,864	$ 1,773,741
Equity	$ -	$ 14,143	$ 24,263	$ 373,691	$ 1,018,701	$ 1,365,911	$ 1,382,760	$ 1,266,958
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capitalization	$ -	$ 14,143	$ 60,656	$ 934,226	$ 2,546,753	$ 3,414,778	$ 3,456,899	$ 3,167,394
Return on								
Deemed Short Term Debt	$ -	$ -	$ 108	$ 422	$ 2,109	$ 2,827	$ 2,862	$ 2,623
Deemed Long Term Debt	$ -	$ -	$ -	$ -	$ 83,717	$ 112,251	$ 113,635	$ 104,119
Equity	$ -	$ 1,273	$ 2,079	$ 29,933	$ 100,342	$ 134,542	$ 136,202	$ 124,795
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Return on Capital	$ -	$ 1,273	$ 2,188	$ 30,355	$ 186,168	$ 249,620	$ 252,699	$ 231,537
Operating Expenses	$ -	$ -	$ -	$ -	$ 99,868	$ -	$ -	$ -
Amortization Expenses (from Sheet 4)								
Smart Meters	$ -	$ -	$ -	$ 45,838	$ 142,941	$ 209,956	$ 230,507	$ 235,307
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software	$ -	$ 3,143	$ 14,178	$ 50,697	$ 97,559	$ 127,140	$ 146,857	$ 155,227
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ 6,185	$ 14,753	$ 18,272	$ 19,406	$ 19,406
Total Amortization Expense in Year	$ -	$ 3,143	$ 14,178	$ 102,720	$ 255,253	$ 355,368	$ 396,770	$ 409,940
Incremental Revenue Requirement before Taxes/PILs	$ -	$ 4,416	$ 16,365	$ 133,075	$ 541,289	$ 604,988	$ 649,469	$ 641,476
Calculation of Taxable Income								
Incremental Operating Expenses	$ -	$ -	$ -	$ -	$ 99,868	$ -	$ -	$ -
Amortization Expense	$ -	$ 3,143	$ 14,178	$ 102,720	$ 255,253	$ 355,368	$ 396,770	$ 409,940
Interest Expense	$ -	$ -	$ 108	$ 422	$ 85,826	$ 115,078	$ 116,498	$ 106,741
Net Income for Taxes/PILs	$ -	$ 1,273	$ 2,079	$ 29,933	$ 100,342	$ 134,542	$ 136,202	$ 124,795
Grossed-up Taxes/PILs (from Sheet 7)	$ -	-$ 2,326.49	-$ 8,847.28	-$ 20,906.66	-$ 6,322.54	$ 25,306.85	$ 49,898.12	$ -
Revenue Requirement, including Grossed-up Taxes/PILs	$ -	$ 2,089	$ 7,518	$ 112,168	$ 534,966	$ 630,295	$ 699,367	$ 641,476

For PILs Calculation

UCC - Smart Meters

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 1,320,144.00	$ 2,690,941.44	$ 2,929,287.24	$ 2,833,184.27
Capital Additions	$ -	$ -	$ -	$ 1,375,150.00	$ 1,537,926.00	$ 472,522.00	$ 144,000.00	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ -	$ -	$ -	$ 1,375,150.00	$ 2,858,070.00	$ 3,163,463.44	$ 3,073,287.24	$ 2,833,184.27
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 687,575.00	$ 768,963.00	$ 236,261.00	$ 72,000.00	$ -
Reduced UCC	$ -	$ -	$ -	$ 687,575.00	$ 2,089,107.00	$ 2,927,202.44	$ 3,001,287.24	$ 2,833,184.27
CCA Rate Class	47	47	47	47	47	47	47	47
CCA Rate	8%	8%	8%	8%	8%	8%	8%	8%
CCA	$ -	$ -	$ -	$ 55,006.00	$ 167,128.56	$ 234,176.20	$ 240,102.98	$ 226,654.74
Closing UCC	$ -	$ -	$ -	$ 1,320,144.00	$ 2,690,941.44	$ 2,929,287.24	$ 2,833,184.27	$ 2,606,529.52

UCC - Computer Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
Opening UCC	$ -	$ -	$ 22,785.30	$ 67,470.39	$ 237,913.22	$ 239,258.90	$ 189,929.96	$ 146,150.98
Capital Additions Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Computer Software	$ -	$ 31,428.00	$ 78,920.00	$ 286,278.00	$ 182,342.00	$ 113,466.83	$ 83,700.00	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ -	$ 31,428.00	$ 101,705.30	$ 353,748.39	$ 420,255.22	$ 352,725.73	$ 273,629.96	$ 146,150.98
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 15,714.00	$ 39,460.00	$ 143,139.00	$ 91,171.00	$ 56,733.42	$ 41,850.00	$ -
Reduced UCC	$ -	$ 15,714.00	$ 62,245.30	$ 210,609.39	$ 329,084.22	$ 295,992.32	$ 231,779.96	$ 146,150.98
CCA Rate Class	45	50	50	50	50	50	50	50
CCA Rate	45%	55%	55%	55%	55%	55%	55%	55%
CCA	$ -	$ 8,642.70	$ 34,234.92	$ 115,835.16	$ 180,996.32	$ 162,795.77	$ 127,478.98	$ 80,383.04
Closing UCC	$ -	$ 22,785.30	$ 67,470.39	$ 237,913.22	$ 239,258.90	$ 189,929.96	$ 146,150.98	$ 65,767.94

UCC - General Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ 111,321.00	$ 131,969.70	$ 125,998.56	$ 100,798.85
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ 123,690.00	$ 47,681.00	$ 22,692.00	$ -	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ -	$ -	$ -	$ 123,690.00	$ 159,002.00	$ 154,661.70	$ 125,998.56	$ 100,798.85
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 61,845.00	$ 23,840.50	$ 11,346.00	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ 61,845.00	$ 135,161.50	$ 143,315.70	$ 125,998.56	$ 100,798.85
CCA Rate Class	8	8	8	8	8	8	8	8
CCA Rate	20%	20%	20%	20%	20%	20%	20%	20%
CCA	$ -	$ -	$ -	$ 12,369.00	$ 27,032.30	$ 28,663.14	$ 25,199.71	$ 20,159.77
Closing UCC	$ -	$ -	$ -	$ 111,321.00	$ 131,969.70	$ 125,998.56	$ 100,798.85	$ 80,639.08

UCC - Applications Software

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	0	0	0	0	0	0	0	0
CCA Rate	0%	0%	0%	0%	0%	0%	0%	0%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

PILs Calculation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
INCOME TAX								
Net Income	$ -	$ 1,272.83	$ 2,079.30	$ 29,932.62	$ 100,342.08	$ 134,542.24	$ 136,201.83	$ 124,795.34
Amortization	$ -	$ 3,142.80	$ 14,177.60	$ 102,720.23	$ 255,253.32	$ 355,367.78	$ 396,769.80	$ 409,939.80
CCA - Smart Meters	$ -	$ -	$ -	-$ 55,006.00	-$ 167,128.56	-$ 234,176.20	-$ 240,102.98	-$ 226,654.74
CCA - Computers	$ -	-$ 8,642.70	-$ 34,234.92	-$ 115,835.16	-$ 180,996.32	-$ 162,795.77	-$ 127,478.98	-$ 80,383.04
CCA - Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA - Other Equipment	$ -	$ -	$ -	-$ 12,369.00	-$ 27,032.30	-$ 28,663.14	-$ 25,199.71	-$ 20,159.77
Change in taxable income	$ -	-$ 4,227.07	-$ 17,978.01	-$ 50,557.31	-$ 19,561.78	$ 64,274.91	$ 140,189.96	$ 207,537.59
Tax Rate (from Sheet 3)	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	25.50%
Income Taxes Payable	$ -	-$ 1,526.82	-$ 6,022.63	-$ 16,683.91	-$ 6,064.15	$ 18,157.66	$ 36,799.86	$ 52,922.09
ONTARIO CAPITAL TAX								
Smart Meters	$ -	$ -	$ -	$ 1,329,311.67	$ 2,724,296.80	$ 2,986,863.00	$ 2,900,356.47	$ 2,665,049.93
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software (Including Application Software)	$ -	$ 28,285.20	$ 93,027.60	$ 328,608.20	$ 413,390.80	$ 399,717.35	$ 336,560.38	$ 181,333.42
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ 117,505.50	$ 150,433.45	$ 154,853.75	$ 135,447.45	$ 116,041.15
Rate Base	$ -	$ 28,285.20	$ 93,027.60	$ 1,775,425.37	$ 3,288,121.05	$ 3,541,434.10	$ 3,372,364.30	$ 2,962,424.50
Less: Exemption								
Deemed Taxable Capital	$ -	$ 28,285.20	$ 93,027.60	$ 1,775,425.37	$ 3,288,121.05	$ 3,541,434.10	$ 3,372,364.30	$ 2,962,424.50
Ontario Capital Tax Rate (from Sheet 3)	0.300%	0.225%	0.225%	0.225%	0.075%	0.000%	0.000%	0.000%
Net Amount (Taxable Capital x Rate)	$ -	$ 63.64	$ 209.31	$ 3,994.71	$ 2,466.09	$ -	$ -	$ -
Change in Income Taxes Payable	$ -	-$ 1,526.82	-$ 6,022.63	-$ 16,683.91	-$ 6,064.15	$ 18,157.66	$ 36,799.86	$ 52,922.09
Change in OCT	$ -	$ 63.64	$ 209.31	$ 3,994.71	$ 2,466.09	$ -	$ -	$ -
PILs	$ -	-$ 1,463.17	-$ 5,813.32	-$ 12,689.21	-$ 3,598.06	$ 18,157.66	$ 36,799.86	$ 52,922.09

Gross Up PILs

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	25.50%
Change in Income Taxes Payable	$ -	-$ 2,390.13	-$ 9,056.59	-$ 24,901.36	-$ 8,788.63	$ 25,306.85	$ 49,898.12	$ 71,036.36
Change in OCT	$ -	$ 63.64	$ 209.31	$ 3,994.71	$ 2,466.09	$ -	$ -	$ -
PILs	**$ -**	**-$ 2,326.49**	**-$ 8,847.28**	**-$ 20,906.66**	**-$ 6,322.54**	**$ 25,306.85**	**$ 49,898.12**	**$ 71,036.36**

Ontario Energy Board

Smart Meter Model

Algoma Power Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1		
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	3.92%
2012 Q1	1.47%	3.92%
2012 Q2	1.47%	3.51%
2012 Q3	1.47%	3.51%
2012 Q4	1.47%	3.51%
2013 Q1		
2013 Q2		
2013 Q3		

Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
Jan-06	2006	Q1	$ -		0.00%	$ -	$ -		
Feb-06	2006	Q1	$ -		0.00%	$ -	$ -		
Mar-06	2006	Q1	$ -		0.00%	$ -	$ -		
Apr-06	2006	Q2	$ -		4.14%	$ -	$ -		
May-06	2006	Q2	$ -		4.14%	$ -	$ -		
Jun-06	2006	Q2	$ -		4.14%	$ -	$ -		
Jul-06	2006	Q3	$ -		4.59%	$ -	$ -		
Aug-06	2006	Q3	$ -		4.59%	$ -	$ -		
Sep-06	2006	Q3	$ -		4.59%	$ -	$ -		
Oct-06	2006	Q4	$ -		4.59%	$ -	$ -		
Nov-06	2006	Q4	$ -		4.59%	$ -	$ -		
Dec-06	2006	Q4	$ -		4.59%	$ -	$ -	$ -	
Jan-07	2007	Q1	$ -		4.59%	$ -	$ -		
Feb-07	2007	Q1	$ -		4.59%	$ -	$ -		
Mar-07	2007	Q1	$ -		4.59%	$ -	$ -		
Apr-07	2007	Q2	$ -		4.59%	$ -	$ -		
May-07	2007	Q2	$ -		4.59%	$ -	$ -		
Jun-07	2007	Q2	$ -		4.59%	$ -	$ -		
Jul-07	2007	Q3	$ -		4.59%	$ -	$ -		
Aug-07	2007	Q3	$ -		4.59%	$ -	$ -		
Sep-07	2007	Q3	$ -		4.59%	$ -	$ -		
Oct-07	2007	Q4	$ -		5.14%	$ -	$ -		
Nov-07	2007	Q4	$ -		5.14%	$ -	$ -		
Dec-07	2007	Q4	$ -		5.14%	$ -	$ -	$ -	
Jan-08	2008	Q1	$ -		5.14%	$ -	$ -		
Feb-08	2008	Q1	$ -		5.14%	$ -	$ -		
Mar-08	2008	Q1	$ -		5.14%	$ -	$ -		
Apr-08	2008	Q2	$ -		4.08%	$ -	$ -		
May-08	2008	Q2	$ -		4.08%	$ -	$ -		
Jun-08	2008	Q2	$ -		4.08%	$ -	$ -		
Jul-08	2008	Q3	$ -		3.35%	$ -	$ -		

Ontario Energy Board

Smart Meter Model

Algoma Power Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
2013 Q4			Aug-08	2008	Q3	$ -		3.35%	$ -	$ -		
			Sep-08	2008	Q3	$ -		3.35%	$ -	$ -		
			Oct-08	2008	Q4	$ -		3.35%	$ -	$ -		
			Nov-08	2008	Q4	$ -		3.35%	$ -	$ -		
			Dec-08	2008	Q4	$ -		3.35%	$ -	$ -	$ -	
			Jan-09	2009	Q1	$ -		2.45%	$ -	$ -		
			Feb-09	2009	Q1	$ -		2.45%	$ -	$ -		
			Mar-09	2009	Q1	$ -		2.45%	$ -	$ -		
			Apr-09	2009	Q2	$ -		1.00%	$ -	$ -		
			May-09	2009	Q2	$ -		1.00%	$ -	$ -		
			Jun-09	2009	Q2	$ -		1.00%	$ -	$ -		
			Jul-09	2009	Q3	$ -		0.55%	$ -	$ -		
			Aug-09	2009	Q3	$ -		0.55%	$ -	$ -		
			Sep-09	2009	Q3	$ -		0.55%	$ -	$ -		
			Oct-09	2009	Q4	$ -		0.55%	$ -	$ -		
			Nov-09	2009	Q4	$ -		0.55%	$ -	$ -		
			Dec-09	2009	Q4	$ -		0.55%	$ -	$ -	$ -	
			Jan-10	2010	Q1	$ -		0.55%	$ -	$ -		
			Feb-10	2010	Q1	$ -		0.55%	$ -	$ -		
			Mar-10	2010	Q1	$ -		0.55%	$ -	$ -		
			Apr-10	2010	Q2	$ -		0.55%	$ -	$ -		
			May-10	2010	Q2	$ -		0.55%	$ -	$ -		
			Jun-10	2010	Q2	$ -		0.55%	$ -	$ -		
			Jul-10	2010	Q3	$ -		0.89%	$ -	$ -		
			Aug-10	2010	Q3	$ -		0.89%	$ -	$ -		
			Sep-10	2010	Q3	$ -		0.89%	$ -	$ -		
			Oct-10	2010	Q4	$ -		1.20%	$ -	$ -		
			Nov-10	2010	Q4	$ -		1.20%	$ -	$ -		
			Dec-10	2010	Q4	$ -		1.20%	$ -	$ -	$ -	
			Jan-11	2011	Q1	$ -	$ 1,317.60	1.47%	$ -	$ 1,317.60		
			Feb-11	2011	Q1	$ 1,317.60	$ 9,904.70	1.47%	$ 1.61	$ 11,223.91		
			Mar-11	2011	Q1	$ 11,222.30	$ 10,780.43	1.47%	$ 13.75	$ 22,016.48		

Ontario Energy Board

Smart Meter Model

Algoma Power Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
			Apr-11	2011	Q2	$ 22,002.73	$ 5,778.64	1.47%	$ 26.95	$ 27,808.32		
			May-11	2011	Q2	$ 27,781.37	$ 10,163.46	1.47%	$ 34.03	$ 37,978.86		
			Jun-11	2011	Q2	$ 37,944.83	$ 9,802.03	1.47%	$ 46.48	$ 47,793.34		
			Jul-11	2011	Q3	$ 47,746.86	$ 2,871.43	1.47%	$ 58.49	$ 50,676.78		
			Aug-11	2011	Q3	$ 50,618.29	$ 12,788.15	1.47%	$ 62.01	$ 63,468.45		
			Sep-11	2011	Q3	$ 63,406.44	$ 10,508.50	1.47%	$ 77.67	$ 73,992.61		
			Oct-11	2011	Q4	$ 73,914.94	$ 40,693.88	1.47%	$ 90.55	$ 114,699.37		
			Nov-11	2011	Q4	$ 114,608.82	$ 7,938.41	1.47%	$ 140.40	$ 122,687.63		
			Dec-11	2011	Q4	$ 122,547.23	$ 6,325.39	1.47%	$ 150.12	$ 129,022.74	$ 129,574.68	
			Jan-12	2012	Q1	$ 128,872.62	$ 10,651.61	1.47%	$ 157.87	$ 139,682.10		
			Feb-12	2012	Q1	$ 139,524.23	$ 6,312.65	1.47%	$ 170.92	$ 146,007.80		
			Mar-12	2012	Q1	$ 145,836.88	$ 10,424.03	1.47%	$ 178.65	$ 156,439.56		
			Apr-12	2012	Q2	$ 156,260.91	$ 6,293.85	1.47%	$ 191.42	$ 162,746.18		
			May-12	2012	Q2	$ 162,554.76	$ 8,130.00	1.47%	$ 199.13	$ 170,883.89		
			Jun-12	2012	Q2	$ 170,684.76	$ 8,138.00	1.47%	$ 209.09	$ 179,031.85		
			Jul-12	2012	Q3	$ 178,822.76	$ 8,146.00	1.47%	$ 219.06	$ 187,187.82		
			Aug-12	2012	Q3	$ 186,968.76	$ 8,153.00	1.47%	$ 229.04	$ 195,350.80		
			Sep-12	2012	Q3	$ 195,121.76	$ 8,161.00	1.47%	$ 239.02	$ 203,521.78		
			Oct-12	2012	Q4	$ 203,282.76	$ 51,379.00	1.47%	$ 249.02	$ 254,910.78		
			Nov-12	2012	Q4	$ 254,661.76	$ 8,176.00	1.47%	$ 311.96	$ 263,149.72		
			Dec-12	2012	Q4	$ 262,837.76	$ 8,182.00	1.47%	$ 321.98	$ 271,341.74	$ 144,824.30	
			Jan-13	2013	Q1	$ 271,019.76		1.47%	$ 332.00	$ 271,351.76		
			Feb-13	2013	Q1	$ 271,019.76		1.47%	$ 332.00	$ 271,351.76		
			Mar-13	2013	Q1	$ 271,019.76		1.47%	$ 332.00	$ 271,351.76		
			Apr-13	2013	Q2	$ 271,019.76		1.47%	$ 332.00	$ 271,351.76		
			May-13	2013	Q2	$ 271,019.76		1.47%	$ 332.00	$ 271,351.76		
			Jun-13	2013	Q2	$ 271,019.76		1.47%	$ 332.00	$ 271,351.76		
			Jul-13	2013	Q3	$ 271,019.76		1.47%	$ 332.00	$ 271,351.76		
			Aug-13	2013	Q3	$ 271,019.76		1.47%	$ 332.00	$ 271,351.76		
			Sep-13	2013	Q3	$ 271,019.76		1.47%	$ 332.00	$ 271,351.76		
			Oct-13	2013	Q4	$ 271,019.76		1.47%	$ 332.00	$ 271,351.76		
			Nov-13	2013	Q4	$ 271,019.76		1.47%	$ 332.00	$ 271,351.76		

Ontario Energy Board

Smart Meter Model

Algoma Power Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	*Year*	*Quarter*	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
			Dec-13	*2013*	*Q4*	$ 271,019.76		1.47%	$ 332.00	$ 271,351.76	$ 3,984.00	
			Total Funding Adder Revenues Collected				**$ 271,019.76**		**$ 3,379.22**	**$ 274,398.98**	**$ 274,398.98**	

Ontario Energy Board

Smart Meter Model

Algoma Power Inc.

This worksheet calculates the interest on OM&A and amortization/depreciation expense, based on monthly data.

Account 1556 - Sub-accounts Operating Expenses, Amortization Expenses, Carrying Charges

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP
2006 Q1	0.00%	0.00%
2006 Q2	4.14%	4.68%
2006 Q3	4.59%	5.05%
2006 Q4	4.59%	4.72%
2007 Q1	4.59%	4.72%
2007 Q2	4.59%	4.72%
2007 Q3	4.59%	5.18%
2007 Q4	5.14%	5.18%
2008 Q1	5.14%	5.18%
2008 Q2	4.08%	5.18%
2008 Q3	3.35%	5.43%
2008 Q4	3.35%	5.43%
2009 Q1	2.45%	6.61%
2009 Q2	1.00%	6.61%
2009 Q3	0.55%	5.67%
2009 Q4	0.55%	4.66%
2010 Q1	0.55%	4.34%
2010 Q2	0.55%	4.34%
2010 Q3	0.89%	4.66%
2010 Q4	1.20%	4.01%
2011 Q1	1.47%	4.29%
2011 Q2	1.47%	4.29%
2011 Q3	1.47%	4.29%
2011 Q4	1.47%	3.92%
2012 Q1	1.47%	3.92%
2012 Q2	1.47%	3.51%
2012 Q3	1.47%	3.51%
2012 Q4	1.47%	3.51%
2013 Q1	0.00%	0.00%
2013 Q2	0.00%	0.00%
2013 Q3	0.00%	0.00%
2013 Q4	0.00%	0.00%

Date	Year	Quarter	Opening Balance (Principal)	OM&A Expenses	Amortization / Depreciation Expense	Closing Balance (Principal)	(Annual) Interest Rate	Interest (on opening balance)	Cumulative Interest
Jan-06	2006	Q1	$ -			-	0.00%	-	-
Feb-06	2006	Q1	-			-	0.00%	-	-
Mar-06	2006	Q1	-			-	0.00%	-	-
Apr-06	2006	Q2	-			-	4.14%	-	-
May-06	2006	Q2	-			-	4.14%	-	-
Jun-06	2006	Q2	-			-	4.14%	-	-
Jul-06	2006	Q3	-			-	4.59%	-	-
Aug-06	2006	Q3	-			-	4.59%	-	-
Sep-06	2006	Q3	-			-	4.59%	-	-
Oct-06	2006	Q4	-			-	4.59%	-	-
Nov-06	2006	Q4	-			-	4.59%	-	-
Dec-06	2006	Q4	-			-	4.59%	-	-
Jan-07	2007	Q1	-			-	4.59%	-	-
Feb-07	2007	Q1	-			-	4.59%	-	-
Mar-07	2007	Q1	-			-	4.59%	-	-
Apr-07	2007	Q2	-			-	4.59%	-	-
May-07	2007	Q2	-			-	4.59%	-	-
Jun-07	2007	Q2	-			-	4.59%	-	-
Jul-07	2007	Q3	-			-	4.59%	-	-
Aug-07	2007	Q3	-			-	4.59%	-	-
Sep-07	2007	Q3	-			-	4.59%	-	-
Oct-07	2007	Q4	-			-	5.14%	-	-
Nov-07	2007	Q4	-			-	5.14%	-	-
Dec-07	2007	Q4	-			-	5.14%	-	-
Jan-08	2008	Q1	-			-	5.14%	-	-
Feb-08	2008	Q1	-			-	5.14%	-	-
Mar-08	2008	Q1	-			-	5.14%	-	-
Apr-08	2008	Q2	-			-	4.08%	-	-
May-08	2008	Q2	-			-	4.08%	-	-
Jun-08	2008	Q2	-			-	4.08%	-	-
Jul-08	2008	Q3	-			-	3.35%	-	-
Aug-08	2008	Q3	-			-	3.35%	-	-
Sep-08	2008	Q3	-			-	3.35%	-	-
Oct-08	2008	Q4	-			-	3.35%	-	-

Nov-08	2008	Q4	-			-	3.35%	-	-
Dec-08	2008	Q4	-			-	3.35%	-	-
Jan-09	2009	Q1	-			-	2.45%	-	-
Feb-09	2009	Q1	-			-	2.45%	-	-
Mar-09	2009	Q1	-			-	2.45%	-	-
Apr-09	2009	Q2	-			-	1.00%	-	-
May-09	2009	Q2	-			-	1.00%	-	-
Jun-09	2009	Q2	-			-	1.00%	-	-
Jul-09	2009	Q3	-			-	0.55%	-	-
Aug-09	2009	Q3	-			-	0.55%	-	-
Sep-09	2009	Q3	-			-	0.55%	-	-
Oct-09	2009	Q4	-			-	0.55%	-	-
Nov-09	2009	Q4	-			-	0.55%	-	-
Dec-09	2009	Q4	-			-	0.55%	-	-
Jan-10	2010	Q1	-			-	0.55%	-	-
Feb-10	2010	Q1	-			-	0.55%	-	-
Mar-10	2010	Q1	-			-	0.55%	-	-
Apr-10	2010	Q2	-			-	0.55%	-	-
May-10	2010	Q2	-			-	0.55%	-	-
Jun-10	2010	Q2	-			-	0.55%	-	-
Jul-10	2010	Q3	-			-	0.89%	-	-
Aug-10	2010	Q3	-			-	0.89%	-	-
Sep-10	2010	Q3	-			-	0.89%	-	-
Oct-10	2010	Q4	-			-	1.20%	-	-
Nov-10	2010	Q4	-			-	1.20%	-	-
Dec-10	2010	Q4	-			-	1.20%	-	-
Jan-11	2011	Q1	-			-	1.47%	-	-
Feb-11	2011	Q1	-			-	1.47%	-	-
Mar-11	2011	Q1	-			-	1.47%	-	-
Apr-11	2011	Q2	-			-	1.47%	-	-
May-11	2011	Q2	-			-	1.47%	-	-
Jun-11	2011	Q2	-			-	1.47%	-	-
Jul-11	2011	Q3	-			-	1.47%	-	-
Aug-11	2011	Q3	-			-	1.47%	-	-
Sep-11	2011	Q3	-			-	1.47%	-	-
Oct-11	2011	Q4	-			-	1.47%	-	-
Nov-11	2011	Q4	-			-	1.47%	-	-
Dec-11	2011	Q4	-			-	1.47%	-	-
Jan-12	2012	Q1	-			-	1.47%	-	-
Feb-12	2012	Q1	-			-	1.47%	-	-
Mar-12	2012	Q1	-			-	1.47%	-	-
Apr-12	2012	Q2	-			-	1.47%	-	-
May-12	2012	Q2	-			-	1.47%	-	-
Jun-12	2012	Q2	-			-	1.47%	-	-
Jul-12	2012	Q3	-			-	1.47%	-	-
Aug-12	2012	Q3	-			-	1.47%	-	-
Sep-12	2012	Q3	-			-	1.47%	-	-
Oct-12	2012	Q4	-			-	1.47%	-	-
Nov-12	2012	Q4	-			-	1.47%	-	-
Dec-12	2012	Q4	-			-	1.47%	-	-
Jan-13	2013	Q1	-			-	1.47%	-	-
Feb-13	2013	Q1	-			-	1.47%	-	-
Mar-13	2013	Q1	-			-	1.47%	-	-
Apr-13	2013	Q2	-			-	1.47%	-	-
May-13	2013	Q2	-			-	1.47%	-	-
Jun-13	2013	Q2	-			-	1.47%	-	-
Jul-13	2013	Q3	-			-	1.47%	-	-
Aug-13	2013	Q3	-			-	1.47%	-	-
Sep-13	2013	Q3	-			-	1.47%	-	-
Oct-13	2013	Q4	-			-	1.47%	-	-

[redacted]	Nov-13	*2013*	*Q4*	-			-	1.47%	-	-
[redacted]	Dec-13	*2013*	*Q4*	-			-	1.47%	-	-
					$ -	$ -	$ -			

Ontario Energy Board

Smart Meter Model

Algoma Power Inc.

This worksheet calculates the interest on OM&A and amortization/depreciation expense, in the absence of monthly data.

Year	OM&A (from Sheet 5)	Amortization Expense (from Sheet 5)	Cumulative OM&A and Amortization Expense	Average Cumulative OM&A and Amortization Expense	Average Annual Prescribed Interest Rate for Deferral and Variance Accounts (from Sheets 8A and 8B)	Simple Interest on OM&A and Amortization Expenses
2006	$ -	$ -	$ -	$ -	4.37%	$ -
2007	$ -	$ 3,142.80	$ 3,142.80	$ 1,571.40	4.73%	$ 74.29
2008	$ -	$ 14,177.60	$ 17,320.40	$ 10,231.60	3.98%	$ 407.22
2009	$ -	$ 102,720.23	$ 120,040.63	$ 68,680.52	1.14%	$ 781.24
2010	$ 99,867.57	$ 255,253.32	$ 475,161.52	$ 297,601.08	0.80%	$ 2,373.37
2011	$ -	$ 355,367.78	$ 830,529.30	$ 652,845.41	1.47%	$ 9,596.83
2012	$ -	$ 396,769.80	$ 1,227,299.10	$ 1,028,914.20	1.47%	$ 15,125.04
2013	$ -	$ 409,939.80	$ 1,637,238.90	$ 1,432,269.00	1.47%	$ 21,054.35

Cumulative Interest to 2011	$ 13,232.94
Cumulative Interest to 2012	$ 28,357.98
Cumulative Interest to 2013	$ 49,412.34

Ontario Energy Board

Smart Meter Model

Algoma Power Inc.

This worksheet calculates the Smart Meter Disposition Rider and the Smart Meter Incremental Revenue Requirement Rate Rider, if applicable. This worksheet also calculates any new Smart Meter Funding Adder that a distributor may wish to request. However, please note that in many 2011 IRM decisions, the Board noted that current funding adders will cease on April 30, 2011 and that the Board's expectation is that distributors will file for a final review of prudence at the earliest opportunity. The Board also noted that the SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board. The Board observed that the SMFA was not intended to be compensatory (return on and of capital) on a cumulative basis over the term the SMFA was in effect. The SMFA was initially designed to fund future investment, and not fully fund prior capital investment. Distributors that seek a new SMFA should provide evidence to support its proposal. This would include documentation of where the distributor is with respect to its smart meter deployment program, and reasons as to why the distributor's circumstances are such that continuation of the SMFA is warranted. Press the "UPDATE WORKSHEET" button after choosing the applicable adders/riders.

Check if applicable		
	Smart Meter Funding Adder (SMFA)	
X	Smart Meter Disposition Rider (SMDR)	**The SMDR is calculated based on costs to December 31, 2011**
X	Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR)	**The SMIRR is calculated based on the incremental revenue requirement associated with the recovery of capital related costs to December 31, 2012 and associated OM&A.**

	2006	2007	2008	2009	2010	2011	2012	2013	Total
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$ -	$ 2,089.14	$ 7,518.07	$ 112,168.46	$ 534,966.02	$ 630,294.87	$ 699,367.25	$ 641,476.33	$ 1,986,403.82
Interest on Deferred and forecasted OM&A and Amortization Expense (Sheet 8A/8B) (Check **one** of the boxes below)	$ -	$ 74.29	$ 407.22	$ 781.24	$ 2,373.37	$ 9,596.83	$ 15,125.04		$ 28,357.98
[ ] Sheet 8A (Interest calculated on monthly balances)									
[X] Sheet 8B (Interest calculated on average annual balances)	$ -	$ 74.29	$ 407.22	$ 781.24	$ 2,373.37	$ 9,596.83	$ 15,125.04	$ 21,054.35	$ 28,357.98
SMFA Revenues (from Sheet 8)	$ -	$ -	$ -	$ -	$ -	$ 128,872.62	$ 142,147.14	$ -	$ 271,019.76
SMFA Interest (from Sheet 8)	$ -	$ -	$ -	$ -	$ -	$ 702.06	$ 2,677.16	$ 3,984.00	$ 7,363.22
Net Deferred Revenue Requirement	$ -	$ 2,163.43	$ 7,925.29	$ 112,949.71	$ 537,339.39	$ 510,317.02	$ 569,667.99	$ 637,492.33	$ 1,736,378.82

Number of Metered Customers (average for 2013 test year) → 11749

- Number of metered customers for which smart meter were deployed as part of program). Residential and GS < 50 kW customer classes and any other metered classes involved (e.g. GS 50 to 4999 kW for which interval meters were upgraded to utilize AMI and ODS assets)

Calculation of Smart Meter Disposition Rider (per metered customer per month)

Years for collection or refunding			4
Deferred Incremental Revenue Requirement from 2006 to December 31, 2012 plus Interest on OM&A and Amortization		$	2,014,761.80
SMFA Revenues collected from 2006 to 2013 test year (inclusive) Plus Simple Interest on SMFA Revenues		$	278,382.98
Net Deferred Revenue Requirement		$	1,736,378.82
SMDR	January 1, 2013 to December 31, 2016	$	3.08
Check: Forecasted SMDR Revenues		$	1,736,972.16

Match

Calculation of Smart Meter Incremental Revenue Requirement Rate Rider (per metered customer per month)

Incremental Revenue Requirement for 2013	$	641,476.33
SMIRR	$	4.55
Check: Forecasted SMIRR Revenues	$	641,495.40

Match

Schedule 2

Smart Meter Disposition Rate Rider Calculation - Algoma Power Inc.
Schedule 2

	Total		Residential		Seasonal		GS < 50	
Allocators								
Smart Meter Costs (2007 to 2012)	$	4,499,796	$	2,684,691	$	1,345,592	$	469,514
Allocation of Smart Meter Costs		100.0%		59.7%		29.9%		10.4%
Number of Meters Installed (2007 to 2012)		11,535		7,040		3,548		947
Allocation of Number of Meters Installed		100.0%		61.0%		30.8%		8.2%
Revenue Requirement								
Total Return on Capital (Deemed Interest Plus Return on Equity)	$	750,660	$	447,862	$	224,473	$	78,325
Amortization	$	1,127,430	$	672,653	$	337,140	$	117,637
OM&A	$	99,868	$	60,951	$	30,718	$	8,199
Total Before PILs	$	1,977,958	$	1,181,466	$	592,331	$	204,161
PILs	$	36,802	$	21,957	$	11,005	$	3,840
Total Revenue Requirement 2007 to 2012	**$**	**2,014,760**	**$**	**1,203,423**	**$**	**603,336**	**$**	**208,001**
		100.0%		**59.7%**		**29.9%**		**10.3%**
Smart Meter Funding Adder Revenues		($271,020)		($165,408)		($83,362)		($22,250)
Carrying Charges		($3,379)		($2,062)		($1,039)		($277)
Total Revenues Collected Plus Carrying Charges		**($274,399)**		**($167,470)**		**($84,401)**		**($22,528)**
Net Deferred Revenue Requirement	**$**	**1,740,361**	**$**	**1,035,953**	**$**	**518,934**	**$**	**185,473**
Metered Customers (Average for 2013)		**11,749**		**7,171**		**3,614**		**965**
Recovery Period in Months		**48**		**48**		**48**		**48**
Smart Meter Disposition Rate Rider ($/Customer/Month)	**$**	**3.09**	**$**	**3.01**	**$**	**2.99**	**$**	**4.01**

Schedule 3

Smart Meter Incremental Revenue Requirement Rate Rider Calculation - Algoma Power Inc.
Schedule 3

	Total	Residential	Seasonal	GS < 50
Allocators				
Smart Meter Costs (2007 to 2012)	$ 4,499,796	$ 2,684,691	$ 1,345,592	$ 469,514
Allocation of Smart Meter Costs	100.0%	59.7%	29.9%	10.4%
Number of Meters Installed (2007 to 2012)	11,535	7,040	3,548	947
Allocation of Number of Meters Installed	100.0%	61.0%	30.8%	8.2%
Revenue Requirement				
Total Return on Capital (Deemed Interest Plus Return on Equity)	$ 252,591	$ 150,702	$ 75,533	$ 26,356
Amortization	$ 409,940	$ 244,580	$ 122,586	$ 42,774
OM&A	$ -	$ -	$ -	$ -
Total Before PILs	$ 662,531	$ 395,283	$ 198,119	$ 69,129
PILs	$ 71,036	$ 42,382	$ 21,242	$ 7,412
Total Revenue Requirement 2013	**$ 733,567**	**$ 437,664**	**$ 219,361**	**$ 76,541**
Metered Customers (Average for 2013)	**11,749**	**7,171**	**3,614**	**965**
Recovery Period in Months	**12**	**12**	**12**	**12**
Smart Meter Incremental Revenue Requirement Rate Rider ($/Customer/Month)	**$ 5.20**	**$ 5.09**	**$ 5.06**	**$ 6.61**

Note:
PILs total will not tie to tab 5 or 9 in smart meter model because model has an incorrect formula and is not pulling in the value.

Schedule “C”

API 2013 Distribution Rate Indexing Methodology

The 2011 Board Approved Rate Design, EB-2009-0278

The starting point for 2012 electricity distribution rate design is the fully allocated Board Approved 2011 revenue requirement. The table shown below is the Board approved 2011 revenue requirement of $19,828,731[2].

Board Approved EB-2009-0278
Equivalent Distribution Rates

2011 Distribution Base Rate Determination											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	20.41	0.1174	1,968,810	12,458,170	14,426,980
Residential - R2	kW	48		151,952	12.0%	88.0%	596.12	16.5559	343,365	2,515,702	2,859,067
Seasonal	kWh	3660	12,622,297		43.8%	56.2%	24.00	0.1073	1,054,008	1,354,803	2,408,811
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1690	-	133,872	133,872
									3,366,183	**16,462,548**	**19,828,731**

The equivalent distribution rates shown in this table are those rates required to recover the revenue requirement in the absence of the RRRP funding and represent the full allocation to the customer classes.

Price Cap Indexing of Equivalent Distribution Rates

In the matter of the EB-2011-0152, the Board approved the following incentive regulation price cap metrics.

Board Approved 2012 Incentive Regulation Price Cap Metrics	
RRRP Adjustment Factor	2.81%
Implicit Price Index	1.70%
Productivity Factor	0.72%
Stretch Factor	0.60%
Price Cap Index	0.38%

These Board Approved 2012 incentive regulation price cap metrics were used to index the fully allocated Board Approved 2011 revenue requirement; the results are provided below.

Board Approved 2012 Application of Incentive Regulation Price Cap to Equivalent Distribution Rates
Price Cap Index 0.38%

2012 Distribution Price Indexed Electricity Distribution Rates											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	20.49	0.1178	1,976,291	12,505,511	14,481,803
Residential - R2	kW	48		151,952	12.0%	88.0%	598.39	16.6188	344,670	2,525,262	2,869,932
Seasonal	kWh	3660	12,622,297		43.8%	56.2%	24.09	0.1077	1,058,013	1,359,951	2,417,965
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1697	-	134,381	134,381
									3,378,974	**16,525,106**	**19,904,080**

These 2012 equivalent distribution rates become the basis for the 2013 distribution rate design.

2 EB-2009-0278 Approved Draft Rate Order, November 22, 2010, Appendix B

Shown below are the assumed RRRP adjustment factor for the 2013 distribution rates and the assumed price cap index metrics for 2013 electricity distribution rates.

Proposed 2013 Incentive Regulation Price Cap Metrics	
RRRP Adjustment Factor (estimated)	2.81%
Implicit Price Index	2.20%
Productivity Factor	0.72%
Stretch Factor	0.60%
Price Cap Index (calculated)	0.88%

Applying these price cap metrics to the 2012 equivalent electricity distribution rates yields the fully allocated Board Approved 2013 revenue requirement with 2013 equivalent distribution rates; the results are provided below.

Proposed 2013 Application of Incentive Regulation Price Cap to Equivalent Distribution Rates
Price Cap Index 0.88%

2012 Distribution Price Indexed Electricity Distribution Rates											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	20.67	0.1189	1,993,683	12,615,560	14,609,242
Residential - R2	kW	48		151,952	12.0%	88.0%	603.65	16.7651	347,703	2,547,484	2,895,187
Seasonal	kWh	3660	12,622,297		43.8%	56.2%	24.30	0.1087	1,067,324	1,371,919	2,439,243
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1712	-	135,564	135,564
									3,408,709	**16,670,527**	**20,079,236**

Revenue to Cost Ratio Update

In EB-2009-0278, the Board approved the following class revenue to cost ratios.

Customer Class	Board Approved Revenue to Cost Ratio
Residential R - 1	114.1%
Residential R - 2	59.8%
Seasonal Customers	115.0%
Street Lighting	43%

There are no changes to the Board Approved revenue to cost ratios proposed in this Application. The table below shows the allocation of revenue requirement to the customer classes on the basis of the 2011 revenue to cost ratios.

No Adjustment Made to the 2011 Board Approved Revenue to Cost Ratios

2011 Cost Allocation Results								
	Cost Allocation Revenue Requirement	Revenue Requirement Allocation Percentage	Cost Allocation Misc.	Cost Allocation Misc. Percentage	2011 Service Revenue Requirement	2011 Misc. Revenue	2011 Base Revenue Requirement	
Residential - R1	12,066,293	63.7%	217,490	63.4%	12,876,372	234,623	12,641,749	
Residential - R2	4,569,290	24.1%	88,133	25.7%	4,876,052	95,075	4,780,977	
Seasonal	1,995,675	10.5%	32,431	9.5%	2,129,655	34,986	2,094,669	
Street Lighting	296,807	1.6%	5,003	1.5%	316,734	5,397	311,336	
	18,928,065	100.0%	343,057	100.0%	20,198,813	370,082	19,828,731	

Board Approved 2011 Base Distribution Rate Cost Allcation Design								
	2011 Approved Revenue @ 100% R|C	Revenue Proportions @ 100% R|C	Approved Proportion of Revenue	Base Revenue @ Approved Proportion	Over/(Under) Contributing	Approved Revenue to Cost Ratio	2011 Cost Allocation R|C	Board's Guideline
Residential - R1	12,641,749	63.8%	72.8%	14,426,980	1,785,231	114.1%	116.7%	85-115%
Residential - R2	4,780,977	24.1%	14.4%	2,859,067	(1,921,909)	59.8%	39.5%	80-180%
Seasonal	2,094,669	10.6%	12.1%	2,408,811	314,142	115.0%	149.9%	85-115%
Street Lighting	311,336	1.6%	0.7%	133,872	(177,464)	43.0%	15.9%	70-120%
	19,828,731	100.0%		19,828,731				

Proposed 2012 Base Distribution Rate Cost Allocation Design								
	2012 Forecasted Revenue @ 100% R|C	Revenue Proportions @ 100% R|C	Proposed Proportion of Revenue	Base Revenue @ Proposed Proportion	Over/(Under) Contributing	Proposed Revenue to Cost Ratio	2010 Cost Allocation R|C	Board's Guideline
Residential - R1	12,689,787	63.8%	72.8%	14,481,803	1,792,015	114.1%	116.71%	85-115%
Residential - R2	4,799,145	24.1%	14.4%	2,869,932	(1,929,213)	59.8%	39.52%	80-180%
Seasonal	2,102,629	10.6%	12.1%	2,417,965	315,336	115.0%	149.94%	85-115%
Street Lighting	312,519	1.6%	0.7%	134,381	(178,138)	43.0%	15.92%	70-120%
	19,904,080	100.0%	100.0%	19,904,080				

Proposed 2013 Base Distribution Rate Cost Allocation Design								
	2013 Forecasted Revenue @ 100% R|C	Revenue Proportions @ 100% R|C	Proposed Proportion of Revenue	Base Revenue @ Proposed Proportion	Over/(Under) Contributing	Proposed Revenue to Cost Ratio	2010 Cost Allocation R|C	Board's Guideline
Residential - R1	12,801,457	63.8%	72.8%	14,609,242	1,807,785	114.1%	0.00%	85-115%
Residential - R2	4,841,377	24.1%	14.4%	2,895,187	(1,946,190)	59.8%	0.00%	80-180%
Seasonal	2,121,132	10.6%	12.1%	2,439,243	318,111	115.0%	0.00%	85-115%
Street Lighting	315,270	1.6%	0.7%	135,564	(179,706)	43.0%	0.00%	70-120%
	20,079,236	100.0%	100.0%	20,079,236				

Smart Meter Cost Recovery – Rate Design

In its Amended Application for Smart Meter Funding and Cost Recovery – Final Disposition dated July 17, 2012, API has requested the disposition of the Net Deferred Revenue Requirement in the amount of $1,740,361 and a 2013 Revenue Requirement amount of $733,567. These amounts are being allocated to the residential – R1 and Seasonal customer classes as provided in Schedules 2 and 3, respectively, in the Amended Application for Smart Meter Funding and Cost Recovery – Final Disposition.

These allocations are detailed as follows.

	Total		Residential R1	Residential R1	Seasonal	Street Lighting
Price Index (October 4, 2012)			0.88%	0.88%	0.88%	0.88%
Revenue Requirement	$ 20,079,236		14,609,242	2,895,187	2,439,243	135,564
Smart Meter Cost Recovery						
Net Deferred Revenue Requirement	$ 1,740,361		1,221,427	-	518,934	-
Incremental Revenue Requirement	$ 733,567		514,206	-	219,361	-
Total Revenue Requirement for 2013	$ 22,553,164		16,344,875	2,895,187	3,177,538	135,564

Residential – R1 customer class rates are adjusted in line with the average of any adjustment to rates approved by the Board; the RRRP Adjustment Factor. Any remaining revenue deficiency related to the revenue requirement of the Residential Class is recovered by API on behalf of its customers through the Rural and Remote Rate Protection ("RRRP"). This methodology is consistent for both cost of service regulation and incentive regulation.

The additional revenue requirement allocated to the Seasonal customer class is fully recovered through rates. Therefore, API has calculated rate riders for the amounts allocated to the Seasonal customer class.

The derivation of the 2013 proposed distribution rates, rate riders for final disposition of Smart Meter costs and the 2012 RRRP funding amount is detailed in the following section.

Derivation of 2013 Proposed Distribution Rates and 2012 RRRP Funding Amount

By virtue of O. Reg. 442/01, the Residential R – 1 and Residential R – 2 distribution rates are the currently approved rates adjusted by the RRRP Adjustment Factor, as determined by the Board.

In this rate design, API has estimated the RRRP Adjustment Factor for 2013 to be 2.81% (the value used in 2012; EB-2011-0152). API acknowledges that the Board will apply the appropriate RRRP Adjustment Factor when the data becomes available.

Determination of Residential R1 & R2 2013 Distribution Rates and RRRP Funding

2013 Distribution Base Rate Determination											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.6%	86.4%	23.12	0.1330	2,230,540	14,114,336	16,344,875
Residential - R2	kW	48		151,952	12.0%	88.0%	603.65	16.7651	347,703	2,547,484	2,895,187
									2,578,243	**16,661,820**	**19,240,063**
2013 Application of Rate Indexing Methodology											
Delivery Charges Indexed by Simple Average of Other LDC Increases in Current Year											
Simple Average Increase in Delivery Charge for 2012 using the Board Determination											**2.81%**
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		39.3%	60.7%	22.11	0.0310	2,133,335	3,294,858	5,428,193
Residential - R2	kW	48		151,952	45.5%	54.5%	612.87	2.7847	353,014	423,143	776,156
Hold Residential - R2 Fixed Charge at $596.12					44.2%	55.8%	596.12	2.8482	343,365	432,791	776,156
									2,476,700	**3,727,649**	**6,204,349**
The Rural and Remote Rate Protection Amount Required for 2013											**$13,035,714**

The RRRP Funding amount for 2012 has been calculated at $13,035,714. It is the difference between the revenue allocated to these classes and the revenue recovered at the adjusted distribution rates.

Rates for the Seasonal and Street Light customer classes are determined on the basis of the Price Cap Index; calculated by API to be 0.88%. API acknowledges that the Board will apply the appropriate Price Cap when the data becomes available. The rate determination is shown below.

Determination of Seasonal and Street Lighting Distribution Rates

2013 Distribution Base Rate Determination											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Seasonal	kWh	3660	12,622,297		47.5%	52.5%	26.38	0.1015	1,158,640	1,280,602	2,439,243
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1712	-	135,564	135,564
Street Lighting					9.0%	91.0%	0.97	0.1557	12,226	123,338	135,564
									1,170,866	**1,403,940**	**2,574,806**

2013 Smart Meter Recovery Rate Rider Determination Net Deferred Revenue Requirement						
Customer Class	Metric	Average # of	Billing Determinant kWh	Billing Determinant kW	Recovery Amount Fixed Allocation	Rate Rider Per kWh
Seasonal	kWh	3660	12,622,297		518,934	0.0411

2013 Smart Meter Recovery Rate Rider Determination Incremental Revenue Requirement						
Customer Class	Metric	Average # of	Billing Determinant kWh	Billing Determinant kW	Recovery Amount Fixed Allocation	Rate Rider Per kWh
Seasonal	kWh	3660	12,622,297		219,361	0.0174

The entire rate design module is provided on the following pages and an electronic copy accompanies this Application.

Schedule “D”

Tax Change Rate Rider

3RD Generation Incentive Regulation Shared Tax Savings Model for 2013 Filers

Version 1.0

Utility Name	Algoma Power Inc.
Assigned EB Number	EB-2012-0104
Name and Title	Douglas Bradbury Director Regulatory Affairs
Phone Number	(905) 994 3634
Email Address	doug.bradbury@fortisontario.com
Date	14-Aug-12
Last COS Re-based Year	**2011**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

3RD Generation Incentive Regulation Shared Tax Savings Model for 2013 Filers

3^{RD} Generation Incentive Regulation Shared Tax Savings Model for 2013 Filers

Enter your 2012 Base Monthly Fixed Charge and Distribution Volumetric Charge into columns labeled "Rate ReBal Base Service Charge" and "Rate ReBal Base Distribution Volumetric Rate kWh/kW" respectively.

Last COS Re-based Year was in 2011

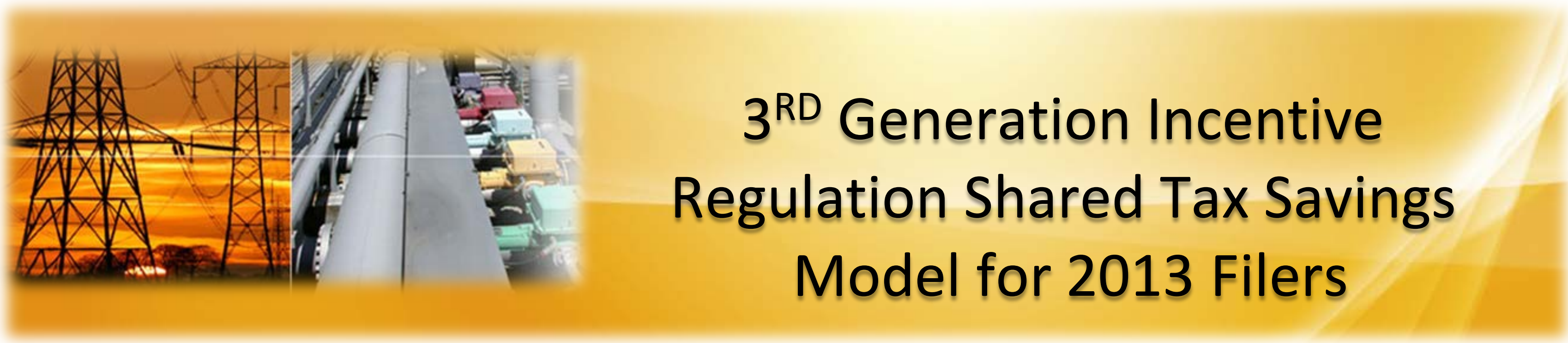
Rate Group	Rate Class	Fixed Metric	Vol Metric	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Rate ReBal Base Service Charge D	Rate ReBal Base Distribution Volumetric Rate kWh E	Rate ReBal Base Distribution Volumetric Rate kW F
RES	Residential Regular	Customer	kWh	8,039	106,119,297		20.41	0.1174	
GSGT50	General Service 50 to 4,999 kW	Customer	kW	48		151,952	596.12		16.5559
RES	Seasonal Residential – Normal Density [R4]	Customer	kWh	3,660	12,622,297		24.00	0.1073	
SL	Street Lighting	Connection	kWh	1,052	791,996			0.1690	
NA	Rate Class 5	NA	NA						
NA	Rate Class 6	NA	NA						
NA	Rate Class 7	NA	NA						
NA	Rate Class 8	NA	NA						
NA	Rate Class 9	NA	NA						
NA	Rate Class 10	NA	NA						
NA	Rate Class 11	NA	NA						
NA	Rate Class 12	NA	NA						
NA	Rate Class 13	NA	NA						
NA	Rate Class 14	NA	NA						
NA	Rate Class 15	NA	NA						
NA	Rate Class 16	NA	NA						
NA	Rate Class 17	NA	NA						
NA	Rate Class 18	NA	NA						
NA	Rate Class 19	NA	NA						
NA	Rate Class 20	NA	NA						
NA	Rate Class 21	NA	NA						
NA	Rate Class 22	NA	NA						
NA	Rate Class 23	NA	NA						
NA	Rate Class 24	NA	NA						
NA	Rate Class 25	NA	NA						

3RD Generation Incentive Regulation Shared Tax Savings Model for 2013 Filers

Calculating Re-Based Revenue from rates. No input required.

Last COS Re-based Year was in 2011

Rate Class	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Rate ReBal Base Service Charge D	Rate ReBal Base Distribution Volumetric Rate kWh E	Rate ReBal Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D *12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Revenue Requirement from Rates J = G + H + I
Residential Regular	8,039	106,119,297	0	20.41	0.1174	0.0000	1,968,912	12,458,405	0	14,427,317
General Service 50 to 4,999 kW	48	0	151,952	596.12	0.0000	16.5559	343,365	0	2,515,702	2,859,067
Seasonal Residential – Normal Density [R	3,660	12,622,297	0	24.00	0.1073	0.0000	1,054,080	1,354,372	0	2,408,452
Street Lighting	1,052	791,996	0	0.00	0.1690	0.0000	0	133,847	0	133,847
							3,366,357	13,946,625	2,515,702	19,828,684

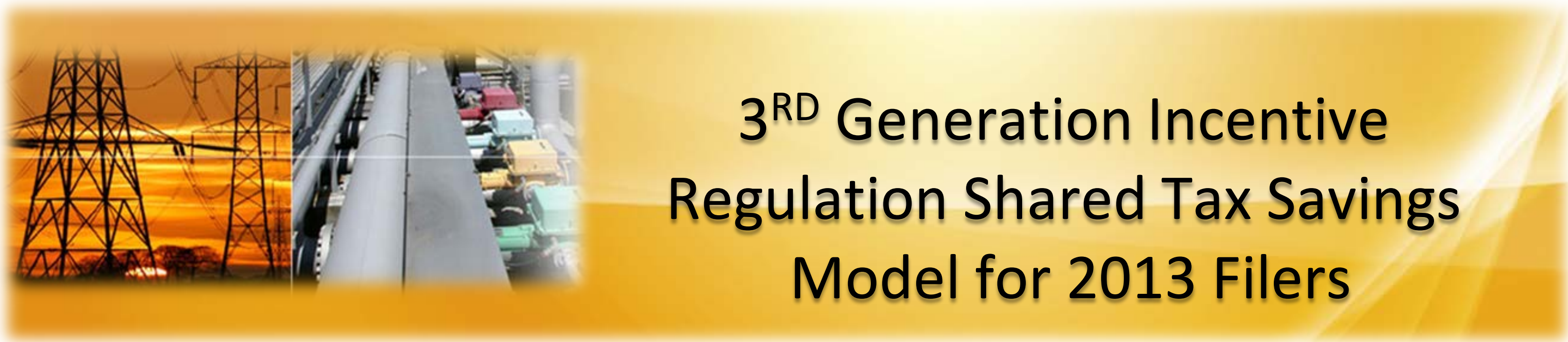


This worksheet calculates the tax sharing amount.

Step 1: Press the Update Button (this will clear all input cells and reveal your latest cost of service re-basing year).
Step 2: In the green input cells below, please enter the information related to the last Cost of Service Filing.

Summary - Sharing of Tax Change Forecast Amounts

For the 2011 year, enter any Tax Credits from the Cost of Service Tax Calculation (Positive #)	$ -	
1. Tax Related Amounts Forecast from Capital Tax Rate Changes	**2011**	**2013**
Taxable Capital	$ -	$ -
Deduction from taxable capital up to $15,000,000	$ -	$ -
Net Taxable Capital	$ -	$ -
Rate	0.000%	0.000%
Ontario Capital Tax (Deductible, not grossed-up)	**$ -**	**$ -**
2. Tax Related Amounts Forecast from Income Tax Rate Changes	**2011**	**2013**
Regulatory Taxable Income	$ 1,269,534	$ 1,269,534
Corporate Tax Rate	28.25%	26.50%
Tax Impact	$ 358,643	$ 336,427
Grossed-up Tax Amount	**$ 499,851**	**$ 457,723**
Tax Related Amounts Forecast from Capital Tax Rate Changes	$ -	$ -
Tax Related Amounts Forecast from Income Tax Rate Changes	$ 499,851	$ 457,723
Total Tax Related Amounts	**$ 499,851**	**$ 457,723**
Incremental Tax Savings		**-$ 42,128**
Sharing of Tax Savings (50%)		**-$ 21,064**



This worksheet calculates a tax change volumetric rate rider. No input required. The outputs in column Q and S are to be entered into Sheet 11 "Proposed Rates" of the 2013 IRM Rate Generator Model. Rate description should be entered as "Rate Rider for Tax Change".

Rate Class	Total Revenue $ by Rate Class A	Total Revenue % by Rate Class B = A / $H	Total Z-Factor Tax Change$ by Rate Class C = $I * B	Billed kWh D	Billed kW E	Distribution Volumetric Rate kWh Rate Rider F = C / D	Distribution Volumetric Rate kW Rate Rider G = C / E
Residential Regular	$14,427,317.3478	72.76%	-$15,326	106,119,297	0	-$0.0001	
General Service 50 to 4,999 kW	$2,859,067	14.42%	-$3,037	0	151,952		-$0.0200
Seasonal Residential – Normal Density [R4]	$2,408,452	12.15%	-$2,558	12,622,297	0	-$0.0002	
Street Lighting	$133,847	0.68%	-$142	791,996	0	-$0.0002	
	$19,828,684	100.00%	-$21,064				
	H		- I				

Schedule “E”

2013 Retail Transmission Service Rates

v 3.0

RTSR Workform for Electricity Distributors (2013 Filers)

Utility Name	Algoma Power Inc.
Assigned EB Number	EB-2012-0104
Name and Title	Douglas Bradbury, Director Regulatory Affairs
Phone Number	905 994 3634
Email Address	doug.bradbury@fortisOntario.com
Date	17-Oct-12
Last COS Re-based Year	**2010**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

RTSR Workform for Electricity Distributors (2013 Filers)

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential	kWh	$ 0.0071	$ 0.0051
General Service 50 to 4,999 kW	kW	$ 2.6396	$ 1.8099
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.8001	$ 2.0003
Seasonal Residential – Normal Density [R4]	kWh	$ 0.0071	$ 0.0051
Street Lighting	kW	$ 1.9907	$ 1.3992
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			

RTSR Workform for Electricity Distributors (2013 Filers)

In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	**kWh**	103,344,861		1.0864		112,273,857	-
General Service 50 to 4,999 kW	**kW**	67,304,494	161,408		**57.15%**	67,304,494	161,408
General Service 50 to 4,999 kW – Interval Metered	**kW**	8,089,538	15,107		**73.39%**	8,089,538	15,107
Seasonal Residential – Normal Density [R4]	**kWh**	10,086,696		1.0864		10,958,187	-
Street Lighting	**kW**	523,958	2,451		**29.30%**	523,958	2,451

RTSR Workform for Electricity Distributors (2013 Filers)

Uniform Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.22	$ 3.57	$ 3.57
Line Connection Service Rate	kW	$ 0.79	$ 0.80	$ 0.80
Transformation Connection Service Rate	kW	$ 1.77	$ 1.86	$ 1.86

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 2.65	$ 2.65	$ 2.65
Line Connection Service Rate	kW	$ 0.64	$ 0.64	$ 0.64
Transformation Connection Service Rate	kW	$ 1.50	$ 1.50	$ 1.50
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.14	$ 2.14

Hydro One Sub-Transmission Rate Rider 6A	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	$ 0.0470	$ -	$ -
RSVA Transmission connection – 4716 – which affects 1586	kW	-$ 0.0250	$ -	$ -
RSVA LV – 4750 – which affects 1550	kW	$ 0.0580	$ -	$ -
RARA 1 – 2252 – which affects 1590	kW	-$ 0.0750	$ -	$ -
Hydro One Sub-Transmission Rate Rider 6A	kW	$ 0.0050	$ -	$ -

RTSR Workform for Electricity Distributors (2013 Filers)

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	38,496	$3.22	$ 123,957	18,899	$0.79	$ 14,930	44,699	$1.77	$ 79,117	$ 94,047
February	36,327	$3.22	$ 116,973	18,693	$0.79	$ 14,767	40,572	$1.77	$ 71,812	$ 86,580
March	35,676	$3.22	$ 114,877	18,281	$0.79	$ 14,442	37,682	$1.77	$ 66,697	$ 81,139
April	26,764	$3.22	$ 86,180	15,152	$0.79	$ 11,970	31,401	$1.77	$ 55,580	$ 67,550
May	24,594	$3.22	$ 79,193	14,883	$0.79	$ 11,758	28,839	$1.77	$ 51,045	$ 62,803
June	22,131	$3.22	$ 71,262	13,827	$0.79	$ 10,923	26,776	$1.77	$ 47,394	$ 58,317
July	24,246	$3.22	$ 78,072	13,577	$0.79	$ 10,726	27,333	$1.77	$ 48,379	$ 59,105
August	28,172	$3.22	$ 90,714	17,840	$0.79	$ 14,094	31,538	$1.77	$ 55,822	$ 69,916
September	28,969	$3.22	$ 93,280	20,359	$0.79	$ 16,084	35,255	$1.77	$ 62,401	$ 78,485
October	27,959	$3.22	$ 90,028	15,412	$0.79	$ 12,175	31,283	$1.77	$ 55,371	$ 67,546
November	28,964	$3.22	$ 93,264	16,299	$0.79	$ 12,876	33,304	$1.77	$ 58,948	$ 71,824
December	38,359	$3.22	$ 123,516	22,622	$0.79	$ 17,871	44,406	$1.77	$ 78,599	$ 96,470
Total	360,657	$ 3.22	$ 1,161,316	205,844	$ 0.79	$ 162,617	413,088	$ 1.77	$ 731,166	$ 893,783

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	38,496	$3.22	$ 123,957	18,899	$0.79	$ 14,930	44,699	$1.77	$ 79,117	$ 94,047
February	36,327	$3.22	$ 116,973	18,693	$0.79	$ 14,767	40,572	$1.77	$ 71,812	$ 86,580
March	35,676	$3.22	$ 114,877	18,281	$0.79	$ 14,442	37,682	$1.77	$ 66,697	$ 81,139
April	26,764	$3.22	$ 86,180	15,152	$0.79	$ 11,970	31,401	$1.77	$ 55,580	$ 67,550
May	24,594	$3.22	$ 79,193	14,883	$0.79	$ 11,758	28,839	$1.77	$ 51,045	$ 62,803
June	22,131	$3.22	$ 71,262	13,827	$0.79	$ 10,923	26,776	$1.77	$ 47,394	$ 58,317
July	24,246	$3.22	$ 78,072	13,577	$0.79	$ 10,726	27,333	$1.77	$ 48,379	$ 59,105
August	28,172	$3.22	$ 90,714	17,840	$0.79	$ 14,094	31,538	$1.77	$ 55,822	$ 69,916
September	28,969	$3.22	$ 93,280	20,359	$0.79	$ 16,084	35,255	$1.77	$ 62,401	$ 78,485
October	27,959	$3.22	$ 90,028	15,412	$0.79	$ 12,175	31,283	$1.77	$ 55,371	$ 67,546
November	28,964	$3.22	$ 93,264	16,299	$0.79	$ 12,876	33,304	$1.77	$ 58,948	$ 71,824
December	38,359	$3.22	$ 123,516	22,622	$0.79	$ 17,871	44,406	$1.77	$ 78,599	$ 96,470
Total	360,657	$ 3.22	$ 1,161,316	205,844	$ 0.79	$ 162,617	413,088	$ 1.77	$ 731,166	$ 893,783

The purpose of this sheet is to calculate the expected billing when current 2012 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	38,496	$ 3.5700	$ 137,431	18,899	$ 0.8000	$ 15,119	44,699	$ 1.8600	$ 83,140	$ 98,259
February	36,327	$ 3.5700	$ 129,687	18,693	$ 0.8000	$ 14,954	40,572	$ 1.8600	$ 75,464	$ 90,418
March	35,676	$ 3.5700	$ 127,363	18,281	$ 0.8000	$ 14,625	37,682	$ 1.8600	$ 70,089	$ 84,713
April	26,764	$ 3.5700	$ 95,547	15,152	$ 0.8000	$ 12,122	31,401	$ 1.8600	$ 58,406	$ 70,527
May	24,594	$ 3.5700	$ 87,801	14,883	$ 0.8000	$ 11,906	28,839	$ 1.8600	$ 53,641	$ 65,547
June	22,131	$ 3.5700	$ 79,008	13,827	$ 0.8000	$ 11,062	26,776	$ 1.8600	$ 49,803	$ 60,865
July	24,246	$ 3.5700	$ 86,558	13,577	$ 0.8000	$ 10,862	27,333	$ 1.8600	$ 50,839	$ 61,701
August	28,172	$ 3.5700	$ 100,574	17,840	$ 0.8000	$ 14,272	31,538	$ 1.8600	$ 58,661	$ 72,933
September	28,969	$ 3.5700	$ 103,419	20,359	$ 0.8000	$ 16,287	35,255	$ 1.8600	$ 65,574	$ 81,862
October	27,959	$ 3.5700	$ 99,814	15,412	$ 0.8000	$ 12,330	31,283	$ 1.8600	$ 58,186	$ 70,516
November	28,964	$ 3.5700	$ 103,401	16,299	$ 0.8000	$ 13,039	33,304	$ 1.8600	$ 61,945	$ 74,985
December	38,359	$ 3.5700	$ 136,942	22,622	$ 0.8000	$ 18,098	44,406	$ 1.8600	$ 82,595	$ 100,693
Total	360,657	$ 3.57	$ 1,287,545	205,844	$ 0.80	$ 164,675	413,088	$ 1.86	$ 768,344	$ 933,019

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
February	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
March	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
April	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
May	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
June	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
July	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
August	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
September	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
October	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
November	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
December	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	38,496	$ 3.57	$ 137,431	18,899	$ 0.80	$ 15,119	44,699	$ 1.86	$ 83,140	$ 98,259
February	36,327	$ 3.57	$ 129,687	18,693	$ 0.80	$ 14,954	40,572	$ 1.86	$ 75,464	$ 90,418
March	35,676	$ 3.57	$ 127,363	18,281	$ 0.80	$ 14,625	37,682	$ 1.86	$ 70,089	$ 84,713
April	26,764	$ 3.57	$ 95,547	15,152	$ 0.80	$ 12,122	31,401	$ 1.86	$ 58,406	$ 70,527
May	24,594	$ 3.57	$ 87,801	14,883	$ 0.80	$ 11,906	28,839	$ 1.86	$ 53,641	$ 65,547
June	22,131	$ 3.57	$ 79,008	13,827	$ 0.80	$ 11,062	26,776	$ 1.86	$ 49,803	$ 60,865
July	24,246	$ 3.57	$ 86,558	13,577	$ 0.80	$ 10,862	27,333	$ 1.86	$ 50,839	$ 61,701
August	28,172	$ 3.57	$ 100,574	17,840	$ 0.80	$ 14,272	31,538	$ 1.86	$ 58,661	$ 72,933
September	28,969	$ 3.57	$ 103,419	20,359	$ 0.80	$ 16,287	35,255	$ 1.86	$ 65,574	$ 81,862
October	27,959	$ 3.57	$ 99,814	15,412	$ 0.80	$ 12,330	31,283	$ 1.86	$ 58,186	$ 70,516
November	28,964	$ 3.57	$ 103,401	16,299	$ 0.80	$ 13,039	33,304	$ 1.86	$ 61,945	$ 74,985
December	38,359	$ 3.57	$ 136,942	22,622	$ 0.80	$ 18,098	44,406	$ 1.86	$ 82,595	$ 100,693
Total	360,657	$ 3.57	$ 1,287,545	205,844	$ 0.80	$ 164,675	413,088	$ 1.86	$ 768,344	$ 933,019

The purpose of this sheet is to calculate the expected billing when forecasted 2013 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	38,496	$ 3.5700	$ 137,431	18,899	$ 0.8000	$ 15,119	44,699	$ 1.8600	$ 83,140	$ 98,259
February	36,327	$ 3.5700	$ 129,687	18,693	$ 0.8000	$ 14,954	40,572	$ 1.8600	$ 75,464	$ 90,418
March	35,676	$ 3.5700	$ 127,363	18,281	$ 0.8000	$ 14,625	37,682	$ 1.8600	$ 70,089	$ 84,713
April	26,764	$ 3.5700	$ 95,547	15,152	$ 0.8000	$ 12,122	31,401	$ 1.8600	$ 58,406	$ 70,527
May	24,594	$ 3.5700	$ 87,801	14,883	$ 0.8000	$ 11,906	28,839	$ 1.8600	$ 53,641	$ 65,547
June	22,131	$ 3.5700	$ 79,008	13,827	$ 0.8000	$ 11,062	26,776	$ 1.8600	$ 49,803	$ 60,865
July	24,246	$ 3.5700	$ 86,558	13,577	$ 0.8000	$ 10,862	27,333	$ 1.8600	$ 50,839	$ 61,701
August	28,172	$ 3.5700	$ 100,574	17,840	$ 0.8000	$ 14,272	31,538	$ 1.8600	$ 58,661	$ 72,933
September	28,969	$ 3.5700	$ 103,419	20,359	$ 0.8000	$ 16,287	35,255	$ 1.8600	$ 65,574	$ 81,862
October	27,959	$ 3.5700	$ 99,814	15,412	$ 0.8000	$ 12,330	31,283	$ 1.8600	$ 58,186	$ 70,516
November	28,964	$ 3.5700	$ 103,401	16,299	$ 0.8000	$ 13,039	33,304	$ 1.8600	$ 61,945	$ 74,985
December	38,359	$ 3.5700	$ 136,942	22,622	$ 0.8000	$ 18,098	44,406	$ 1.8600	$ 82,595	$ 100,693
Total	360,657	$ 3.57	$ 1,287,545	205,844	$ 0.80	$ 164,675	413,088	$ 1.86	$ 768,344	$ 933,019

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
February	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
March	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
April	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
May	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
June	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
July	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
August	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
September	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
October	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
November	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
December	-	$ 2.6500	$ -	-	$ 0.6400	$ -	-	$ 1.5000	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	38,496	$ 3.57	$ 137,431	18,899	$ 0.80	$ 15,119	44,699	$ 1.86	$ 83,140	$ 98,259
February	36,327	$ 3.57	$ 129,687	18,693	$ 0.80	$ 14,954	40,572	$ 1.86	$ 75,464	$ 90,418
March	35,676	$ 3.57	$ 127,363	18,281	$ 0.80	$ 14,625	37,682	$ 1.86	$ 70,089	$ 84,713
April	26,764	$ 3.57	$ 95,547	15,152	$ 0.80	$ 12,122	31,401	$ 1.86	$ 58,406	$ 70,527
May	24,594	$ 3.57	$ 87,801	14,883	$ 0.80	$ 11,906	28,839	$ 1.86	$ 53,641	$ 65,547
June	22,131	$ 3.57	$ 79,008	13,827	$ 0.80	$ 11,062	26,776	$ 1.86	$ 49,803	$ 60,865
July	24,246	$ 3.57	$ 86,558	13,577	$ 0.80	$ 10,862	27,333	$ 1.86	$ 50,839	$ 61,701
August	28,172	$ 3.57	$ 100,574	17,840	$ 0.80	$ 14,272	31,538	$ 1.86	$ 58,661	$ 72,933
September	28,969	$ 3.57	$ 103,419	20,359	$ 0.80	$ 16,287	35,255	$ 1.86	$ 65,574	$ 81,862
October	27,959	$ 3.57	$ 99,814	15,412	$ 0.80	$ 12,330	31,283	$ 1.86	$ 58,186	$ 70,516
November	28,964	$ 3.57	$ 103,401	16,299	$ 0.80	$ 13,039	33,304	$ 1.86	$ 61,945	$ 74,985
December	38,359	$ 3.57	$ 136,942	22,622	$ 0.80	$ 18,098	44,406	$ 1.86	$ 82,595	$ 100,693
Total	360,657	$ 3.57	$ 1,287,545	205,844	$ 0.80	$ 164,675	413,088	$ 1.86	$ 768,344	$ 933,019

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0071	112,273,857	-	$ 797,144	59.1%	$ 761,293	$ 0.0068
General Service 50 to 4,999 kW	kW	$ 2.6396	67,304,494	161,408	$ 426,053	31.6%	$ 406,891	$ 2.5209
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.8001	8,089,538	15,107	$ 42,301	3.1%	$ 40,399	$ 2.6742
Seasonal Residential – Normal Density [R4]	kWh	$ 0.0071	10,958,187	-	$ 77,803	5.8%	$ 74,304	$ 0.0068
Street Lighting	kW	$ 1.9907	523,958	2,451	$ 4,879	0.4%	$ 4,660	$ 1.9012
					$ 1,348,180			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0051	112,273,857	-	$ 572,597	60.0%	$ 559,849	$ 0.0050
General Service 50 to 4,999 kW	kW	$ 1.8099	67,304,494	161,408	$ 292,132	30.6%	$ 285,629	$ 1.7696
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.0003	8,089,538	15,107	$ 30,219	3.2%	$ 29,546	$ 1.9558
Seasonal Residential – Normal Density [R4]	kWh	$ 0.0051	10,958,187	-	$ 55,887	5.9%	$ 54,643	$ 0.0050
Street Lighting	kW	$ 1.3992	523,958	2,451	$ 3,429	0.4%	$ 3,353	$ 1.3680
					$ 954,264			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.

Rate Class	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0068	112,273,857	-	$ 761,293	59.1%	$ 761,293	$ 0.0068
General Service 50 to 4,999 kW	kW	$ 2.5209	67,304,494	161,408	$ 406,891	31.6%	$ 406,891	$ 2.5209
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.6742	8,089,538	15,107	$ 40,399	3.1%	$ 40,399	$ 2.6742
Seasonal Residential – Normal Density [R4]	kWh	$ 0.0068	10,958,187	-	$ 74,304	5.8%	$ 74,304	$ 0.0068
Street Lighting	kW	$ 1.9012	523,958	2,451	$ 4,660	0.4%	$ 4,660	$ 1.9012
					$ 1,287,545			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

Rate Class	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0050	112,273,857	-	$ 559,849	60.0%	$ 559,849	$ 0.0050
General Service 50 to 4,999 kW	kW	$ 1.7696	67,304,494	161,408	$ 285,629	30.6%	$ 285,629	$ 1.7696
General Service 50 to 4,999 kW – Interval Metered	kW	$ 1.9558	8,089,538	15,107	$ 29,546	3.2%	$ 29,546	$ 1.9558
Seasonal Residential – Normal Density [R4]	kWh	$ 0.0050	10,958,187	-	$ 54,643	5.9%	$ 54,643	$ 0.0050
Street Lighting	kW	$ 1.3680	523,958	2,451	$ 3,353	0.4%	$ 3,353	$ 1.3680
					$ 933,019			

RTSR Workform for Electricity Distributors (2013 Filers)

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2013 IRM Rate Generator, Sheet 11 "Proposed Rates", column I. Please note that the rate description for the RTSRs has been transfered to Sheet 11, Column A from Sheet 4.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0068	$ 0.0050
General Service 50 to 4,999 kW	kW	$ 2.5209	$ 1.7696
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.6742	$ 1.9558
Seasonal Residential – Normal Density [R4]	kWh	$ 0.0068	$ 0.0050
Street Lighting	kW	$ 1.9012	$ 1.3680

Schedule “F”

Deferral and Variance Account Continuity Schedule

3RD Generation Incentive Regulation Model for 2013 Filers

Version 2.3

Utility Name	Algoma Power Inc.
Service Territory	*(if applicable)*
Assigned EB Number	EB-2012-0104
Name of Contact and Title	Douglas Bradbury, Director Regulatory Affairs
Phone Number	905 994 3634
Email Address	doug.bradbury@fortisonartio.com
We are applying for rates effective	January-01-13

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

		2005									
Account Descriptions	**Account Number**	Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [2]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
Group 1 Accounts											
LV Variance Account	1550					0					0
RSVA - Wholesale Market Service Charge	1580	186,623	153,425			340,048					0
RSVA - Retail Transmission Network Charge	1584	(4,479)	30,291			25,812					0
RSVA - Retail Transmission Connection Charge	1586	(276,208)	(98,022)			(374,230)					0
RSVA - Power (excluding Global Adjustment)	1588	175,161	14,043			189,204					0
RSVA - Power - Sub-account - Global Adjustment	1588		(694,543)			(694,543)					0
Recovery of Regulatory Asset Balances	1590	(32,674)	(991,475)			(1,024,149)					0
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595					0					0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595					0					0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595					0					0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		48,423	(1,586,281)	0	0	(1,537,858)	0	0	0	0	0
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		48,423	(891,738)	0	0	(843,315)	0	0	0	0	0
RSVA - Power - Sub-account - Global Adjustment	**1588**	0	(694,543)	0	0	(694,543)	0	0	0	0	0
Deferred Payments in Lieu of Taxes	1562					0					0
Total of Group 1 and Account 1562		48,423	(1,586,281)	0	0	(1,537,858)	0	0	0	0	0
Special Purpose Charge Assessment Variance Account[4]	**1521**										
LRAM Variance Account	**1568**										
Total including Accounts 1562, 1521 and 1568		48,423	(1,586,281)	0	0	(1,537,858)	0	0	0	0	0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

1 Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

2 For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

3 If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

4 Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

5 Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [2]	Board-Approved Disposition during 2006	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
Group 1 Accounts											
LV Variance Account	1550	0				0	0				0
RSVA - Wholesale Market Service Charge	1580	340,048	(206,699)			133,349	0				0
RSVA - Retail Transmission Network Charge	1584	25,812	50,430			76,242	0				0
RSVA - Retail Transmission Connection Charge	1586	(374,230)	(62,725)			(436,955)	0				0
RSVA - Power (excluding Global Adjustment)	1588	189,204	1,243,905			1,433,109	0				0
RSVA - Power - Sub-account - Global Adjustment	1588	(694,543)	723,172			28,629	0				0
Recovery of Regulatory Asset Balances	1590	(1,024,149)	(1,130,047)			(2,154,196)	0				0
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0				0	0				0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		(1,537,858)	618,036	0	0	(919,822)	0	0	0	0	0
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		(843,315)	(105,136)	0	0	(948,451)	0	0	0	0	0
RSVA - Power - Sub-account - Global Adjustment	**1588**	(694,543)	723,172	0	0	28,629	0	0	0	0	0
Deferred Payments in Lieu of Taxes	1562	0				0	0				0
Total of Group 1 and Account 1562		(1,537,858)	618,036	0	0	(919,822)	0	0	0	0	0
Special Purpose Charge Assessment Variance Account[4]	**1521**										
LRAM Variance Account	**1568**										
Total including Accounts 1562, 1521 and 1568		(1,537,858)	618,036	0	0	(919,822)	0	0	0	0	0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

		2007									
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-07**	**Transactions Debit / (Credit) during 2007 excluding interest and adjustments [2]**	**Board-Approved Disposition during 2007**	**Adjustments during 2007 - other [1]**	**Closing Principal Balance as of Dec-31-07**	**Opening Interest Amounts as of Jan-1-07**	**Interest Jan-1 to Dec-31-07**	**Board-Approved Disposition during 2007**	**Adjustments during 2007 - other [1]**	**Closing Interest Amounts as of Dec-31-07**
Group 1 Accounts											
LV Variance Account	1550	0				0	0				0
RSVA - Wholesale Market Service Charge	1580	133,349	(265,204)			(131,855)	0				0
RSVA - Retail Transmission Network Charge	1584	76,242	7,879			84,121	0				0
RSVA - Retail Transmission Connection Charge	1586	(436,955)	(83,444)			(520,399)	0				0
RSVA - Power (excluding Global Adjustment)	1588	1,433,109	237,709			1,670,818	0				0
RSVA - Power - Sub-account - Global Adjustment	1588	28,629	78,082			106,711	0				0
Recovery of Regulatory Asset Balances	1590	(2,154,196)	(1,142,641)			(3,296,837)	0				0
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0				0	0				0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		(919,822)	(1,167,619)	0	0	(2,087,441)	0	0	0	0	0
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		(948,451)	(1,245,701)	0	0	(2,194,152)	0	0	0	0	0
RSVA - Power - Sub-account - Global Adjustment	**1588**	28,629	78,082	0	0	106,711	0	0	0	0	0
Deferred Payments in Lieu of Taxes	1562	0				0	0				0
Total of Group 1 and Account 1562		(919,822)	(1,167,619)	0	0	(2,087,441)	0	0	0	0	0
Special Purpose Charge Assessment Variance Account[4]	**1521**										
LRAM Variance Account	**1568**										
Total including Accounts 1562, 1521 and 1568		(919,822)	(1,167,619)	0	0	(2,087,441)	0	0	0	0	0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

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		2008									
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-08**	**Transactions Debit / (Credit) during 2008 excluding interest and adjustments [2]**	**Board-Approved Disposition during 2008**	**Adjustments during 2008 - other [1]**	**Closing Principal Balance as of Dec-31-08**	**Opening Interest Amounts as of Jan-1-08**	**Interest Jan-1 to Dec-31-08**	**Board-Approved Disposition during 2008**	**Adjustments during 2008 - other [1]**	**Closing Interest Amounts as of Dec-31-08**
Group 1 Accounts											
LV Variance Account	1550	0				0	0				0
RSVA - Wholesale Market Service Charge	1580	(131,855)	(105,287)	186,623		(423,765)	0		54,581	54,581	0
RSVA - Retail Transmission Network Charge	1584	84,121	(169,228)	(4,479)		(80,628)	0		882	882	0
RSVA - Retail Transmission Connection Charge	1586	(520,399)	(95,411)	(276,208)		(339,602)	0		(65,690)	(65,690)	0
RSVA - Power (excluding Global Adjustment)	1588	1,670,818	269,861	175,161		1,765,518	0		31,701	31,701	0
RSVA - Power - Sub-account - Global Adjustment	1588	106,711	(137,496)			(30,785)	0				0
Recovery of Regulatory Asset Balances	1590	(3,296,837)	672,682	(1,463,712)	128,163	(1,032,280)	0	(75,014)	(335,505)	(128,163)	132,328
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0				0	0				0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		(2,087,441)	435,121	(1,382,615)	128,163	(141,542)	0	(75,014)	(314,031)	(106,689)	132,328
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		(2,194,152)	572,617	(1,382,615)	128,163	(110,757)	0	(75,014)	(314,031)	(106,689)	132,328
RSVA - Power - Sub-account - Global Adjustment	**1588**	106,711	(137,496)	0	0	(30,785)	0	0	0	0	0
Deferred Payments in Lieu of Taxes	1562	0				0	0				0
Total of Group 1 and Account 1562		(2,087,441)	435,121	(1,382,615)	128,163	(141,542)	0	(75,014)	(314,031)	(106,689)	132,328
Special Purpose Charge Assessment Variance Account[4]	**1521**										
LRAM Variance Account	**1568**										
Total including Accounts 1562, 1521 and 1568		(2,087,441)	435,121	(1,382,615)	128,163	(141,542)	0	(75,014)	(314,031)	(106,689)	132,328

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

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		2009									
Account Descriptions	**Account Number**	**Opening Principal Amounts as of Jan-1-09**	**Transactions Debit / (Credit) during 2009 excluding interest and adjustments [2]**	**Board-Approved Disposition during 2009**	**Adjustments during 2009 - other [1]**	**Closing Principal Balance as of Dec-31-09**	**Opening Interest Amounts as of Jan-1-09**	**Interest Jan-1 to Dec-31-09**	**Board-Approved Disposition during 2009**	**Adjustments during 2009 - other [1]**	**Closing Interest Amounts as of Dec-31-09**
Group 1 Accounts											
LV Variance Account	1550	0				0	0				0
RSVA - Wholesale Market Service Charge	1580	(423,765)	(5,545)			(429,310)	0	(4,943)		(13,042)	(17,985)
RSVA - Retail Transmission Network Charge	1584	(80,628)	(51,054)			(131,682)	0	(1,248)		8,786	7,538
RSVA - Retail Transmission Connection Charge	1586	(339,602)	(49,342)			(388,944)	0	(4,118)		(31,630)	(35,748)
RSVA - Power (excluding Global Adjustment)	1588	1,765,518	1,174,915			2,940,433	0	21,020		155,647	176,667
RSVA - Power - Sub-account - Global Adjustment	1588	(30,785)	9,965			(20,820)	0	949		(46,943)	(45,994)
Recovery of Regulatory Asset Balances	1590	(1,032,280)	138,528			(893,752)	132,328	(10,313)			122,015
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0				0	0				0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		(141,542)	1,217,467	0	0	1,075,925	132,328	1,347	0	72,818	206,493
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		(110,757)	1,207,502	0	0	1,096,745	132,328	398	0	119,761	252,487
RSVA - Power - Sub-account - Global Adjustment	**1588**	(30,785)	9,965	0	0	(20,820)	0	949	0	(46,943)	(45,994)
Deferred Payments in Lieu of Taxes	1562	0				0	0				0
Total of Group 1 and Account 1562		(141,542)	1,217,467	0	0	1,075,925	132,328	1,347	0	72,818	206,493
Special Purpose Charge Assessment Variance Account[4]	**1521**										
LRAM Variance Account	**1568**										
Total including Accounts 1562, 1521 and 1568		(141,542)	1,217,467	0	0	1,075,925	132,328	1,347	0	72,818	206,493

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

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Account Descriptions	Account Number	2010 Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [2]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [1]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
Group 1 Accounts											
LV Variance Account	1550	0				0	0				0
RSVA - Wholesale Market Service Charge	1580	(429,310)	(205,889)			(635,199)	(17,985)	(979)		(1,181)	(20,145)
RSVA - Retail Transmission Network Charge	1584	(131,682)	(27,302)			(158,984)	7,538	(218)		(362)	6,958
RSVA - Retail Transmission Connection Charge	1586	(388,944)	(111,180)			(500,124)	(35,748)	(601)		(1,070)	(37,419)
RSVA - Power (excluding Global Adjustment)	1588	2,940,433	1,987		(1,051,227)	1,891,193	176,667	(2,363)		8,086	182,390
RSVA - Power - Sub-account - Global Adjustment	1588	(20,820)	(601,137)		953,932	331,975	(45,994)	(4,030)		(57)	(50,081)
Recovery of Regulatory Asset Balances	1590	(893,752)	483,852			(409,900)	122,015	(4,885)		10,312	127,442
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0				0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0				0	0				0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		1,075,925	(459,669)	0	(97,295)	518,961	206,493	(13,076)	0	15,728	209,145
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		1,096,745	141,468	0	(1,051,227)	186,986	252,487	(9,046)	0	15,785	259,226
RSVA - Power - Sub-account - Global Adjustment	**1588**	(20,820)	(601,137)	0	953,932	331,975	(45,994)	(4,030)	0	(57)	(50,081)
Deferred Payments in Lieu of Taxes	1562	0				0	0				0
Total of Group 1 and Account 1562		1,075,925	(459,669)	0	(97,295)	518,961	206,493	(13,076)	0	15,728	209,145
Special Purpose Charge Assessment Variance Account[4]	**1521**		49,575			49,575		343			343
LRAM Variance Account	**1568**					0					0
Total including Accounts 1562, 1521 and 1568		1,075,925	(410,094)	0	(97,295)	568,536	206,493	(12,733)	0	15,728	209,488

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	2011 Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [2]	Board-Approved Disposition during 2011	Other [1] Adjustments during Q1 2011	Other [1] Adjustments during Q2 2011	Other [1] Adjustments during Q3 2011	Other [1] Adjustments during Q4 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [1]	Closing Interest Amounts as of Dec-31-11
Group 1 Accounts														
LV Variance Account	1550	0							0	0				0
RSVA - Wholesale Market Service Charge	1580	(635,199)	(210,874)	(429,310)					(416,763)	(20,145)	(4,523)	(19,166)		(5,502)
RSVA - Retail Transmission Network Charge	1584	(158,984)	89,427	(131,682)					62,125	6,958	51	7,176		(167)
RSVA - Retail Transmission Connection Charge	1586	(500,124)	1,753	(388,944)					(109,426)	(37,419)	(1,816)	(36,818)		(2,417)
RSVA - Power (excluding Global Adjustment)	1588	1,891,193	2,239,618	2,940,433				(2,060,627)	(870,249)	182,390	13,825	184,753		11,462
RSVA - Power - Sub-account - Global Adjustment	1588	331,975	(1,401,907)	(20,820)				1,507,363	458,251	(50,081)	(17,230)	(46,051)		(21,260)
Recovery of Regulatory Asset Balances	1590	(409,900)	87,359						(322,541)	127,442	(4,994)			122,448
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0							0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0	2,852,765						2,852,765	0	124,468			124,468
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0							0	0				0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		518,961	3,658,140	1,969,677	0	0	0	(553,264)	1,654,160	209,145	109,782	89,894	0	229,033
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		186,986	5,060,048	1,990,497	0	0	0	(2,060,627)	1,195,910	259,226	127,011	135,945	0	250,292
RSVA - Power - Sub-account - Global Adjustment	**1588**	331,975	(1,401,907)	(20,820)	0	0	0	1,507,363	458,251	(50,081)	(17,230)	(46,051)	0	(21,260)
Deferred Payments in Lieu of Taxes	1562	0							0	0				0
Total of Group 1 and Account 1562		518,961	3,658,140	1,969,677	0	0	0	(553,264)	1,654,160	209,145	109,782	89,894	0	229,033
Special Purpose Charge Assessment Variance Account[4]	**1521**	49,575	(54,639)						(5,064)	343	197			540
LRAM Variance Account	**1568**	0							0	0				0
Total including Accounts 1562, 1521 and 1568		568,536	3,603,501	1,969,677	0	0	0	(553,264)	1,649,097	209,488	109,979	89,894	0	229,572

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

		2012				Projected Interest on Dec-31-11 Balances			2.1.7 RRR	
Account Descriptions	**Account Number**	**Principal Disposition during 2012 - instructed by Board**	**Interest Disposition during 2012 - instructed by Board**	**Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012**	**Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012**	**Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [3]**	**Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [3]**	**Total Claim**	**As of Dec 31-11**	**Variance RRR vs. 2011 Balance *(Principal + Interest)***
Group 1 Accounts										
LV Variance Account	1550			0	0	0		0		0
RSVA - Wholesale Market Service Charge	1580	(205,889)	(4,006)	(210,874)	(1,497)	(3,100)		(215,471)	(422,266)	0
RSVA - Retail Transmission Network Charge	1584	(27,302)	(619)	89,427	452	1,315		91,194	61,958	0
RSVA - Retail Transmission Connection Charge	1586	(111,180)	(2,235)	1,753	(182)	26		1,597	(111,843)	0
RSVA - Power (excluding Global Adjustment)	1588	(1,049,240)	(17,787)	178,991	29,249	2,631		210,871	1,201,840	2,060,627
RSVA - Power - Sub-account - Global Adjustment	1588	352,795	1,156	105,456	(22,416)	1,550		84,590	(1,070,372)	(1,507,363)
Recovery of Regulatory Asset Balances	1590			(322,541)	122,448	(4,741)		(204,834)	(200,093)	0
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595			0	0	0		0		0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595			2,852,765	124,468	41,936		3,019,168	2,977,233	0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595			0	0	0		0		0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		(1,040,816)	(23,491)	2,694,977	252,524	39,616	0	2,987,116	2,436,457	553,264
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		(1,393,611)	(24,647)	2,589,521	274,940	38,066	0	2,902,526	3,506,829	2,060,627
RSVA - Power - Sub-account - Global Adjustment	**1588**	352,795	1,156	105,456	(22,416)	1,550	0	84,590	(1,070,372)	(1,507,363)
Deferred Payments in Lieu of Taxes	1562			0	0	0	0	0		0
										0
Total of Group 1 and Account 1562		(1,040,816)	(23,491)	2,694,977	252,524	39,616	0	2,987,116	2,436,457	553,264
Special Purpose Charge Assessment Variance Account[4]	**1521**	(5,064)	540	0	0	0	0	0	(4,524)	0
LRAM Variance Account	**1568**			0	0	0	0	0		0
Total including Accounts 1562, 1521 and 1568		(1,045,880)	(22,951)	2,694,977	252,524	39,616	0	2,987,116	2,431,933	553,264

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Schedule “G”

Deferral and Variance Account Disposition

December 31, 2011 - Regulatory Assets

NAME OF UTILITY	Algoma Power Inc		
NAME OF CONTACT	Douglas R. Bradbury	**DOCID NUMBER**	EB-2012-0104
E-mail Address	doug.bradbury@fortisontario.com		
VERSION NUMBER	v1.0	**PHONE NUMBER**	905-994-3634
Date	16-Oct-12	**(extension)**	

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:

Account Description	Account Number	Closing Principal Amounts as of Dec 31, 2011 Adj for Dispositions During 2012	Interest to Dec 31, 2011	Interest Jan 1, 2012 to Dec 31, 2012		Total Claim
RSVA - Wholesale Market Service Charge	1580	$ (210,874)	$ (1,497)	$ (3,100)		$ (215,471)
RSVA - Retail Transmission Network Charge	1584	$ 89,427	$ 452	$ 1,315		$ 91,194
RSVA - Retail Transmission Connection Charge	1586	$ 1,753	$ (182)	$ 26		$ 1,597
RSVA - Power excluding Global Adjustment	1588	$ 178,991	$ 29,249	$ 2,631		$ 210,871
Recovery of Regulatory Asset Balances	1590	$ (322,541)	$ 122,448	$ (4,741)		$ (204,834)
Sub-Totals		$ 59,297	$ 28,023	$ 872	$ -	$ 88,192
Totals per column		$ 59,297	$ 28,023	$ 872	$ -	$ 88,192

2011 Actual Data	kW	kWhs
RESIDENTIAL - R1		103,344,861
SEASONAL		10,086,696
RESIDENTIAL - R2	176,515	75,394,032
Street Lighting	2,451	523,958
Totals	178,966	189,349,547

Allocators	kW	kWhs	1590 Recovery Share
RESIDENTIAL - R1	0.0%	54.6%	82.5%
SEASONAL	0.0%	5.3%	9.5%
RESIDENTIAL - R2	98.6%	39.8%	7.7%
Street Lighting	1.4%	0.3%	0.3%
Totals	100%	100%	100%

Rate Riders Calculation

NAME OF UTILITY	Algoma Power Inc		
NAME OF CONTACT	Douglas R. Bradbury	**DOCID NUMBER**	EB-2012-0104
E-mail Address	doug.bradbury@fortisontario.com		
VERSION NUMBER	v1.0	**PHONE NUMBER**	905-994-3634
Date	16-Oct-12	**(extension)**	

Regulatory Asset Accounts:	**Account Number**	**Amount**	**ALLOCATOR**	**RESIDENTIAL - R1**	**SEASONAL**	**RESIDENTIAL - R2**	**Street Lighting**	**Total**
RSVA - Wholesale Market Service Charge	1580	$ (215,471)	kWh	$ (117,602)	$ (11,478)	$ (85,795)	$ (596)	$ (215,471)
RSVA - Retail Transmission Network Charge	1584	$ 91,194	kWh	$ 49,773	$ 4,858	$ 36,311	$ 252	$ 91,194
RSVA - Retail Transmission Connection Charge	1586	$ 1,597	kWh	$ 872	$ 85	$ 636	$ 4	$ 1,597
RSVA - Power excluding Global Adjustment	1588	$ 210,871	kWh	$ 115,091	$ 11,233	$ 83,963	$ 584	$ 210,871
Recovery of Regulatory Asset Balances	1590	$ (204,834)	Recovery Share	$ (168,988)	$ (19,459)	$ (15,772)	$ (615)	$ (204,834)
Subtotal - RSVA		$ (116,642)		$ (120,854)	$ (14,761)	$ 19,344	$ (370)	$ (116,642)
Total to be Recovered		$ (116,642)		$ (120,854)	$ (14,761)	$ 19,344	$ (370)	$ (116,642)
Balance to be collected or refunded (# years below)		$ (116,642)		$ (120,854)	$ (14,761)	$ 19,344	$ (370)	$ (116,642)
Balance to be collected or refunded per year		$ (116,642)		$ (120,854)	$ (14,761)	$ 19,344	$ (370)	$ (116,642)

Class	# years	**RESIDENTIAL - R1**	**SEASONAL**	**RESIDENTIAL - R2**	**Street Lighting**	
Regulatory Asset Rate Riders	1	$ (0.0012)	$ (0.0015)	$ 0.1096	$ (0.0007)	
Billing Determinants		kWh	kWh	kW	kWh	
	Check	- 3,159.94	- 368.82	2.52	368.75	- 3,157.49

December 31, 2011 - Regulatory Assets

NAME OF UTILITY	Algoma Power Inc		
NAME OF CONTACT	Douglas R. Bradbury	**DOCID NUMBER**	EB-2012-0104
E-mail Address	doug.bradbury@fortisontario.com		
VERSION NUMBER	v1.0	**PHONE NUMBER**	905-994-3634
Date	16-Oct-12	**(extension)**	

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:

Account Description	**Account Number**	**Closing Principal Amounts as of Dec 31, 2011 Adj for Dispositions During 2012**	**Interest to Dec 31, 2011**	**Interest Jan 1, 2012 to Dec 31, 2012**		**Total Claim**
RSVA - Power - Sub-account - Global Adjustment	1588	$ 105,456	$ (22,416)	$ 1,550		$ 84,590
Sub-Totals		$ 105,456	$ (22,416)	$ 1,550	$ -	$ 84,590
Totals per column		$ 105,456	$ (22,416)	$ 1,550	$ -	$ 84,590

2011 Actual Data	**kW**	**kWhs**	**Estimated Non-RPP kWs**	**Non-RPP kWhs**
RESIDENTIAL - R1		103,344,861		6,822,753
SEASONAL		10,086,696		190,416
RESIDENTIAL - R2	176,515	75,394,032	164,831	70,403,413
Street Lighting	2,451	523,958	1,725	368,716
Totals	178,966	189,349,547	166,556	77,785,299

Allocators	**kW**	**kWhs**	**Estimated Non-RPP kWs**	**Non-RPP kWhs**
RESIDENTIAL - R1	0.0%	54.6%	0.0%	8.8%
SEASONAL	0.0%	5.3%	0.0%	0.2%
RESIDENTIAL - R2	98.6%	39.8%	99.0%	90.5%
Street Lighting	1.4%	0.3%	1.0%	0.5%
Totals	100%	100%	100%	100%

Rate Riders Calculation

NAME OF UTILITY	Algoma Power Inc		
NAME OF CONTACT	Douglas R. Bradbury	**DOCID NUMBER**	EB-2012-0104
E-mail Address	doug.bradbury@fortisontario.com		
VERSION NUMBER	v1.0	**PHONE NUMBER**	905-994-3634
Date	16-Oct-12	**(extension)**	

Regulatory Asset Accounts:	**Account Number**	**Amount**	**ALLOCATOR**	**RESIDENTIAL - R1**	**SEASONAL**	**RESIDENTIAL - R2**	**Street Lighting**	**Total**
RSVA - Power - Sub-account - Global Adjustment	1588	$ 84,590	Non-RPP kWhs	$ 7,420	$ 207	$ 76,562	$ 401	$ 84,590
Subtotal - RSVA		$ 84,590		$ 7,420	$ 207	$ 76,562	$ 401	$ 84,590
Balance to be collected or refunded (# years below)		$ 84,590		$ 7,420	$ 207	$ 76,562	$ 401	$ 84,590
Balance to be collected or refunded per year		$ 84,590		$ 7,420	$ 207	$ 76,562	$ 401	$ 84,590

Class	# years		**RESIDENTIAL - R1**	**SEASONAL**	**RESIDENTIAL - R2**	**Street Lighting**	
Regulatory Asset Rate Riders	1		$ 0.0011	$ 0.0011	$ 0.4645	$ 0.0011	
Billing Determinants			kWh	kWh	kW	kWh	
		Check	85.41	2.38	1.53	- 399.07	- 309.75

Schedule “H”

Bill Impacts

Algoma Power Inc.
2013 Distribution Rate Impact Module
2013 IR
Electricty Distribution Rate Proposal
EB-2012-0104

October 22, 2012

Electricity Distribution Impacts
Rates Effective January 1, 2013

Monthly Rates and Charges	Metric	Current Approved Rates	Proposed January 1, 2013
Residential - R1			
Monthly Service Charge	$	21.51	22.11
Smart Meter Rate Adder	$	1.00	-
Distribution Volumetric Rate	$/kWh	0.0302	0.0310
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kWh	0.0003	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	0.0046	0.0046
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	(0.0061)	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kWh		(0.0012)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kWh		0.0011
Rate Rider for Tax Changes - effective until December 31, 2012	$/kWh	(0.0002)	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0071	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh		
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25
Residential - R2			
Monthly Service Charge	$	596.12	596.12
Smart Meter Rate Adder	$	1.00	-
Distribution Volumetric Rate	$/kW	2.7086	2.8482
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kW	0.0272	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kW	2.2664	2.2664
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kW	(2.8219)	(2.8219)
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kW		0.1096
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kW		0.4645
Rate Rider for PILs - effective until December 31, 2013	$/kW		
Rate Rider for Tax Changes - effective until December 31, 2012	$/kW	(0.0273)	(0.0200)
Retail Transmission Rate - Network Service Rate	$/kW	2.6396	2.5209
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8099	1.7696
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	$/kW	2.8001	2.6742
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	$/kW	2.0003	1.9558
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh		
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25
Seasonal			
Monthly Service Charge	$	26.15	26.38
Smart Meter Rate Adder	$	1.00	-
Distribution Volumetric Rate	$/kWh	0.1006	0.1015
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kWh	0.0002	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	0.0046	0.0046
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	(0.0061)	(0.0061)
Rate Rider for Deferral/Variance Account Disposition - effective until November 30, 2015	$/kWh	0.0307	0.0307
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kWh		(0.0015)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kWh		0.0011
Rate Rider for PILs - effective until December 31, 2013	$/kWh		
Smart Meter Cost Recovery Rate Rider - Net Deferred Revenue Requirement, effective until December 31, 2013	$/kWh		0.0411
Smart Meter Cost Recovery Rate Rider - Incremental Revenue Requirement, effective until December 31, 2013	$/kWh		0.0174
Rate Rider for Tax Changes - effective until December 31, 2012	$/kWh	(0.0003)	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0071	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh		
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25
Street Lighting			
Monthly Service Charge	$	0.96	0.97
Smart Meter Rate Adder	$	-	-
Distribution Volumetric Rate	$/kWh	0.1543	0.1557
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kWh	0.0001	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	0.0048	0.0048
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	(0.0061)	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kWh		(0.0007)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kWh		0.0011
Rate Rider for PILs - effective until December 31, 2013	$/kWh		
Rate Rider for Tax Changes - effective until December 31, 2012	$/kWh	(0.0002)	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kW	1.9907	1.9012
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3992	1.3680
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh		
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25
Other			
Debt Retirement Charge	$/kWh	0.0020	0.0020
Energy - First Tier	$/kWh	0.0750	0.0750
Energy - Second Tier	$/kWh	0.0880	0.0880
Loss Factor			
Total Loss Factor		1.0864	1.0864
GST / HST		13%	13%

Electricity Distribution Impacts
Rates Effective January 1, 2013

Residential - R1	Metric	Current Approved Rates	Proposed January 1, 2013
Monthly Service Charge	$	21.51	22.11
Smart Meter Rate Adder	$	1.00	-
Distribution Volumetric Rate	$/kWh	0.0302	0.0310
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kWh	0.0003	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	0.0046	0.0046
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	(0.0061)	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	(0.0012)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	
Rate Rider for Tax Changes - effective until December 31, 2012	$/kWh	(0.0002)	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0071	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh	-	-
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	800	kWh		kW
RPP Tier One	750	kWh	Load Factor	

Loss Factor	1.0864

Residential - R1	Volume	Rate	Charge	Volume	Rate	Charge	Impacts		
		$	$		$	$	$	%	% of Total Bill
Energy, First Tier (kWh)	750	0.0750	56.25	750	0.0750	56.25	0.00	0.00%	38.59%
Energy, Second Tier (kWh)	119	0.0880	10.48	119	0.0880	10.48	0.00	0.00%	7.19%
Sub-Total: Energy			66.73			66.73	0.00	0.00%	45.79%
Monthly Service Charge	1	21.51	21.51	1	22.11	22.11	0.60	2.79%	15.17%
Smart Meter Rate Adder	1	1.00	1.00	1	0.00	0.00	-1.00	-100.00%	0.00%
Distribution Volumetric Rate	800	0.0302	24.16	800	0.0310	24.80	0.64	2.65%	17.02%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	800	0.0003	0.24	800	0.0000	0.00	-0.24	-100.00%	0.00%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	800	0.0046	3.68	800	0.0046	3.68	0.00	0.00%	2.52%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	800	-0.0061	-4.88	800	-0.0061	-4.88	0.00	0.00%	-3.35%
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	800	0.0000	0.00	800	-0.0012	-0.96	-0.96	0.00%	-0.66%
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for Tax Changes - effective until December 31, 2012	800	-0.0002	-0.16	800	-0.0001	-0.08	0.08	-50.00%	-0.05%
Total: Distribution			45.55			44.67	-0.88	-1.93%	30.65%
Retail Transmission Rate - Network Service Rate	869	0.0071	6.17	869	0.0068	5.91	-0.26	-4.23%	4.05%
Retail Transmission Rate - Line and Transformation Connection Service Rate	869	0.0051	4.43	869	0.0050	4.35	-0.09	-1.96%	2.98%
Total: Retail Transmission			10.60			10.26	-0.35	-3.28%	7.04%
Sub-Total: Delivery (Distribution and Retail Transmission)			56.15			54.93	-1.23	-2.19%	37.68%
Wholesale Market Service Rate	869	0.0052	4.52	869	0.0052	4.52	0.00	0.00%	3.10%
Rural Rate Protection Charge	869	0.0011	0.96	869	0.0011	0.96	0.00	0.00%	0.66%
Special Purpose Charge	869	0.0000	0.00	869	0.0000	0.00	0.00	0.00%	0.00%
Standard Supply Service - Administarive Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.17%
Sub-Total: Regulatory			5.73			5.73	0.00	0.00%	3.93%
Debt Retirement Charge	800	0.0020	1.60	800	0.0020	1.60	0.00	0.00%	1.10%
Total Bill Before Taxes			130.21			128.98	-1.23	-0.94%	88.50%
GST / HST		13%	16.93		13%	16.77	-0.16	-0.94%	11.50%
Total Bill			**$ 147.14**			**$ 145.75**	**$ (1.39)**	-0.94%	100.00%
OCEB Credit			**$ 14.71**			**$ 14.58**			
Balance after OCEB Credit has been applied			**$ 132.42**			**$ 131.18**	**$ (1.25)**	**-0.94%**	

Electricity Distribution Impacts
Rates Effective January 1, 2013

Residential - R1	Metric	Current Approved Rates	Proposed January 1, 2013
Monthly Service Charge	$	21.51	22.11
Smart Meter Rate Adder	$	1.00	-
Distribution Volumetric Rate	$/kWh	0.0302	0.0310
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kWh	0.0003	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	0.0046	0.0046
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	(0.0061)	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	(0.0012)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	0.0011
Rate Rider for Tax Changes - effective until December 31, 2012	$/kWh	(0.0002)	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0071	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh	-	-
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	800	kWh		kW
RPP Tier One	750	kWh	Load Factor	

Loss Factor	1.0864

Residential - R1	Volume	Rate	Charge	Volume	Rate	Charge	Impacts		
		$	$		$	$	$	%	% of Total Bill
Energy, First Tier (kWh)	750	0.0750	56.25	750	0.0750	56.25	0.00	0.00%	38.33%
Energy, Second Tier (kWh)	119	0.0880	10.48	119	0.0880	10.48	0.00	0.00%	7.14%
Sub-Total: Energy			66.73			66.73	0.00	0.00%	45.47%
Monthly Service Charge	1	21.51	21.51	1	22.11	22.11	0.60	2.79%	15.07%
Smart Meter Rate Adder	1	1.00	1.00	1	0.00	0.00	-1.00	-100.00%	0.00%
Distribution Volumetric Rate	800	0.0302	24.16	800	0.0310	24.80	0.64	2.65%	16.90%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	800	0.0003	0.24	800	0.0000	0.00	-0.24	-100.00%	0.00%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	800	0.0046	3.68	800	0.0046	3.68	0.00	0.00%	2.51%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	800	-0.0061	-4.88	800	-0.0061	-4.88	0.00	0.00%	-3.33%
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	800	0.0000	0.00	800	-0.0012	-0.96	-0.96	0.00%	-0.65%
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	800	0.0000	0.00	800	0.0011	0.88	0.88	0.00%	0.60%
	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for Tax Changes - effective until December 31, 2012	800	-0.0002	-0.16	800	-0.0001	-0.08	0.08	-50.00%	-0.05%
Total: Distribution			45.55			45.55	0.00	0.00%	31.04%
Retail Transmission Rate - Network Service Rate	869	0.0071	6.17	869	0.0068	5.91	-0.26	-4.23%	4.03%
Retail Transmission Rate - Line and Transformation Connection Service Rate	869	0.0051	4.43	869	0.0050	4.35	-0.09	-1.96%	2.96%
Total: Retail Transmission			10.60			10.26	-0.35	-3.28%	6.99%
Sub-Total: Delivery (Distribution and Retail Transmission)			56.15			55.81	-0.35	-0.62%	38.03%
Wholesale Market Service Rate	869	0.0052	4.52	869	0.0052	4.52	0.00	0.00%	3.08%
Rural Rate Protection Charge	869	0.0011	0.96	869	0.0011	0.96	0.00	0.00%	0.65%
Special Purpose Charge	869	0.0000	0.00	869	0.0000	0.00	0.00	0.00%	0.00%
Standard Supply Service - Administarive Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.17%
Sub-Total: Regulatory			5.73			5.73	0.00	0.00%	3.90%
Debt Retirement Charge	800	0.0020	1.60	800	0.0020	1.60	0.00	0.00%	1.09%
Total Bill Before Taxes			130.21			129.86	-0.35	-0.27%	88.50%
GST / HST		13%	16.93		13%	16.88	-0.05	-0.27%	11.50%
Total Bill			**$ 147.14**			**$ 146.75**	**$ (0.39)**	-0.27%	100.00%
OCEB Credit			**$ 14.71**			**$ 14.67**			
Balance after OCEB Credit has been applied			**$ 132.42**			**$ 132.07**	**$ (0.35)**	**-0.27%**	

Electricity Distribution Impacts
Rates Effective January 1, 2013

Residential - R1	Metric	Current Approved Rates	Proposed January 1, 2013
Monthly Service Charge	$	21.51	22.11
Smart Meter Rate Adder	$	1.00	-
Distribution Volumetric Rate	$/kWh	0.0302	0.0310
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kWh	0.0003	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	0.0046	0.0046
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	(0.0061)	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	(0.0012)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	
Rate Rider for Tax Changes - effective until December 31, 2012	$/kWh	(0.0002)	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0071	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh	-	-
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	2,000 kWh	kW		**Loss Factor** 1.0864
RPP Tier One	750 kWh	Load Factor		

Residential - R1	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Impacts $	Impacts %	% of Total Bill
Energy, First Tier (kWh)	750	0.0750	56.25	750	0.0750	56.25	0.00	0.00%	16.40%
Energy, Second Tier (kWh)	1423	0.0880	125.21	1423	0.0880	125.21	0.00	0.00%	36.50%
Sub-Total: Energy			181.46			181.46	0.00	0.00%	52.90%
Monthly Service Charge	1	21.51	21.51	1	22.11	22.11	0.60	2.79%	6.45%
Smart Meter Rate Adder	1	1.00	1.00	1	0.00	0.00	-1.00	-100.00%	0.00%
Distribution Volumetric Rate	2000	0.0302	60.40	2000	0.0310	62.00	1.60	2.65%	18.08%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	2000	0.0003	0.60	2000	0.0000	0.00	-0.60	-100.00%	0.00%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	2000	0.0046	9.20	2000	0.0046	9.20	0.00	0.00%	2.68%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	2000	-0.0061	-12.20	2000	-0.0061	-12.20	0.00	0.00%	-3.56%
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	2000	0.0000	0.00	2000	-0.0012	-2.40	-2.40	0.00%	-0.70%
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	2000	0.0000	0.00	2000	0.0000	0.00	0.00	0.00%	0.00%
	2000	0.0000	0.00	2000	0.0000	0.00	0.00	0.00%	0.00%
	2000	0.0000	0.00	2000	0.0000	0.00	0.00	0.00%	0.00%
	2000	0.0000	0.00	2000	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for Tax Changes - effective until December 31, 2012	2000	-0.0002	-0.40	2000	-0.0001	-0.20	0.20	-50.00%	-0.06%
Total: Distribution			80.11			78.51	-1.60	-2.00%	22.89%
Retail Transmission Rate - Network Service Rate	2173	0.0071	15.43	2173	0.0068	14.78	-0.65	-4.23%	4.31%
Retail Transmission Rate - Line and Transformation Connection Service Rate	2173	0.0051	11.08	2173	0.0050	10.86	-0.22	-1.96%	3.17%
Total: Retail Transmission			26.51			25.64	-0.87	-3.28%	7.47%
Sub-Total: Delivery (Distribution and Retail Transmission)			106.62			104.15	-2.47	-2.32%	30.36%
Wholesale Market Service Rate	2173	0.0052	11.30	2173	0.0052	11.30	0.00	0.00%	3.29%
Rural Rate Protection Charge	2173	0.0011	2.39	2173	0.0011	2.39	0.00	0.00%	0.70%
Special Purpose Charge	2173	0.0000	0.00	2173	0.0000	0.00	0.00	0.00%	0.00%
Standard Supply Service - Administarive Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.07%
Sub-Total: Regulatory			13.94			13.94	0.00	0.00%	4.06%
Debt Retirement Charge	2000	0.0020	4.00	2000	0.0020	4.00	0.00	0.00%	1.17%
Total Bill Before Taxes			306.01			303.54	-2.47	-0.81%	88.50%
GST / HST		13%	39.78		13%	39.46	-0.32	-0.81%	11.50%
Total Bill			**$ 345.79**			**$ 343.00**	**$ (2.79)**	-0.81%	100.00%
OCEB Credit			**$ 34.58**			**$ 34.30**			
Balance after OCEB Credit has been applied			**$ 311.22**			**$ 308.70**	**$ (2.51)**	**-0.81%**	

Electricity Distribution Impacts
Rates Effective January 1, 2013

Residential - R1	Metric	Current Approved Rates	Proposed January 1, 2013
Monthly Service Charge	$	21.51	22.11
Smart Meter Rate Adder	$	1.00	-
Distribution Volumetric Rate	$/kWh	0.0302	0.0310
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kWh	0.0003	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	0.0046	0.0046
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	(0.0061)	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	(0.0012)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	0.0011
Rate Rider for Tax Changes - effective until December 31, 2012	$/kWh	(0.0002)	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0071	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh	-	-
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	2,000	kWh		kW
RPP Tier One	750	kWh	Load Factor	

Loss Factor	1.0864

Residential - R1	Volume	Rate	Charge	Volume	Rate	Charge	Impacts		
		$	$		$	$	$	%	% of Total Bill
Energy, First Tier (kWh)	750	0.0750	56.25	750	0.0750	56.25	0.00	0.00%	16.28%
Energy, Second Tier (kWh)	1423	0.0880	125.21	1423	0.0880	125.21	0.00	0.00%	36.24%
Sub-Total: Energy			181.46			181.46	0.00	0.00%	52.52%
Monthly Service Charge	1	21.51	21.51	1	22.11	22.11	0.60	2.79%	6.40%
Smart Meter Rate Adder	1	1.00	1.00	1	0.00	0.00	-1.00	-100.00%	0.00%
Distribution Volumetric Rate	2000	0.0302	60.40	2000	0.0310	62.00	1.60	2.65%	17.95%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	2000	0.0003	0.60	2000	0.0000	0.00	-0.60	-100.00%	0.00%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	2000	0.0046	9.20	2000	0.0046	9.20	0.00	0.00%	2.66%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	2000	-0.0061	-12.20	2000	-0.0061	-12.20	0.00	0.00%	-3.53%
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	2000	0.0000	0.00	2000	-0.0012	-2.40	-2.40	0.00%	-0.69%
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	2000	0.0000	0.00	2000	0.0011	2.20	2.20	0.00%	0.64%
	2000	0.0000	0.00	2000	0.0000	0.00	0.00	0.00%	0.00%
	2000	0.0000	0.00	2000	0.0000	0.00	0.00	0.00%	0.00%
	2000	0.0000	0.00	2000	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for Tax Changes - effective until December 31, 2012	2000	-0.0002	-0.40	2000	-0.0001	-0.20	0.20	-50.00%	-0.06%
Total: Distribution			80.11			80.71	0.60	0.75%	23.36%
Retail Transmission Rate - Network Service Rate	2173	0.0071	15.43	2173	0.0068	14.78	-0.65	-4.23%	4.28%
Retail Transmission Rate - Line and Transformation Connection Service Rate	2173	0.0051	11.08	2173	0.0050	10.86	-0.22	-1.96%	3.14%
Total: Retail Transmission			26.51			25.64	-0.87	-3.28%	7.42%
Sub-Total: Delivery (Distribution and Retail Transmission)			106.62			106.35	-0.27	-0.25%	30.78%
Wholesale Market Service Rate	2173	0.0052	11.30	2173	0.0052	11.30	0.00	0.00%	3.27%
Rural Rate Protection Charge	2173	0.0011	2.39	2173	0.0011	2.39	0.00	0.00%	0.69%
Special Purpose Charge	2173	0.0000	0.00	2173	0.0000	0.00	0.00	0.00%	0.00%
Standard Supply Service - Administarive Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.07%
Sub-Total: Regulatory			13.94			13.94	0.00	0.00%	4.03%
Debt Retirement Charge	2000	0.0020	4.00	2000	0.0020	4.00	0.00	0.00%	1.16%
Total Bill Before Taxes			306.01			305.74	-0.27	-0.09%	88.50%
GST / HST		13%	39.78		13%	39.75	-0.03	-0.09%	11.50%
Total Bill			**$ 345.79**			**$ 345.49**	**$ (0.30)**	-0.09%	100.00%
OCEB Credit			**$ 34.58**			**$ 34.55**			
Balance after OCEB Credit has been applied			**$ 311.22**			**$ 310.94**	**$ (0.27)**	**-0.09%**	

Electricity Distribution Impacts
Rates Effective January 1, 2013

Residential - R2	Metric	Current Approved Rates	Proposed January 1, 2013
Monthly Service Charge	$	596.12	596.12
Smart Meter Rate Adder	$	1.00	-
Distribution Volumetric Rate	$/kW	2.7086	2.8482
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kW	0.0272	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kW	2.2664	2.2664
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kW	(2.8219)	(2.8219)
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kW	-	0.1096
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kW	-	
Rate Rider for PILs - effective until December 31, 2013	$/kW	-	-
Rate Rider for Tax Changes - effective until December 31, 2012	$/kW	(0.0273)	(0.0200)
Retail Transmission Rate - Network Service Rate	$/kW	2.6396	2.5209
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8099	1.7696
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	$/kW	2.8001	2.6742
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	$/kW	2.0003	1.9558
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh	-	-
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	90,000 kWh	225 kW	Loss Factor	1.0864
RPP Tier One	750 kWh	Load Factor 54.8%		

Residential - R2	Volume	Rate	Charge	Volume	Rate	Charge	Impacts		
		$	$		$	$	$	%	% of Total Bill
Energy, First Tier (kWh)	750	0.0750	56.25	750	0.0750	56.25	0.00	0.00%	0.43%
Energy, Second Tier (kWh)	97026	0.0880	8538.29	97026	0.0880	8538.29	0.00	0.00%	65.30%
Sub-Total: Energy			8594.54			8594.54	0.00	0.00%	65.73%
Monthly Service Charge	1	596.12	596.12	1	596.12	596.12	0.00	0.00%	4.56%
Smart Meter Rate Adder	1	1.00	1.00	1	0.00	0.00	-1.00	-100.00%	0.00%
Distribution Volumetric Rate	225	2.7086	609.44	225	2.8482	640.85	31.41	5.15%	4.90%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	225	0.0272	6.12	225	0.0000	0.00	-6.12	-100.00%	0.00%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	225	2.2664	509.94	225	2.2664	509.94	0.00	0.00%	3.90%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	225	-2.8219	-634.93	225	-2.8219	-634.93	0.00	0.00%	-4.86%
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	225	0.0000	0.00	225	0.1096	24.66	24.66	0.00%	0.19%
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	225	0.0000	0.00	225	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for PILs - effective until December 31, 2013	225	0.0000	0.00	225	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for Tax Changes - effective until December 31, 2012	225	-0.0273	-6.14	225	-0.0200	-4.50	1.64	-26.74%	-0.03%
Total: Distribution			1081.545			1132.14	50.59	4.68%	8.66%
Retail Transmission Rate - Network Service Rate	244	2.6396	645.22	244	2.5209	616.21	-29.02	-4.50%	4.71%
Retail Transmission Rate - Line and Transformation Connection Service Rate	244	1.8099	442.41	244	1.7696	432.56	-9.85	-2.23%	3.31%
Total: Retail Transmission			1087.64			1048.77	-38.87	-3.57%	8.02%
Sub-Total: Delivery (Distribution and Retail Transmission)			2169.18			2180.91	11.73	0.54%	16.68%
Wholesale Market Service Rate	97776	0.0052	508.44	97776	0.0052	508.44	0.00	0.00%	3.89%
Rural Rate Protection Charge	97776	0.0011	107.55	97776	0.0011	107.55	0.00	0.00%	0.82%
Special Purpose Charge	97776	0.0000	0.00	97776	0.0000	0.00	0.00	0.00%	0.00%
Standard Supply Service - Administarive Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			616.24			616.24	0.00	0.00%	4.71%
Debt Retirement Charge	90000	0.0020	180.00	90000	0.0020	180.00	0.00	0.00%	1.38%
Total Bill Before Taxes			11559.96			11571.68	11.73	0.10%	88.50%
GST / HST		13%	1502.79		13%	1504.32	1.52	0.10%	11.50%
Total Bill			$ 13,062.75			$ 13,076.00	$ 13.25	0.10%	100.00%

Electricity Distribution Impacts
Rates Effective January 1, 2013

Residential - R2	Metric	Current Approved Rates	Proposed January 1, 2013
Monthly Service Charge	$	596.12	596.12
Smart Meter Rate Adder	$	1.00	-
Distribution Volumetric Rate	$/kW	2.7086	2.8482
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kW	0.0272	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kW	2.2664	2.2664
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kW	(2.8219)	(2.8219)
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kW	-	0.1096
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kW	-	0.4645
Rate Rider for PILs - effective until December 31, 2013	$/kW	-	-
Rate Rider for Tax Changes - effective until December 31, 2012	$/kW	(0.0273)	(0.0200)
Retail Transmission Rate - Network Service Rate	$/kW	2.6396	2.5209
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8099	1.7696
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	$/kW	2.8001	2.6742
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	$/kW	2.0003	1.9558
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh	-	-
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	90,000	kWh	225	kW	Loss Factor	1.0864
RPP Tier One	750	kWh	Load Factor	54.8%		

Residential - R2	Volume	Rate	Charge	Volume	Rate	Charge	Impacts		
		$	$		$	$	$	%	% of Total Bill
Energy, First Tier (kWh)	750	0.0750	56.25	750	0.0750	56.25	0.00	0.00%	0.43%
Energy, Second Tier (kWh)	97026	0.0880	8538.29	97026	0.0880	8538.29	0.00	0.00%	64.71%
Sub-Total: Energy			8594.54			8594.54	0.00	0.00%	65.14%
Monthly Service Charge	1	596.12	596.12	1	596.12	596.12	0.00	0.00%	4.52%
Smart Meter Rate Adder	1	1.00	1.00	1	0.00	0.00	-1.00	-100.00%	0.00%
Distribution Volumetric Rate	225	2.7086	609.44	225	2.8482	640.85	31.41	5.15%	4.86%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	225	0.0272	6.12	225	0.0000	0.00	-6.12	-100.00%	0.00%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	225	2.2664	509.94	225	2.2664	509.94	0.00	0.00%	3.86%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	225	-2.8219	-634.93	225	-2.8219	-634.93	0.00	0.00%	-4.81%
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	225	0.0000	0.00	225	0.1096	24.66	24.66	0.00%	0.19%
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	225	0.0000	0.00	225	0.4645	104.51	104.51	0.00%	0.79%
Rate Rider for PILs - effective until December 31, 2013	225	0.0000	0.00	225	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for Tax Changes - effective until December 31, 2012	225	-0.0273	-6.14	225	-0.0200	-4.50	1.64	-26.74%	-0.03%
Total: Distribution			1081.545			1236.65	155.11	14.34%	9.37%
Retail Transmission Rate - Network Service Rate	244	2.6396	645.22	244	2.5209	616.21	-29.02	-4.50%	4.67%
Retail Transmission Rate - Line and Transformation Connection Service Rate	244	1.8099	442.41	244	1.7696	432.56	-9.85	-2.23%	3.28%
Total: Retail Transmission			1087.64			1048.77	-38.87	-3.57%	7.95%
Sub-Total: Delivery (Distribution and Retail Transmission)			2169.18			2285.42	116.24	5.36%	17.32%
Wholesale Market Service Rate	97776	0.0052	508.44	97776	0.0052	508.44	0.00	0.00%	3.85%
Rural Rate Protection Charge	97776	0.0011	107.55	97776	0.0011	107.55	0.00	0.00%	0.82%
Special Purpose Charge	97776	0.0000	0.00	97776	0.0000	0.00	0.00	0.00%	0.00%
Standard Supply Service - Administarive Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			616.24			616.24	0.00	0.00%	4.67%
Debt Retirement Charge	90000	0.0020	180.00	90000	0.0020	180.00	0.00	0.00%	1.36%
Total Bill Before Taxes			11559.96			11676.20	116.24	1.01%	88.50%
GST / HST		13%	1502.79		13%	1517.91	15.11	1.01%	11.50%
Total Bill			**$ 13,062.75**			**$ 13,194.10**	**$ 131.35**	1.01%	100.00%

Electricity Distribution Impacts
Rates Effective January 1, 2013

Residential Customers with an Interval Meter

Residential - R2	Metric	Current Approved Rates	Proposed January 1, 2013
Monthly Service Charge	$	596.12	596.12
Smart Meter Rate Adder	$	1.00	-
Distribution Volumetric Rate	$/kW	2.7086	2.8482
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kW	0.0272	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kW	2.2664	2.2664
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kW	(2.8219)	(2.8219)
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kW	-	0.1096
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kW	-	
Rate Rider for PILs - effective until December 31, 2013	$/kW	-	-
Rate Rider for Tax Changes - effective until December 31, 2012	$/kW	(0.0273)	(0.0200)
Retail Transmission Rate - Network Service Rate	$/kW	2.6396	2.5209
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8099	1.7696
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	$/kW	2.8001	2.6742
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	$/kW	2.0003	1.9558
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh	-	-
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	1,100,000 kWh	2500 kW	Loss Factor	1.0864
RPP Tier One	750 kWh	Load Factor 60.3%		

Residential - R2	Volume	Rate	Charge	Volume	Rate	Charge	Impacts		
		$	$		$	$	$	%	% of Total Bill
Energy, First Tier (kWh)	750	0.0750	56.25	750	0.0750	56.25	0.00	0.00%	0.04%
Energy, Second Tier (kWh)	1194290	0.0880	105097.52	1194290	0.0880	105097.52	0.00	0.00%	69.40%
Sub-Total: Energy			105153.77			105153.77	0.00	0.00%	69.44%
Monthly Service Charge	1	596.12	596.12	1	596.12	596.12	0.00	0.00%	0.39%
Smart Meter Rate Adder	1	1.00	1.00	1	0.00	0.00	-1.00	-100.00%	0.00%
Distribution Volumetric Rate	2500	2.7086	6771.50	2500	2.8482	7120.50	349.00	5.15%	4.70%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	2500	0.0272	68.00	2500	0.0000	0.00	-68.00	-100.00%	0.00%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	2500	2.2664	5666.00	2500	2.2664	5666.00	0.00	0.00%	3.74%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	2500	-2.8219	-7054.75	2500	-2.8219	-7054.75	0.00	0.00%	-4.66%
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	2500	0.0000	0.00	2500	0.1096	274.00	274.00	0.00%	0.18%
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	2500	0.0000	0.00	2500	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for PILs - effective until December 31, 2013	2500	0.0000	0.00	2500	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for Tax Changes - effective until December 31, 2012	2500	-0.0273	-68.25	2500	-0.0200	-50.00	18.25	-26.74%	-0.03%
Total: Distribution			5979.62			6551.87	572.25	9.57%	4.33%
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	2716	2.8001	7605.07	2716	2.6742	7263.13	-341.94	-4.50%	4.80%
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	2716	2.0003	5432.81	2716	1.9558	5311.95	-120.86	-2.22%	3.51%
Total: Retail Transmission			13037.89			12575.08	-462.81	-3.55%	8.30%
Sub-Total: Delivery (Distribution and Retail Transmission)			19017.51			19126.95	109.44	0.58%	12.63%
Wholesale Market Service Rate	1195040	0.0052	6214.21	1195040	0.0052	6214.21	0.00	0.00%	4.10%
Rural Rate Protection Charge	1195040	0.0011	1314.54	1195040	0.0011	1314.54	0.00	0.00%	0.87%
Special Purpose Charge	1195040	0.0000	0.00	1195040	0.0000	0.00	0.00	0.00%	0.00%
Standard Supply Service - Administarive Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			7529.00			7529.00	0.00	0.00%	4.97%
Debt Retirement Charge	1100000	0.0020	2200.00	1100000	0.0020	2200.00	0.00	0.00%	1.45%
Total Bill Before Taxes			133900.28			134009.72	109.44	0.08%	88.50%
GST / HST		13%	17407.04		13%	17421.26	14.23	0.08%	11.50%
Total Bill			**$ 151,307.31**			**$ 151,430.99**	**$ 123.67**	0.08%	100.00%

Electricity Distribution Impacts
Rates Effective January 1, 2013

Residential Customers with an Interval Meter

Residential - R2	Metric	Current Approved Rates	Proposed January 1, 2013
Monthly Service Charge	$	596.12	596.12
Smart Meter Rate Adder	$	1.00	-
Distribution Volumetric Rate	$/kW	2.7086	2.8482
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kW	0.0272	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kW	2.2664	2.2664
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kW	(2.8219)	(2.8219)
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kW	-	0.1096
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kW	-	0.4645
Rate Rider for PILs - effective until December 31, 2013	$/kW	-	-
Rate Rider for Tax Changes - effective until December 31, 2012	$/kW	(0.0273)	(0.0200)
Retail Transmission Rate - Network Service Rate	$/kW	2.6396	2.5209
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8099	1.7696
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	$/kW	2.8001	2.6742
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	$/kW	2.0003	1.9558
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh	-	-
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	1,100,000 kWh	2500 kW		
RPP Tier One	750 kWh	Load Factor 60.3%		
			Loss Factor	1.0864

Residential - R2	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Impacts $	Impacts %	% of Total Bill
Energy, First Tier (kWh)	750	0.0750	56.25	750	0.0750	56.25	0.00	0.00%	0.04%
Energy, Second Tier (kWh)	1194290	0.0880	105097.52	1194290	0.0880	105097.52	0.00	0.00%	68.81%
Sub-Total: Energy			105153.77			105153.77	0.00	0.00%	68.84%
Monthly Service Charge	1	596.12	596.12	1	596.12	596.12	0.00	0.00%	0.39%
Smart Meter Rate Adder	1	1.00	1.00	1	0.00	0.00	-1.00	-100.00%	0.00%
Distribution Volumetric Rate	2500	2.7086	6771.50	2500	2.8482	7120.50	349.00	5.15%	4.66%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	2500	0.0272	68.00	2500	0.0000	0.00	-68.00	-100.00%	0.00%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	2500	2.2664	5666.00	2500	2.2664	5666.00	0.00	0.00%	3.71%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	2500	-2.8219	-7054.75	2500	-2.8219	-7054.75	0.00	0.00%	-4.62%
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	2500	0.0000	0.00	2500	0.1096	274.00	274.00	0.00%	0.18%
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	2500	0.0000	0.00	2500	0.4645	1161.25	1161.25	0.00%	0.76%
Rate Rider for PILs - effective until December 31, 2013	2500	0.0000	0.00	2500	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for Tax Changes - effective until December 31, 2012	2500	-0.0273	-68.25	2500	-0.0200	-50.00	18.25	-26.74%	-0.03%
Total: Distribution			5979.62			7713.12	1733.50	28.99%	5.05%
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	2716	2.8001	7605.07	2716	2.6742	7263.13	-341.94	-4.50%	4.76%
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	2716	2.0003	5432.81	2716	1.9558	5311.95	-120.86	-2.22%	3.48%
Total: Retail Transmission			13037.89			12575.08	-462.81	-3.55%	8.23%
Sub-Total: Delivery (Distribution and Retail Transmission)			19017.51			20288.20	1270.69	6.68%	13.28%
Wholesale Market Service Rate	1195040	0.0052	6214.21	1195040	0.0052	6214.21	0.00	0.00%	4.07%
Rural Rate Protection Charge	1195040	0.0011	1314.54	1195040	0.0011	1314.54	0.00	0.00%	0.86%
Special Purpose Charge	1195040	0.0000	0.00	1195040	0.0000	0.00	0.00	0.00%	0.00%
Standard Supply Service - Administarive Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%
Sub-Total: Regulatory			7529.00			7529.00	0.00	0.00%	4.93%
Debt Retirement Charge	1100000	0.0020	2200.00	1100000	0.0020	2200.00	0.00	0.00%	1.44%
Total Bill Before Taxes			133900.28			135170.97	1270.69	0.95%	88.50%
GST / HST		13%	17407.04		13%	17572.23	165.19	0.95%	11.50%
Total Bill			**$ 151,307.31**			**$ 152,743.20**	**$ 1,435.88**	0.95%	100.00%

Electricity Distribution Impacts
Rates Effective January 1, 2013

Seasonal	Metric	Current Approved Rates	Proposed January 1, 2013
Monthly Service Charge	$	26.15	26.38
Smart Meter Rate Adder	$	1.00	-
Distribution Volumetric Rate	$/kWh	0.1006	0.1015
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kWh	0.0002	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	0.0046	0.0046
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	(0.0061)	(0.0061)
Rate Rider for Deferral/Variance Account Disposition - effective until November 30, 2015	$/kWh	0.0307	0.0307
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	(0.0015)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	
Rate Rider for PILs - effective until December 31, 2013	$/kWh	-	-
Smart Meter Cost Recovery Rate Rider - Net Deferred Revenue Requirement, effective until December 31, 2013	$/kWh	-	0.0411
Smart Meter Cost Recovery Rate Rider - Incremental Revenue Requirement, effective until December 31, 2013	$/kWh	-	0.0174
Rate Rider for Tax Changes - effective until December 31, 2012	$/kWh	(0.0003)	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0071	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh	-	-
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	287	kWh		kW	Loss Factor	1.0864
RPP Tier One	750	kWh	Load Factor			

Seasonal	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Impacts $	Impacts %	% of Total Bill
Energy, First Tier (kWh)	312	0.0750	23.38	312	0.0750	23.38	0.00	0.00%	18.81%
Energy, Second Tier (kWh)	0	0.0880	0.00	0	0.0880	0.00	0.00	0.00%	0.00%
Sub-Total: Energy			23.38			23.38	0.00	0.00%	18.81%
Monthly Service Charge	1	26.15	26.15	1	26.38	26.38	0.23	0.88%	21.21%
Smart Meter Rate Adder	1	1.00	1.00	1	0.00	0.00	-1.00	-100.00%	0.00%
Distribution Volumetric Rate	287	0.1006	28.87	287	0.1015	29.13	0.26	0.89%	23.43%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	287	0.0002	0.06	287	0.0000	0.00	-0.06	-100.00%	0.00%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	287	0.0046	1.32	287	0.0046	1.32	0.00	0.00%	1.06%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	287	-0.0061	-1.75	287	-0.0061	-1.75	0.00	0.00%	-1.41%
Rate Rider for Deferral/Variance Account Disposition - effective until November 30, 2015	287	0.0307	8.81	287	0.0307	8.81	0.00	0.00%	7.09%
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	287	0.0000	0.00	287	-0.0015	-0.43	-0.43	0.00%	-0.35%
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	287	0.0000	0.00	287	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for PILs - effective until December 31, 2013	287	0.0000	0.00	287	0.0000	0.00	0.00	0.00%	0.00%
Smart Meter Cost Recovery Rate Rider - Net Deferred Revenue Requirement, effective until December 31, 201	287	0.0000	0.00	287	0.0411	11.80	11.80	0.00%	9.49%
Smart Meter Cost Recovery Rate Rider - Incremental Revenue Requirement, effective until December 31, 2013	287	0.0000	0.00	287	0.0174	4.99	4.99	0.00%	4.02%
Rate Rider for Tax Changes - effective until December 31, 2012	287	-0.0003	-0.09	287	-0.0002	-0.06	0.03	-33.33%	-0.05%
Total: Distribution			64.37			80.19	15.82	24.57%	64.49%
Retail Transmission Rate - Network Service Rate	312	0.0071	2.21	312	0.0068	2.12	-0.09	-4.23%	1.71%
Retail Transmission Rate - Line and Transformation Connection Service Rate	312	0.0051	1.59	312	0.0050	1.56	-0.03	-1.96%	1.25%
Total: Retail Transmission			3.80			3.68	-0.12	-3.28%	2.96%
Sub-Total: Delivery (Distribution and Retail Transmission)			68.18			83.87	15.69	23.02%	67.45%
Wholesale Market Service Rate	312	0.0052	1.62	312	0.0052	1.62	0.00	0.00%	1.30%
Rural Rate Protection Charge	312	0.0011	0.34	312	0.0011	0.34	0.00	0.00%	0.28%
Special Purpose Charge	312	0.0000	0.00	312	0.0000	0.00	0.00	0.00%	0.00%
Standard Supply Service - Administarive Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%
Sub-Total: Regulatory			2.21			2.21	0.00	0.00%	1.78%
Debt Retirement Charge	287	0.0020	0.57	287	0.0020	0.57	0.00	0.00%	0.46%
Total Bill Before Taxes			94.35			110.04	15.69	16.63%	88.50%
GST / HST		13%	12.27		13%	14.31	2.04	16.63%	11.50%
Total Bill			**$ 106.62**			**$ 124.35**	**$ 17.73**	16.63%	100.00%
OCEB Credit			**$ 10.66**			**$ 12.44**			
Balance after OCEB Credit has been applied			**$ 95.95**			**$ 111.92**	**$ 15.96**	**16.63%**	

Electricity Distribution Impacts
Rates Effective January 1, 2013

Seasonal	Metric	Current Approved Rates	Proposed January 1, 2013
Monthly Service Charge	$	26.15	26.38
Smart Meter Rate Adder	$	1.00	-
Distribution Volumetric Rate	$/kWh	0.1006	0.1015
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kWh	0.0002	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	0.0046	0.0046
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	(0.0061)	(0.0061)
Rate Rider for Deferral/Variance Account Disposition - effective until November 30, 2015	$/kWh	0.0307	0.0307
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	(0.0015)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	0.0011
Rate Rider for PILs - effective until December 31, 2013	$/kWh	-	-
Smart Meter Cost Recovery Rate Rider - Net Deferred Revenue Requirement, effective until December 31, 2013	$/kWh	-	0.0411
Smart Meter Cost Recovery Rate Rider - Incremental Revenue Requirement, effective until December 31, 2013	$/kWh	-	0.0174
Rate Rider for Tax Changes - effective until December 31, 2012	$/kWh	(0.0003)	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0071	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0051	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh	-	-
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	287	kWh		kW	Loss Factor	1.0864
RPP Tier One	750	kWh	Load Factor			

Seasonal	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Impacts $	Impacts %	% of Total Bill
Energy, First Tier (kWh)	312	0.0750	23.38	312	0.0750	23.38	0.00	0.00%	18.75%
Energy, Second Tier (kWh)	0	0.0880	0.00	0	0.0880	0.00	0.00	0.00%	0.00%
Sub-Total: Energy			23.38			23.38	0.00	0.00%	18.75%
Monthly Service Charge	1	26.15	26.15	1	26.38	26.38	0.23	0.88%	21.15%
Smart Meter Rate Adder	1	1.00	1.00	1	0.00	0.00	-1.00	-100.00%	0.00%
Distribution Volumetric Rate	287	0.1006	28.87	287	0.1015	29.13	0.26	0.89%	23.36%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	287	0.0002	0.06	287	0.0000	0.00	-0.06	-100.00%	0.00%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	287	0.0046	1.32	287	0.0046	1.32	0.00	0.00%	1.06%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	287	-0.0061	-1.75	287	-0.0061	-1.75	0.00	0.00%	-1.40%
Rate Rider for Deferral/Variance Account Disposition - effective until November 30, 2015	287	0.0307	8.81	287	0.0307	8.81	0.00	0.00%	7.07%
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	287	0.0000	0.00	287	-0.0015	-0.43	-0.43	0.00%	-0.35%
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	287	0.0000	0.00	287	0.0011	0.32	0.32	0.00%	0.25%
Rate Rider for PILs - effective until December 31, 2013	287	0.0000	0.00	287	0.0000	0.00	0.00	0.00%	0.00%
Smart Meter Cost Recovery Rate Rider - Net Deferred Revenue Requirement, effective until December 31, 201	287	0.0000	0.00	287	0.0411	11.80	11.80	0.00%	9.46%
Smart Meter Cost Recovery Rate Rider - Incremental Revenue Requirement, effective until December 31, 2013	287	0.0000	0.00	287	0.0174	4.99	4.99	0.00%	4.00%
Rate Rider for Tax Changes - effective until December 31, 2012	287	-0.0003	-0.09	287	-0.0002	-0.06	0.03	-33.33%	-0.05%
Total: Distribution			64.37			80.51	16.13	25.06%	64.56%
Retail Transmission Rate - Network Service Rate	312	0.0071	2.21	312	0.0068	2.12	-0.09	-4.23%	1.70%
Retail Transmission Rate - Line and Transformation Connection Service Rate	312	0.0051	1.59	312	0.0050	1.56	-0.03	-1.96%	1.25%
Total: Retail Transmission			3.80			3.68	-0.12	-3.28%	2.95%
Sub-Total: Delivery (Distribution and Retail Transmission)			68.18			84.19	16.01	23.48%	67.51%
Wholesale Market Service Rate	312	0.0052	1.62	312	0.0052	1.62	0.00	0.00%	1.30%
Rural Rate Protection Charge	312	0.0011	0.34	312	0.0011	0.34	0.00	0.00%	0.28%
Special Purpose Charge	312	0.0000	0.00	312	0.0000	0.00	0.00	0.00%	0.00%
Standard Supply Service - Administarive Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%
Sub-Total: Regulatory			2.21			2.21	0.00	0.00%	1.78%
Debt Retirement Charge	287	0.0020	0.57	287	0.0020	0.57	0.00	0.00%	0.46%
Total Bill Before Taxes			94.35			110.36	16.01	16.97%	88.50%
GST / HST		13%	12.27		13%	14.35	2.08	16.97%	11.50%
Total Bill			**$ 106.62**			**$ 124.71**	**$ 18.09**	16.97%	100.00%
OCEB Credit			**$ 10.66**			**$ 12.47**			
Balance after OCEB Credit has been applied			**$ 95.95**			**$ 112.24**	**$ 16.28**	**16.97%**	

Electricity Distribution Impacts
Rates Effective January 1, 2013

Street Lighting	Metric	Current Approved Rates	Proposed January 1, 2013
Monthly Service Charge	$	0.96	0.97
Smart Meter Rate Adder	$	-	-
Distribution Volumetric Rate	$/kWh	0.1543	0.1557
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kWh	0.0001	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	0.0048	0.0048
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	(0.0061)	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	(0.0007)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	
Rate Rider for PILs - effective until December 31, 2013	$/kWh	-	-
Rate Rider for Tax Changes - effective until December 31, 2012	$/kWh	(0.0002)	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kW	1.9907	1.9012
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3992	1.3680
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh	-	-
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	25,000	kWh	71.46	kW	Loss Factor	1.0864
RPP Tier One	750	kWh	Load Factor	48%		

Street Lighting	Volume	Rate	Charge	Volume	Rate	Charge	Impacts		
		$	$		$	$	$	%	% of Total Bill
Energy, First Tier (kWh)	750	0.0750	56.25	750	0.0750	56.25	0.00	0.00%	0.69%
Energy, Second Tier (kWh)	26410	0.0880	2324.08	26410	0.0880	2324.08	0.00	0.00%	28.51%
Sub-Total: Energy			2380.33			2380.33	0.00	0.00%	29.20%
Monthly Service Charge	428	0.96	410.88	428	0.97	415.16	4.28	1.04%	5.09%
Smart Meter Rate Adder	428	0.00	0.00	428	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	25000	0.1543	3857.50	25000	0.1557	3892.50	35.00	0.91%	47.74%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	25000	0.0001	2.50	25000	0.0000	0.00	-2.50	-100.00%	0.00%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	25000	0.0048	120.00	25000	0.0048	120.00	0.00	0.00%	1.47%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	25000	-0.0061	-152.50	25000	-0.0061	-152.50	0.00	0.00%	-1.87%
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	25000	0.0000	0.00	25000	-0.0007	-17.50	-17.50	0.00%	-0.21%
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	25000	0.0000	0.00	25000	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for PILs - effective until December 31, 2013	25000	0.0000	0.00	25000	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for Tax Changes - effective until December 31, 2012	25000	-0.0002	-5.00	25000	-0.0002	-5.00	0.00	0.00%	-0.06%
Total: Distribution			4233.38			4252.66	19.28	0.46%	52.16%
Retail Transmission Rate - Network Service Rate	77.6	1.9907	154.55	77.6	1.9012	147.60	-6.95	-4.50%	1.81%
Retail Transmission Rate - Line and Transformation Connection Service Rate	77.6	1.3992	108.63	77.6	1.3680	106.20	-2.42	-2.23%	1.30%
Total: Retail Transmission			263.17			253.80	-9.37	-3.56%	3.11%
Sub-Total: Delivery (Distribution and Retail Transmission)			4496.55			4506.46	9.91	0.22%	55.27%
Wholesale Market Service Rate	27160	0.0052	141.23	27160	0.0052	141.23	0.00	0.00%	1.73%
Rural Rate Protection Charge	27160	0.0011	29.88	27160	0.0011	29.88	0.00	0.00%	0.37%
Special Purpose Charge	27160	0.0000	0.00	27160	0.0000	0.00	0.00	0.00%	0.00%
Standard Supply Service - Administarive Charge (if applicable)	428	0.25	107.00	428	0.25	107.00	0.00	0.00%	1.31%
Sub-Total: Regulatory			278.11			278.11	0.00	0.00%	3.41%
Debt Retirement Charge	25000	0.0020	50.00	25000	0.0020	50.00	0.00	0.00%	0.61%
Total Bill Before Taxes			7204.99			7214.90	9.91	0.14%	88.50%
GST / HST		13%	936.65		13%	937.94	1.29	0.14%	11.50%
Total Bill			**$ 8,141.64**			**$ 8,152.84**	**$ 11.20**	0.14%	100.00%

Electricity Distribution Impacts
Rates Effective January 1, 2013

Street Lighting	Metric	Current Approved Rates	Proposed January 1, 2013
Monthly Service Charge	$	0.96	0.97
Smart Meter Rate Adder	$	-	-
Distribution Volumetric Rate	$/kWh	0.1543	0.1557
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	$/kWh	0.0001	-
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	0.0048	0.0048
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	$/kWh	(0.0061)	(0.0061)
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	(0.0007)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	$/kWh	-	0.0011
Rate Rider for PILs - effective until December 31, 2013	$/kWh	-	-
Rate Rider for Tax Changes - effective until December 31, 2012	$/kWh	(0.0002)	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kW	1.9907	1.9012
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3992	1.3680
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0011	0.0011
Special Purpose Charge	$/kWh	-	-
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	25,000	kWh	71.46 kW	Loss Factor	1.0864
RPP Tier One	750	kWh	Load Factor 48%		

Street Lighting	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Impacts $	Impacts %	% of Total Bill
Energy, First Tier (kWh)	750	0.0750	56.25	750	0.0750	56.25	0.00	0.00%	0.69%
Energy, Second Tier (kWh)	26410	0.0880	2324.08	26410	0.0880	2324.08	0.00	0.00%	28.40%
Sub-Total: Energy			2380.33			2380.33	0.00	0.00%	29.09%
Monthly Service Charge	428	0.96	410.88	428	0.97	415.16	4.28	1.04%	5.07%
Smart Meter Rate Adder	428	0.00	0.00	428	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	25000	0.1543	3857.50	25000	0.1557	3892.50	35.00	0.91%	47.56%
Rate Rider for Foregone Revenue Recovery - effective until December 31, 2012	25000	0.0001	2.50	25000	0.0000	0.00	-2.50	-100.00%	0.00%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	25000	0.0048	120.00	25000	0.0048	120.00	0.00	0.00%	1.47%
Rate Rider for Deferral/Variance Account Disposition - effective until May 31, 2013	25000	-0.0061	-152.50	25000	-0.0061	-152.50	0.00	0.00%	-1.86%
Rate Rider for Deferral/Variance Account Disposition (2012) - effective until December 31, 2013	25000	0.0000	0.00	25000	-0.0007	-17.50	-17.50	0.00%	-0.21%
Rate Rider for Global Adjustment Sub-Account Disposition (2012) - effective until December 31, 2013	25000	0.0000	0.00	25000	0.0011	27.50	27.50	0.00%	0.34%
Rate Rider for PILs - effective until December 31, 2013	25000	0.0000	0.00	25000	0.0000	0.00	0.00	0.00%	0.00%
Rate Rider for Tax Changes - effective until December 31, 2012	25000	-0.0002	-5.00	25000	-0.0002	-5.00	0.00	0.00%	-0.06%
Total: Distribution			4233.38			4280.16	46.78	1.11%	52.30%
Retail Transmission Rate - Network Service Rate	77.6	1.9907	154.55	77.6	1.9012	147.60	-6.95	-4.50%	1.80%
Retail Transmission Rate - Line and Transformation Connection Service Rate	77.6	1.3992	108.63	77.6	1.3680	106.20	-2.42	-2.23%	1.30%
Total: Retail Transmission			263.17			253.80	-9.37	-3.56%	3.10%
Sub-Total: Delivery (Distribution and Retail Transmission)			4496.55			4533.96	37.41	0.83%	55.40%
Wholesale Market Service Rate	27160	0.0052	141.23	27160	0.0052	141.23	0.00	0.00%	1.73%
Rural Rate Protection Charge	27160	0.0011	29.88	27160	0.0011	29.88	0.00	0.00%	0.37%
Special Purpose Charge	27160	0.0000	0.00	27160	0.0000	0.00	0.00	0.00%	0.00%
Standard Supply Service - Administarive Charge (if applicable)	428	0.25	107.00	428	0.25	107.00	0.00	0.00%	1.31%
Sub-Total: Regulatory			278.11			278.11	0.00	0.00%	3.40%
Debt Retirement Charge	25000	0.0020	50.00	25000	0.0020	50.00	0.00	0.00%	0.61%
Total Bill Before Taxes			7204.99			7242.40	37.41	0.52%	88.50%
GST / HST		13%	936.65		13%	941.51	4.86	0.52%	11.50%
Total Bill			**$ 8,141.64**			**$ 8,183.91**	**$ 42.27**	0.52%	100.00%

Electricity Distribution Impacts
Rates Effective January 1, 2013

Rate Impacts Summary Arising from the Rate Design Proposal									
Customer Class	Usage Profile		Delivery Charges			Total Bill		
	kWh	kW	Current	Proposed	% Chg.	Current	Proposed	% Chg.
Residential R1	800	-	56.15	54.93	-2.2%	132.42	131.18	-0.9%
Residential R1	2,000	-	106.62	104.15	-2.3%	311.22	308.70	-0.8%
Residential R2	90,000	225	2,169.18	2,180.91	0.5%	13,062.75	13,076.00	0.1%
Seasonal	287	-	61.36	75.48	23.0%	95.95	111.92	16.6%
Street Lighting	25,000	71	4,496.55	4,506.46	0.2%	8,141.64	8,152.84	0.1%