June 7, 2010

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: ALGOMA POWER INC., 2010 AND 2011 ELECTRICITY DISTRIBUTION RATE APPLICATION ("AMENDED APPLICATION") – BOARD FILE NO.: EB-2009-0278

Algoma Power Inc. ("API") hereby submits this amended application (the "Amended Application") to its 2010 and 2011 cost of service electricity distribution rate application (the "Application"). The Application was filed with the Board on June 1, 2010.

The Amended Application was necessitated by a request from Board staff, subsequent to filing the Application. On June 3, 2010, Board staff requested that API update the simple average increase in delivery charges for other electricity distributors in the current year to be 5.5% for 2010, and 2.0% for 2011, to reflect the more current data now available. API provided Board staff with this update on June 7, 2010. Later on June 7, 2010, The Board Secretary's Office requested that API file an amended application to reflect this change.

The changes to the simple average increase in delivery charges for other electricity distributors in the current year have impacted rate design, rate impacts, overview of operating revenue, the Rural and Remote Rate Protection and the proposed tariff of rates and charges. The header of the amended exhibits in the Amended Application has been modified to read, Amended: June 7, 2010.

The Amended Application contains a new exhibit; Exhibit 1, Tab 1, Schedule 2-1. This Exhibit summarizes the amendment.

We enclose two paper copies and a CD with the Amended Application in searchable PDF and Microsoft Excel formats.

Please do not hesitate to contact me if you require further information.

Yours truly,

Original Signed By

Douglas Bradbury
Director, Regulatory Affairs

Enclosures

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ALGOMA POWER INC.
APPLICATION FOR APPROVAL OF ELECTRICITY RATES
EFFECTIVE JULY 1, 2010

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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 and other service charges for the distribution of electricity.

APPLICATION

Introduction

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. API hereby applies to the Ontario Energy Board (the "Board" or the "OEB"), pursuant to section 78 of the *Ontario Energy Board Act, 1998* as amended (the "OEB Act") for an order or orders approving just and reasonable distribution rates based on 2010 and 2011 Test Years.

3. As set out in API's pre-filed evidence, API is seeking to recover its forecasted 2010 revenue requirement of $18,928,065 through rates that will be effective on July 1, 2010. API is also seeking to recover its forecasted 2011 revenue requirement of $20,452,136 through rates that will be effective January 1, 2011.

4. A list of specific approvals sought is set out at Exhibit 1, Tab 1, Schedule 5 of API's pre-filed evidence and are incorporated by reference in this Application.

5. API is unique in the way its distribution rates are set by the Board. Pursuant to Ontario Regulation 442/01, with the exception of Seasonal and Street Lighting, 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 is recovered by API on behalf of its customers through the Rural and Remote Rate Protection ("RRRP"). In this Application, API has, at the request of Board staff, used 5.5% and 2.0% as the average adjustment for rates for other distributors for 2010 and 2011 respectively. API requests that the Board determine the average of any adjustment to rates approved by the Board for other distributors in both 2010 and 2011.

Proposed Structure of the Proceeding

6. Because the 2011 average rate adjustment will not be known until later in 2011, the Board will not be able to order API's 2011 rates until sometime in 2011. Since API is seeking 2011 rates effective January 1, 2011 (ie. before the Board can determine the average 2011 rate adjustment for distributors), API has requests that its 2010 rates be made interim after January 1, 2011, pending the implementation of API's 2011 rates.

7. API requests that this proceeding be adjourned *sine die* after the implementation of its 2010 rates and the approval of its 2011 revenue requirement, until the Board is able to determine the 2011 average rate adjustment for distributors. At that time, the proceeding could reconvene for the purpose of determining API's 2011 rates that reflect the 2011 average rate adjustment for distributors.

8. To summarize, API is requesting that the proceeding have two phases that are separated by an adjournment. The first phase would serve the purpose of, among other things:
    - approving API's 2010 and 2011 revenue requirements;

- determining the average rate increase for distributors in 2010;
- designing 2010 rates;
- implementing the 2010 rates effective July 1, 2010; and
- making API's 2010 rates interim effective January 1, 2011.

At the end of phase 1, the Board could adjourn the proceeding *sine die* until it is able to determine the average 2011 rate adjustment for distributors. At that time, the proceeding could reconvene (ie. phase 2) for the purpose of:

- determining the average rate increase for distributors in 2011;
- designing 2011 rates; and
- implementation of the 2011 rates effective January 1, 2011.

9. Except where specifically identified in this Application, the Applicant followed *Chapter 2 Filing Requirements for Electricity Transmission and Distribution Companies' Cost of Service Rate Applications, Based on a Forward Test Year* dated May 27, 2009 (the "Filing Requirements") in preparing this Application.

10. The Applicant requests that, pursuant to section 34.01 of the Board's *Rules of Practice and Procedure,* this proceeding be conducted by way of written hearing.

11. The written evidence, as filed with the Board, may be amended from time to time prior to the Board's final decision on the Application. Further, the Applicant may seek meetings with Board staff and intervenors in an attempt to identify and reach agreements to settle issues arising out of this Application.

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

13. API requests that a copy of all documents filed with the Board by each party to this Application be served on the Applicant and the Applicant's counsel as follows:

(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

(b) The Applicant's counsel:

Mr. R. Scott Hawkes
Vice President, Corporate Services and General Counsel
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) 994-3642
Fax:	(905) 994-2211
Email Address:	scott.hawkes@cnpower.com

– and –

Mr. Andrew Taylor
Andrew Taylor, Energy Law

Mailing Address:	120 Adelaide Street West Suite 2500 Toronto, Ontario M5H 1T1
Telephone:	(416) 644-1568
Fax:	(416) 367-1954
Email Address:	ataylor@energyboutique.ca

DATED at Fort Erie, Ontario this June 1, 2010.

ALGOMA POWER INC.

By its counsel,

R. Scott Hawkes

BACKGROUND

Algoma Power Inc. ("API") filed its 2010 and 2011 Cost of Service Electricity Distribution Rate Application, EB-2009-0278 on June 1, 2010. As a component of that Application, API was required to estimate the simple average increase in delivery charges for other electricity distributors in the current year. API determined this average increase in delivery charges using information posted on the Board's website on May 7, 2010. Based on that information, API determined the simple average increase in delivery charges to be 0.7%; this was the value used in API's 2010 and 2011 rate design.

On June 3, 2010, by way of email, Board staff advised API that more current data related to the increase in delivery charges for other electricity distributors was now available. Board staff requested that API update its rate design to reflect the simple average increase in delivery charges for other electricity distributors in the current year to be 5.5% for its 2010 rate design. Additionally, Board staff requested that API use an estimated value of 2.0% to determine 2011 distribution rates.

As a second matter, Board staff requested API to use 800 kWh to determine bill impacts for the Residential – R1 customers. API had previously used 1000 kWh to reflect the higher average usage per customer. In this Amendment, API is providing bill impacts using monthly consumption of 800 kWh.

Rate Design

Accompanying this Amendment are three live Excel spreadsheets which have been updated to reflect delivery charge increases for the Residential R – 1 and Residential R – 2 customer classes for 2010 and 2011 of 5.5% and 2.0% respectively. These Excel spreadsheets are:

- API_RateDesignModule_20100607Ad1.xls
- 2010 Rate Impact Sheet 20100607Ad1.xls
- 2010 Rate Impact Sheet 20100607Ad1.xls

Print copies of the spreadsheets follow at the end of this document and are in the order shown above.

The table shown below is a reproduction of Exhibit 8, Tab 1, Schedule 2, Table 1 from the API Application. The table shown here reflects the revised distribution charges for 2010 and 2011 utilizing the 5.5% and 2.0% escalation factors.

Exhibit 1, Tab 1, Schedule 2-1, Table 1

2007 Board Approved Tariff, EB-2007-0744				Proposed		
Delivery Charges				Delivery Charges		
Monthly Rates and Charges	Metric	Effective September 2007		Proposed July 1, 2010		Proposed January 1, 2011
Residential - R1						
Monthly Service Charge	$	20.41		21.53		21.96
Distribution Volumetric Rate	$/kWh	0.0287		0.0303		0.0309
Residential - R2						
Monthly Service Charge	$	596.12		628.91		641.48
Distribution Volumetric Rate	$/kW	2.4549		2.5899		2.6417
Seasonal						
Monthly Service Charge	$	24.00		24.00		24.00
Distribution Volumetric Rate	$/kWh	0.0700		0.0993		0.0852
Street Lighting						
Monthly Service Charge	$	-		0.98		1.08
Distribution Volumetric Rate	$/kWh	0.0496		0.1292		0.2208
Rural and Remote Rate Protection	$	8,861,800		10,186,621		11,596,870

Below is a reproduction of Exhibit 8, Tab 1, Schedule 2, Table 2 from the API Application, this table provides the estimated the Rural and Remote Rate Protection ("RRRP") funding that is applicable to the Residential class (R1 and R2) pursuant to O. Reg. 442/01.

Exhibit 1, Tab 1, Schedule 2-1, Table 2

2010 and 2011	
Rural and Remote Rate Protection Funding Requirement	
2010	$10,186,621
2011	$11,596,870

Average Bill Impacts

The tables below provide the average delivery charge and bill impacts for rate designs provided in the Amendment.

Exhibit 1, Tab 1, Schedule 2-1, Table 3

Average Delivery Charge and Total Bill Impact for Rates Effective July 1, 2010

Selected Delivery Charge and Bill Impacts Per Amendment									
	Monthly Delivery Charge					Total Bill			
			Change					Change	
	Current	Addendum	$	%		Current	Addendum	$	%
R – 1, 800 kWh	49.53	56.76	7.23	14.6%		121.62	138.16	16.54	13.6%
R – 1, 2000 kWh	93.2	108.11	14.91	16.0%		283.31	319.51	36.2	12.8%

Exhibit 1, Tab 1, Schedule 2-1, Table 4

Average Delivery Charge and Total Bill Impact for Rates Effective January 1, 2011

Selected Delivery Charge and Bill Impacts Per Amendment									
	Monthly Delivery Charge					Total Bill			
			Change					Change	
	Current	Addendum	$	%		Current	Addendum	$	%
R – 1, 800 kWh	56.76	60.95	4.19	7.4%		138.16	142.90	4.74	3.4%
R – 1, 2000 kWh	108.11	117.94	9.83	9.1%		319.51	330.62	11.11	3.5%

Print versions of the models follow.

Algoma Power Inc.

Proposed

TARIFF OF RATES AND CHARGES

Effective July 1, 2010

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

EB-2009-0278

Amended: June 7, 2010

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

IMPLEMENTATION DATES

DISTRIBUTION RATES – July 1, 2010 for all consumption or deemed consumption service used on or after that date.
SPECIFIC SERVICE CHARGES – July 1, 2010 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – July 1, 2010 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – July 1, 2010 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential Customers

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.

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.

Seasonal Customers

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.

Street Lighting

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.

Algoma Power Inc.

Proposed

TARIFF OF RATES AND CHARGES

Effective July 1, 2010

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

EB-2009-0278

Amended: June 7, 2010

MONTHLY RATES AND CHARGES

Residential – R1		
Service Charge	$	21.53
Smart Meter Rate Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0303
Deferral Account Rate Rider – effective until December 31, 2010	$/kWh	(0.0041)
Deferral Account Rate Rider – effective until December 31, 2012	$/kWh	0.0054
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Residential – R2		
Service Charge	$	628.91
Smart Meter Rate Adder	$	1.00
Distribution Volumetric Rate	$/kW	2.5899
Deferral Account Rate Rider – effective until December 31, 2010	$/kW	(0.2025)
Deferral Account Rate Rider – effective until December 31, 2012	$/kW	0.0044
Retail Transmission Rate – Network Service Rate	$/kW	1.9737
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7882
Retail Transmission Rate – Network Service Rate – Interval Metered >1,000 kW	$/kW	2.0937
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered >1,000 kW	$/kW	1.9763
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Seasonal		
Service Charge	$	24.00
Smart Meter Rate Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0993
Deferral Account Rate Rider – effective until December 31, 2010	$/kWh	(0.0041)
Deferral Account Rate Rider – effective until December 31, 2012	$/kWh	0.0083
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting		
Service Charge	$	0.98
Distribution Volumetric Rate	$/kWh	0.1292
Deferral Account Rate Rider – effective until December 31, 2010	$/kWh	(0.0016)
Deferral Account Rate Rider – effective until December 31, 2012	$/kWh	0.0219
Retail Transmission Rate – Network Service Rate	$/kW	1.4885
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3824
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Algoma Power Inc.

Proposed

TARIFF OF RATES AND CHARGES

Effective July 1, 2010

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

EB-2009-0278

Amended: June 7, 2010

Specific Service Charges

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

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)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

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 charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing 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		

Algoma Power Inc.

Proposed

TARIFF OF RATES AND CHARGES

Effective July 1, 2010

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

EB-2009-0278

Amended: June 7, 2010

Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

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

Algoma Power Inc.

Proposed

TARIFF OF RATES AND CHARGES

Effective January 1, 2011

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EB-2009-0278

Amended: June 7, 2010

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders 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, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

IMPLEMENTATION DATES

DISTRIBUTION RATES – July 1, 2010 for all consumption or deemed consumption service used on or after that date.
SPECIFIC SERVICE CHARGES – July 1, 2010 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – July 1, 2010 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – July 1, 2010 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential Customers

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.

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.

Seasonal Customers

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.

Street Lighting

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.

Algoma Power Inc.

Proposed

TARIFF OF RATES AND CHARGES

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EB-2009-0278

Amended: June 7, 2010

MONTHLY RATES AND CHARGES

Residential – R1		
Service Charge	$	21.96
Smart Meter Rate Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0309
Deferral Account Rate Rider – effective until December 31, 2010	$/kWh	
Deferral Account Rate Rider – effective until December 31, 2012	$/kWh	0.0054
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Residential – R2		
Service Charge	$	641.48
Smart Meter Rate Adder	$	1.00
Distribution Volumetric Rate	$/kW	2.6417
Deferral Account Rate Rider – effective until December 31, 2010	$/kW	
Deferral Account Rate Rider – effective until December 31, 2012	$/kW	0.0044
Retail Transmission Rate – Network Service Rate	$/kW	1.9737
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7882
Retail Transmission Rate – Network Service Rate – Interval Metered >1,000 kW	$/kW	2.0937
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered >1,000 kW	$/kW	1.9763
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Seasonal		
Service Charge	$	24.00
Smart Meter Rate Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0852
Deferral Account Rate Rider – effective until December 31, 2010	$/kWh	
Deferral Account Rate Rider – effective until December 31, 2012	$/kWh	0.0083
Deferral Account Rate Rider – effective until December 31, 2015	$/kWh	0.0307
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Street Lighting		
Service Charge	$	1.08
Distribution Volumetric Rate	$/kWh	0.2208
Deferral Account Rate Rider – effective until December 31, 2010	$/kWh	
Deferral Account Rate Rider – effective until December 31, 2012	$/kWh	0.0219
Retail Transmission Rate – Network Service Rate	$/kW	1.4885
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3824
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Algoma Power Inc.

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Specific Service Charges

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

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)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

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 charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing 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

Algoma Power Inc.

Proposed

TARIFF OF RATES AND CHARGES

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EB-2009-0278

Amended: June 7, 2010

More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

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

APPLICANT'S DISTRIBUTION LICENCE

API operates under OEB Electricity Distribution Licence ED-2009-0072. A copy of this licence is attached as Appendix A to this Schedule.

APPENDIX A

Electricity Distribution Licence

ED-2009-0072

Algoma Power Inc.

Valid Until

May 4, 2029

Original Signed By

_____
Jennifer Lea
Counsel, Special Projects
Ontario Energy Board
Date of Issuance: May 5, 2009
Effective Date: July 1, 2009
Date of Amendment: January 11, 2010

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

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4

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1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**distribution services**" means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**Licensee**" means Algoma Power Inc.;

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**regulation**" means a regulation made under the Act or the Electricity Act;

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

"**wholesaler**" means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor's distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

14.2 Without limiting the generality of paragraph 14.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

15 Restrictions on Provision of Information

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on May 5, 2009 and expire on May 4, 2029. The term of this Licence may be extended by the Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender=s transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. The Licensee is licensed in respect to the geographic area comprised of the following list of townships:

Memaskwosh	Wishart	Miskokomon
Alanen	Herrick	Dulhut
Charbonneau	Tilley	Nebon
Dahl	Marne	Laronde
Dumas	Havilland	Redsky
Finan	Shields	Allouez
Riggs	Kars	Stone
Rennie	Vankoughnet	Alaire
Keating	Hodgins	Barager
Knicely		Bray
Leclaire	Aweres	Broome
Aguonie	Anderson	Goodwillie
Bruyere		Grootenboer
Legarde Add'l	Garden River Reserve IR14	Labonte
Levesque	Chesley Add'l	Peever
Menzies	Aberdeen	Raaflaub
Corbiere		Smilsky
Debassige	Tarbutt & Tarbutt Add'l	Tronsen
Echum	Plummer Add'l	Nicolet
Warpula	Rose	Olsen
Michipicoten	St. Joseph	Palmer
Fiddler	Jocelyn	Brule
Keesickquayash	Ashley	Fisher
Groseilliers	Chapais	Archibald
Bostwick	Dambrossio	Ley
Lastheels		Tupper
Michano	Jacobson	Gaudette
Nadjiwon	West	Fenwick
Rabazo	Stover	Deroche
Nebonaionquet	Killins	Whitman

Peterson	Lalibert	Pennefather
Restoule	Abotossaway	Jarvis
Tiernan	Bird	Chesley
Stoney	Copenace	Noganosh
Asselin	Legarde	Pawlis
Barnes	Macaskill	Quill
Brimacombe	Musquash	Giles
Bullock	Cowie	Rix
Greenwood	Dolson	Duncan
Labelle	St. Germain	Kehoe
Larson	Andre	MacDonald, Meredith & Aberdeen Add'l
Home	Esquega	Galbraith
Slater	Isaac	Laird
Tolmonen	Laforme	Johnson
Kincaid	Franchere	
Norberg	Michipicoten	Hilton
Ryan	Maness	Morin

2. Concessions 3, 4 and 5 of the Township of Dennis;

3. Approximately forty (40) square kilometres at the western limit of the former Township of Thessalon;

4. 5 rural customers in Kirkwood Township supplied off two short line taps into the Township;

5. Plus the following locations within the City of Sault Ste. Marie:

   (a) 45 Third Line West as at March 14, 2003, excluding those areas of land within 45 Third Line West that are serviced by PUC Distribution Inc. (PUC) as identified in PUC's distribution licence, those being:

   - the areas of land on which the facilities on the northeast corner of 45 Third Line West are located, namely the "gatehouse" and "office";

   (b) 77 Third Line West as at July 9, 2004;

   (c) 3 Sackville Road;

   (d) 150 Conmee Avenue;

   (e) 429 Hudson Street, excluding those areas within 429 Hudson Street that are serviced by PUC as identified in PUC's distribution licence, those being:

(i) the area of land on which the facility near the northwest corner of Hudson Street and Wellington Street West is located, namely the “yard office”;

(ii) the area of land on which the facility near the junction of Hudson Street and St. George Avenue West is located, namely the “skimmer shack”; and

(iii) the area of land on which the railroad crossing signals are located, near the junction of Hudson Street and St. Andrew Terrace; and

(g) 2 Sackville Road.

The service area excludes the following locations west of Thessalon on the north side of Hwy.17 which are supplied by Hydro One Networks Inc.:

(a) 12564 Highway 17 West

(b) 12600 Highway 17 West

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998***.**

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity

consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998***.**

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998***.**

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

CONTACT INFORMATION

API – contact information for matters related to this application is as follows:

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Fax: (905) 994-2207

Email: doug.bradbury@fortisontario.com

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Vice President, Corporate Services and General Counsel
Algoma Power Inc.

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Fax: (905) 871-8676

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(b) The Applicant's Counsel:

Andrew Taylor, Energy Law

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Toronto, Ontario
M5H 1T1
Telephone: (416) 644-1568
Fax: (416) 367-1954

Email: ataylor@energyboutique.ca

LIST OF SPECIFIC APPROVALS REQUESTED

API is requesting that the Board provide it with an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, as specified in this Application, effective July 1, 2010 and January 1, 2011.

In this Application, API has proposed, in addition to rates and charges, matters which require the Board's consideration and approval. These include the following:

Phase 1 of the Proceeding:

- The Proposed 2010 and 2011 Return on Equity (Exhibit 5, Tab 1, Schedule 1)
- The Proposed 2010 and 2011 Cost of Debt (Exhibit 5, Tab 1, Schedule 1)
- The Proposed 2010 and 2011 Cost of Capital (Exhibit 5, Tab 1, Schedule 1)
- The Proposed 2010 Service Revenue Requirement
- The appropriate 2010 RRRP Funding
- The Proposed 2011 Service Revenue Requirement
- The Shared Services and Shared Assets Proposal (Exhibit 4, Tab 5, Schedule 1)
- The Proposed 2010 and 2011 Customer Forecasts (Exhibit 3, Tab 2, Schedule 1)
- The Proposed 2010 and 2011 Normalized Load Forecasts (Exhibit 3, Tab 2, Schedule 1)
- The Proposed 2010 and 2011 Cost Allocations (Exhibit 7, Tab 1, Schedule 2)
- The Proposed 2010 and 2011 Distribution Loss Factors (Exhibit 8, Tab 5, Schedule 1)
- The Proposed 2010 and 2011 Retail Transmission Service Rates (Exhibit 8, Tab 3, Schedule 1)
- The determination of the average of any adjustment to rates approved by the Board for other distributors in 2010
- The Proposed Tariff of Rates and Charges Effective July 1, 2010 (Exhibit 1, Tab 1, Schedule 2, Appendix A), as updated by average of any adjustment to rates approved by the Board for other distributors in 2010

- The Proposed mitigation plan to dispose of the Seasonal Deferral (Exhibit 8, Tab 1, Schedule 2)
- The Proposal to recover certain Regulatory Deferral and Variance Accounts (Exhibit 9, Tab 2, Schedule 1)
- The Proposal to recover Extraordinary Events Costs (Exhibit 9, Tab 2, Schedule 2)
- The Proposal to continue the Deferral Account Rate Rider – effective until December 31, 2010 approved in EB-2007-0744
- The Proposed creation of IFRS Deferral Account and a Pension Expense Variance Account arising from the Board's consideration of this Application (Exhibit 9, Tab 1, Schedule 5)
- The Proposed Smart Meter Rate Adder (Exhibit 10, Tab 1, Schedule 1)
- The Proposed Changes in Methodology; Amortization Rates and Capitalization of Overhead Costs (Exhibit 1, Tab 2, Schedule 3)
- Making API's approved 2010 distribution rates interim as of January 1, 2011

Phase 2 of the Proceeding:

- The determination of the average of any adjustment to rates approved by the Board for other distributors in 2011
- The Proposed Tariff of Rates and Charges Effective January 1, 2011 (Exhibit 1, Tab 1, Schedule 2, Appendix A), as updated by average of any adjustment to rates approved by the Board for other distributors in 2011
- The appropriate 2011 RRRP Funding

DRAFT ISSUES LIST

API has identified the following as issues related to this Application:

1. Rate Base for the Test Years
    a. Capital Expenditures 2008
    b. Capital Expenditures 2009
    c. Capital Expenditures 2010
    d. Capital Expenditures 2011
    e. Capital Planning and Budgeting Process
    f. Capitalization Policy
    g. Amortization
    h. Working Capital Allowance

2. Operating Revenue for the Test Years
    a. Distribution Revenue
    b. Rural and Remote Rate Protection
    c. Load Forecast Methodology
    d. Other Revenue
    e. Specific Service Charges

3. Operating Costs for the Test Years
    a. Operations, Maintenance & Administration
    b. Shared Services and Corporate Allocations
    c. Depreciation and Amortization
    d. Income Tax and Ontario Capital Tax

4. Cost of Capital and Rate of Return for the Test Years
    a. Capital Structure
    b. Cost of Debt

c. Cost of Equity

5. Revenue Requirement for the Test Years

6. Cost Allocation
   a. Cost Allocation Methodology
   b. Cost Allocation Study
   c. Revenue-to-cost ratios
   d. Rate classification alignment

7. Rate Design
   a. Class rate design
   b. RRRP design
   c. Retail Service Transmission Rates
   d. Loss Adjustment Factors
   e. Street Lighting rate mitigation
   f. Seasonal customer deferral account disposition
   g. Rate impacts in the Test Years

8. Deferral and Variance Accounts
   a. Recoverable Accounts
   b. Account Balances
   c. Calculation and application of Rate Riders

9. Smart Meter Initiative
   a. Smart Meter Rate Adder

PROCEDURAL ORDERS, CORRESPONDENCE AND/OR NOTICES

As of the date of filing, there are no procedural orders, correspondence or other notices issued by the Board to API. Any procedural orders, correspondence or other notices issued during the course of the proceeding will be filed at this Schedule.

ACCOUNTING ORDERS REQUESTED

As part of this proceeding, there are no accounting orders requested.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

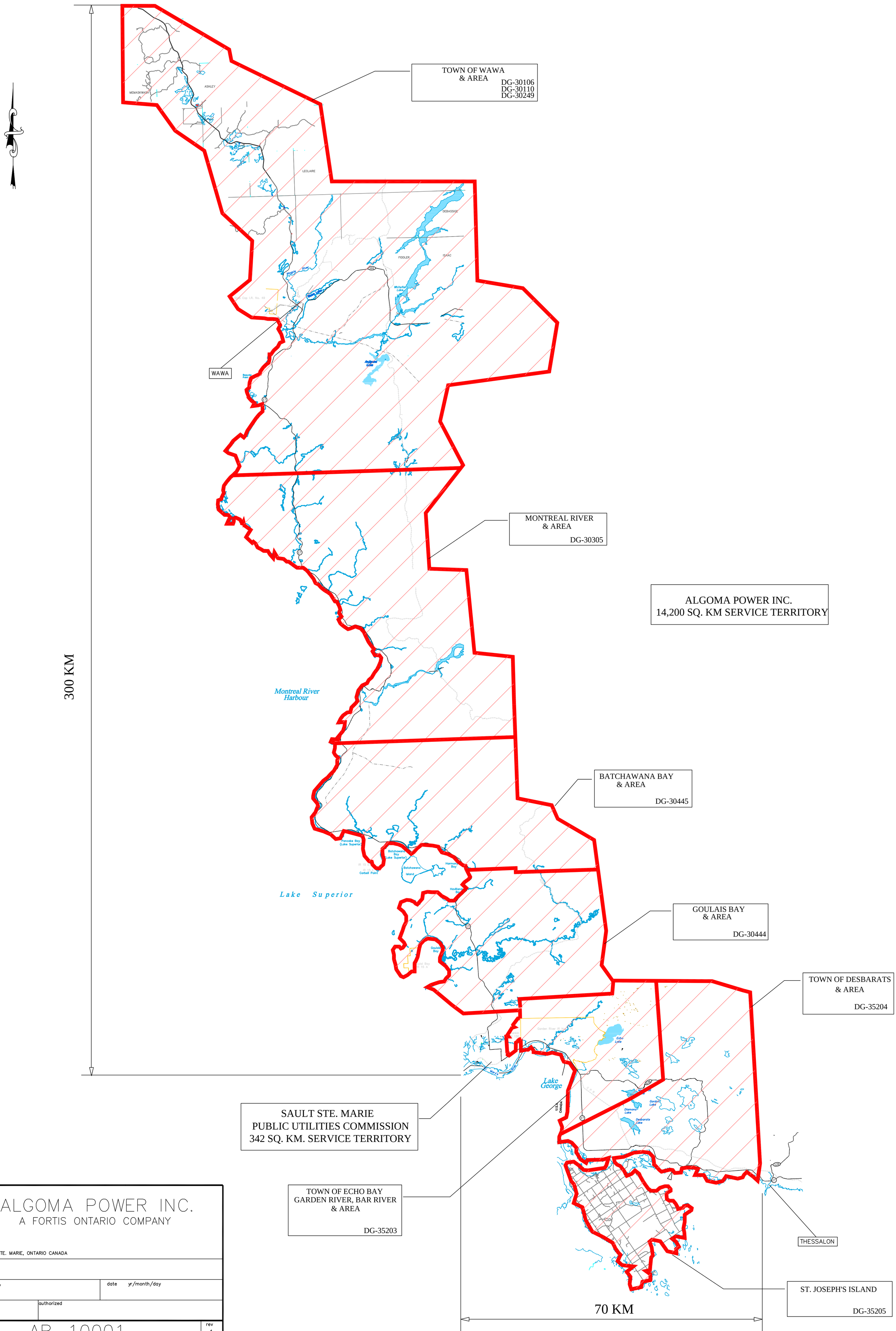
API has followed the OEB's Uniform System of Accounts (referred to in this Application as the "USoA") in the preparation of this Application.

MAPS OF APPLICANT'S DISTRIBUTION SYSTEM

Map "AB-10001, API Service Area Overview" contains a legend to provide context as to the location of the rest of the maps included with respect to the API distribution system. An index of these maps is set out below.

Please refer to the legend to determine the location of land areas depicted on the other maps of API's Distribution System.

Map No.	Description
AB-10001	API Service Area Overview
DG-30106	Town of Wawa
DG-30110	Wawa Michipicoten
DG-30249	Hawk Junction, Goudreau, Lochalsh, Missinabie
DG-30305	Montreal River Area
DG-30444	Goulais Bay Area
DG-30445	Batchawana Bay Area
DG-30611	City of Sault Ste. Marie
DG-35203	Garden River & Bar River Areas
DG-35204	Desbarats & Bruce Mines Areas
DG-35205	St. Joseph's Island



ALGOMA POWER INC.
A FORTIS ONTARIO COMPANY

SAULT STE. MARIE, ONTARIO CANADA

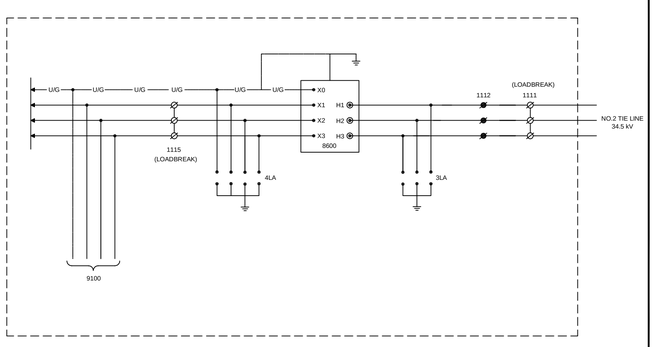
location	
designed by	date yr/month/day
scale	authorized
dwg no AB—10001	rev 1

WAWA No.1
SUB 91

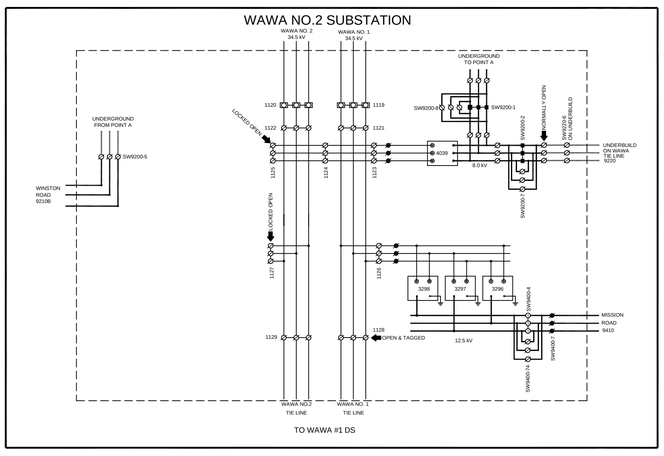
WAWA No.2
SUB 92/94

GOVERNMENT ROAD
ALGOMA ST
MACKEY ST
LAURIER ST
ONTARIO ST
GANLEY ST
GOLD ST
CAVERHILL STREET
ST MARIE ST
MAIN ST
JOLIET ST
MAGPIE ROAD
SPRUCE ST
POPLAR ST
BOYER ST
DARWIN ST
PARKHILL ST
MAPLE ST
BIRCH ST
QUEEN STREET
KLONDIKE ST
WINSTON ROAD
CHRIS SIMON DRIVE
MISSION ROAD
SECOND AVE
FIRST AVE
THIRD AVE
CHURCHILL AVE
BECK AVE
TAMARACK AVE
SUPERIOR AVE
REGINA CRES
MAGPIE ROAD
ROSS ST
ARNOTT ST
GRACE ST
WOOD AVE
NYMAN AVE
McKINLEY AVE
BROADWAY AVE
TORONTO AVE
MONTREAL ST
WAWA STREET
WATER STREET
GLADSTONE AVE
MONTREAL AVE S.
CENTENNIAL AVE.
GEORGE STREET
HILLCREST AVE
"A" ST
HILLCREST HEIGHTS
HIGHSCHOOL AREA
R.C. SEPARATE SCHOOL AREA
SIR JAMES DUNN PUBLIC SCHOOL AREA
ARENA AND CURLING RINK
LADY DUNN HOSPITAL
CARL M. BECK PUBLIC SCHOOL
TRAILER PARK
CEMETARY
WAWA MOTOR HOTEL

WAWA NO.1 SUBSTATION



WAWA NO.2 SUBSTATION



TO WAWA #1 DS

LEGEND

PRIMARY	2.4 / 4.15 kV	4.6 / 8.32 kV	7.2 / 12.5 kV	14.4. / 25 kV
SINGLE (1) PHASE				
TWO (2) PHASE				
THREE (3) PHASE				
INTERRUPTING DEVICES				
RECLOSER	SINGLE (1) PHASE		THREE (3) PHASE	
SECTIONALIZER	SINGLE (1) PHASE		THREE (3) PHASE	
FUSE CUTOUT	FUSED CUTOUT		SOLID BLADE CUTOUT	OIL SWITCH (S)
LINE BREAKS	PROXIMITY D.E.'S		OPEN BACK-TO-BACK D.E.'s	JUMPERED BACK-TO-BACK D.E.'s
TRANSFORMATION	AUTO TRANSFORMER		SUBSTATION TRANSFORMER	VOLTAGE REGULATOR (VR)
GENERATION	GENERATION (G)		OPEN POINT	

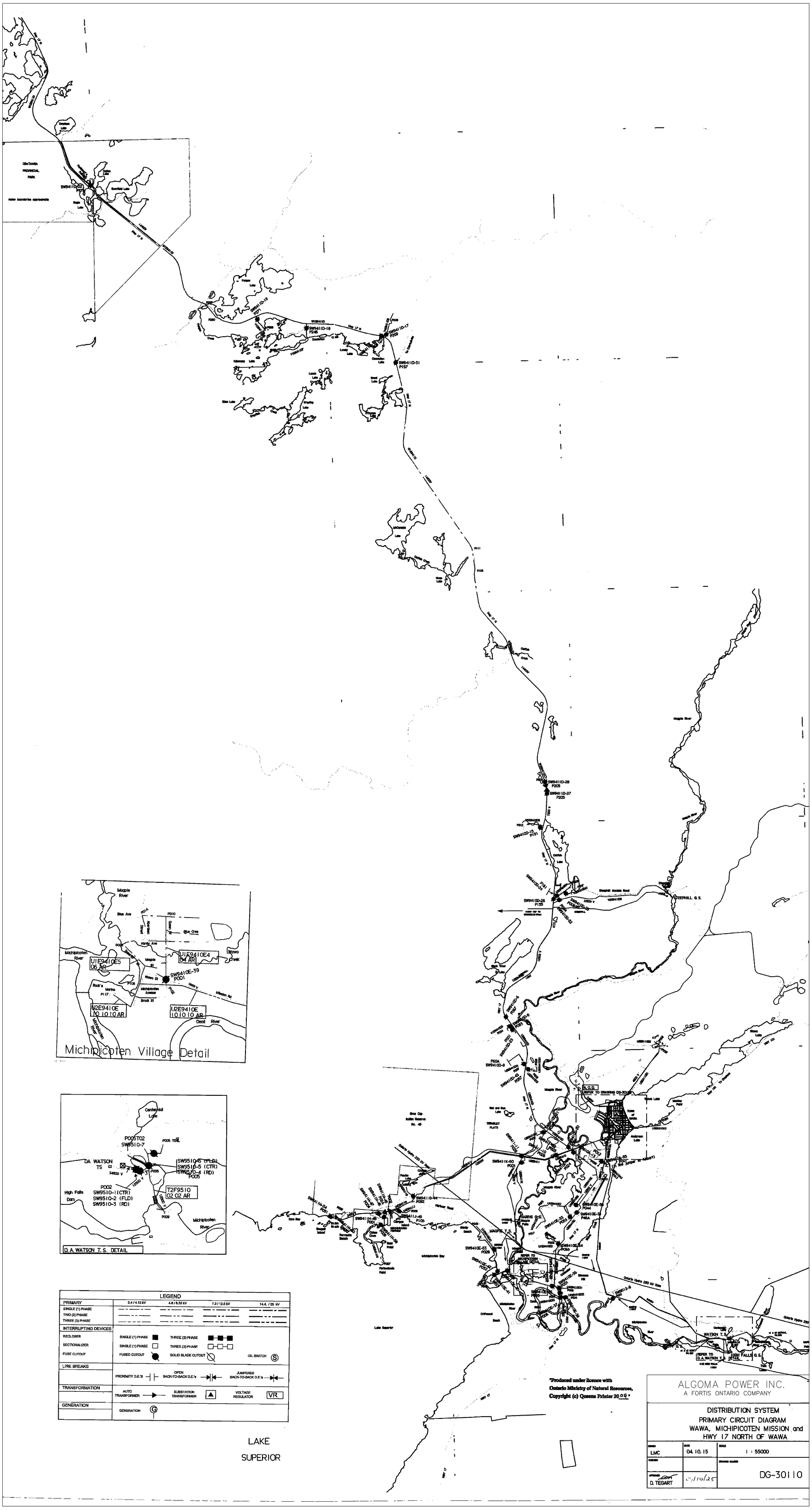
ALGOMA POWER INC.

A FORTIS ONTARIO COMPANY

PRIMARY CIRCUIT DIAGRAM DETAIL FOR THE TOWN OF WAWA

FOR REFERENCE ONLY
NOT FOR USE IN SWITCHING

APP'D		SIGNED	
DATE	04 FEB 10	DRAWING NO.	REVISION
SCALE	NTS	DG-30106	5


CHAPLEAU CROWN GAME PRESERVE
CHAPLEAU CROWN GAME PRESERVE
CHAPLEAU CROWN GAME PRESERVE

DUBREUILVILLE

Refer to Goudreau Detail

GOUDREAU SUB 82

LOCHALSH SUB No. 83

MISSANABIE SUB No. 84

Goudreau Detail

Troupe Lake

Sherman Lake

Herman Lake

Otto Lake

Summit Lake

Philip Lake

Dipneedle Lake

GOUDREAU SUB No. 82

MISSANABIE SUBSTATION

44 kV

5473

971

4.8 kV

SW8420-2 P000

SW8400-1 P000

8420

8410

HAWK JUNCTION SUBSTATION

44kV NO. 4 CIRCUIT

1181

V2G8100

HAWK JUNCTION SUB No. 81

TOWN OF HAWK JUNCTION

CEDAR ST

SPRUCE ST

PINE ST

MAPLE ST

POPLAR ST

SANDRA ST

QUEEN ST

KING ST

COLLEGE ST

DUKE ST

FRONT ST

BOUCHER ST

FIELD CENTRE ROAD

Algoma Central Railway

McVeigh Bay

Hawk Lake

HWY 101

HWY 101 D.S. SUB No. 97

MOLLINGSWORTH G .S.

HAWK JUNCTION SUB No. 81

ALGOMA GAMIGAMI T.S.

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LEGEND

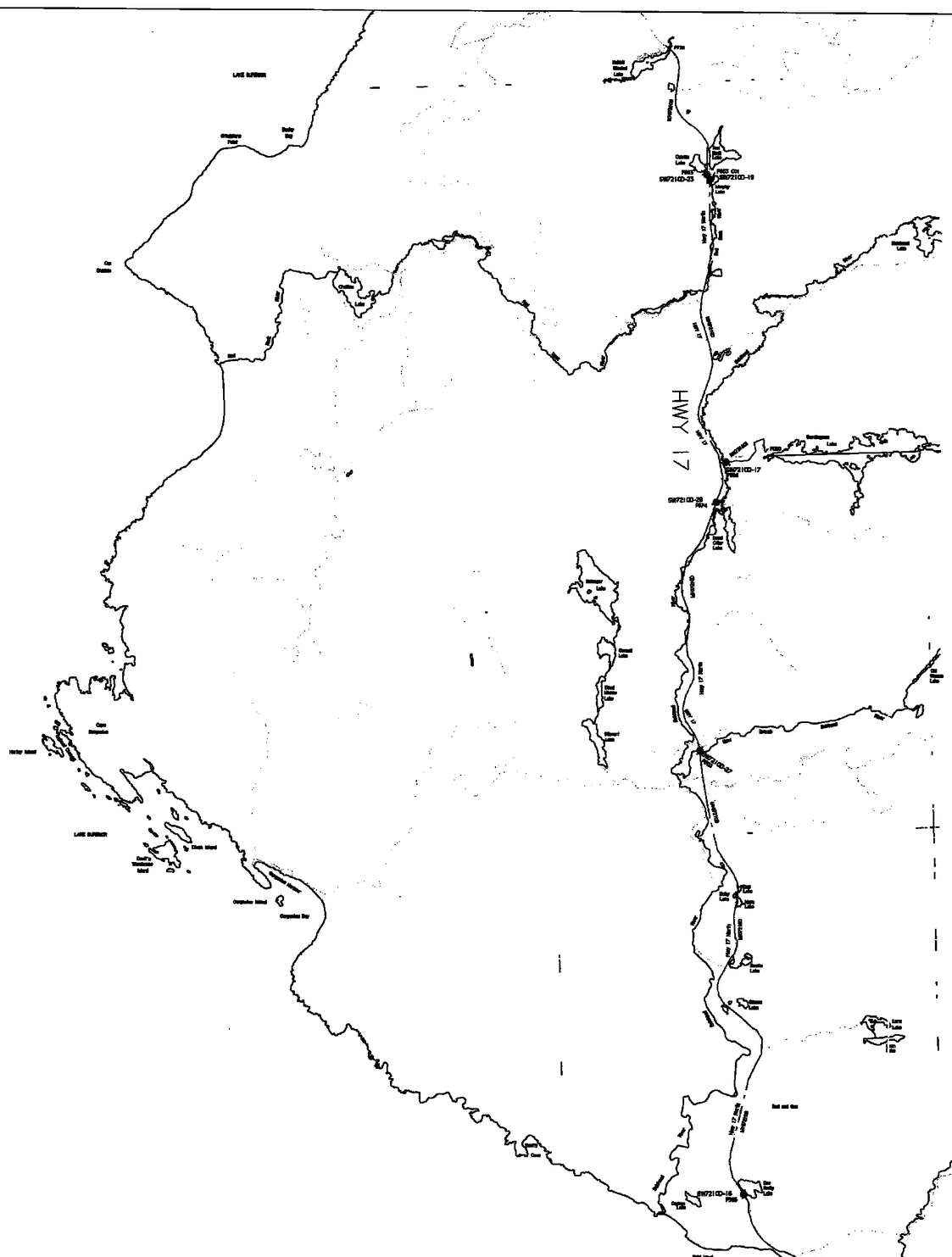
PRIMARY	2.4 / 4.15 kV	4.8 / 8.32 kV	7.2 / 12.5 kV	14.4 . / 25 kV
SINGLE (1) PHASE				
TWO (2) PHASE				
THREE (3) PHASE				

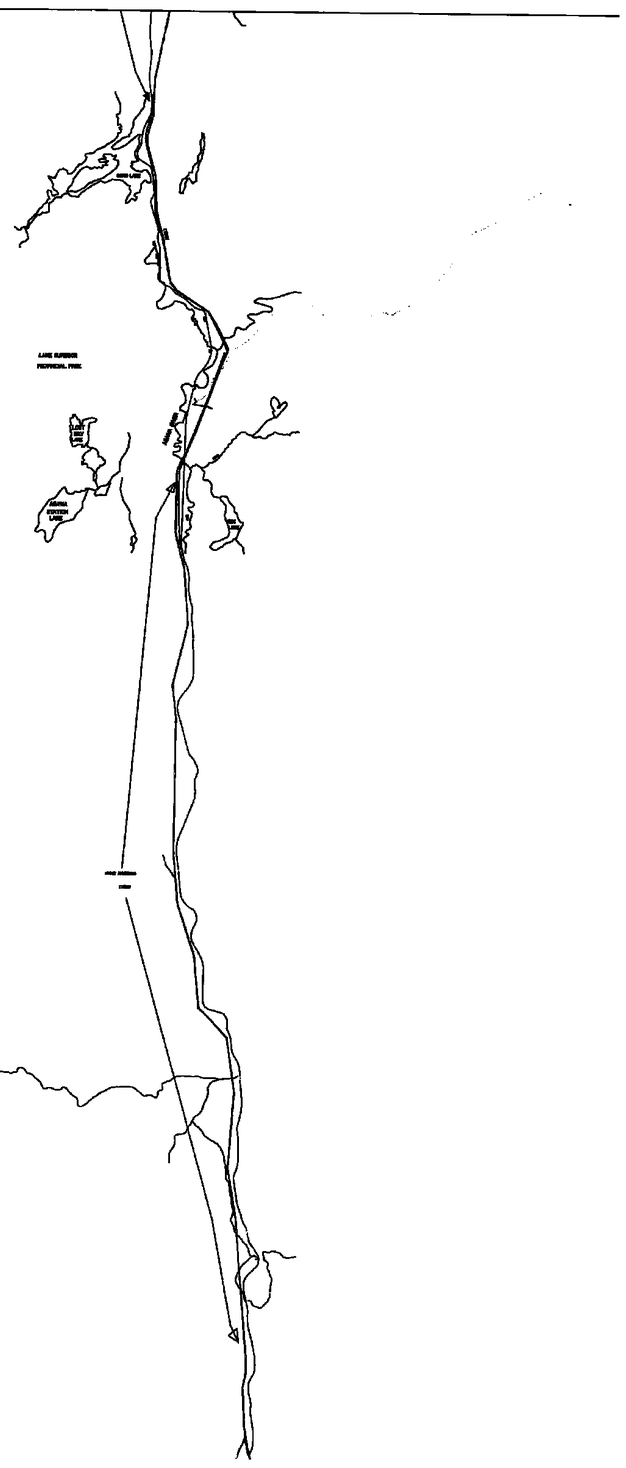
INTERRUPTING DEVICES			
RECLOSER	SINGLE (1) PHASE	THREE (3) PHASE	
SECTIONALIZER	SINGLE (1) PHASE	THREE (3) PHASE	
FUSE CUTOUT	FUSED CUTOUT	SOLID BLADE CUTOUT	OIL SWITCH (S)
LINE BREAKS	PROXIMITY D.E.'S	OPEN BACK-TO-BACK D.E.'s	JUMPERED BACK-TO-BACK D.E.'s
TRANSFORMATION	AUTO TRANSFORMER	SUBSTATION TRANSFORMER	VOLTAGE REGULATOR (VR)
GENERATION	GENERATION (G)		

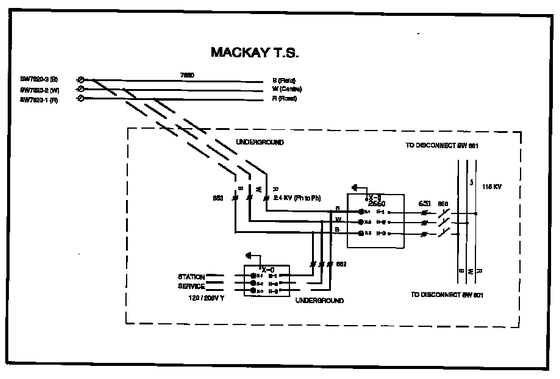
ALGOMA POWER INC.
A FORTIS ONTARIO COMPANY

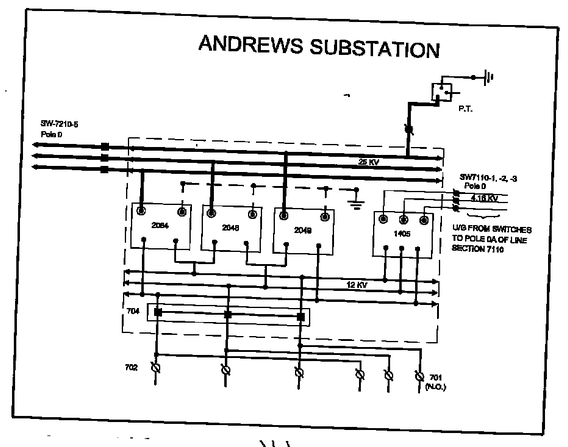
DISTRIBUTION SYSTEM
PRIMARY CIRCUIT DIAGRAM
GOUDREAU, HAWK JUNCTION, LOCHALSH
MISSANABIE, & HWY 101

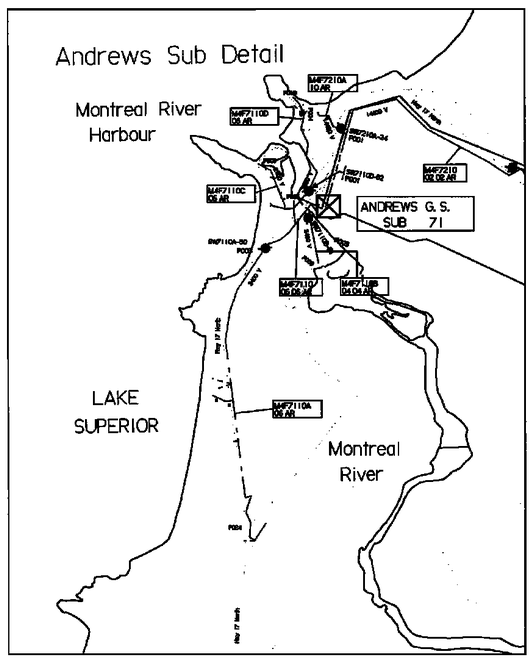
LMC	04. 10. 18	1:50000	
D. TEGART	04/10/05	DG-30249	4

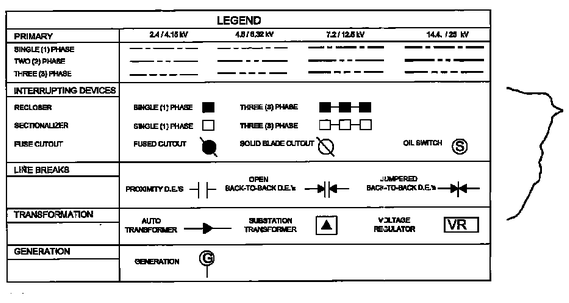


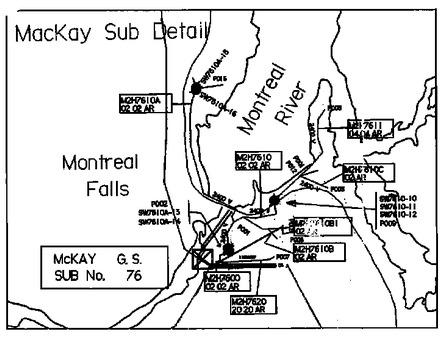


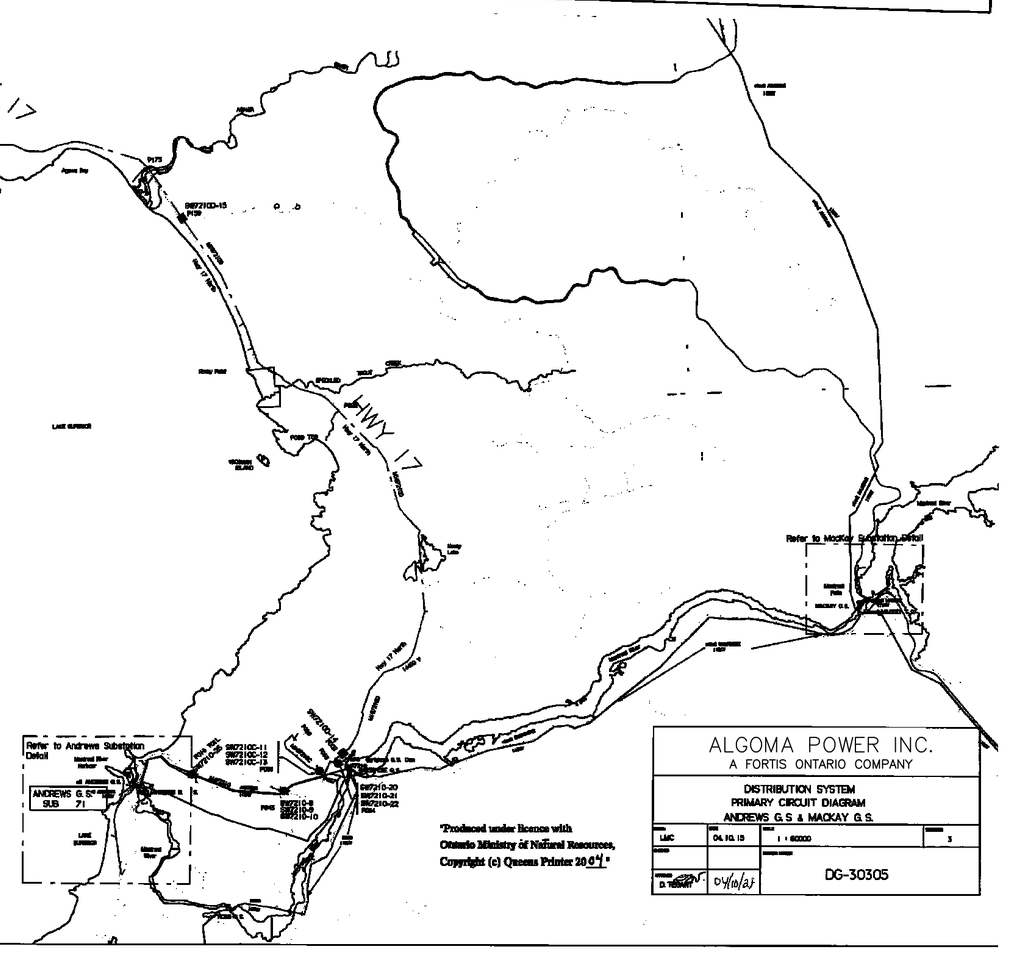












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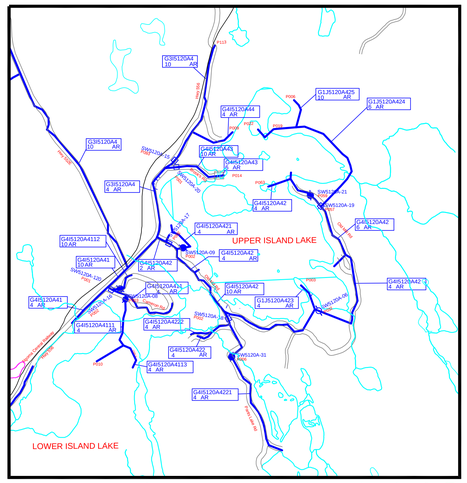
ALGOMA POWER INC.
A FORTIS ONTARIO COMPANY

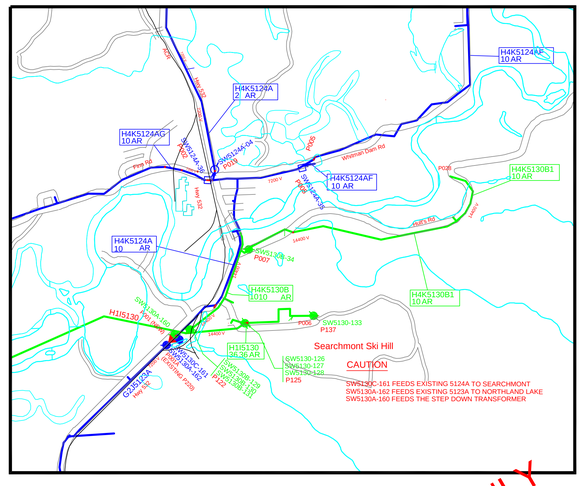
DISTRIBUTION SYSTEM
PRIMARY CIRCUIT DIAGRAM
ANDREWS G.S & MACKAY G.S.

LMC	04.10.15	1 : 60000	3
D. TREMBAY	04/10/15	DG-30305	

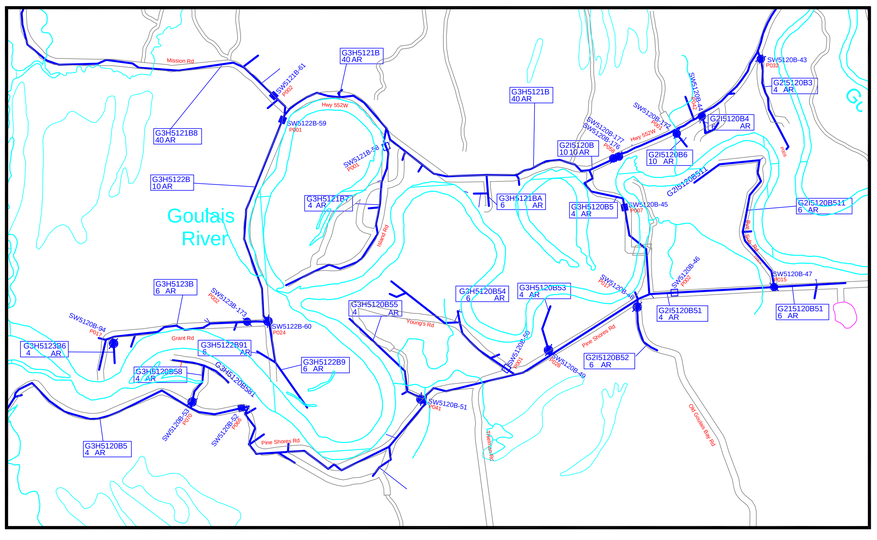
ISLAND LAKE DETAIL



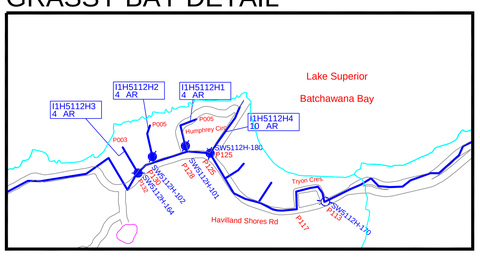
SEARCHMONT DETAIL



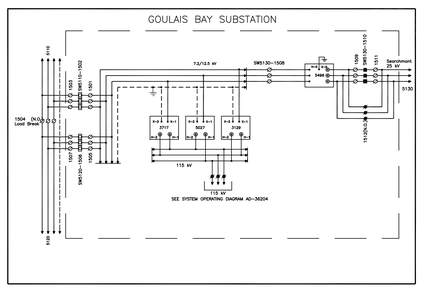
GOULAIS RIVER WEST

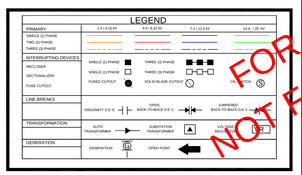


GRASSY BAY DETAIL



GOULAIS BAY SUBSTATION





ALGOMA POWER INC.
A FORTIS ONTARIO COMPANY

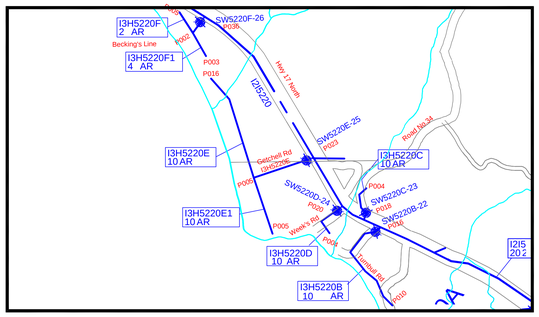
GOULAIS SUB 51

DISTRIBUTION
PRIMARY CIRCUIT DIAGRAM

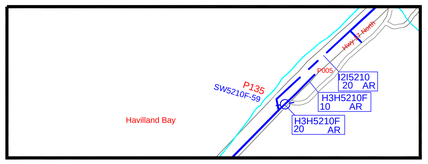
APP'D	SIGNED
DATE JANUARY 29, 2007	DRAWING NO. DG-30444
SCALE NTS	REVISION /2

FOR REFERENCE ONLY
NOT FOR USE IN SWITCHING

JONES LANDING DETAIL

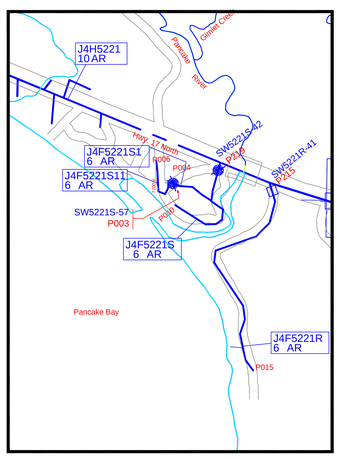


L.S. H3H5210F DETAIL

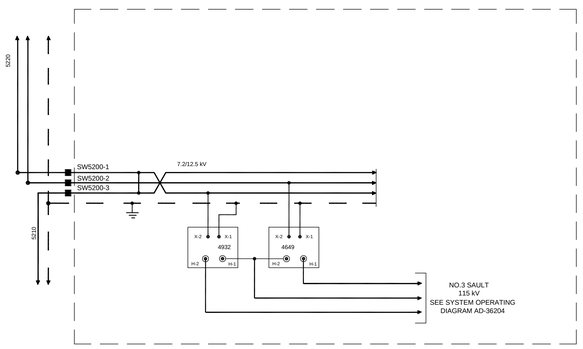


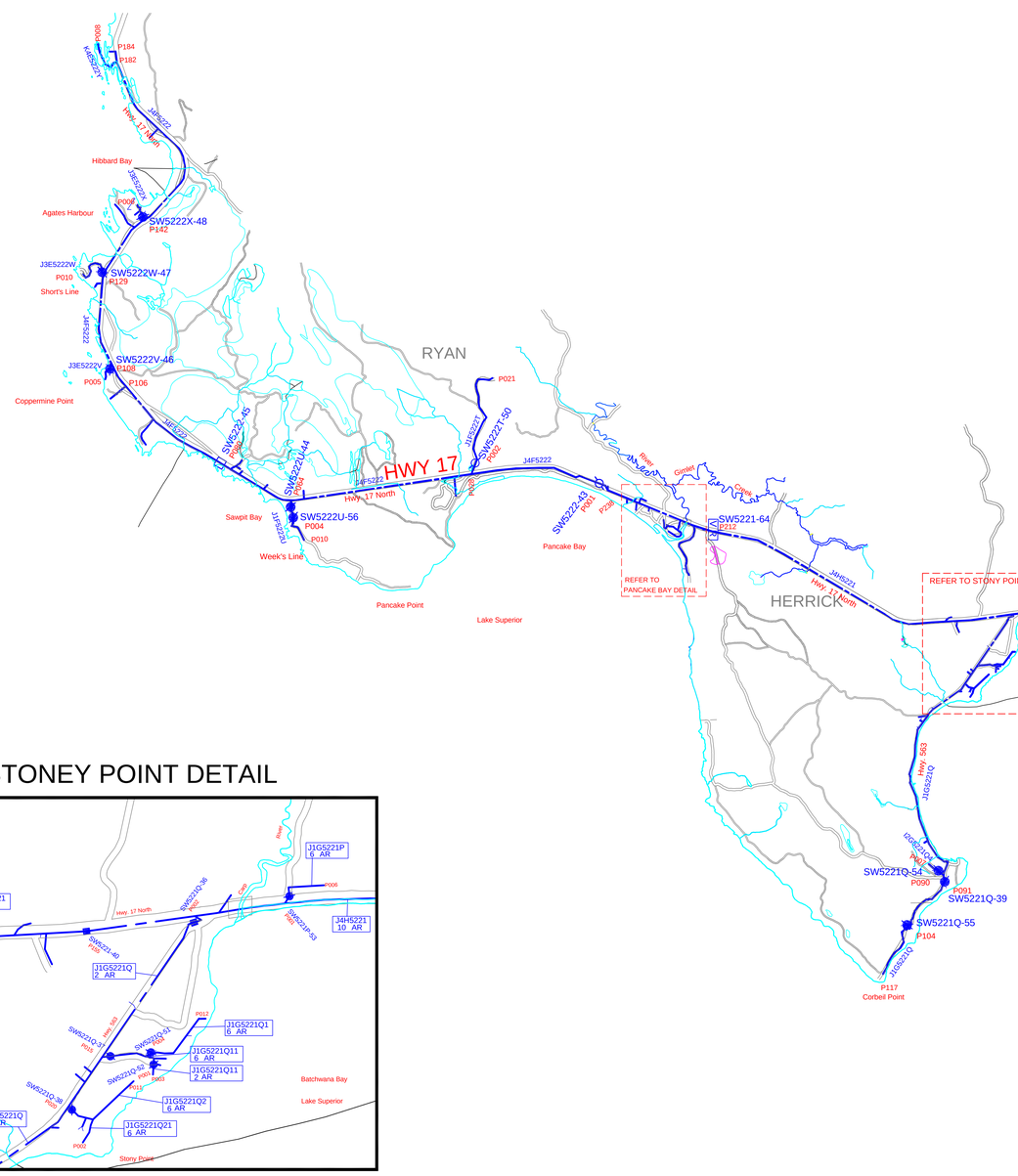
STONEY POINT DETAIL

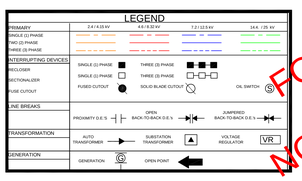
PANCAKE BAY DETAIL



BATCHAWANA BAY SUBSTATION







FOR REFERENCE ONLY
NOT FOR USE IN SWITCHING

ALGOMA POWER INC.
A FORTIS ONTARIO COMPANY

BATCHAWANA SUB 52

DISTRIBUTION
PRIMARY CIRCUIT DIAGRAM

APP'D
SIGNED
DATE MARCH 5, 2007
SCALE NTS
DRAWING NO. DG-30445
REVISION /2

THIRD LINE TS
STATION SERVICE

SW4110-330

SOO4110
22AR

SW4110-331

BONIFERO
MILLWORKS

SOO4110
22AR

SW4110-327

CHINA
STEEL

SW4110-328

NORTHERN AVE TS
SEE SYSTEM OPERATING DIAGRAM AD-36204

DOMINION
BRIDGE

SW4120-329
SW4120-142

SOO4120
866 866 AR

ACR

SW4120-332

KENT CR
LETHBRIDGE
GREENFIELD
MAYFAIR
BEAUMONT
CHATFIELD
THIRD LINE WEST
(unopened allowance)
THIRD LINE EAST
IND COURT B
IND COURT A
INDUSTRIAL PARK
BARRETT
SHERBROOK
FAIRVIEW
HILLSIDE
SHERWOOD
HOLDEN
SILVERDALE
SUNNYDALE
PENNO
ELLIOTT
HILL
PEOPLES
ST PATRICK
LIDSTONE
LLOYD
EVERETT
MAXANNE CR.
BAINBRIDGE
SHAFER
LENNOX
SWARTZ
HENRIETTA
GILLIES
PATRICK
SHERBOURNE
WELLINGTON WEST
DUNDAS
BLOOR WEST
ADELAIDE
CARLETON
HIGHLAND
WESTRIDGE
WOODHURST
CABOT
HIGHCREST
NORTHRIDGE
MARY
FORT CREEK
LASALLE
SACKVILLE
NIAGARA
NORTH
SUPERIOR
MONTCALM
SELKIRK
HARRY
WHITE OAK W
WHITE OAK E
SECOND LINE EAST
JOHN
CLERGUE
NORTHERN W
ANITA
ELM
KITCHENER
GRANDVILLE
STRAND
GLADWYN
HARGREAVES
MORRISON
BEECH
GRANGEMILL
GRANDHAVEN
KNOX
GRANDVIEW
WILSON
NINO
GRANDMONT
GRAND
GRANDRIVER
REID
BYRNE
KEHOE
NORTHLAND
PARLIAMENT
CHARLES
JOHN
BUSH
MORIN
NELSON
BIRCH
YORK
WELLINGTON W
BOYDELL
CORNWALL
ST MARYS
CHESTNUT
WALNUT
SPRUCE
GRANDY
GRANITE
ST GEORGES W
ST GEORGES E
ST ANDREWS
PARDEE
CONMEE
MARSH
HUDSON
GLF SUBSTATION
R.R. X-ING SIGNALS
(NOT ON ACR)
PUC SUPPLY

LEGEND

PRIMARY	2.4 / 4.15 kV	4.6 / 8.32 kV	7.2 / 12.5 kV	14.4 . / 25 kV
SINGLE (1) PHASE				
TWO (2) PHASE				
THREE (3) PHASE				

INTERRUPTING DEVICES				
RECLOSER	SINGLE (1) PHASE		THREE (3) PHASE	
SECTIONALIZER	SINGLE (1) PHASE		THREE (3) PHASE	
FUSE CUTOUT	FUSED CUTOUT		SOLID BLADE CUTOUT	OIL SWITCH (S)

LINE BREAKS			
	PROXIMITY D.E.'S	OPEN BACK-TO-BACK D.E.'s	JUMPERED BACK-TO-BACK D.E.'s

TRANSFORMATION			
	AUTO TRANSFORMER	SUBSTATION TRANSFORMER	VOLTAGE REGULATOR (VR)

GENERATION		
	GENERATION (G)	OPEN POINT

ALGOMA POWER INC.

A FORTIS ONTARIO COMPANY

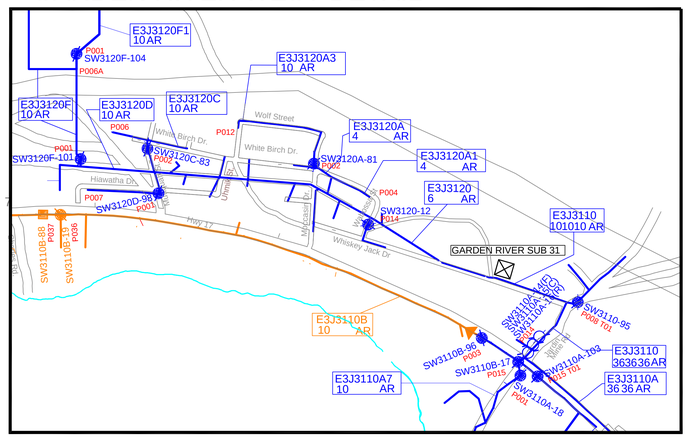
12KV DISTRIBUTION
SAULT STE. MARIE

DISTRIBUTION
PRIMARY CIRCUIT DIAGRAM

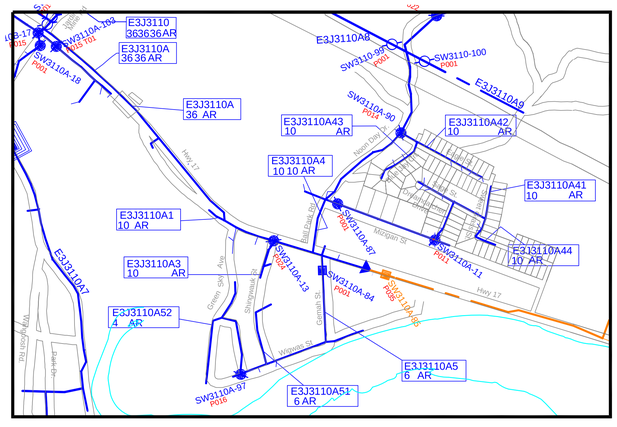
APP'D	SIGNED	
DATE APRIL 07, 2008	DRAWING NO. DG-30611	REVISION 0
SCALE NTS		

ECHO BAY DETAIL

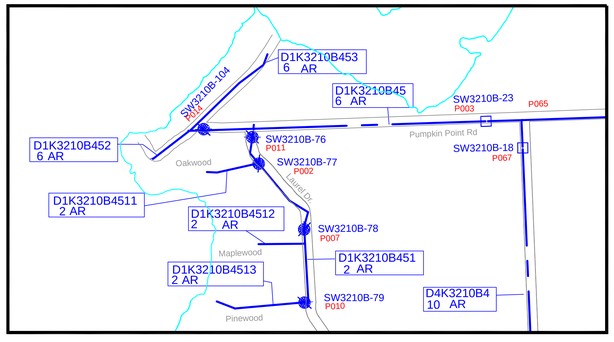
GARDEN RIVER WEST DETAIL

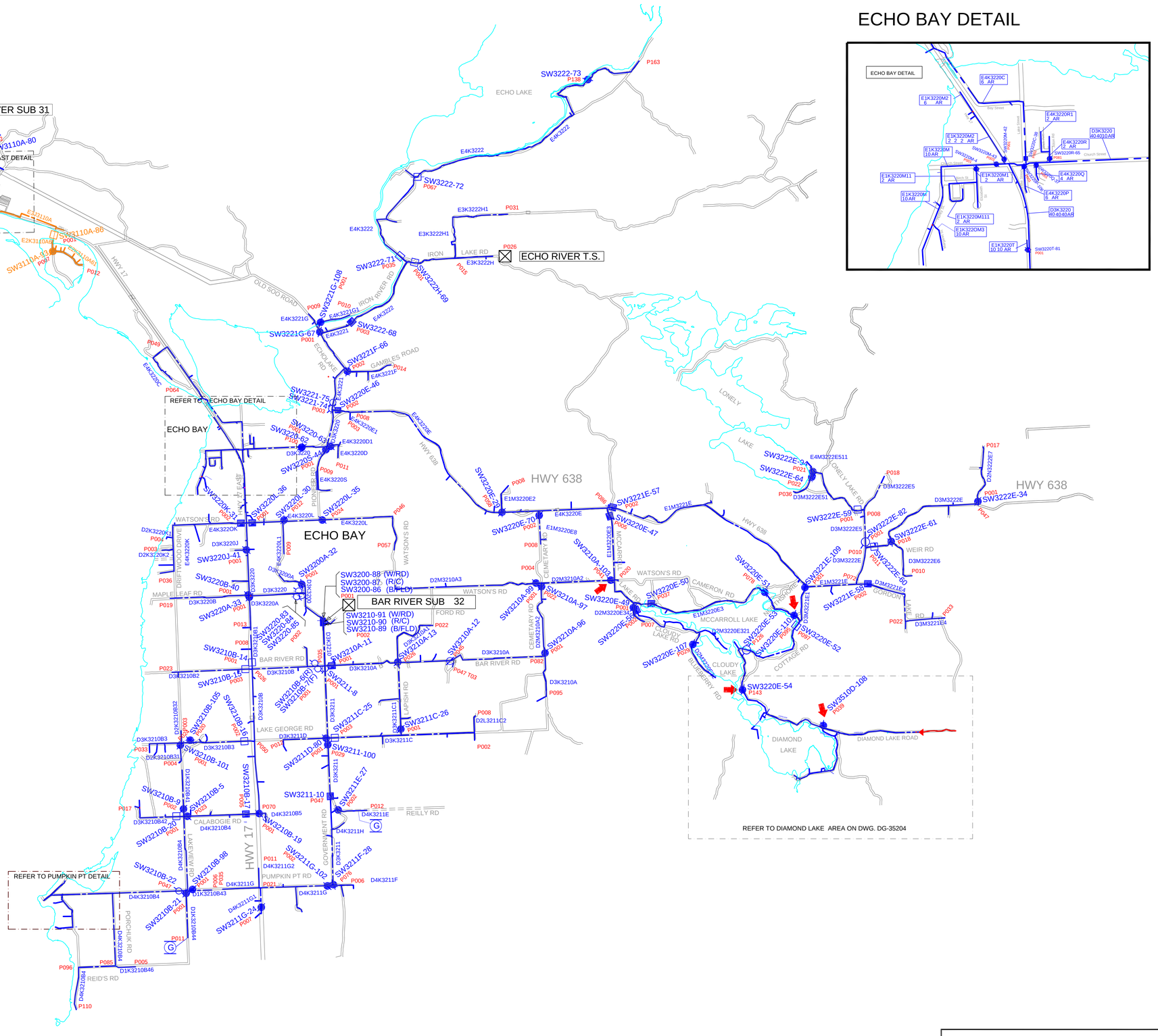


GARDEN RIVER EAST DETAIL



PUMPKIN POINT DETAIL




REFER TO GARDEN RIVER WEST DETAIL
GARDEN RIVER SUB 31
REFER TO GARDEN RIVER EAST DETAIL
SW3110A-80
SW3110A-82
SW3110B-89
SW3110A-86
SW3110A-93
SW3222-73
P163
P138
ECHO LAKE
E4K3222
SW3222-72
P067
E3K3222H1
P031
E3K3222H1
IRON
LAKE RD
P026
ECHO RIVER T.S.
E3K3222H
SW3222-71
P035
SW3222H-69
P015
IRON RIVER RD
SW3221G-108
E4K3221G
E4K3221G1
SW3222-68
SW3221G-67
E4K3221
P003
SW3221F-66
P002
E4K3221F
P014
GAMBLES ROAD
ECHO LAKE RD
OLD SOO ROAD
HWY 17
SW3220E-46
SW3221-75
SW3221-74
REFER TO ECHO BAY DETAIL
ECHO BAY
SW3220-63
SW3220-62
E4K3220E1
E4K3220D1
D3K3220
E4K3220D
SW3220S
E4K3220S
SW3220L-36
SW3220L-30
SW3220L-35
E4K3220L
SW3220K-31
D2K3220K1
D2K3220K2
E4K3220K
D3K3220J
SW3220J-41
SW3220A-32
D3K3220A
SW3200-88 (W/RD)
SW3200-87 (R/C)
SW3200-86 (B/FLD)
BAR RIVER SUB 32
SW3210-91 (W/RD)
SW3210-90 (R/C)
SW3210-89 (B/FLD)
SW3220B-40
SW3220A-33
D3K3220B
D3K3220B1
SW3220-84
SW3220-85
SW3220-86
SW3210B-14
BAR RIVER RD
D3K3210B
D3K3210B2
SW3210B-15
SW3210B-R(C)
SW3210B-T(F)
SW3210A-11
SW3211-8
D3K3210A
SW3210A-12
SW3210A-13
D3K3210A1
SW3210A-99
SW3210A-96
SW3210A-97
D3K3210A
P082
D3K3210A
P095
P047 703
FORD RD
P022
D3K3210B3
D2K3210B31
SW3210B-101
SW3210B-105
SW3210B-16
D3K3210B
D3K3211
LAKE GEORGE RD
D3K3211D
SW3211-100
SW3211D-80
SW3211C-25
SW3211C-26
D3K3211C
D2L3211C2
P002
SW3210B-9
SW3210B-5
SW3210B-17
SW3211-10
P047
P012
D4K3211E
REILLY RD
D3K3210B42
D4K3210B4
CALABOGIE RD
SW3210B-20
SW3210B-19
D4K3210B5
P070
D4K3211H
GOVERNMENT RD
SW3211C-102
SW3211F-28
D4K3211F
P006
D4K3211G
PUMPKIN PT RD
REFER TO PUMPKIN PT DETAIL
SW3210B-22
SW3210B-98
SW3210B-21
D4K3210B4
D1K3210B46
D4K3211G-24
POINT AUX PINS RD
REID'S RD
P110
HWY 638
E4K3220E
E1M3220E2
SW3220E-70
SW3220E-47
E1M3221E
SW3221E-57
E1M3220E8
SW3210A-103
E1M3220E3
D2M3220E34
SW3220E-49
SW3220E-50
SW3220E-51
SW3220E-53
SW3220E-55
SW3220E-110
SW3220E-52
SW3220E-107
WATSON'S RD
CAMERON RD
MCCARROLL LAKE
LOWERY LAKE RD
CEMETERY RD
D2M3210A2
D2M3210A3
D2M3220E321
D2M3220E4
D2M3220E5
D2M3220E6
D2M3220E7
D2M3220E8
D2M3220E9
D2M3220E10
D2M3220E11
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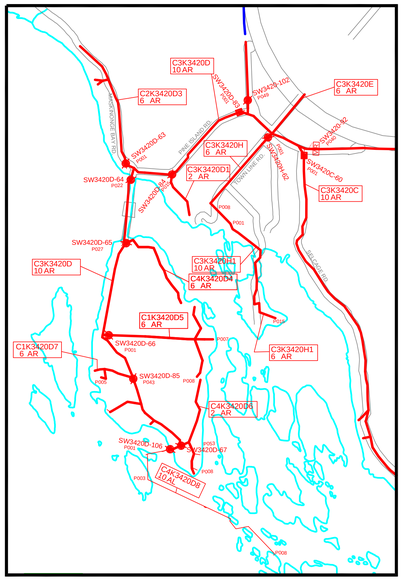
D2M3220E15
D2M3220E16
D2M3220E17
D2M3220E18
D2M3220E19
D2M3220E20
D2M3220E21
D2M3220E22
D2M3220E23
D2M3220E24
D2M3220E25
D2M3220E26
D2M3220E27
D2M3220E28
D2M3220E29
D2M3220E30
D2M3220E31
D2M3220E32
D2M3220E33
D2M3220E34
D2M3220E35
D2M3220E36
D2M3220E37
D2M3220E38
D2M3220E39
D2M3220E40
D2M3220E41
D2M3220E42
D2M3220E43

PINE ISLAND DETAIL


C3K3420D
10 AR
C2K3420D3
6 AR
C3K3420E
6 AR
SW3420D-64
SW3420D-63
C3K3420H
6 AR
C3K3420D1
2 AR
SW3420D-62
SW3420C-60
C3K3420C
10 AR
SW3420D-65
C3K3420D
10 AR
C3K3420H1
10 AR
C4K3420D4
6 AR
C1K3420D5
6 AR
C1K3420D7
6 AR
SW3420D-66
SW3420D-85
C3K3420H1
6 AR
C4K3420D3
6 AR
SW3420D-102
C4K3420D7
10 AR
C4K3420D8
10 AR
PINE ISLAND RD
SW3420D-67
SW3420D-68
SW3420D-69
SW3420D-70
SW3420D-71
SW3420D-72
SW3420D-73
SW3420D-74
SW3420D-75
SW3420D-76
SW3420D-77
SW3420D-78
SW3420D-79
SW3420D-80
SW3420D-81
SW3420D-82
SW3420D-83
SW3420D-84
SW3420D-86
SW3420D-87
SW3420D-88
SW3420D-89
SW3420D-90
SW3420D-91
SW3420D-92
SW3420D-93
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SW3420D-110
SW3420D-111
SW3420D-112
SW3420D-113
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SW3420D-115
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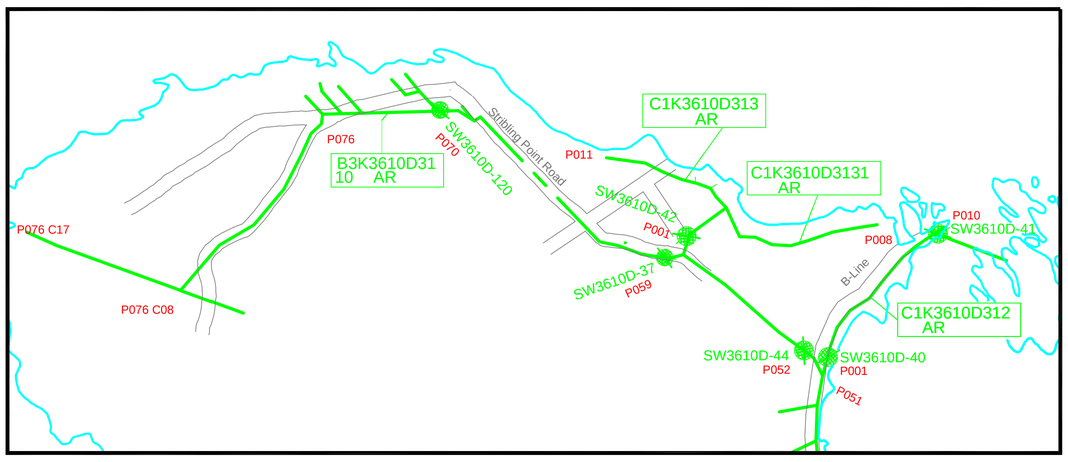
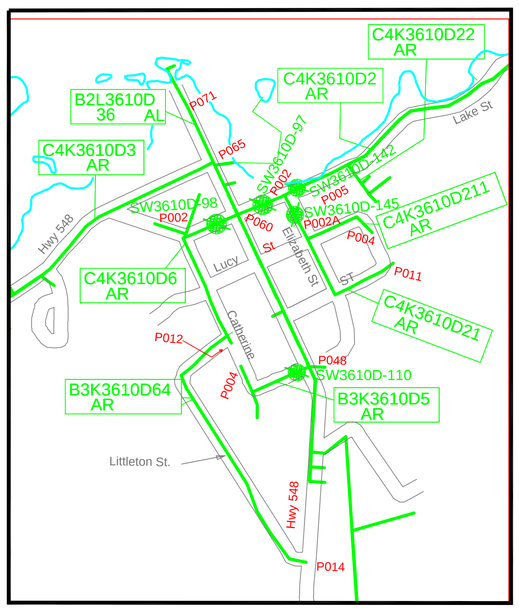
SW3420D-117
SW3420D-118
SW3420D-119
SW3420D-120
SW3420D-121
SW3420D-122
SW3420D-123
SW3420D-124
SW3420D-125
SW3420D-126
SW3420D-127
SW3420D-128
SW3420D-129
SW3420D-130
SW3420D-131
SW3420D-132
SW3420D-133
SW3420D-134
SW3420D-135
SW3420D-136
SW3420D-137
SW3420D-138
SW3420D-139
SW3420D-140
SW3420D-141
SW3420D-142

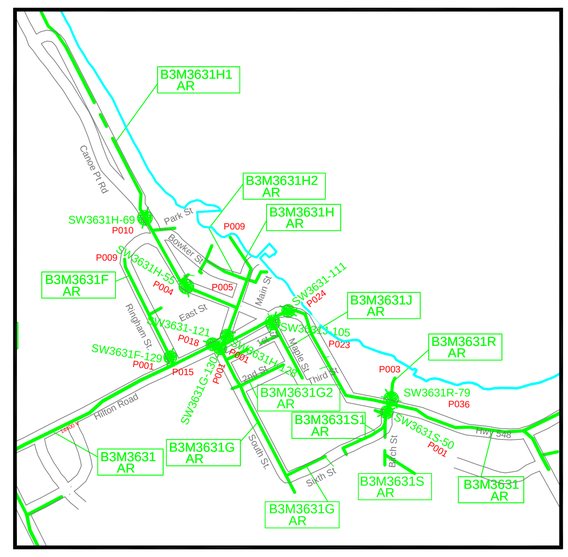
STRIBLING POINT

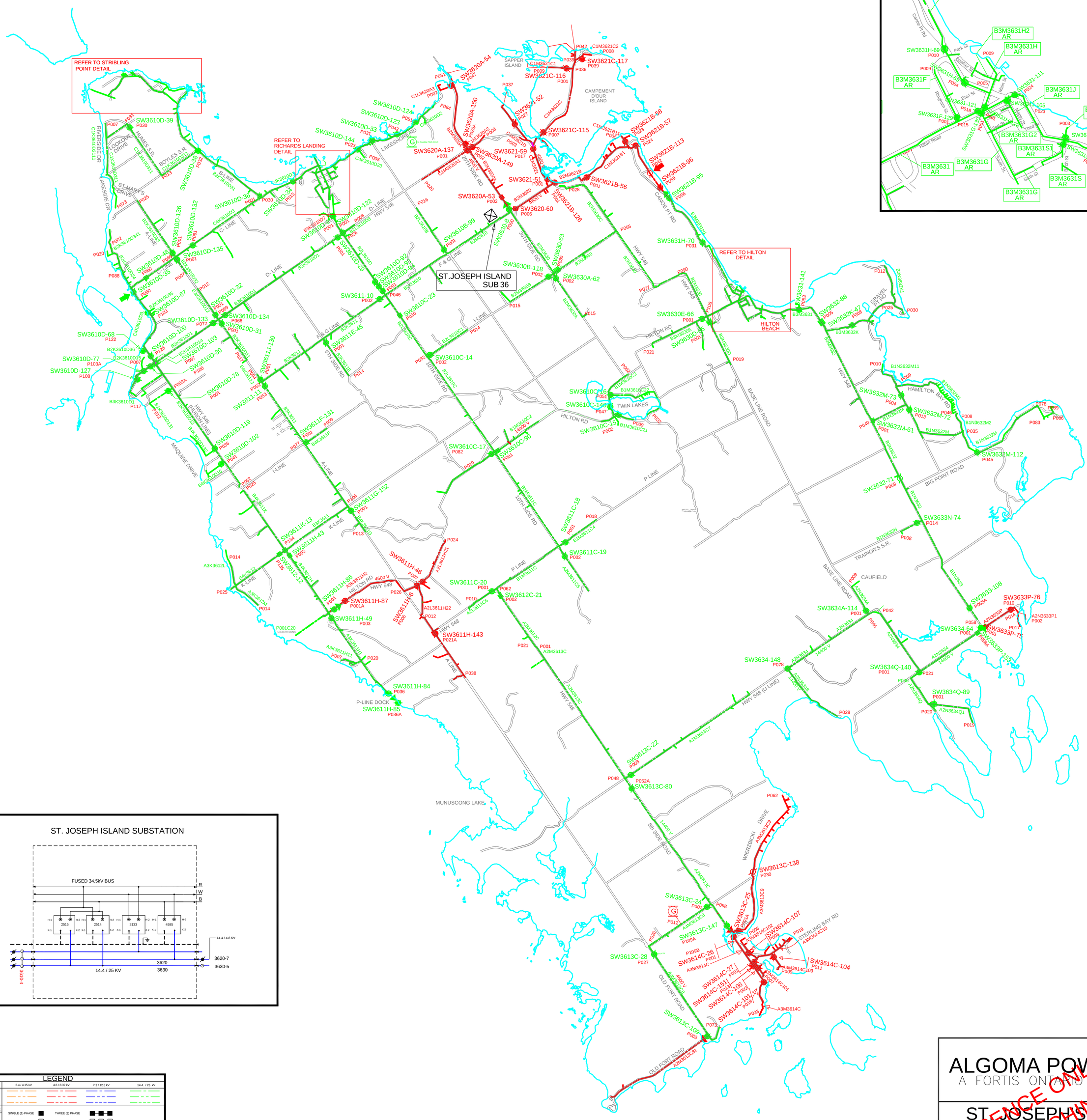


RICHARDS LANDING



HILTON BEACH




REFER TO STRIBLING POINT DETAIL
REFER TO RICHARDS LANDING DETAIL
REFER TO HILTON DETAIL
ST.JOSEPH ISLAND SUB 36
SW3610D-39
SW3610D-38
SW3610D-36
SW3610D-34
SW3610D-122
SW3610D-123
SW3610D-124
SW3610D-144
SW3610D-33
SW3620A-137
SW3620A-149
SW3620A-150
SW3620A-54
SW3621-59
SW3621-51
SW3620A-53
SW3620-60
SW3621C-115
SW3621C-116
SW3621C-117
SW3621-52
SW3621B-58
SW3621B-57
SW3621B-113
SW3621B-96
SW3621B-95
SW3621B-56
SW3621B-126
SW3620-63
SW3630B-118
SW3630A-62
SW3630E-66
SW3630D-65
SW3631-141
SW3631H-70
SW3610B-99
SW3610D-92
SW3610D-93
SW3610D-94
SW3610D-29
SW3610D-32
SW3610D-48
SW3610D-35
SW3610D-67
SW3610D-136
SW3610D-132
SW3610D-135
SW3610D-134
SW3610D-133
SW3610D-31
SW3610D-100
SW3610D-103
SW3610D-30
SW3610D-78
SW3610D-119
SW3610D-102
SW3610D-68
SW3610D-77
SW3610D-127
SW3611-10
SW3610C-23
SW3610C-14
SW3611E-45
SW3611J-139
SW3611-12
SW3611F-131
SW3610C-17
SW3610C-90
SW3610C-16
SW3610C-140
SW3610C-15
SW3611G-152
SW3611K-13
SW3611H-43
SW3612-12
SW3611H-86
SW3611H-87
SW3611H-49
SW3611H-46
SW3611H-6
SW3611H-143
SW3611H-84
SW3611H-85
SW3611C-18
SW3611C-19
SW3611-51
SW3611-52
SW3611-53
SW3611-54
SW3611-55
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SW3611-74
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SW3611-81
SW3611-82
SW3611-83
SW3611-84
SW3611-85
SW3611-86
SW3611-87
SW3611-88
SW3611-89
SW3611-90

LIST OF NEIGHBOURING ELECTRICITY DISTRIBUTORS

The following electricity distributors are adjacent to API's service territory:

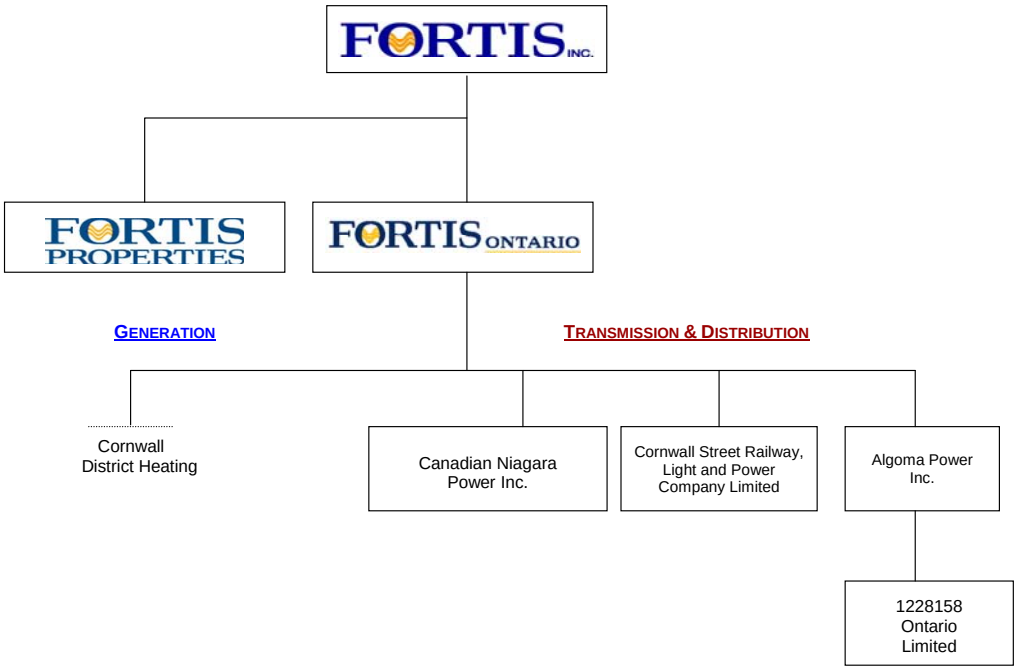
- PUC Distribution Inc. (ED-2002-0546)
- Hydro One Networks Inc. (ED-2003-0043)

EXPLANATION OF HOST OR EMBEDDED ELECTRICAL DISTRIBUTORS

Dubreuil Forest Products Ltd. is a licenced distributor (ED-2003-0092) that is served by API's distribution business.

CORPORATE ENTITIES RELATIONSHIP CHART

The following chart illustrates the corporate entities relationship of API, its shareholder and its Board licensed affiliates:



Organization of Entities

API is a wholly-owned subsidiary of FortisOntario Inc. ("FortisOntario"), which is headquartered in Fort Erie, Ontario. FortisOntario owns and operates generation, transmission and distribution businesses in the province of Ontario. Founded in 1892, FortisOntario began generating electricity in 1905 from its Rankine Generating Station located on the Canadian side of the Niagara River and subsequently began distributing electricity to the Town of Fort Erie in 1907. The Rankine Generating Station ceased operations in 2005 and was transferred to the Niagara Parks Commission in 2009. Most of FortisOntario's remaining generation assets were transferred in 2005 to Fortis Properties, an

affiliate, as part of an internal reorganization. Accordingly, the operations based in Ontario that are part of the API corporate organization are primarily transmission and distribution.

FortisOntario is the Ontario-based subsidiary of Fortis Inc. ("Fortis"), which is the largest investor-owned distribution utility in Canada. With total assets of $12 billion and annual revenues totalling $3.9 billion, Fortis serves almost 2,000,000 gas and electricity consumers. Its regulated holdings include a natural gas distribution utility in British Columbia and electric distribution utilities in five Canadian provinces and three Caribbean countries. Fortis owns non-regulated hydroelectric generation assets in Newfoundland and Labrador, Ontario, British Columbia, Belize and Upper New York State. Fortis is a publicly traded company listed on the TSX.

FortisOntario also owns Cornwall Street Railway Light and Power Company Limited ("Cornwall Electric"), which serves 23,700 customers. FortisOntario holds a ten percent (10%) interest in Westario Power Inc. (ED-2002-0515), a 21,800 customer electricity distributor located in mid-western Ontario, Rideau St. Lawrence Holdings Inc. (ED-2003-0003), a 5,900 customer electricity distributor located in southeastern Ontario, and Grimsby Power Inc. (ED-2002-0554), a 10,100 customer electricity distributor located in the Niagara region. Accordingly, Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc. are not affiliates of API, as defined by the *Ontario Energy Board Act, 1998*.

FortisOntario is also a licenced generator, which owns a 5 MW natural gas cogeneration district heating plant located in Cornwall, Ontario. The Cornwall district heating facility is an embedded generator selling district heating to local customers and electricity directly to Cornwall Electric, which is isolated from the IESO-controlled grid.

The utility distribution business for the service areas of Fort Erie, and Gananoque are owned and operated by Canadian Niagara Power Inc. ("CNPI"). The utility distribution assets for the service territory of Port Colborne are leased by CNPI from Port Colborne Hydro Inc., a wholly-owned subsidiary of the City of Port Colborne. CNPI also owns and operates a transmission business. The utility distribution business for the Cornwall service area is

owned and operated by Cornwall Electric. The utility distribution business for the service area of API is owned and operated by API.

Representation on API Board

API has three directors who serve on its board of directors. Two of the API directors are also officers of API, CNPI, FortisOntario and Cornwall Electric and one director is independent.

Shared Corporate Services

As API was only recently acquired by FortisOntario on October 8, 2009, the transition into this new organization is still being implemented. During the 2010 and 2011 Test Years the only shared corporate services that will be provided on a limited basis are as follows:

- Executive Services
- Finance
- Information Technology
- Human Resources
- Health, Safety and Environment
- Regulatory
- Engineering Design Management for Capital Projects

It is anticipated that beyond the Test Years additional shared corporate services may be provided to API from affiliates as the integration becomes fully implemented.

OEB Licence Numbers

API has distribution licence (ED-2009-0072). CNPI has distribution licence (ED-2002-0572) and a transmission licence (ET-2003-0073). Cornwall Electric is also a licensed distributor

(ED-2004-0405). FortisOntario has a generation licence (EG-2003-0107). Fortis Properties has a generation licence (EG-2003-0106).

PLANNED CHANGES IN CORPORATE OR OPERATIONAL STRUCTURE

As of the date of filing this Application, there are no planned changes in corporate or operational structure.

STATUS OF BOARD DIRECTIVES

As of the date of filing this Application, there are no outstanding Board directives from previous Board decisions and/or orders.

LIST OF POTENTIAL WITNESSES

API has requested a written hearing in respect of this Application. If, however, the OEB determines that an oral hearing is necessary and the scope of that hearing is fully realized, API will provide a list of witnesses at that time.

OTHER MATTERS

API wishes to put the OEB on notice of a potential circumstance beyond its control that could affect API's distribution rates.

In August 2007, Great Lakes Power Limited ("GLPL") filed a rate application (EB-2007-0744) with the OEB for, among other things, the recovery of revenue requirement that had been deferred since 2002 as part of a rate mitigation plan. The total deferred amount (approximately $15 million) was recorded in regulatory asset account 1574.

The OEB, in its October 30, 2008 decision (the "Decision"), denied recovery of this amount. GLPL appealed the Decision to the Divisional Court, and the Divisional Court dismissed GLPL's appeal. GLPL was granted leave to appeal to the Ontario Court of Appeal, and that appeal was heard on April 29, 2010.

It is a possibility that the Court of Appeal could allow GLPL to recover the deferred amount. Any recovery of the deferred amount would have to be through API's rates, since API's customers were formerly GLPL's customers, and GLPL is no longer an electricity distributor. It is unknown at this time when the Court of Appeal will issue a decision. API will do its best to keep the OEB abreast of any material developments in GLPL's appeal that could impact API's distribution rates.

SUMMARY OF THE APPLICATION

Introduction

This distribution rate Application filed by API is based on 2010 and 2011 Test Years. API is seeking to recover its forecasted 2010 revenue requirement of $18,928,065 through rates that will be effective on July 1, 2010. API is also seeking to recover its forecasted 2011 revenue requirement of $20,452,136 through rates that will be effective January 1, 2011.

As discussed below, with the exception of API's Seasonal and Street Light rates, API's distribution rates are to be set by the Board based on the average of any adjustment to rates approved by the Board for other distributors for the same rate year. Because the 2011 average rate adjustment will not be known until later in 2011, the Board will not be able to order API's 2011 rates until sometime in 2011. Since API is seeking 2011 rates effective January 1, 2011 (ie. before the Board can determine the average 2011 rate adjustment for distributors), API has requested that its 2010 rates be made interim on January 1, 2011, pending the implementation of API's 2011 rates. API has requested that this proceeding be adjourned *sine die* (after the implementation of its 2010 rates and the approval of its 2011 revenue requirement) until the Board is able to determine the 2011 average rate adjustment for distributors. At that time, the proceeding could reconvene for the purpose of determining 2011 rates.

To summarize, API is requesting that the proceeding have two phases that are separated by an adjournment. The first phase would serve the purpose of, among other things:

- approving API's 2010 and 2011 revenue requirements;
- determining the average rate adjustment for distributors in 2010;
- designing 2010 rates;
- implementing the 2010 rates effective July 1, 2010; and
- making API's 2010 rates interim effective January 1, 2011.

At the end of phase 1, the Board could adjourn the proceeding *sine die* until it is able to determine the average 2011 rate increase for distributors. At that time, the proceeding could reconvene (ie. phase 2) for the limited purpose of:

- determining the average rate adjustment for distributors in 2011;
- designing 2011 rates; and
- implementation of the 2011 rates effective January 1, 2011.

For the purpose of this Application, API has organized and filed its materials in accordance with *Chapter 2 of the Filing Requirements for Transmission and Distribution Rate Applications*, dated May 27, 2009 (the "Filing Requirements").

The Regulatory Context of API's Application

API is unique in the way its distribution rates are set by the Board. As described in greater detail below, pursuant to Ontario Regulation 442/01, with the exception of Seasonal and Street lighting, 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 is recovered by API on behalf of its customers through the Rural and Remote Rate Protection ("RRRP"). Details of this regulation can be found in Exhibit 8, Tab 1, Schedule 1. Therefore, with the exception of Seasonal and Street lighting customers, any increase in distribution rates that API's customers may experience as a result of this Application, will not exceed the average 2010 rate increase for other distributors, regardless of the quantum of API's forecasted revenue requirement.

In addition to the unique regulatory context of API's Application, when compared to most LDCs in Ontario, API is also unique from a geographic and operating cost perspective. These unique aspects play a significant role in the capital and operational decisions of API and its required approach to servicing its customers. This Application should be considered within the context of these unique aspects and elements which impact both revenue requirement and revenue recovery.

Description of API's Unique Aspects

API is a licensed distributor (ED-2009-0072), and its distribution system covers an area of more than 14,200 square kilometres in a remote area of Northern Ontario, north and east of the City of Sault Ste. Marie. API serves less than 11,800 customers, and its distribution system consists of 1,845 kilometres of voltages from 2.4 kV up to 44 kV. There are only 6.3 customers per kilometre of distribution line fed from 13 distribution supply points from GLPL's transmission system and 14 sub-transmission distribution substations.

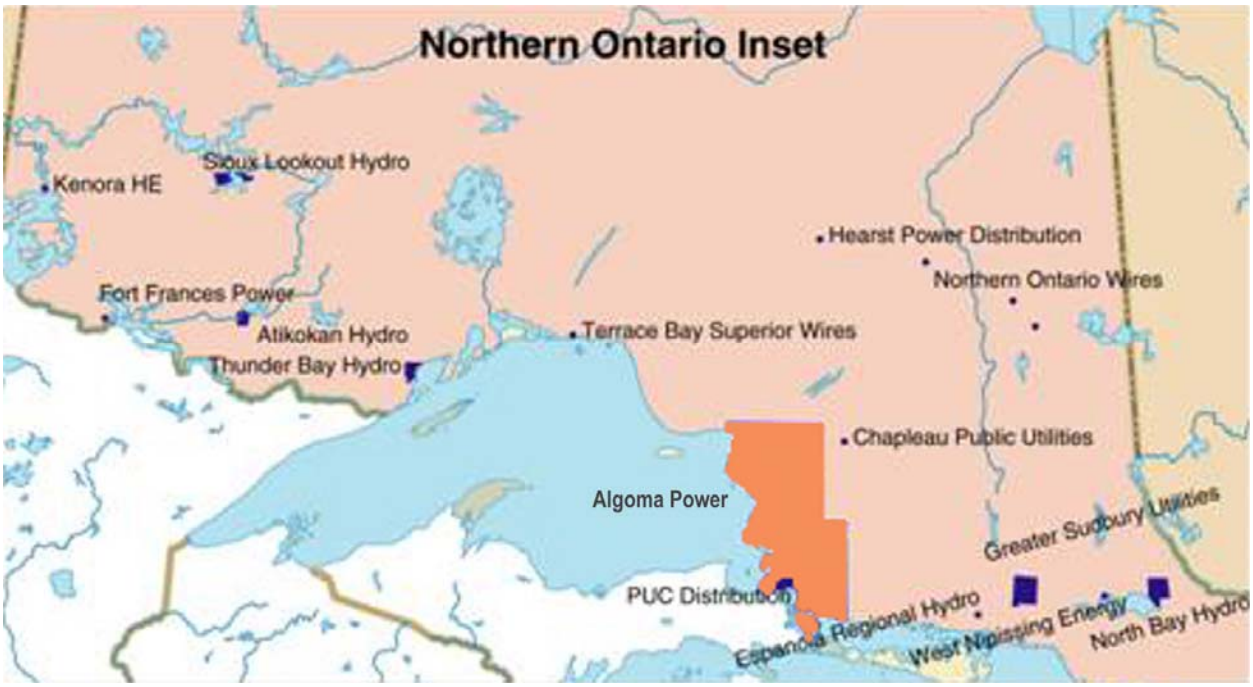
As described below, there are various unique aspects, such as geography and population density, in addition to transition issues resulting from the recent corporate reorganization and change in ownership, which have had a direct impact on API's distribution business and revenue requirement. The combined effect of these converging aspects are contributing factors to API's higher per customer cost required to deliver safe and reliable distribution services. This reality is evident when one compares API to other similarly sized LDCs operating in more favorable geographic and population dense service areas. Absent the availability of the RRRP, the recovery of API's full revenue requirement would result in significant and unsustainable rate increases for API customers.

Expansive Service Territory

API's distribution system represents a very large geographic area covering approximately 14,200 square kilometers extending 93 km east and approximately 255 km north of the City of Sault Ste. Marie. The following map illustrates the size of API's territory (which is shown shaded in orange) relative to neighbouring LDC's.[1] With the exception of Hydro One Networks Inc., no other LDC in the province has a service territory as large as API's. Its service territory includes more than 135 townships.

[1] From the Electricity Distributor's Association's *Ontario Electricity Primer, Revised February 2004,* page 3.

Exhibit 1, Tab 2, Schedule 1, Map 1 – Illustration of Service Areas



Rural and Rugged Terrain

When considering API's 14,200 square kilometres of service territory, less than 0.1% could be considered urban. Although API's distribution service area is adjacent to the City of Sault Ste. Marie, the City is served by PUC Distribution Inc. ("PUC"). The terrain and topography of the land on which API's distribution system is located on some of the most rugged and challenging land areas in Ontario.

Dense Vegetation

API's service area is very diverse in vegetation species and vegetation growth rates. The dense vegetation in API's distribution service area makes access to the distribution system challenging, further contributing to the cost of construction, line maintenance and right-of-way maintenance.

Climate and Distribution System Characteristics

The weather in northern Ontario is extremely harsh. However, less than one per cent of API's distribution system is underground or submarine construction; 99% is overhead. Consequently, API's large and widely dispersed distribution assets experience greater exposure to weather-related and equipment-related outages, with corresponding impacts noted below:

i) greater reliability issues due to longer radial feeder lines;
ii) longer repair times due to longer travel distances and difficult access in many locations;
iii) higher system line losses due to longer lines; and
iv) higher costs and staff levels per customer served.

Unlike other distribution systems, API's distribution system is predominantly radial, with limited back-up from alternative circuits. Component failures require immediate repair and/or replacement prior to service restoration, often at premium time, thereby adding to API's costs.

Low Customer Density

As noted above, API serves less than 11,800 customers. This lower number of customers relative to its vast distribution service area, results in a very low population density within API's distribution service area and underscores the cost management and revenue recovery challenges. For example, as illustrated on Map 1 above, while PUC's service area is much smaller than API's, the PUC serves close to three times the number of customers in an area that is only 2.4% the size of API's Service Area (342 km^2 vs. 14,200 km^2). Further, if all of the other service areas shown on the Map 1-2-1 A were combined, the combined area would still be smaller than API's service territory.

There are only 6.3 customers per kilometre on API's distribution lines. This is the lowest utility customer/line ratio in Ontario.[1] Maps that show API's distribution lines are set out at Exhibit 1,

[1] As acknowledged by Hydro One Networks Inc. in its RUD model filed with the Board in May of 2000.

Tab 1, Schedule 10. These maps illustrate how API's distribution system stretches over a vast geographic area. The implications of API's low customer density relative to its geographic size, necessitates that a significant amount of capital assets are dedicated to serving a small number of customers. From a rates perspective, costs of that capital and O&M must be absorbed by a small number of customers. Since neither API's customer density or energy consumption is growing in size, increases in costs, absent the application of the RRRP for these customers, would result in significant and unsustainable increases in rates.

Historically, parts of API's distribution system were built to service the resource sector and the communities that developed around those enterprises. As a number of those industries declined, the result was a sparsely populated service territory with predominantly residential and seasonal customers. This explains why parts of API's system are characterized by long radial lines serving few customers.

Examples of long API distribution lines that serve relatively few customers are set out in the following table:

Exhibit 1, Tab 2, Schedule 1, Table 1 – Length of Line for Customers Served

Line Description	Length (km)	Voltage (kV)	Customers
Highway 101 to JP Tower	26.9	7.2	6
Hawk Junction to Goudreau DS	21.5	44	0*
Wawa to Hammer Lake	80.6	14.4	66
Andrews TS to Rabbit Blanket	72.8	14.4	18

*This line feeds the Goudreau DS which connects customers by way of feeders

API is an outlier relative to other LDCs due to API's low customer density (on an asset per customer basis) as illustrated by the following table from the *Comparitor and Cohorts Study for 2006 EDR* :[1]

Exhibit 1, Tab 2, Schedule 1, Table 1 B – Comparator and Cohort Study

LDC Name	Cohort	Assets per Customer	Asset per km Line	Assets per kWh	Assets per kW	Distribution Transformers per Customer	Distribution losses per km Line	Expenses per Customer	Expenses per kWh
Atikokan Hydro	2	-.71	-1.16	-.55	-.56	-.21	-.32	1.17	.99
Chapleau PUC	2	-.46	.10	-.47	-.57	-.54	.49	.59	.29
Espanola Regional Hydro	2	-.59	-.88	-.39	-.33	-.24	-1.12	-.07	.11
Fort Frances Power	2	-.10	.61	-.07	-.11	-.13	.09	-.79	-.59
Gravenhurst Hydro	2	-.41	-.78	-.02	-.13	.87	.11	-.70	-.21
Great Lakes Power	2	3.29	-.74	3.38	3.34	2.86	-1.25	2.78	3.20
Greater Sudbury Hydro	2	.59	1.88	.45	.63	-.89	1.00	-.27	-.17
Hearst Power	2	-.89	-.74	-.97	-.97	.05	.34	-.45	-.91
Kenora Hydro	2	-.46	.49	-.25	-.22	-.90	.63	-.70	-.40
Lakeland Power	2	-.34	-1.15	-.43	-.40	-.13	-1.17	-.45	-.52
North Bay Hydro	2	.27	.80	-.06	.03	-.42	-.98	-.18	-.35
Sioux Lookout Hydro	2	-.08	-1.07	-.52	-.58	1.33	-.07	.93	-.07
Terrace Bay Superior Wires	2	.31	1.14	.24	-.02	-.27	-.14	-.81	-.61
Thunder Bay Hydro	2	.08	.28	.02	.24	-.70	-.25	-.07	-.05
West Nipissing Energy	2	-.50	1.22	-.36	-.36	-.70	2.63	-.97	-.71

Separation From Transmission Business and Operation as A Stand Alone Entity

Today, API's distribution business is operationally very different from the way it was in 2007, when it was last before the Board for distribution rates. As a new corporation, now licenced to own and operate an electricity distribution business, on a "stand-alone" basis in Northern Ontario, API is going through a significant transition. Historically, it was operated as a division of Great Lakes Power Limited ("GLPL") as part of an integrated utility that included generation, transmission and distribution. Certain costs were shared between the transmission and distribution businesses which operated as interrelated regulated utilities with a number of synergies such as: one contingency of employees, fleet assets, building, office, system control centre, information technology and corporate services. GLPL could legally operate as an integrated utility because it was exempt from Section 71 of the OEB Act by Ontario Regulation 161/99. However, pursuant to that regulation, GLPL's exemption from Section 71 ended on December 31, 2008.

[1] Phase II Report, *Part I Methodology and Study Findings: Comparators and Cohorts Study for 2006 EDR,* October 2005

In a Decision and Order dated May 5, 2009 (EB-2009-0072,0073,0075), the Board:

i) approved the transfer of the distribution assets from GLPL to Great Lakes Power Distribution Inc. ("GLPD");

ii) cancelled GLPL's electricity transmission licence (ET-2008-0342) and amended Great Lakes Power Transmission LP's ("GLPT") electricity transmission licence (ET-2007-0649) to permit GLPT to own and operate its transmission system;

iii) granted an electricity distribution licence to GLPD (ED-2009-0072); and

iv) cancelled GLPL's electricity distribution licence (ED-2008-0342), subject to the condition that the commercial transaction for the transfer of distribution assets closed on or before December 31, 2009.

The transfer of the assets from GLPL to GLPD which closed on July 1, 2009 marked the effective date of the legal separation of Great Lakes Power's distribution businesses. Effective upon this closing, the Board transferred GLPL's distribution rate order (EB-2007-0744) to GLPD. Subsequently, FortisOntario purchased all of the issued and outstanding shares of GLPD, and pursuant to a Decision and Order dated September 1, 2009 (EB-2009-0282), the Board approved the purchase. The purchase by FortisOntario closed on October 8, 2009. Effective upon closing and pursuant to articles of amendment, the name of the corporation Great Lakes Power Distribution Inc. was changed to "Algoma Power Inc." A licence amendment application was filed in respect of the name change, and API was issued a new licence ED-2009-0072 pursuant to Decision and Order EB-2009-0403.

Since the split from the integrated business in July 2009 and the purchase of API by FortisOntario in October 2009, a number of services are no longer being provided or shared with the transmission business. Some services are still being provided pursuant to arms-length agreements between API and GLPT such as the sub-lease of the office and service centre building and IT services. A discussion of the sub-lease can be found in Exhibit 4, Tab 3, Schedule 1 (Operating Costs Variance Analysis) and a discussion of the IT services agreement can be found in Exhibit 2, Tab 4, Schedule 5, Appendix A (Information Technology Strategy and Major Assets). Other services have required additional internal staffing such as the

appointment of a new Regional Manager, while certain shared corporate services are provided by FortisOntario (See Exhibit 4, Tab 5, Schedule 1, Appendix A (BDR Report)). Given its geographic separation, API is staffed to operate on a stand alone regional basis in order to comply with and provide the level of service required of a licenced distributor. FortisOntario will continue to explore ways of achieving synergies between API and other FortisOntario owned utilities.

METHODOLOGY

For the purpose of this Application, API has organized and filed additional materials in accordance with the Filing Requirements.

REVENUE REQUIREMENT AND DEFICIENCY

The following tables summarize the general components of API's 2010 and 2011 distribution revenue requirements.

Exhibit 1, Tab 2, Schedule 1, Table 1 C – Summary of Revenue Requirement:

	2010	2011	Reference
Cost of Capital			
Rate Base	$ 69,509,146	$ 76,864,742	Exhibit 2, Tab 1, Schedule 1
Requested Rate of Return	7.31%	7.31%	Exhibit 5, Tab 1, Schedule 1
	5,081,119	5,618,813	
Cost of Service			
Operation, Maintenance & Administrative	8,889,236	9,670,207	Exhibit 4, Tab 1, Schedule 1
Depreciation & Amortization	4,056,672	4,512,684	Exhibit 4, Tab 7, Schedule 1
Property Taxes	150,000	150,000	Exhibit 4, Tab 8, Schedule 5
Capital Taxes	49,776	-	Exhibit 4, Tab 8, Schedule 2
Income Taxes	701,262	500,433	Exhibit 4, Tab 8, Schedule 2
Service Revenue Requirement	18,928,065	20,452,137	
Other Revenue	(343,057)	(370,082)	Exhibit 3, Tab 3, Schedule 1
Base Revenue Requirement	$ 18,585,008	$ 20,082,055	

API's revenue deficiencies in 2010 and 2011 will be $1,308,758 and $2,743,432 respectively, as numerically described at Exhibit 6, Tab 1, Schedule 2.

RATE BASE

As set out at Exhibit 2, Tab 1, Schedule 1, API's rate base from 2007 to 2011 can be numerically summarized as follows:

Exhibit 1, Tab 2, Schedule 1, Table 1 D – Rate Base

	2007	2008	2009	2010 Test Year	2011 Test Year
Average Net Fixed Assets	$ 54,366,451	$ 59,358,980	$ 61,975,367	$ 65,578,302	$ 72,714,604
Working Capital Allowance	3,407,565	3,384,469	3,510,103	3,930,844	4,150,138
Rate Base	**$ 57,774,016**	**$ 62,743,449**	**$ 65,485,469**	**$ 69,509,146**	**$ 76,864,742**

Additional information on API's rate base is at Exhibit 2.

OPERATING REVENUE

API's operating revenue forecasts for 2010 and 2011 are described at Exhibit 3. Operating revenue consists of revenue collected through rates, RRRP and other sources. The following is a numerical summary of API's operating revenues from 2007 to 2011:

Exhibit 1, Tab 2, Schedule 1, Table 1 E – Operating Revenue Summary

	2007	2008	2009	2010 Test Year	2011 Test Year
Total Operating Revenue	**$ 13,184,373**	**$ 18,535,556**	**$ 17,566,544**	**$ 17,619,307**	**$ 17,708,704**

OPERATING COSTS

API's operating costs include: operations, maintenance & administration; depreciation & amortization; capital & property taxes; and income taxes. A summary of API's OM&A costs for 2007 through 2011 is set out in the following table:

Exhibit 1, Tab 2, Schedule 1, Table 1 F – OM&A Cost Summary:

Description	2007 Actual	2008 Actual	2009 Actual	2010 Test Year	2011 Test Year
Operating	$ 1,312,953	$ 1,288,685	$ 1,352,598	$ 1,408,536	$ 1,480,059
Maintenance	3,368,649	2,979,950	3,183,635	3,717,293	4,258,631
Billing and Collection	1,057,441	1,061,466	1,188,958	1,280,443	1,311,726
Community Relations	1,902	1,119	735	10,000	10,000
Administrative and General	2,465,274	3,370,454	3,052,844	2,642,964	2,779,791
Total	$ 8,206,220	$ 8,701,673	$ 8,778,771	$ 9,059,236	$ 9,840,207

Additional information on API's operating costs is at Exhibit 4.

COST OF CAPITAL

API's cost of capital can be numerically summarized as follows:

Exhibit 1, Tab 2, Schedule 1, Table 1 G – Cost of Capital Summary:

	2007	2008	2009	2010 Test Year	2011 Test Year
Rate Base	$ 57,774,016	$ 62,743,449	$ 65,485,469	$ 69,509,146	$ 76,864,742
Rate of Return	7.34%	7.34%	7.34%	7.31%	7.31%
Total Cost of Capital	**$ 4,240,613**	**$ 4,605,369**	**$ 4,806,633**	**$ 5,081,119**	**$ 5,618,813**

BUDGET PROCESS

When preparing its operations and administration budget for an upcoming year, API uses a bottom up approach that considers the needs and requirements of the organization for the upcoming year. To the extent possible, planned human resources, purchased services, materials and other costs are all identified and accounted for. API forecasts its budget based on a review of its historic costs with consideration for required and available resources, both internal and external.

API seeks to maximize its use of internal resources before relying on external resources. When external resources are required, API typically uses them on a temporary or contract basis to minimize overall costs over the long term.

With respect to the maintenance budget, API uses the information gathered through the implementation of the Asset Management Process, which is described at Exhibit 2, Tab 5, Schedule 1. Information is gathered from various sources, including through inspections, testing and asset condition assessments. The information is reviewed in consideration of required and available resources, and is compared to historical spending patterns. The resulting maintenance budget assists API in implementing an effective maintenance program that is expected to maximize the operational life of assets in service, and to enhance the safe and reliable supply of electricity to consumers in the service territory.

For details on API's capital budgeting process, please refer to the Asset Management Process at Exhibit 2, Tab 5, Schedule 1. As indicated, API has a comprehensive program for managing its existing assets through the inspection and maintenance of lines and stations and asset condition assessments.

Management is responsible for preparing the budgets of the respective departments including using operating and capital budgets. Labour hours are charged to both capital and operating job orders. Non-labour costs are also taken into account.

A revenue model was prepared based on existing distribution rates and forecast loads as explained in Exhibit 3. The load forecast was reviewed and approved by senior management.

The operating and capital budgets are reviewed prior to allocations for shared corporate services. The shared corporate services allocations are reviewed and approved separately by senior management. The finance department is responsible for managing the budgeting process.

The departmental operating and capital budgets, as prepared by the management, are reviewed by the Regional Manager before final review and sign-off by the senior management team. These budgets are then presented to the board of directors for approval.

CHANGES IN METHODOLOGY

Amortization Rates

On April 28, 2010 the Board released an *Asset Amortization Study* prepared by Kinectrics Inc. This study, which is subject to further input, will be used to assist utilities in updating amortization rates and becoming IFRS compliant. API proposes, after finalization of the study, that the amortization rates in the 2011 Test Year be updated based on the study including the specific circumstances of API. Subsequent evidence will be filed including updated amortization rates once the study is finalized. Based on initial review of the study, API believes the updated amortization rates will reduce the amount of depreciation in the revenue requirement.

Capitalized Overhead Costs

API capitalizes costs that are directly attributable to capital projects and is requesting the approval to capitalize overhead costs associated with capital work. Capitalized overhead costs represent the amount of overhead costs that are required to support capital projects in a given year. Overhead costs will be capitalized for the administrative departments based on the ratio of unionized labour costs between capital and operating expenditures. The administration departments will include finance, information technology, human resources, health, safety & environmental, materials management and management.

Exhibit 1, Tab 2, Schedule 3, Table 1

Overhead Capitalized

2010 and 2011 Test Years

2010		2011	
Capitalization Rate[(1)]	Amount Capitalized ($'000)	Capitalization Rate[(1)]	Amount Capitalized ($'000)
7.2%	$821	8.0%	$874

(1) Based on amount capitalized over total capital spend.

The methodology proposed is consistent with the methodology used by CNPI and approved by the Board in EB-2008-0222.

API is aware of the Board's letter dated February 24, 2010, *Accounting for Overhead Costs Associated with Capital Works,* and therefore is requesting specific approval.

SCHEDULE OF OVERALL REVENUE DEFICIENCY/SUFFICIENCY

The revenue deficiency/sufficiency for 2010 and 2011 Test Year was calculated using the following inputs:

- 2007 approved rates;
- 2010 and 2011 load forecast and forecast of customers and connections, as developed using the methodology described in Exhibit 3 (Operating Revenue); and
- The base revenue requirement calculated below.

REVENUE DEFICIENCY/SUFFICIENCY

Description		2007 Board Approved	2007 Actual	2008 Actual	2009 Actual	2010 Test Year	2011 Test Year
Distribution Revenue		17,631,884	13,184,373	18,535,556	17,566,544	17,619,307	17,708,704
Operation, Maintenance & Administrative		7,995,724	8,022,318	8,530,565	8,615,754	8,889,236	9,670,207
Depreciation & Amortization		3,607,303	3,559,152	3,727,967	3,651,441	4,056,672	4,512,684
Property Taxes		164,250	163,402	163,956	146,241	150,000	150,000
Capital Taxes (2010 and 2011 Tax Model Output)		123,167	52,047	(39,436)	200,226	49,776	
Total Costs		11,890,444	11,796,920	12,383,051	12,613,662	13,145,684	14,332,891
Utility Income before Taxes		5,741,441	1,387,453	6,152,505	4,952,882	4,473,623	3,375,813
Income tax (2010 and 2011 Tax Model Output)		1,492,000	96,587	1,580,251	833,310	701,262	500,433
Utility Income	**A**	4,249,441	1,290,866	4,572,254	4,119,572	3,772,361	2,875,380
Rate Base	**B**	57,518,786	57,774,016	62,743,449	65,485,469	69,509,146	76,864,742
Indicated Rate of Return	**C=A/B**	7.34%	2.23%	7.29%	6.29%	5.43%	3.74%
Approved/Requested Rate of Return	**D**	7.34%	7.34%	7.34%	7.34%	7.31%	7.31%
(Deficiency)/Sufficiency in Return	**E=C-D**	0.00%	-5.11%	-0.05%	-1.05%	-1.88%	-3.57%
Revenue (Deficiency)/Sufficiency	**F=B*E**	-	(2,949,747)	(33,115)	(687,062)	(1,308,758)	(2,743,432)
Service Revenue Requirement		17,631,884	16,134,120	18,568,672	18,253,606	18,928,065	20,452,136
Less Revenue Offset		(383,884)	(395,713)	(726,826)	(375,362)	(343,057)	(370,082)
Base Revenue Requirement		17,248,000	15,738,406	17,841,846	17,878,244	18,585,008	20,082,054
Add Transformer credit		34,300	46,766	47,885	51,078	51,942	51,942
Less RRRP as Board approved		(8,861,847)	(4,509,821)	(8,861,847)	(8,861,847)	(8,861,847)	(8,861,847)
Revenue to collected in rates		8,420,453	11,275,351	9,027,884	9,067,475	9,775,103	11,272,149

Revenue Requirement Work Form

Name of LDC: Algoma Power Inc. (1)

File Number: EB-2009-0278

Rate Year: 2010 *Version:* *1.0*

Table of Content

Sheet	Name
A	Data Input Sheet
1	Rate Base
2	Utility Income
3	Taxes/PILS
4	Capitalization/Cost of Capital
5	Revenue Sufficiency/Deficiency
6	Revenue Requirement
7	Bill Impacts

Notes:

(1) Pale green cells represent inputs

(2) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

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Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2010

Ontario

		Data Input					(1)
		Application		Adjustments		Per Board Decision	
1	**Rate Base**						
	Gross Fixed Assets (average)	$112,088,240	(4)			$112,088,240	
	Accumulated Depreciation (average)	($46,509,938)	(5)			($46,509,938)	
	Allowance for Working Capital:						
	Controllable Expenses	$9,039,236	(6)			$9,039,236	
	Cost of Power	$17,166,389				$17,166,389	
	Working Capital Rate (%)	15.00%					
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$17,276,250					
	Distribution Revenue at Proposed Rates	$18,585,008					
	Other Revenue:						
	Specific Service Charges	$105,000					
	Late Payment Charges	$7,500					
	Other Distribution Revenue	$230,557					
	Other Income and Deductions						
	Operating Expenses:						
	OM+A Expenses	$8,889,236				$8,889,236	
	Depreciation/Amortization	$4,056,672				$4,056,672	
	Property taxes	$150,000				$150,000	
	Capital taxes	$49,776					
	Other expenses						
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($1,177,788)	(3)				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$483,871					
	Income taxes (grossed up)	$701,262					
	Capital Taxes	$49,776					
	Federal tax (%)	18.00%					
	Provincial tax (%)	13.00%					
	Income Tax Credits	$ -					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(2)				(2)
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)						
						Capital Structure must total 100%	
	Cost of Capital						
	Long-term debt Cost Rate (%)	5.87%					
	Short-term debt Cost Rate (%)	2.07%					
	Common Equity Cost Rate (%)	9.85%					
	Prefered Shares Cost Rate (%)						

Notes:

This input sheet provides all inputs needed to complete sheets 1 through 6 (Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the components. Notes should be put on the applicable pages to understand the context of each such note.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(3) Net of addbacks and deductions to arrive at taxable income.
(4) Average of Gross Fixed Assets at beginning and end of the Test Year
(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2010

Ontario

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$112,088,240	$ -	$112,088,240
2	Accumulated Depreciation (average)	(3)	($46,509,938)	$ -	($46,509,938)
3	Net Fixed Assets (average)	(3)	$65,578,302	$ -	$65,578,302
4	Allowance for Working Capital	(1)	$3,930,844	$ -	$3,930,844
5	**Total Rate Base**		$69,509,146	$ -	$69,509,146

(1) Allowance for Working Capital - Derivation

6	Controllable Expenses		$9,039,236	$ -	$9,039,236
7	Cost of Power		$17,166,389	$ -	$17,166,389
8	Working Capital Base		$26,205,625	$ -	$26,205,625
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$3,930,844	$ -	$3,930,844

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2010

Ontario

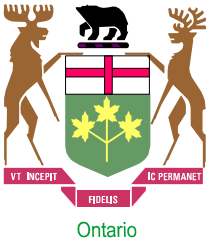
Utility income

Line No.	Particulars		Application	Adjustments	Per Board Decision
	Operating Revenues:				
1	Distribution Revenue (at Proposed Rates)		$18,585,008	$ -	$18,585,008
2	Other Revenue	(1)	$343,057	$ -	$343,057
3	Total Operating Revenues		$18,928,065	$ -	$18,928,065
	Operating Expenses:				
4	OM+A Expenses		$8,889,236	$ -	$8,889,236
5	Depreciation/Amortization		$4,056,672	$ -	$4,056,672
6	Property taxes		$150,000	$ -	$150,000
7	Capital taxes		$49,776	$ -	$49,776
8	Other expense		$ -	$ -	$ -
9	Subtotal		$13,145,684	$ -	$13,145,684
10	Deemed Interest Expense		$2,342,458	$ -	$2,342,458
11	Total Expenses (lines 4 to 10)		$15,488,142	$ -	$15,488,142
12	**Utility income before income taxes**		$3,439,923	$ -	$3,439,923
13	Income taxes (grossed-up)		$701,262	$ -	$701,262
14	**Utility net income**		$2,738,660	$ -	$2,738,660

Notes

(1) **Other Revenues / Revenue Offsets**

	Application	Adjustments	Per Board Decision
Specific Service Charges	$105,000		$105,000
Late Payment Charges	$7,500		$7,500
Other Distribution Revenue	$230,557		$230,557
Other Income and Deductions	$ -		$ -
Total Revenue Offsets	$343,057		$343,057



Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2010

Taxes/PILs

Line No.	Particulars	Application	Per Board Decision
	Determination of Taxable Income		
1	Utility net income	$2,738,660	$2,738,660
2	Adjustments required to arrive at taxable utility income	($1,177,788)	($1,177,788)
3	Taxable income	$1,560,872	$1,560,872
	Calculation of Utility income Taxes		
4	Income taxes	$483,871	$483,871
5	Capital taxes	$49,776	$49,776
6	Total taxes	$533,647	$533,647
7	Gross-up of Income Taxes	$217,391	$217,391
8	Grossed-up Income Taxes	$701,262	$701,262
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$751,038	$751,038
10	Other tax Credits	$ -	$ -
	Tax Rates		
11	Federal tax (%)	18.00%	18.00%
12	Provincial tax (%)	13.00%	13.00%
13	Total tax rate (%)	31.00%	31.00%

Notes

Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2010

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Application				
	Debt				
1	Long-term Debt	56.00%	$38,925,122	5.87%	$2,284,905
2	Short-term Debt	4.00%	$2,780,366	2.07%	$57,554
3	**Total Debt**	60.00%	$41,705,487	5.62%	$2,342,458
	Equity				
4	Common Equity	40.00%	$27,803,658	9.85%	$2,738,660
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$27,803,658	9.85%	$2,738,660
7	**Total**	100%	$69,509,146	7.31%	$5,081,119
	Per Board Decision				
	Debt				
8	Long-term Debt	56.00%	$38,925,122	5.87%	$2,284,905
9	Short-term Debt	4.00%	$2,780,366	2.07%	$57,554
10	**Total Debt**	60.00%	$41,705,487	5.62%	$2,342,458
	Equity				
11	Common Equity	40.0%	$27,803,658	9.85%	$2,738,660
12	Preferred Shares	0.0%	$ -	0.00%	$ -
13	**Total Equity**	40.0%	$27,803,658	9.85%	$2,738,660
14	**Total**	100%	$69,509,146	7.31%	$5,081,119

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2010

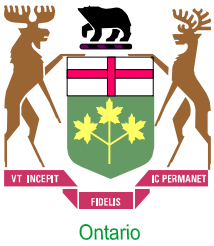
Ontario

Revenue Sufficiency/Deficiency

Line No.	Particulars	Per Application		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$1,308,757		$1,308,757
2	Distribution Revenue	$17,276,250	$17,276,251	$17,276,250	$17,276,251
3	Other Operating Revenue Offsets - net	$343,057	$343,057	$343,057	$343,057
4	**Total Revenue**	$17,619,307	$18,928,065	$17,619,307	$18,928,065
5	Operating Expenses	$13,145,684	$13,145,684	$13,145,684	$13,145,684
6	Deemed Interest Expense	$2,342,458	$2,342,458	$2,342,458	$2,342,458
	Total Cost and Expenses	$15,488,142	$15,488,142	$15,488,142	$15,488,142
7	**Utility Income Before Income Taxes**	$2,131,165	$3,439,923	$2,131,165	$3,439,923
	Tax Adjustments to Accounting				
8	Income per 2009 PILs	($1,177,788)	($1,177,788)	($1,177,788)	($1,177,788)
9	**Taxable Income**	$953,377	$2,262,135	$953,377	$2,262,135
10	Income Tax Rate	31.00%	31.00%	31.00%	31.00%
11	**Income Tax on Taxable Income**	$295,547	$701,262	$295,547	$701,262
12	**Income Tax Credits**	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$1,835,618	$2,738,660	$1,835,618	$2,738,660
14	**Utility Rate Base**	$69,509,146	$69,509,146	$69,509,146	$69,509,146
	Deemed Equity Portion of Rate Base	$27,803,658	$27,803,658	$27,803,658	$27,803,658
15	Income/Equity Rate Base (%)	6.60%	9.85%	6.60%	9.85%
16	Target Return - Equity on Rate Base	9.85%	9.85%	9.85%	9.85%
	Sufficiency/Deficiency in Return on Equity	-3.25%	0.00%	-3.25%	0.00%
17	Indicated Rate of Return	6.01%	7.31%	6.01%	7.31%
18	Requested Rate of Return on Rate Base	7.31%	7.31%	7.31%	7.31%
19	Sufficiency/Deficiency in Rate of Return	-1.30%	0.00%	-1.30%	0.00%
20	Target Return on Equity	$2,738,660	$2,738,660	$2,738,660	$2,738,660
21	Revenue Sufficiency/Deficiency	$903,042	$0	$903,042	$0
22	**Gross Revenue Sufficiency/Deficiency**	$1,308,757 **(1)**		$1,308,757 **(1)**	

Notes:

(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)



Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2010

Line No.	Particulars	Revenue Requirement	
		Application	Per Board Decision
1	OM&A Expenses	$8,889,236	$8,889,236
2	Amortization/Depreciation	$4,056,672	$4,056,672
3	Property Taxes	$150,000	$150,000
4	Capital Taxes	$49,776	$49,776
5	Income Taxes (Grossed up)	$701,262	$701,262
6	Other Expenses	$ -	$ -
7	Return		
	Deemed Interest Expense	$2,342,458	$2,342,458
	Return on Deemed Equity	$2,738,660	$2,738,660
8	Distribution Revenue Requirement before Revenues	$18,928,065	$18,928,065
9	Distribution revenue	$18,585,008	$18,585,008
10	Other revenue	$343,057	$343,057
11	**Total revenue**	$18,928,065	$18,928,065
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0 (1)	$0 (1)

Notes

(1) Line 11 - Line 8

Ontario

Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2010

		Selected Delivery Charge and Bill Impacts Per Draft Rate Order								
		Monthly Delivery Charge					Total Bill			
		Current	Per Draft Rate Order	Change $	Change %		Current	Per Draft Rate Order	Change $	Change %
Residential	**1000** kWh/month	$ 49.53	$ 56.76	$ 7.23	14.6%		$ 121.62	$ 138.16	$ 16.54	13.6%
GS < 50kW	**2000** kWh/month	$ 93.20	$ 108.11	$ 14.91	16.0%		$ 283.31	$ 319.51	$ 36.20	12.8%

Notes:

The first line should read Residential - R1 800 kWh per month
The second line should read Residential - R1 2000 kWh per month

Revenue Requirement Work Form

Name of LDC: Algoma Power Inc. (1)

File Number: EB-2009-0278

Rate Year: 2011 *Version:* *1.0*

Table of Content

Sheet	Name
A	Data Input Sheet
1	Rate Base
2	Utility Income
3	Taxes/PILS
4	Capitalization/Cost of Capital
5	Revenue Sufficiency/Deficiency
6	Revenue Requirement
7	Bill Impacts

Notes:

(1) Pale green cells represent inputs

(2) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

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Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2011

Ontario

		Data Input					(1)
		Application		Adjustments		Per Board Decision	
1	**Rate Base**						
	Gross Fixed Assets (average)	$124,202,053	(4)			$124,202,053	
	Accumulated Depreciation (average)	($51,487,449)	(5)			($51,487,449)	
	Allowance for Working Capital:						
	Controllable Expenses	$9,820,207	(6)			$9,820,207	
	Cost of Power	$17,847,379				$17,847,379	
	Working Capital Rate (%)	15.00%					
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$17,338,622					
	Distribution Revenue at Proposed Rates	$20,082,054					
	Other Revenue:						
	Specific Service Charges	$110,000					
	Late Payment Charges	$7,500					
	Other Distribution Revenue	$252,582					
	Other Income and Deductions						
	Operating Expenses:						
	OM+A Expenses	$9,670,207				$9,670,207	
	Depreciation/Amortization	$4,512,684				$4,512,684	
	Property taxes	$150,000				$150,000	
	Capital taxes	$0					
	Other expenses						
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($1,757,459)	(3)				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$359,061					
	Income taxes (grossed up)	$500,433					
	Capital Taxes	$ -					
	Federal tax (%)	16.50%					
	Provincial tax (%)	11.75%					
	Income Tax Credits	$ -					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(2)				(2)
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)						
						Capital Structure must total 100%	
	Cost of Capital						
	Long-term debt Cost Rate (%)	5.87%					
	Short-term debt Cost Rate (%)	2.07%					
	Common Equity Cost Rate (%)	9.85%					
	Prefered Shares Cost Rate (%)						

Notes:

This input sheet provides all inputs needed to complete sheets 1 through 6 (Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the components. Notes should be put on the applicable pages to understand the context of each such note.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(3) Net of addbacks and deductions to arrive at taxable income.
(4) Average of Gross Fixed Assets at beginning and end of the Test Year
(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2011

Ontario

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$124,202,053	$ -	$124,202,053
2	Accumulated Depreciation (average)	(3)	($51,487,449)	$ -	($51,487,449)
3	Net Fixed Assets (average)	(3)	$72,714,604	$ -	$72,714,604
4	Allowance for Working Capital	(1)	$4,150,138	$ -	$4,150,138
5	**Total Rate Base**		$76,864,742	$ -	$76,864,742

(1) Allowance for Working Capital - Derivation

6	Controllable Expenses		$9,820,207	$ -	$9,820,207
7	Cost of Power		$17,847,379	$ -	$17,847,379
8	Working Capital Base		$27,667,586	$ -	$27,667,586
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$4,150,138	$ -	$4,150,138

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2011

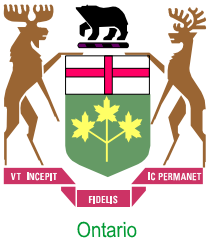
Ontario

Line No.	Particulars		Utility income		
			Application	Adjustments	Per Board Decision
	Operating Revenues:				
1	Distribution Revenue (at Proposed Rates)		$20,082,054	$ -	$20,082,054
2	Other Revenue	(1)	$370,082	$ -	$370,082
3	Total Operating Revenues		$20,452,136	$ -	$20,452,136
	Operating Expenses:				
4	OM+A Expenses		$9,670,207	$ -	$9,670,207
5	Depreciation/Amortization		$4,512,684	$ -	$4,512,684
6	Property taxes		$150,000	$ -	$150,000
7	Capital taxes		$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -
9	Subtotal		$14,332,891	$ -	$14,332,891
10	Deemed Interest Expense		$2,590,342	$ -	$2,590,342
11	Total Expenses (lines 4 to 10)		$16,923,233	$ -	$16,923,233
12	**Utility income before income taxes**		$3,528,903	$ -	$3,528,903
13	Income taxes (grossed-up)		$500,433	$ -	$500,433
14	**Utility net income**		$3,028,470	$ -	$3,028,470

Notes

(1) **Other Revenues / Revenue Offsets**

	Application	Adjustments	Per Board Decision
Specific Service Charges	$110,000		$110,000
Late Payment Charges	$7,500		$7,500
Other Distribution Revenue	$252,582		$252,582
Other Income and Deductions	$ -		$ -
Total Revenue Offsets	$370,082		$370,082



Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2011

Taxes/PILs

Line No.	Particulars	Application	Per Board Decision
	Determination of Taxable Income		
1	Utility net income	$3,028,471	$3,028,471
2	Adjustments required to arrive at taxable utility income	($1,757,459)	($1,757,459)
3	Taxable income	$1,271,012	$1,271,012
	Calculation of Utility income Taxes		
4	Income taxes	$359,061	$359,061
5	Capital taxes	$ -	$ -
6	Total taxes	$359,061	$359,061
7	Gross-up of Income Taxes	$141,372	$141,372
8	Grossed-up Income Taxes	$500,433	$500,433
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$500,433	$500,433
10	Other tax Credits	$ -	$ -
	Tax Rates		
11	Federal tax (%)	16.50%	16.50%
12	Provincial tax (%)	11.75%	11.75%
13	Total tax rate (%)	28.25%	28.25%

Notes

Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2011

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Application				
	Debt				
1	Long-term Debt	56.00%	$43,044,255	5.87%	$2,526,698
2	Short-term Debt	4.00%	$3,074,590	2.07%	$63,644
3	**Total Debt**	60.00%	$46,118,845	5.62%	$2,590,342
	Equity				
4	Common Equity	40.00%	$30,745,897	9.85%	$3,028,471
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$30,745,897	9.85%	$3,028,471
7	**Total**	100%	$76,864,742	7.31%	$5,618,813
	Per Board Decision				
	Debt				
8	Long-term Debt	56.00%	$43,044,255	5.87%	$2,526,698
9	Short-term Debt	4.00%	$3,074,590	2.07%	$63,644
10	**Total Debt**	60.00%	$46,118,845	5.62%	$2,590,342
	Equity				
11	Common Equity	40.0%	$30,745,897	9.85%	$3,028,471
12	Preferred Shares	0.0%	$ -	0.00%	$ -
13	**Total Equity**	40.0%	$30,745,897	9.85%	$3,028,471
14	**Total**	100%	$76,864,742	7.31%	$5,618,813

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2011

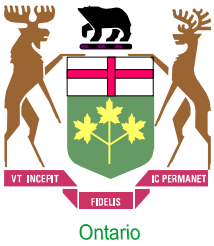
Ontario

Revenue Sufficiency/Deficiency

Line No.	Particulars	Per Application		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$2,743,433		$2,743,433
2	Distribution Revenue	$17,338,622	$17,338,621	$17,338,622	$17,338,621
3	Other Operating Revenue Offsets - net	$370,082	$370,082	$370,082	$370,082
4	**Total Revenue**	$17,708,704	$20,452,136	$17,708,704	$20,452,136
5	Operating Expenses	$14,332,891	$14,332,891	$14,332,891	$14,332,891
6	Deemed Interest Expense	$2,590,342	$2,590,342	$2,590,342	$2,590,342
	Total Cost and Expenses	$16,923,233	$16,923,233	$16,923,233	$16,923,233
7	**Utility Income Before Income Taxes**	$785,471	$3,528,903	$785,471	$3,528,903
	Tax Adjustments to Accounting				
8	Income per 2009 PILs	($1,757,459)	($1,757,459)	($1,757,459)	($1,757,459)
9	**Taxable Income**	($971,988)	$1,771,444	($971,988)	$1,771,444
10	Income Tax Rate	28.25%	28.25%	28.25%	28.25%
11	**Income Tax on Taxable Income**	($274,587)	$500,433	($274,587)	$500,433
12	**Income Tax Credits**	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$1,060,058	$3,028,470	$1,060,058	$3,028,470
14	**Utility Rate Base**	$76,864,742	$76,864,742	$76,864,742	$76,864,742
	Deemed Equity Portion of Rate Base	$30,745,897	$30,745,897	$30,745,897	$30,745,897
15	Income/Equity Rate Base (%)	3.45%	9.85%	3.45%	9.85%
16	Target Return - Equity on Rate Base	9.85%	9.85%	9.85%	9.85%
	Sufficiency/Deficiency in Return on Equity	-6.40%	0.00%	-6.40%	0.00%
17	Indicated Rate of Return	4.75%	7.31%	4.75%	7.31%
18	Requested Rate of Return on Rate Base	7.31%	7.31%	7.31%	7.31%
19	Sufficiency/Deficiency in Rate of Return	-2.56%	0.00%	-2.56%	0.00%
20	Target Return on Equity	$3,028,471	$3,028,471	$3,028,471	$3,028,471
21	Revenue Sufficiency/Deficiency	$1,968,413	($1)	$1,968,413	($1)
22	**Gross Revenue Sufficiency/Deficiency**	$2,743,433 **(1)**		$2,743,433 **(1)**	

Notes:

(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)



Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2011

Line No.	Particulars	Revenue Requirement	
		Application	Per Board Decision
1	OM&A Expenses	$9,670,207	$9,670,207
2	Amortization/Depreciation	$4,512,684	$4,512,684
3	Property Taxes	$150,000	$150,000
4	Capital Taxes	$ -	$ -
5	Income Taxes (Grossed up)	$500,433	$500,433
6	Other Expenses	$ -	$ -
7	Return		
	Deemed Interest Expense	$2,590,342	$2,590,342
	Return on Deemed Equity	$3,028,471	$3,028,471
8	Distribution Revenue Requirement before Revenues	$20,452,137	$20,452,137
9	Distribution revenue	$20,082,054	$20,082,054
10	Other revenue	$370,082	$370,082
11	**Total revenue**	$20,452,136	$20,452,136
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($1) (1)	($1) (1)

Notes

(1) Line 11 - Line 8

Ontario

Revenue Requirement Work Form

Name of LDC: Algoma Power Inc.
File Number: EB-2009-0278
Rate Year: 2011

		Selected Delivery Charge and Bill Impacts Per Draft Rate Order								
		Monthly Delivery Charge					Total Bill			
		Current	Per Draft Rate Order	Change $	Change %		Current	Per Draft Rate Order	Change $	Change %
Residential	**1000** kWh/month	$ 56.76	$ 60.95	$ 4.19	7.4%		$ 138.16	$ 142.90	$ 4.74	3.4%
GS < 50kW	**2000** kWh/month	$ 108.11	$ 117.94	$ 9.83	9.1%		$ 319.51	$ 330.62	$ 11.11	3.5%

Notes:

The first line should read Residential - R1 800 kWh per month
The second line should read Residential - R1 2000 kWh per month

AUDITED FINANCIAL STATEMENTS AS AT DECEMBER 31, 2009

Accompanying this Schedule as Appendix A are the audited financial statements for API for the year ended December 31, 2009.

APPENDIX A

Financial Statements

Algoma Power Inc.

December 31, 2009

AUDITORS' REPORT

To the Shareholder of
Algoma Power Inc.

We have audited the balance sheet of **Algoma Power Inc.** as at December 31, 2009 and the statements of earnings (loss), capital account and deficit, and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2009 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The comparative figures for the preceding year were audited by other accountants who expressed an opinion without reservation on those statements in their report dated April 27, 2009.

Ernst & Young LLP

Chartered Accountants
Licensed Public Accountants

Toronto, Canada,
January 22, 2010.

Algoma Power Inc.

BALANCE SHEET

[in thousands of dollars]

As at December 31

	2009 $	2008 $
ASSETS		
Current		
Cash *[notes 11 and 12]*	**873**	100
Restricted cash *[note 9[c]]*	**100**	—
Accounts receivable *[notes 11 and 12]*	**5,312**	12,655
Income taxes recoverable *[note 11]*	**11**	—
Due from related parties *[notes 6, 11 and 12]*	**4,498**	10,114
Materials and supplies	**255**	288
Regulatory assets *[note 14]*	**1,341**	—
Prepaid expenses	**26**	114
Total current assets	**12,416**	23,271
Utility capital assets, net *[note 2]*	**49,905**	53,126
Intangible assets, net *[note 3]*	**14,051**	12,820
Accrued benefit asset *[note 4]*	**2,074**	1,783
Future income tax assets *[note 5]*	**3,191**	—
Regulatory assets *[note 14]*	**3,871**	1,216
Rate mitigation accrual *[note 14]*	**—**	14,890
	85,508	107,106
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities *[notes 11 and 12]*	**4,015**	4,344
Regulatory liabilities *[note 14]*	**—**	118
Income taxes payable	**—**	1,742
Total current liabilities	**4,015**	6,204
Due to related parties *[note 6[a]]*	**—**	40,831
Long-term debt *[notes 6[j], 11 and 12]*	**45,600**	—
Accrued benefit liability *[note 4]*	**3,037**	2,939
Other regulatory liability *[note 5]*	**286**	—
Operating debt facility *[note 6[c]]*	**—**	12,000
Capital debt facility *[note 6[d]]*	**—**	20,500
Total liabilities	**52,938**	82,474
Commitments, contingencies and guarantees *[note 10]*		
Shareholder's equity		
Capital stock *[note 7]*	**44,008**	—
Capital account *[note 7]*	**—**	24,632
Deficit	**(11,438)**	—
Total shareholder's equity	**32,570**	24,632
	85,508	107,106

See accompanying notes

Algoma Power Inc.

STATEMENT OF EARNINGS (LOSS)

[in thousands of dollars]

Year ended December 31

	2009 $	2008 $
Operating revenue	**32,181**	32,474
Expenses		
Purchased power	**14,639**	13,869
Operating	**10,820**	9,687
Amortization *[note 8]*	**3,651**	3,728
	29,110	27,284
Operating earnings before the following	**3,071**	5,190
Provision for rate mitigation accrual *[note 14]*	**(14,890)**	—
Earnings (loss) before income taxes	**(11,819)**	5,190
Provision for (recovery of) income taxes *[note 5]*	**(2,072)**	1,742
Net earnings (loss) for the year	**(9,747)**	3,448

See accompanying notes

Algoma Power Inc.

STATEMENT OF CAPITAL ACCOUNT AND DEFICIT

[in thousands of dollars]

Year ended December 31

	2009 $	2008 $
Capital account, beginning of year	**24,632**	21,184
Net earnings, operating as a division	**1,691**	3,448
Transfer of capital account to capital stock	**(26,323)**	—
	—	24,632
Deficit, beginning of year	—	—
Net loss, operating as a legal entity	**(11,438)**	—
Capital (deficit), end of year	**(11,438)**	24,632

See accompanying notes

Algoma Power Inc.

STATEMENT OF CASH FLOWS

[in thousands of dollars]

Year ended December 31

	2009 $	2008 $
OPERATING ACTIVITIES		
Net earnings (loss) for the year	**(9,747)**	3,448
Add (deduct) items not involving cash		
Amortization	**3,651**	3,728
Loss on disposal of property, plant and equipment	**33**	19
Future income taxes	**(3,191)**	—
Other regulatory liability	**286**	—
Provision for rate mitigation accrual	**14,890**	—
Accrued benefit asset	**(291)**	—
Regulatory assets	**(3,996)**	(842)
Regulatory liabilities	**(118)**	242
	1,517	6,595
Net change in non-cash working capital balances related to operations *[note 9]*	**11,096**	4,524
Cash provided by operating activities	**12,613**	11,119
INVESTING ACTIVITIES		
Additions to property, plant and equipment	**(5,764)**	(11,119)
Additions to intangible assets	**(1,586)**	—
Cash used in investing activities	**(7,350)**	(11,119)
FINANCING ACTIVITIES		
Due to related parties	**(4,390)**	—
Cash used in financing activities	**(4,390)**	—
Net increase in cash during the year	**873**	—
Cash, beginning of year	**100**	100
Cash, end of year	**973**	100

See accompanying notes

Algoma Power Inc.

NOTES TO FINANCIAL STATEMENTS

[in thousands of dollars]

December 31, 2009

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Incorporation and financial statements

Algoma Power Inc. ["API" or the "Corporation"] is engaged in the distribution of electricity to the area adjacent to Sault Ste. Marie, Canada and is subject to the regulations of the Ontario Energy Board [the "OEB"].

API operated as a division of Great Lakes Power Limited ["GLPL"] from January 1, 2009 to June 30, 2009. In order to comply with Section 71 of OEB regulatory requirements, GLPL split out its distribution division by creating a separate legal entity called Great Lakes Power Distribution Inc. ["GLPDI"]. This entity began operating as a separate legal entity effective July 1, 2009. On October 8, 2009, there was a change of control as FortisOntario Inc. acquired 100% of the shares of GLPDI and changed the name to Algoma Power Inc.

Adoption of new accounting standards

Effective January 1, 2009, API adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants ["CICA"]:

Rate-regulated operations

Effective January 1, 2009, the Canadian Accounting Standards Board [the "AcSB"] amended: [i] CICA Handbook Section 1100, *Generally Accepted Accounting Principles*, removing the temporary exemption providing relief to entities subject to rate regulation from the requirement to apply the section to the recognition and measurement of assets and liabilities arising from rate regulation; and [ii] Section 3465, *Income Taxes,* to require the recognition of future income tax liabilities and assets, as well as offsetting regulatory assets and liabilities, by entities subject to rate regulation.

Effective January 1, 2009, with the removal of the temporary exemption in Section 1100, API must now apply Section 1100 to the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. All assets and liabilities arising from rate regulation do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs API to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described

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in Section 1000, *Financial Statement Concepts*. These assets and liabilities qualify for recognition as assets and liabilities under Section 1000. Therefore, there was no effect on API's financial statements due to the removal of the temporary exemption in Section 1100, as at January 1, 2009.

Effective January 1, 2009, API recognized regulatory assets related to future income tax liabilities, without prior period restatement, for the amount of future income taxes expected to be recovered from customers in future electricity rates of $459.

Goodwill and intangible assets

Effective January 1, 2009, API adopted the new CICA Handbook Section 3064, *Goodwill and Intangible Assets*. This section, which replaces Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*, establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. On January 1, 2009, API reclassified $12,820 to intangible assets and reduced utility capital assets by the same amount for the reclassification of the net book value of land rights, right of ways and computer software costs.

Future accounting policies

International Financial Reporting Standards ["IFRS"]

In February 2008, the AcSB confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In October 2009, the AcSB issued a third and final Omnibus Exposure Draft confirming that publicly accountable enterprises in Canada will be required to apply IFRS, in full and without modification, beginning January 1, 2011. API's expected IFRS transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported on API's opening IFRS balance sheet as at January 1, 2010 and amounts reported by API for the year ended December 31, 2010. The AcSB proposes that CICA Handbook Section 1506, *Accounting Changes*, paragraph 30, which would require an entity to disclose information relating to a new primary source of GAAP that has been issued but is not yet effective and that the entity has not applied, not be applied with respect to this Exposure Draft. API is continuing to assess the financial reporting impacts of adopting IFRS. In July 2009, the IASB issued the Exposure Draft, *Rate-Regulated Activities,* with a final standard expected to be issued in the second quarter of 2010. Based on the Exposure Draft as it currently exists, regulatory assets and liabilities arising from activities subject to cost-of-service regulation can be recognized under IFRS when certain conditions are met. The ability to record regulatory assets and liabilities, as proposed, should reduce the earnings' volatility of the Corporation's regulated utilities that may have otherwise resulted under IFRS in the absence of an accounting standard for rate-regulated activities, but will result in the requirement to provide enhanced balance sheet presentation and

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note disclosures. However, uncertainty as to the final outcome of this Exposure Draft, and the final standard on accounting for rate-regulated activities under IFRS, has resulted in API being unable to reasonably estimate and conclude on the impact on API's future financial position and results of operations with respect to differences, if any, in accounting for rate-regulated activities under IFRS versus Canadian GAAP.

Regulation

API adopted CICA Handbook Accounting Guideline 19, *Disclosure by Entities Subject to Rate Regulation*. API is regulated by the OEB. Accounting standards recognize that rate regulation can create economic benefits and obligations, which are reported in the financial statements as regulatory assets and liabilities. When the regulation provides assurance that incurred costs will be recovered in the future, API may defer these costs and report them as a regulatory asset. If current recovery is provided for costs expected to be incurred in the future, API reports a regulatory liability. Also, if the regulation provides for lesser or greater planned revenue to be received or returned by API through future rates, API recognizes and reports a regulatory asset or liability, respectively. The measurement of such regulatory assets and liabilities are subject to certain estimates and assumptions, including assumptions made in the interpretation of the relevant regulation.

API's current distribution rates are based on a 2007 test year. In October 2008, the OEB approved rates for Great Lakes Power Distribution, effective September 1, 2007. The rates are based on a deemed equity of 50% and an ROE of 8.57%. As part of this approval, the OEB approved the use and implementation of Ontario Regulation 335/07, which is the Rural and Remote Rate Protection subsidy program ["RRRP"]. The RRRP is calculated as the deficiency between the approved revenue requirement from the OEB and current customer distribution rates adjusted for the average rate increase across the Province of Ontario. API qualifies for this subsidy because it has less than seven customers per kilometer and a service area that extends beyond 10,000 kilometers. All general service and large customer classes have been re-classified as residential class, under Ontario Regulation 445/07, which allows API access to this subsidy.

Materials and supplies

Materials and supplies are recorded at average cost. Materials and supplies expensed to operating expense in 2009 were $120 [2008 - $86].

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Utility capital assets

Nature of distribution assets

Distribution assets are those used to distribute electricity at lower voltages [generally below 50 kilovolts]. These assets include poles, tower and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Service life ranges

Utility capital assets are stated at cost, less accumulated amortization. Amortization has been calculated on the cost of the distribution assets on a straight-line basis at rates prescribed in the OEB Handbook as follows:

	Method	Rate/service life
Buildings	Straight-line	5 to 50 years
Equipment	Straight-line	5 to 25 years
Distribution stations, towers and related fixtures	Straight-line	25 to 40 years

Construction work in progress is not amortized until the assets are put into service.

Capitalization of interest

Interest on funds used during construction is charged to construction work in progress at the prescribed rate of return applicable to the rate base.

Asset retirement obligations

API follows the CICA Handbook which requires the recording of the fair value of the future expenditures required to settle legal obligations associated with asset retirements. API has determined that there are asset retirement obligations ["AROs"] associated with some parts of its distribution systems; however, none of these are material requiring recognition under EIC 159 at this time.

Revenue recognition

Revenue on the distribution of electricity is recognized on the accrual basis. Electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of the year a certain amount of consumed electricity will not have been billed. Electricity that is consumed but not yet billed to the customers is estimated and accrued as revenue in the current year. Unbilled revenue included in accounts receivable as at December 31, 2009 is $2,899 [2008 - $3,295].

Purchased power

Purchased power represents all pass through charges billed to API by the Independent Electricity System Operator ["IESO"]. This expense is comprised of Energy, Transmission, and Wholesale Market Service charges.

Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the balance sheet date. Gains and losses on translation are included in the statement of earnings (loss). Revenue and expenses are translated into Canadian dollars at the exchange rate prevailing on the transaction date.

Pension and employee future benefits

The cost of retirement benefits for API's defined benefit pension plan and post-employment benefits is recognized as the benefits are earned by employees. API uses the projected benefit method pro-rated on the length of service and management's best estimate assumptions to value its pension and other retirement benefits. Assets are valued at fair value for purposes of calculating the expected return on plan assets. Past service costs resulting from plan amendments are being amortized on a linear basis over the average remaining service period of active members expected to receive the benefits under the plan. Cumulative gains and losses in excess of 10% of the greater of the accrued benefit obligation and the market value of the plan assets are amortized over the average remaining service period of active members expected to receive benefits under the plan. The average remaining service lives under the defined benefit pension plan as at December 31, 2009 varies from 9.8 to 15.17 years [2008 - 12.0 to 16.0 years]. The average remaining service life under the post-employment benefit plan as at December 31. 2009 is 17.0 years [2008 - 16.0 years].

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Income taxes

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting bases of assets and liabilities. Future income tax assets and liabilities are measured using substantively enacted tax rates and laws expected to apply to taxable income in the period in which temporary differences are expected to be recovered or settled.

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities, and the reported amounts of revenue and expenses during the reporting period. During the years presented, management has made a number of estimates and valuation assumptions including accruals, amortization, asset impairment and those relevant to the defined benefit pension plan. Estimates are based on historical experience, current trends and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from estimates. These estimates are reviewed periodically and, as adjustments are necessary they are reported in earnings in the period in which they become known.

Impairment of long-lived assets

API reviews long-lived assets for other than temporary impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable. The determination of whether impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. Should an asset be considered to be impaired, an impairment loss is recognized in an amount equal to the excess of the asset's carrying value over its fair value.

2. UTILITY CAPITAL ASSETS

Utility capital assets consist of the following:

	2009		
	Cost $	**Accumulated amortization** $	**Net book value** $
Land	**537**	**—**	**537**
Buildings	**791**	**367**	**424**
Equipment	**17,647**	**9,767**	**7,880**
Distribution stations, towers and related fixtures	**72,161**	**33,131**	**39,030**
Capital work in progress	**2,034**	**—**	**2,034**
	93,170	**43,265**	**49,905**

	2008		
	Cost $	**Accumulated amortization** $	**Net book value** $
Land	525	—	525
Buildings	7,537	2,360	5,177
Equipment	21,516	12,971	8,545
Distribution stations, towers and related fixtures	65,878	30,915	34,963
Capital work in progress	3,916	—	3,916
	99,372	46,246	53,126

As at December 31, 2009, materials and supplies in the amount of $1,014 [2008 - $1,053] have been classified as capital work in progress.

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3. INTANGIBLE ASSETS

Intangible assets consist of the following:

	2009		
	Cost $	**Accumulated amortization** $	**Net book value** $
Clearing of right of ways	**14,898**	**1,194**	**13,704**
Land rights	**317**	**—**	**317**
Software costs	**68**	**38**	**30**
	15,283	**1,232**	**14,051**

	2008		
	Cost $	**Accumulated amortization** $	**Net book value** $
Clearing of right of ways	13,261	839	12,422
Land rights	317	—	317
Software costs	1,958	1,877	81
	15,536	2,716	12,820

4. PENSION AND EMPLOYEE FUTURE BENEFITS

API maintains a defined benefit pension plan and a defined contribution pension plan providing pension benefits, and defined benefit plans providing other retirement benefits to most of its employees.

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NOTES TO FINANCIAL STATEMENTS

[in thousands of dollars]

December 31, 2009

Information about API's defined benefit plan is as follows:

	Pension benefit plans	Other plans
	2009	2009
	$	$
Accrued benefit obligation		
Balance, July 1, 2009	**14,215**	**2,935**
Current service cost	**38**	**42**
Interest cost	**265**	**138**
Employee contributions	**33**	
Benefits paid	**(214)**	**(63)**
Actuarial loss	**2,309**	**1,224**
Balance, end of year	**16,646**	**4,276**
Plan assets		
Fair value, July 1, 2009	**—**	**—**
Actual return on plan assets	**272**	
Contributions	**275**	**63**
Benefits paid	**(214)**	**(63)**
Plan expenses		
Acquisitions	**14,562**	**—**
Fair value, end of year	**14,895**	**—**
Funded status - deficit	**(1,751)**	**(4,276)**
Unamortized amounts		
Actuarial loss	**3,249**	**31**
Transitional obligation	**576**	**1,208**
Accrued benefit asset (liability)	**2,074**	**(3,037)**

The measurement date for the plan assets and the accrued benefit obligation is September 30, 2009. The effective date of the most recent actuarial valuation for API was as of July 1, 2009 and the next required valuation for funding purposes is as of July 31, 2012.

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The plan assets held at the measurement date are represented by the following categories:

	%
Canadian equity funds	**33**
U.S. equity funds	**22**
EAFE equity funds	**5**
Canadian fixed income funds	**40**

	Pension benefit plans 2009 $	Other plans 2009 $
Significant assumptions used		
Discount rate	**6.40%**	**6.60%**
Expected long-term rate of return on plan assets	**6.25%**	**—**
Rate of compensation increase	**4.00%**	**—**
Average remaining service period of active employees [years]	**15**	**17**
Net benefit expense for the year		
Current service cost	**76**	**42**
Interest cost	**530**	**138**
Expected return on plan assets	**(545)**	**—**
Actuarial loss (gain)	**—**	**(3)**
Amortization of transitional obligation and past service costs	**77**	**96**
Net benefit expense	**138**	**273**

The impact on 2009 of a one-percentage-point increase in the assumed health care cost trend rate would be to increase the service and interest cost of other retirement plan benefits by $34 and increase the other retirement benefit liability by $745. The impact of a one-percentage-point decrease in the assumed health care cost trend rate would be to decrease the service cost and interest cost of other retirement plan benefits by $27 and decrease the other retirement benefit liability by $591.

While operating as a division, API was part of a multiemployer registered defined benefit, final pay pension plan and an unfunded non-pension benefit plan, both provided by GLPL. It also participated in a defined contribution pension plan provided by GLPL to certain employees. The

accrued benefit liability allocated to API as at December 31, 2008 was $1,220. The total employer expense for the defined contribution pension plan was $133.

Effective July 1, 2009 employees of GLPL were transferred to API. The employees were members of the Retirement Fund of GLPL prior to July 1, 2009. A Retirement Fund of API [formerly Retirement Fund of Great Lakes Power Distribution] was established for employees transferred to API. An application has been submitted to the Financial Services Commission of Ontario for the transfer of these assets and liabilities from the GLPL Plan with respect to the employees' benefits accrued prior to July 1, 2009 in the GLPL Plan, as well as benefits in the GLPL Plan for inactive members formerly employed by the "distribution" division of GLPL. Since, the employees were transferred effective July 1, 2009, information prior to July 1, 2009 is not readily available.

5. INCOME TAXES

The provision for (recovery of) income taxes consists of the following:

	2009 $
Current income taxes	**833**
Future income tax recovery	**(3,191)**
Future taxes transferred to other regulatory liability	**286**
	(2,072)

The tax loss pertaining to the provision of the rate mitigation accrual is considered a non-capital loss which will expire in 2029.

For the period when API was operating as a division of GLPL, the calculation of the income taxes was based on a separate tax return basis. However, GLPL was managing its tax position for the benefit of its business as a whole, and its tax strategies were not necessarily reflective of the tax strategies that API, operating as a division, would have followed as a standalone company.

Future income taxes are provided for temporary differences. There is a regulatory effect on the statement of earnings (loss) to ensure that the (recovery) resulting from future income taxes will not affect the cost of service. As such, a corresponding regulatory liability of $286 is set up to offset the future income tax recovery resulting in a net recovery of $2,072 on the statement of earnings (loss). Future income tax assets and liabilities as at December 31 are comprised of the following:

	2009 $
Future income tax assets (liabilities)	
Utility capital assets	**45**
Pension asset	**(518)**
Employee future benefits	**759**
Rate mitigation accrual	**2,905**
Net future income tax assets	**3,191**

6. RELATED PARTY TRANSACTIONS

[a] API, as a division of GLPL from January 1 to June 30, 2009, has provided advances to and received advances from entities under common control and other divisions of GLPL in the normal course of operations. These advances were non-interest bearing and unsecured. At December 31, 2009, there were no outstanding advances owing to these entities under common control and other divisions of GLPL.

[b] In the normal course of operations, Riskcorp Inc., a broker company affiliated with Brookfield Asset Management Inc., GLPL's ultimate parent, entered into transactions with GLPL to provide insurance. These transactions have been measured at exchange value. The total cost allocated to API in 2009 for these services was $78 [2008 - $105] and no amount remains outstanding at year end [2008 - nil].

[c] The operating debt facility in the amount of $12,000 which represented funds due to another division of GLPL was paid in full during the year before API became a legal entity.

[d] Capital debt facility in the amount of $20,500 [2008 - $20,500] represents the amount of debt permitted under the application with the OEB, as adjusted, to be allocated to fund the ownership of property, plant and equipment, and is unsecured. These funds were due to another division of GLPL. Interest charged to income on these funds were at a rate of 6.10% [2008 - 6.25%]. Net interest expense on the capital debt facility during the year was as follows:

	2009 $	2008 $
Interest expense incurred	**1,910**	1,281
Regulatory carrying charge offset	**—**	(117)
Capitalized interest	**(79)**	(76)
	1,831	1,088

[e] In accordance with an OM&A agreement that existed between API, as a division of GLPL and Great Lakes Power Transmission Limited Partnership ["GLPTLP"], a related party through common control, GLPTLP's transmission assets were operated by API as a division until June 30, 2009, and all costs were passed on to GLPTLP. API as a division was responsible for all operating, maintenance, administrative, and capital activity, the cost of which was tracked and billed to GLPTLP with no mark-up. At July 1, assets with a net book value of $5,622 were sold to GLPTLP with proceeds equal to net book value. This included the sale of the building on Sackville Road and Information Technology assets. A lease agreement was developed whereby API pays lease costs and shared operating costs to GLPTLP. During the period from July 1 to October 7, API and GLPTLP were related parties by virtue of common control. Therefore during this period, the lease costs amounted to $37 and shared operating costs billed by GLPTLP amounted to $84. Other services provided by GLPTLP during the period included General Manager Services and Information Technology services amounting to $83 and $43 respectively. System Control services provided by GLPTLP during the period amounted to $15.

[f] At July 1, 2009, API as its own entity was still required to pay Sault Hydro, a division of GLPL, for Meter Service Provider ["MSP"] services. During the period from July 1, 2009 to October 7, 2009 these two companies were related by virtue of common control. The total MSP costs for this period totalled $26.

[g] Details of relationships with related parties at December 31 are as follows:

- FortisOntario Inc. owns a 100% interest in the capital stock of API.
- Canadian Niagara Power Inc. ["CNPI"] is a wholly owned subsidiary of FortisOntario Inc.

NOTES TO FINANCIAL STATEMENTS

[in thousands of dollars]

December 31, 2009

[h] Subsequent to the acquisition by FortisOntario Inc., API entered into transactions with related parties summarized as follows:

	2009 $
Receipts	
Interest on cash advance to FortisOntario Inc.	**3**
Payments	
Interest on promissory notes to FortisOntario Inc.	**809**
Services provided by CNPI	**15**

[i] The transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As at December 31, the amounts due from (to) related parties are summarized as follows:

	2009 $
FortisOntario Inc.	**4,629**
CNPI	**(131)**
	4,498

[j]

	2009 $
Promissory note payable to FortisOntario Inc.	**45,600**

Interest charged to income on the above funds is at a rate of 7.62%. This promissory note is unsecured and due on demand. It is management's expectation that this loan will not come due during the following year. As such, the promissory note has been classified as a long-term liability.

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7. CAPITAL STOCK

The capital account represents the net assets of API as it operated as a division of GLPL. The amount comprises the contribution of GLPL and the accumulation of operating income of the division. Prior to the acquisition by FortisOntario Inc. the capital account and certain loans and advances were exchanged for 90,831,810 common shares in the amount of $89,606. On October 8, 2009, the new shareholder authorized a reduction of stated capital and a return of capital in the amount of $45,600 in exchange for a note payable *[note 6]*.

The authorized and issued capital stock consists of 90,831,810 common shares without par value.

8. AMORTIZATION

The amortization of utility capital and intangible assets and consists of the following:

	2009 $	2008 $
Amortization of utility capital assets	**3,296**	3,728
Amortization of intangible assets	**355**	—
	3,651	3,728

9. STATEMENT OF CASH FLOWS

[a] The net change in non-cash working capital balances related to operations is comprised of the following:

	2009 $	2008 $
Accounts receivable	**7,343**	(6,666)
Due from related parties	**5,616**	13,185
Prepaid expenses	**88**	4
Materials and supplies	**33**	(39)
Long-term portion of rate mitigation accrual	**—**	(1,200)
Accounts payable and accrued liabilities	**(329)**	1,972
Accrued benefit liability	**98**	—
Income taxes payable/recoverable	**(1,753)**	(2,732)
	11,096	4,524

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[b] Supplemental cash flow information:

	2009 $
Interest paid	1,909
Income taxes paid	200

[c] Restricted cash relates to a deposit made with the Ministry of Environment. This is for a Certificate of Approval required for API to replace a letter of credit that Brookfield Renewable Power previously put in place with the Ministry of Environment.

10. COMMITMENTS, CONTINGENCIES AND GUARANTEES

API has a lease agreement with GLPTLP for use of the premises on Sackville Road. The lease is to last until December 31, 2014 and annual rent is $138 per year.

API may, from time to time, be involved in legal proceedings, claims, and litigation that arise in the ordinary course of business which API believes would not reasonably be expected to have a material adverse effect on the financial condition of API.

API has asset retirement obligations associated with its property, plant and equipment. The retirement date for these assets cannot be reasonably estimated and therefore the fair value of the associated liability cannot be estimated at this time. As a result, no liability has been accrued in these financial statements.

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11. FINANCIAL INSTRUMENTS

API has designated its financial instruments as follows:

	2009		2008	
	Carrying value $	Estimated fair value $	Carrying value $	Estimated fair value $
Held-for-trading				
Cash	**873**	**873**	100	100
Loans and receivables				
Accounts receivable	**5,312**	**5,312**	12,655	12,655
Due from related parties	**4,498**	**4,498**	10,114	10,114
Income taxes recoverable	**11**	**11**	—	—
Other financial liabilities				
Accounts payable and accrued liabilities	**4,015**	**4,015**	4,344	4,344
Long term debt	**45,600**	**45,600**	40,831	40,831

The fair value of cash approximates its carrying value due to the short-term nature of this instrument.

Accounts receivable, income taxes recoverable, due to/from related parties and accounts payable and accrued liabilities are initially measured at fair value and the carrying value approximates the amortized cost.

The fair value of the long term debt is measured at amortized cost using the effective interest rate method. Due to the nature of this asset the carrying value approximates its amortized cost.

12. FINANCIAL RISK MANAGEMENT

API is primarily exposed to market risk, credit risk, interest rate risk, and liquidity risk as a result of holding financial instruments in the normal course of business.

Market risk

Market risk is the risk that the fair value of future cash flows of financial assets or liabilities will fluctuate due to movements in market prices.

Interest rate risk

API is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings. Short-term borrowings for 2009 and 2008 are nil.

Credit risk

Credit risk is the risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

For cash and accounts receivable due from customers, API's credit risk is limited to the carrying value on the balance sheet.

API is exposed to credit risk from its distribution customers but has various policies to minimize this risk. These policies include requiring customer deposits, performing disconnections and using third party collection agencies for overdue accounts. API has a large and diversified distribution customer base which minimizes the concentration of credit risk.

	$
Not past due	**4,774**
Past due 0 - 30 days	**103**
Past due 31 - 60 days	**91**
Past due 61 days and over	**444**
	5,412
Less allowance for doubtful accounts	**(100)**
	5,312

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Liquidity risk

Liquidity risk is the risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Liquidity risk to API is minimized since the financing of regulated capital and other expenditures is done through internally generated funds. These funds are a result of allowable rate regulated returns and recoveries under the OEB rate regulations mechanism.

API is a subsidiary of FortisOntario Inc., wholly owned 100% by Fortis Inc., a large investor-owned utility, which has had the ability to raise sufficient and cost-effective financing. However, the ability to arrange financing on a go-forward basis is subject to numerous factors, including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions. The recent volatility in the global markets may increase the cost of and timing of issuance of long-term capital by Fortis Inc. and its subsidiaries.

13. CAPITAL MANAGEMENT

API manages its capital to approximate the deemed capital structure reflected in the utility's customer rates or anticipated future rates. API's distribution rates are based on a deemed capital structure of 50% debt and 50% equity. API's capital structure consists of affiliated debt and common equity.

The managed capital is as follows:

	2009 Actual	
	$	%
Debt	**45,600**	**58**
Equity	**32,570**	**42**
	78,170	**100**

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14. EFFECTS OF RATE REGULATION

API operates in accordance with the regulations of the OEB. Regulatory assets and liabilities represent certain revenues earned or costs incurred in the current year or in prior years that have been or are expected to be recovered from customers upon approval from the OEB. In the absence of rate regulation, these balances would have been recorded as revenues or expenses in the statement of earnings (loss).

As a result of the OEB's October 30, 2008 Decision and Order [the "Decision"] on API's August 31, 2007 rate application, there have been a number of changes to existing regulatory asset balances between December 31, 2008 and December 31, 2009.

[a] The Division recorded the following regulatory assets and liabilities as at December 31:

	2009 $	2008 $
Current		
Retail settlement and other variance accounts [net of recoveries]	**924**	(118)
Deferred legal costs	**411**	—
Deferred IFRS costs	**6**	—
	1,341	(118)
Long-term		
Seasonal revenue accrual	**1,936**	1,106
Smart meter variance account	**1,935**	110
	3,871	1,216

OEB variance accounts

As prescribed by regulatory order, OEB variance accounts are used to record the net of amounts charged by the IESO and amounts billed to customers, resulting in a regulatory asset or liability. These balances will be recovered or refunded through rates as approved by the OEB.

In the Decision, the OEB approved $103 for recovery of OEB variance accounts. This balance was transferred to the regulatory asset recovery account.

Seasonal revenue accrual

The seasonal revenue accrual is related to a shortfall in revenue contributions from the seasonal customer class. The total cost allocated to the seasonal customer class is significantly higher than the total revenue generated through rates by that class. In order to recover the full cost, significant rate shock would have been incurred. In the Decision, the OEB accepted API's proposal to mitigate significant rate impacts to the seasonal customer class by limiting the rate increase to 10%. The shortfall in revenue would be accrued and recovered in a future period. The risk of the OEB ultimately denying the amounts is minimal, as the account has been approved for use in this context.

Smart meter variance account

In 2006, the Ontario Government committed to install a smart electricity meter in all Ontario homes and small business by the end of 2010. Distributors will be eligible to recover all prudent and reasonable costs that arise from this smart metering initiative.

As prescribed by regulatory order, this regulatory account shall be used by the distributor to record incremental operating, maintenance, amortization and administrative expenses directly related to smart meters. The risk of non-approval of this balance is negligible because API believes that the costs are prudent and reasonable, and recovery is prescribed by regulatory order.

PILs variance account

As prescribed by regulatory order, this regulatory account relates to the true-up of over- or under-collected funds related to tax recovery by API. Statutory changes in tax legislation should not impact a distributor's earnings, therefore any variance in a distributor's tax payable [from approved amount] resulting from a statutory change is to be recorded as an offset in this account. The balance of this account will be returned to API's ratepayers after a future proceeding with the OEB.

Regulatory asset recovery

As a result of the OEB's findings in the Decision, a number of regulatory accounts were approved for recovery and combined in one regulatory account. Also included in this account were all funds collected from 2004 through 2008 related to regulatory asset recovery. The balance of this account was to be recovered from customers or returned to customers, depending on the ultimate balance. As at December 31, 2009, $761,424 was in this account, payable to API's ratepayers.

[b] Rate mitigation accrual

The rate mitigation accrual relates to the return on equity portion of the revenue requirement from the 2002 rate application to the OEB. Distribution revenue in the amount of $14,890 [2008 - $14,890] has been accrued in accordance with the mitigation strategy submitted with the 2002 rate application, with the current portion in the amount of nil [2008 - nil] recorded in accounts receivable.

On August 31, 2007, management filed an application to the OEB to continue recovery of its rate mitigation accrual balance up to the date the proposed rates become effective. In the OEB's Decision, recovery of the entire account balance was denied, and any collected funds were to be transferred to the regulatory asset recovery account, and returned to the Division's ratepayers.

On November 28, 2008, management filed an appeal of the portion of the Decision that denied the rate mitigation accrual. The appeal factum was filed with the Ontario Superior Court of Justice - Divisional Court, and was filed on the basis that the OEB erred in law. The appeal to the Divisional Court was heard on June 2, 2009. In a decision dated July 21, 2009, the Divisional Court denied GLP's appeal. GLP sought leave to appeal the Divisional Court's decision to the Court of Appeal by filing a Notice of Motion For Leave To Appeal on August 5, 2009. Leave To Appeal was granted by the Court of Appeal on November 10, 2009. As of the date these financial statements were issued, no updated information was available. As a result, an allowance in the amount of $14,890 was set up to offset this accrual.

15. COMPARATIVE FIGURES

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the 2009 financial statements.

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RECONCILIATION OF 2007 AUDITED FINANCIAL STATEMENTS TO REGULATORY STATEMENTS - ($000'S)

Account	2007 Audited	2007 RRR	Variance	Note
Net Regulatory Assets and Liabilities	498	15,254	(14,756)	(1)
Rate Mitigation Accrual	13,690	-	13,690	(1)
Utility Capital Assets				
Costs	102,983	102,983	-	
Less: amortization	(45,480)	(45,480)	-	
	57,503	57,503	-	
Revenue				
Sales of Electricity		14,537		
Distribution Services Revenue		12,796		
Other Operating Revenue		388		
Other Revenue		(29)		
Power Supply Expenses		(14,540)		
	13,182	13,152	30	(2)
Operating Expenses				
Operation (Working Capital)		1,497		
Maintenance (Working Capital)		3,369		
Billing and Collection (Working Capital)		1,059		
Administrative and General Expenses (Working Capital)		2,097		
	8,456	8,022	434	(3)
Amortization of Assets	3,559	3,559	-	
Loss on Disposal of Assets	22	-	22	(2)
Donations	-	21	(21)	(3)
Interest Expense - Unclassified	1,257	1,257	-	
Income Tax Expense - Unclassified	77	312	(235)	(4)
Profit(Loss)	(189)	(19)	(170)	(5)

RECONCILIATION OF 2008 AUDITED FINANCIAL STATEMENTS TO REGULATORY STATEMENTS - ($000'S)

Account	2008 Audited	2008 RRR	Variance	Note
Net Regulatory Assets and Liabilities	1,098	15,907	(14,809)	(6)
Rate Mitigation Accrual	14,890	-	14,890	(6)
Inventory	288	1,340	(1,052)	(7)
Utility Capital Assets				
Costs	99,372	113,855	(14,483)	
Less: amortization	(46,246)	(48,962)	2,716	
	53,126	64,893	(11,767)	(7)
Intangibles				
Costs	15,536	-	15,536	
Less: amortization	(2,716)	-	(2,716)	
	12,820	-	12,820	(8)
Revenue				
Sales of Electricity		13,864		
Distribution Services Revenue		18,336		
Other Operating Revenue		200		
Other Revenue		490		
Power Supply Expenses		(13,869)		
	18,605	19,021	(416)	(9)
Operating Expenses				
Operation (Working Capital)		1,492		
Maintenance (Working Capital)		2,980		
Billing and Collection (Working Capital)		1,062		
Administrative and General Expenses (Working Capital)		2,997		
	8,623	8,531	92	(10)
Amortization of Assets	3,728	3,728	-	
Loss on Disposal of Assets	19	-	19	(9)
Donations	-	7	(7)	(10)
Other income (expense)	(43)	-	(43)	(10)
Interest Expense - Unclassified	1,088	1,550	(462)	(9)
Income Tax Expense - Unclassified	1,742	1,705	37	(11)
Profit(Loss)	3,448	3,500	(52)	(12)

RECONCILIATION OF 2009 AUDITED FINANCIAL STATEMENTS TO REGULATORY STATEMENTS - ($000'S)

Account	2009 Audited	2009 RRR	Variance	Note
Net Regulatory Assets and Liabilities	4,926	5,223	(297)	(13)
Inventory	255	1,269	(1,014)	(7)
Utility Capital Assets				
Costs	93,170	107,440	(14,270)	
Less: amortization	(43,265)	(44,498)	1,233	
	49,905	62,942	(13,037)	(7)
Intangibles				
Costs	15,283	-	15,283	
Less: amortization	(1,232)	-	(1,232)	
	14,051	-	14,051	(8)
Revenue				
Sales of Electricity		14,614		
Distribution Services Revenue		17,219		
Other Operating Revenue		347		
Other Revenue		(9)		
Power Supply Expenses		(14,639)		
	17,542	17,532	10	(14)
Operating Expenses				
Operation (Working Capital)		1,667		
Maintenance (Working Capital)		3,184		
Billing and Collection (Working Capital)		1,189		
Administrative and General Expenses (Working Capital)		2,575		
	10,820	8,615	2,205	(15)
Amortization of Assets	3,651	3,651	-	
Donations	-	17	(17)	(15)
Interest Expense	-	1,831	(1,831)	(15)
Extraordinary Items	-	11,985	(11,985)	(16)
Provision for Rate Mitigration	14,890	-	14,890	(16)
Income Tax Expense	(2,072)	1,180	(3,252)	(17)
Profit(Loss)	(9,747)	(9,747)	-	

(1) Rate mitigation accrual is reclassed and current portion is moved to accounts receivable.
(2) Reclassification of loss on disposal $22 and job costs $8.
(3) Reclassification of donations $21, capital and property tax $320 and job costs $8. Increased audit expense $85.
(4) Reclassification of capital and property tax $320 offset by increased tax expense $85.
(5) Increased audit expense $85 and increased tax expense $85.
(6) Rate mitigation accrual is reclassed and additional tax credit $81.
(7) Reclassification to intangibles.
(8) Reclassification from utility capital assets.
(9) Reclassification of interest income $462 and other income(expense) $(43) offset by tax adjustment $83 and rounding $6.
(10) Reclassification of donations $7 and capital and property tax $125 offset by loss on disposal $19. Increase in pension expense $52 and rounding $6 offset by capital tax adjustment $79.
(11) Reclassification of capital and property tax $125. Increased tax expense $162.
(12) Increased pension expense $52.
(13) Reclassification of retailer settlements from OEB account 2405 to regulatory. Deferred tax $286 set up as regulatory liability.
(14) Reclassification of other revenue to expense.
(15) Reclassification of capital and property tax $347, interest expense $1,831, other revenue(expense)$(9) and donations $17.
(16) Reclassification of rate mitigation $14,890 and taxes $(2,905).
(17) Reclassification of capital and property tax $347 and taxes re rate mitigation $2,905.

ALGOMA POWER INC.
STATEMENT OF EARNINGS AND RETAINED EARNINGS
Years ended December 31,

	Forecast 2011	Forecast 2010	Actual Regulatory 2009
Revenue			
Electric revenue	$ 35,556,083	$ 34,785,696	$ 32,180,639
less: purchased power	17,847,379	17,166,389	14,638,690
	17,708,704	17,619,307	17,541,949
Expenses			
Distribution	5,738,690	5,125,829	4,536,233
Administrative	2,609,791	2,472,964	2,889,827
Customer service	1,321,726	1,290,443	1,189,693
Taxes, other than income taxes	150,000	150,000	146,241
Amortization	4,512,684	4,056,672	3,651,441
	14,332,891	13,095,908	12,413,436
Operating income	3,375,813	4,523,399	5,128,513
Other income			
Interest income	-	-	21,293
Services income	-	-	2,416
Gain (loss) on disposals	-	-	(32,667)
Other	(20,000)	(20,000)	(14,907,091)
	(20,000)	(20,000)	(14,916,049)
Interest Expense	3,658,000	3,399,720	1,830,707
Net income (loss) before taxes	(302,187)	1,103,679	(11,618,243)
Income taxes	(85,368)	342,140	(1,871,293)
Net earnings (loss) for the year	(216,819)	761,539	(9,746,950)
Retained earnings (deficiency), beginning of year	(10,675,979)	(11,437,518)	(1,690,568)
Dividends			-
Retained earnings (deficiency), end of year	$ (10,892,797)	$ (10,675,979)	$ (11,437,518)

ALGOMA POWER INC.
BALANCE SHEET
As at December 31

	Forecast 2011	Forecast 2010	Actual Regulatory 2009
Assets			
Current Assets			
Cash (bank indebtedness)	$ (7,313,423)	$ (613,743)	$ 973,079
Accounts receivable	5,358,487	5,358,487	4,883,891
Due from affiliated parties	-	-	5,438,105
Materials and supplies	1,300,000	1,300,000	1,269,336
Regulatory assets	10,150,876	9,766,876	5,639,949
Prepaid expenses and other	30,000	30,000	25,699
	9,525,940	15,841,620	18,230,058
Property, plant and equipment	77,193,686	70,235,523	62,941,614
Future Income Tax Asset	3,000,000	3,000,000	3,190,610
	$ 89,719,627	$ 89,077,143	$ 84,362,282
Liabilities and Shareholder's Equity			
Current liabilities			
Accounts payable and accrued liabilities	$ 3,730,000	$ 3,730,000	$ 3,539,155
Customer deposits	450,000	450,000	474,261
Due to affiliated parties	1,148,862	289,560	928,936
	5,328,862	4,469,560	4,942,351
Affiliate long-term debt	50,000,000	50,000,000	45,600,000
Other liabilities	285,781	285,781	285,781
Accrued other retirement benefit liability	990,000	990,000	963,886
	56,604,643	55,745,341	51,792,018
Shareholder's equity			
Common stock	44,007,781	44,007,781	44,007,781
Retained earnings (deficiency)	(10,892,797)	(10,675,979)	(11,437,518)
	33,114,984	33,331,802	32,570,263
	$ 89,719,627	$ 89,077,143	$ 84,362,282

INFORMATION ON PARENT AND SUBSIDIARIES

As indicated in the API Corporate Entities Relationship Chart in Exhibit 1, Tab 1, Schedule 13, API is the Applicant and is a wholly-owned subsidiary of FortisOntario. FortisOntario is a wholly-owned subsidiary of Fortis, a diversified international utility holding company with investments in a natural gas utility and several electricity distribution utilities in five Canadian provinces and three Caribbean countries. Fortis shares are listed on the TSX and trade under the symbol FTS.

FortisOntario is a holding company primarily for electricity transmission and distribution businesses in Ontario. FortisOntario has more than one hundred years of experience in providing electricity distribution services in Ontario initially in the Niagara region (Fort Erie and Port Colborne) and then eastern Ontario (Gananoque and Cornwall) and more recently in the Algoma district in northern Ontario. API is a wholly-owned subsidiary of FortisOntario (see Exhibit 1, Tab 1, Schedule 13). API has one wholly-owned subsidiary, 1228158 Ontario Limited, which is a non-operating subsidiary that holds certain land interests. FortisOntario is also a licenced generator and owns generation assets in Ontario.

API and its parent, FortisOntario, do not produce annual reports, prospectuses or information circulars. API and FortisOntario do not have credit ratings from credit rating agencies.

MATERIALITY THRESHOLD

API's revenue requirement is equal to $18,928,065. In accordance with the Filing Guide, the default materiality threshold is 0.5% of revenue requirement for distributors with a revenue requirement greater than $10 million and less then or equal to $200 million. Since API's revenue requirement falls within this range, and based upon the Filing Guide, the technical materiality threshold is $94,640 ($18,928,065*0.5%). However, for the purpose of this Application API has generally used a slightly lower materiality threshold of $75,000.

RATE BASE OVERVIEW

This Exhibit 2 (Rate Base) provides API's distribution rate base forecast for 2010 and 2011 Test Years. In accordance with the Filing Requirements, the rate base is used to determine the revenue requirement for the 2010 and 2011 Test Years and includes a forecast average net book value of fixed assets plus a working capital allowance.

2010 Rate Base ($)	
2009 Net Book Value	61,921,081
2010 Net Book Value	69,235,523
Average Net Book Value	65,578,302
Working Capital Allowance	3,930,844
2010 Rate Base	**69,509,146**

2011 Rate Base ($)	
2010 Net Book Value	69,235,523
2011 Net Book Value	76,193,686
Average Net Book Value	72,714,604
Working Capital Allowance	4,150,138
2011 Rate Base	**76,864,742**

Exhibit 2, Tab 1 (Rate Base Overview), including its schedules and appendix provides an overview of the distribution system and rate base variance.

Exhibit 2, Tab 2 (Gross Fixed Assets and Accumulated Depreciation) including its schedules, describes API's fixed assets continuity statements, and gross fixed assets table.

Exhibit 2, Tab 3 (Allowance for Working Capital) including its schedules, calculates the working capital requirements. API has used the 15% method to calculate the working capital allowance consistent with the majority of distributors that have recently rebased.

Exhibit 2, Tab 4 (Capital Expenditures) including its schedules and appendices, describe API's capital expenditures in the areas of capital plant, facilities and equipment, information technology, and transportation for the period 2007 Actual to 2011 Test Year.

Exhibit 2, Tab 5 (Asset Management Process), including its schedule, describe API's asset management process and capital plan.

Exhibit 2, Tab 6 (Service Quality Indicators and Reliability Performance) including its schedule, describe API's service quality and reliability performance for the period 2007 – 2009.

The Table 1 below, lists API's capital expenditures by OEB account for the period 2007 Actual to 2011 Test Year.

Exhibit 2, Tab 1, Schedule 1, Table 1

CAPITAL EXPENDITURES

Fixed Asset Additions

Acct Description	OEB Acct #	2007	2008	2009	2010	2011
CLEARING RIGHTS OF WAY	1806	2,271,025	3,283,860	1,637,793	2,068,412	2,217,628
LAND AND LAND RIGHTS	1805			12,354		54,374
BUILDINGS AND FIXTURES	1808	33,636	256,173	596	263,161	21,749
STATION EQUIPMENT	1820	238,080	736,159	120,263	1,434,409	93,342
POLES TOWERS & FIXTURES	1830	2,603,580	1,880,127	4,450,636	3,925,877	3,884,635
O/H CONDUCTORS & DEVICES	1835	873,215	1,025,935	1,554,033	1,749,657	1,310,655
U/G CONDUCTORS & DEVICES	1845		495,589	15,449		95,698
LINE TRANSFORMERS	1850	640,293	569,828	419,852	943,005	627,613
SERVICES	1855	190,053	142,096	118,501	333,033	343,839
METERS	1860	11,841	30,344	46,812	168,071	27,187
STREET LIGHT/SIGNAL SYSTM	1875					
OTHER TANGIBLE PROPERTY	1990					
BUILDINGS AND FIXTURES	1908	1,205	45,085	48,529		
OFFICE FURNITURE & EQUIP	1915	1,460	14,177	4,779		27,187
TRANSPORT EQUIP	1930	799,287	285,972	685,982	318,340	625,297
LABORATORY EQUIPMENT	1945			9,231		
TOOLS & WORK EQUIPMENT	1940	63,320	92,899	77,389	53,057	54,374
COMMUNICATIONS EQUIPMENT	1955	1,879	4,828		55,049	
MISCELLANEOUS EQUIPMENT	1960		11,441			
COMPUTER HARDWARE	1920	459,042	131,609	156,663	26,528	442,601
COMPUTER SOFTWARE	1925	37,180	81,966	23,828	32,515	1,043,647
Total		**8,225,096**	**9,088,087**	**9,382,690**	**11,371,113**	**10,869,825**

OVERVIEW OF DISTRIBUTION SYSTEM

API owns and operates the electricity distribution system in portions of the district of Algoma, serving approximately 11,720 customers located in a number of townships and First Nations territory. The service territory includes an area of approximately 14,200 square kilometers, and 1845 km of distribution lines, over 99% of which are overhead lines. The API system meets a winter peak demand of approximately 40 MW**.**

The API distribution system is supplied from the Great Lakes Power Transmission ("GLPT")-owned 115kV transmission system through 12 separate metering points located at 7 different transmission substations and on a GLPT-owned 44 kV transmission circuit. Three of the GLPT-owned transmission stations and the 44 kV transmission circuit supply 34.5 kV and 44 kV API-owned distribution feeders that in turn supply 13 distribution substations and an embedded distributor. A number of customers are also supplied directly from API's 34.5 kV and 44 kV feeders due to the size of their loads and/or their remote locations. The other GLPT-owned transmission substations supply distribution feeders directly at lower distribution-level voltages. There are a wide variety of voltages presently in use on API's distribution system, including: 44 kV Delta, 34.5 kV Delta, 24.9Y/14.4 kV, 12.5Y/7.2 kV, 8.3Y/4.8 kV, 4.16Y/2.4 kV, 12 kV Delta, 4.8 kV Delta and 2.4 kV Delta.

The distribution systems associated with the various voltage classes are described as follows:

44 kV Delta – A single 44 kV radial feeder is supplied as a tap from a 44 kV transmission circuit in rural areas east of Wawa. This feeder is approximately 86 km in total length, and is mainly located in extremely remote areas. The feeder supplies an embedded distributor, a distribution substation, three single-phase step-down type substations and a number of customer-owned substations connected directly at 44 kV.

34.5 kV Delta – API operates two 34.5 kV systems in its service territory, one in the Wawa area and the other in the area east of Sault Ste. Marie. The Wawa system consists of two 34.5 kV feeders running in parallel from a transmission substation to the town of Wawa, where they join

at a distribution substation to form a closed loop. These feeders supply two distribution substations in the town of Wawa as well as a single-phase step-down transformer supplying a small load in a rural area outside the town. The system east of Sault Ste. Marie consists of three 34.5 kV feeders supplied from two separate transmission substations. These feeders supply 6 distribution substations, a voltage regulating station and a customer-owned substation connected directly at 34.5 kV. The feeders are normally operated radially; however, the system contains many normally open feeder interties, allowing load transfers between feeders and providing alternate supplies to many of the distribution substations. In general, many of API's larger load centres are located at long distances from its transmission supply points and use of the 34.5 kV systems allows these areas to be supplied with acceptable voltage levels and lower overall system losses than would be possible with direct supply at lower distribution-level voltages.

24.9Y/14.4 kV – This voltage level is used in areas where use of API's predominant voltage of 12.5Y/7.2 kV would result in unacceptable voltage levels or excessive line losses on the distribution system. The largest system in this voltage class is located on St. Joseph Island, which serves almost 1800 customers spread over an area of 365 square kilometres. This voltage level is also used on three other feeders, either as a direct supply from a transmission station at this voltage level, or through the use of step-up transformers from a 12.5Y/7.2 kV feeder.

12.5Y/7.2 kV – This voltage level serves slightly more than half of API's customers and makes up 52% of API's line kilometres. These percentages are increasing year over year through voltage conversion programs. In most areas, this voltage level can provide acceptable voltage profiles while reducing losses as compared to lower voltages previously used. As this is a common voltage level, equipment is readily available at reasonable costs and with minimal lead-time. Most of the distribution feeders east of Sault Ste. Marie are supplied at this voltage level via 34.5 kV to 12.5Y/7.2 kV substations. This voltage level is also supplied directly from a number of transmission supply points North of Sault Ste. Marie, and on a feeder from one of the distribution substations in Wawa that supplies the rural load outside of the town.

12 kV Delta – This voltage is used only on a feeder supplying customers within the city of Sault Ste. Marie. This feeder supplies the six locations within Sault Ste. Marie that are described in Schedule 1 (5) of API's Distribution Licence.

8.3Y/4.8 kV and 4.8 kV Delta – Most areas using 8.3Y/4.8 kV in the area east of Sault Ste. Marie have been converted to 12.5Y/7.2 kV, or 24.9Y/14.4 kV in the case of St. Joseph Island. Some small pockets of single-phase 4.8 kV will remain after 2010, being supplied by single-phase step-down transformers from the other voltages. These areas will continue to be converted to higher voltages in conjunction with conductor replacement, pole replacement or other capital programs in these areas.

The entire 4.8 kV Delta system in the Town of Wawa was converted to 8.3Y/4.8 kV in 2009. Use of the 8.3Y/4.8 kV voltage level in this case was considered the most economical and practical choice for converting the 4.8 kV delta system. This allowed the entire conversion to take place over a period of months rather than years, with minimal service interruptions. It also allowed most of the existing distribution transformers as well as a large substation transformer to be re-used and will allow 4.8 kV transformers removed from other areas to be transferred to Wawa for future use. As there are 12.5Y/7.2 kV feeders in rural areas surrounding the town, use of the 8.3Y/4.8 kV feeders will be limited to the town site itself. With the use of this voltage level, API does not anticipate any concerns with regards to system capacity or power quality in the foreseeable future.

There are also a number of lightly loaded feeders being supplied at 8.3Y/4.8 kV or at 4.8 kV single-phase in remote areas near Wawa supplied from the 44kV circuit. Given the extremely small load levels in these areas, and the fact that the Wawa work centre will be required to maintain an inventory of 4.8 kV class equipment for use on feeders within the town, there is little likelihood for voltage conversion in these areas in the foreseeable future.

4.16Y/2.4 kV – This voltage class is currently in use in the Town of Bruce Mines, east of Sault Ste. Marie. The Bruce Mines distribution station currently contains two transformer banks. One

transformer bank supplies a 12.5Y/7.2 kV feeder that supplies rural areas around the town, while the other supplies a 4.16Y/2.4 kV feeder that supplies loads within the town.

2.4 kV Delta – This voltage is used to supply a small feeder directly from a transmission substation in a remote area. As there are approximately only twelve customers on this feeder and much of the load is seasonal, there are no short-term plans to convert this feeder to another voltage class.

API's distribution substations are generally split between newer and older vintage, with five substations having been built or upgraded in the last 1-10 years and the other eight substations and one voltage regulating station being in the 30-50+ year old range. Capital projects over the next few years will also focus on upgrading and modernizing distribution substations to improve reliability and to reduce safety and environmental risks. The larger traditional 3-phase substations will mostly be upgraded at the existing sites, with one of these substations simply being retired after load transfers in 2010. Newer pieces of equipment installed in these substations will be re-used in the new substation design to the extent practical. The smaller single-phase step-down type substations will simply have structures, transformers or miscellaneous equipment replaced as condition assessments and asset management practices dictate, similar to other distribution line assets.

RATE BASE VARIANCE TABLE

Description	2007 Board Approved	2007 Actual	Variance from 2007 Board Approved	2008 Actual	Variance from 2007 Actual	2009 Actual	Variance from 2008 Actual	2010 Test Year	Variance from 2009 Actual	2011 Test Year	Variance from 2010 Test
Gross Fixed Assets	101,817,367	102,152,542	335,175	110,974,956	8,822,414	106,402,683	(4,572,273)	117,773,796	11,371,113	130,630,310	12,856,514
Accumulated Depreciation	(45,198,825)	(45,464,234)	(265,409)	(48,945,304)	(3,481,070)	(44,481,601)	4,463,703	(48,538,274)	(4,056,672)	(54,436,624)	(5,898,350)
Net Book Value	56,618,542	56,688,309	69,766	62,029,652	5,341,343	61,921,081	(108,570)	69,235,523	7,314,441	76,193,686	6,958,163
Average Net book Value	54,130,800	54,366,451	235,651	59,358,980	4,992,529	61,975,367	2,616,386	65,578,302	3,602,935	72,714,604	7,136,302
Working Capital Requirement	22,586,574	22,717,099	130,525	22,563,127	(153,972)	23,400,685	837,558	26,205,625	2,804,941	27,667,586	1,461,961
Working Capital Allowance	3,387,986	3,407,565	19,579	3,384,469	(23,096)	3,510,103	125,634	3,930,844	420,741	4,150,138	219,294
Rate Base	**57,518,786**	**57,774,016**	**255,230**	**62,743,449**	**4,969,433**	**65,485,469**	**2,742,020**	**69,509,146**	**4,023,677**	**76,864,742**	**7,355,596**

Appendix 2-C
Fixed Asset Continuity Statements

				2007									
				Cost				Accumulated Depreciation					
CCA Class	Depreication Rate	Acct Description	OEB Acct #	Opening	Additions	Disposals	Closing	Opening	Deprec.	Disposals	Closing	Net Book Value
47	2.5%	CLEARING RIGHTS OF WAY	1806	7,705,877	2,271,025		9,976,901	337,072	217,894		554,966	9,421,935
		LAND AND LAND RIGHTS	1805	841,604			841,604				0	841,604
47	2.0%	BUILDINGS AND FIXTURES	1808	6,533,263	33,636		6,566,898	1,918,327	130,447		2,048,774	4,518,124
1 & 47	3.3%	STATION EQUIPMENT	1820	8,885,887	238,080		9,123,967	3,463,205	269,562		3,732,767	5,391,200
47	4.0%	POLES TOWERS & FIXTURES	1830	28,103,514	2,603,580	(12,578)	30,694,517	12,080,709	1,065,346	12,578	13,133,478	17,561,039
47	4.0%	O/H CONDUCTORS & DEVICES	1835	13,682,473	873,215	(8,986)	14,546,701	6,304,416	496,447	8,986	6,791,876	7,754,824
47	4.0%	U/G CONDUCTORS & DEVICES	1845	460,099			460,099	121,459	19,087		140,546	319,553
47	4.0%	LINE TRANSFORMERS	1850	8,134,433	640,293	(2,310)	8,772,416	4,067,742	302,741	231	4,370,252	4,402,164
47	4.0%	SERVICES	1855	2,678,357	190,053		2,868,410	1,526,243	91,011		1,617,253	1,251,157
47	4.0%	METERS	1860	2,170,714	11,841	(9,773)	2,172,783	1,219,683	63,926	4,301	1,279,307	893,475
47	10.0%	STREET LIGHT/SIGNAL SYSTM	1875	16,523			16,523	16,523			16,523	
1 & 47	4.0%	OTHER TANGIBLE PROPERTY	1990	2,150,996			2,150,996	1,170,538	74,343		1,244,881	906,115
47	4.0%	BUILDINGS AND FIXTURES	1908	667,551	1,205		668,756	125,675	26,738		152,413	516,343
47	10.0%	OFFICE FURNITURE & EQUIP	1915	779,264	1,460	(3,168)	777,556	654,375	38,872	2,666	690,580	86,976
10	20.0%	TRANSPORT EQUIP	1930	4,244,121	799,287	(404,990)	4,638,418	3,729,192	313,663	393,252	3,649,603	988,815
8	10.0%	LABORATORY EQUIPMENT	1945	230,701			230,701	230,701			230,701	
8	10.0%	TOOLS & WORK EQUIPMENT	1940	1,346,733	63,320	(31,867)	1,378,186	850,725	77,955	31,867	896,813	481,373
8	10.0%	COMMUNICATIONS EQUIPMENT	1955	393,688	1,879		395,567	322,508	15,372		337,880	57,686
47	10.0%	MISCELLANEOUS EQUIPMENT	1960	111,116			111,116	65,102	11,112		76,213	34,903
47& 50	10% & 20%	COMPUTER HARDWARE	1920	3,522,538	459,042	(80,891)	3,900,689	2,396,340	336,757	78,450	2,654,647	1,246,042
12	20.0%	COMPUTER SOFTWARE	1925	1,839,081	37,180		1,876,261	1,853,405	7,878		1,861,282	14,979
		Subtotal		**94,498,531**	**8,225,096**	**(554,562)**	**102,169,065**	**42,453,937**	**3,559,152**	**532,332**	**45,480,757**	**56,688,309**
		Less Non-Distribution Assets		**16,523**			**16,523**	**16,523**			**16,523**	**0**
		Total		**94,482,008**	**8,225,096**	**(554,562)**	**102,152,542**	**42,437,414**	**3,559,152**	**532,332**	**45,464,234**	**56,688,309**

Appendix 2-C
Fixed Asset Continuity Statements

				2008									
				Cost				Accumulated Depreciation					
CCA Class	Depreication Rate	Acct Description	OEB Acct #	Opening	Additions	Disposals	Closing	Opening	Deprec.	Disposals	Closing	Net Book Value
47	2.5%	CLEARING RIGHTS OF WAY	1806	9,976,901	3,283,860		13,260,761	554,966	284,610		839,575	12,421,186
		LAND AND LAND RIGHTS	1805	841,604			841,604					841,604
47	2.0%	BUILDINGS AND FIXTURES	1808	6,566,898	256,173		6,823,071	2,048,774	131,495		2,180,269	4,642,802
1 & 47	3.3%	STATION EQUIPMENT	1820	9,123,967	736,159		9,860,126	3,732,767	165,118		3,897,886	5,962,240
47	4.0%	POLES TOWERS & FIXTURES	1830	30,694,517	1,880,127	(87,164)	32,487,480	13,133,478	1,151,448	87,164	14,197,761	18,289,719
47	4.0%	O/H CONDUCTORS & DEVICES	1835	14,546,701	1,025,935	(21,323)	15,551,313	6,791,876	527,808	21,323	7,298,362	8,252,952
47	4.0%	U/G CONDUCTORS & DEVICES	1845	460,099	495,589		955,688	140,546	23,176		163,722	791,966
47	4.0%	LINE TRANSFORMERS	1850	8,772,416	569,828		9,342,244	4,370,252	328,284		4,698,536	4,643,708
47	4.0%	SERVICES	1855	2,868,410	142,096		3,010,506	1,617,253	94,346		1,711,600	1,298,906
47	4.0%	METERS	1860	2,172,783	30,344	(26,534)	2,176,593	1,279,307	63,378	21,074	1,321,611	854,982
47	10.0%	STREET LIGHT/SIGNAL SYSTM	1875	16,523			16,523	16,523			16,523	
1 & 47	4.0%	OTHER TANGIBLE PROPERTY	1990	2,150,996			2,150,996	1,244,881	74,343		1,319,224	831,772
47	4.0%	BUILDINGS AND FIXTURES	1908	668,756	45,085		713,841	152,413	26,901		179,314	534,528
47	10.0%	OFFICE FURNITURE & EQUIP	1915	777,556	14,177		791,733	690,580	31,143		721,724	70,010
10	20.0%	TRANSPORT EQUIP	1930	4,638,418	285,972	27,379	4,951,770	3,649,603	328,429	(27,379)	4,005,411	946,359
8	10.0%	LABORATORY EQUIPMENT	1945	230,701		(130,509)	100,192	230,701		130,509	100,192	
8	10.0%	TOOLS & WORK EQUIPMENT	1940	1,378,186	92,899	(27,523)	1,443,562	896,813	81,259	14,206	963,866	479,697
8	10.0%	COMMUNICATIONS EQUIPMENT	1955	395,567	4,828		400,394	337,880	15,080		352,960	47,434
47	10.0%	MISCELLANEOUS EQUIPMENT	1960	111,116	11,441		122,557	76,213	11,302		87,515	35,042
47& 50	10% & 20%	COMPUTER HARDWARE	1920	3,900,689	131,609		4,032,298	2,654,647	374,375		3,029,022	1,003,276
12	20.0%	COMPUTER SOFTWARE	1925	1,876,261	81,966		1,958,227	1,861,282	15,474		1,876,757	81,471
		Subtotal		**102,169,065**	**9,088,087**	**(265,674)**	**110,991,479**	**45,480,757**	**3,727,967**	**246,897**	**48,961,827**	**62,029,652**
		Less Non-Distribution Assets		**16,523**			**16,523**	**16,523**			**16,523**	**0**
		Total		**102,152,542**	**9,088,087**	**(265,674)**	**110,974,956**	**45,464,234**	**3,727,967**	**246,897**	**48,945,304**	**62,029,652**

Appendix 2-C
Fixed Asset Continuity Statements

				2009									
				Cost				Accumulated Depreciation					
CCA Class	Depreication Rate	Acct Description	OEB Acct #	Opening	Additions	Disposals	Closing	Opening	Deprec.	Disposals	Closing	Net Book Value
47	2.5%	CLEARING RIGHTS OF WAY	1806	13,260,761	1,637,793		14,898,554	839,575	354,768		1,194,343	13,704,210
		LAND AND LAND RIGHTS	1805	841,604	12,354		853,958					853,958
47	2.0%	BUILDINGS AND FIXTURES	1808	6,823,071	596	(6,248,049)	575,618	2,180,269	19,679	1,907,901	292,046	283,571
1 & 47	3.3%	STATION EQUIPMENT	1820	9,860,126	120,263		9,980,389	3,897,886	302,061		4,199,946	5,780,443
47	4.0%	POLES TOWERS & FIXTURES	1830	32,487,480	4,450,636	(52,917)	36,885,199	14,197,761	1,264,240	52,917	15,409,084	21,476,115
47	4.0%	O/H CONDUCTORS & DEVICES	1835	15,551,313	1,554,033	(57,194)	17,048,153	7,298,362	583,130	57,194	7,824,298	9,223,855
47	4.0%	U/G CONDUCTORS & DEVICES	1845	955,688	15,449		971,137	163,722	41,663		205,385	765,752
47	4.0%	LINE TRANSFORMERS	1850	9,342,244	419,852		9,762,097	4,698,536	345,157		5,043,693	4,718,403
47	4.0%	SERVICES	1855	3,010,506	118,501		3,129,007	1,711,600	95,612		1,807,212	1,321,795
47	4.0%	METERS	1860	2,176,593	46,812	(212,470)	2,010,935	1,321,611	58,482	135,473	1,244,619	766,316
47	10.0%	STREET LIGHT/SIGNAL SYSTM	1875	16,523			16,523	16,523			16,523	
1 & 47	4.0%	OTHER TANGIBLE PROPERTY	1990	2,150,996			2,150,996	1,319,224	74,343		1,393,567	757,429
47	4.0%	BUILDINGS AND FIXTURES	1908	713,841	48,529	(547,234)	215,137	179,314	440	105,167	74,586	140,550
47	10.0%	OFFICE FURNITURE & EQUIP	1915	791,733	4,779	(8,632)	787,880	721,724	41,802	25,497	738,028	49,852
10	20.0%	TRANSPORT EQUIP	1930	4,951,770	685,982	(1,671,185)	3,966,567	4,005,411	252,887	1,237,103	3,021,195	945,372
8	10.0%	LABORATORY EQUIPMENT	1945	100,192	9,231		109,423	100,192	77		100,269	9,154
8	10.0%	TOOLS & WORK EQUIPMENT	1940	1,443,562	77,389	(15,012)	1,505,940	963,866	84,882	7,506	1,041,242	464,697
8	10.0%	COMMUNICATIONS EQUIPMENT	1955	400,394		(1,526)	398,868	352,960	13,535	1,043	365,452	33,416
47	10.0%	MISCELLANEOUS EQUIPMENT	1960	122,557			122,557	87,515	8,781		96,296	26,261
47& 50	10% & 20%	COMPUTER HARDWARE	1920	4,032,298	156,663	(3,226,896)	962,064	3,029,022	109,217	2,746,460	391,779	570,285
12	20.0%	COMPUTER SOFTWARE	1925	1,958,227	23,828	(1,913,849)	68,206	1,876,757	687	1,838,884	38,559	29,647
		Subtotal		**110,991,479**	**9,382,690**	**(13,954,964)**	**106,419,206**	**48,961,827**	**3,651,442**	**8,115,145**	**44,498,124**	**61,921,081**
		Less Non-Distribution Assets		**16,523**			**16,523**	**16,523**			**16,523**	**0**
		Total		**110,974,956**	**9,382,690**	**(13,954,964)**	**106,402,683**	**48,945,304**	**3,651,442**	**8,115,145**	**44,481,601**	**61,921,081**

The splitting out of the distribution assets from Great Lakes Power Limited to Great Lakes Power Distribution Inc. on July 1, 2009 did not include the building on Sackville Road in Sault Ste. Marie, certain fleet vehicles, and the information technology hardware and software. The removal of those assets was based on the net book value.

Appendix 2-C
Fixed Asset Continuity Statements

				2010									
				Cost				Accumulated Depreciation					
CCA Class	Depreication Rate	Acct Description	OEB Acct #	Opening	Additions	Disposals	Closing	Opening	Deprec.	Disposals	Closing	Net Book Value
47	2.5%	CLEARING RIGHTS OF WAY	1806	14,898,554	2,068,412		16,966,966	1,194,343	398,319		1,592,662	15,374,304
		LAND AND LAND RIGHTS	1805	853,958			853,958					853,958
47	2.0%	BUILDINGS AND FIXTURES	1808	575,618	263,161		838,778	292,046	13,841		305,887	532,891
1 & 47	3.3%	STATION EQUIPMENT	1820	9,980,389	1,434,409		11,414,798	4,199,946	317,171		4,517,117	6,897,681
47	4.0%	POLES TOWERS & FIXTURES	1830	36,885,199	3,925,877		40,811,076	15,409,084	1,437,809		16,846,893	23,964,183
47	4.0%	O/H CONDUCTORS & DEVICES	1835	17,048,153	1,749,657		18,797,810	7,824,298	645,002		8,469,301	10,328,510
47	4.0%	U/G CONDUCTORS & DEVICES	1845	971,137			971,137	205,385	41,869		247,254	723,883
47	4.0%	LINE TRANSFORMERS	1850	9,762,097	943,005		10,705,102	5,043,693	377,515		5,421,209	5,283,893
47	4.0%	SERVICES	1855	3,129,007	333,033		3,462,040	1,807,212	101,282		1,908,494	1,553,546
47	4.0%	METERS	1860	2,010,935	168,071		2,179,006	1,244,619	62,851		1,307,470	871,536
47	10.0%	STREET LIGHT/SIGNAL SYSTM	1875	16,523			16,523	16,523			16,523	
1 & 47	4.0%	OTHER TANGIBLE PROPERTY	1990	2,150,996			2,150,996	1,393,567	74,343		1,467,910	683,086
47	4.0%	BUILDINGS AND FIXTURES	1908	215,137			215,137	74,586	8,605		83,192	131,945
47	10.0%	OFFICE FURNITURE & EQUIP	1915	787,880			787,880	738,028	14,326		752,354	35,526
10	20.0%	TRANSPORT EQUIP	1930	3,966,567	318,340		4,284,906	3,021,195	333,050		3,354,245	930,661
8	10.0%	LABORATORY EQUIPMENT	1945	109,423			109,423	100,269	923		101,192	8,231
8	10.0%	TOOLS & WORK EQUIPMENT	1940	1,505,940	53,057		1,558,996	1,041,242	90,411		1,131,653	427,343
8	10.0%	COMMUNICATIONS EQUIPMENT	1955	398,868	55,049		453,917	365,452	15,250		380,702	73,215
47	10.0%	MISCELLANEOUS EQUIPMENT	1960	122,557			122,557	96,296	5,305		101,601	20,956
47& 50	10% & 20%	COMPUTER HARDWARE	1920	962,064	26,528		988,593	391,779	111,491		503,271	485,322
12	20.0%	COMPUTER SOFTWARE	1925	68,206	32,515		100,721	38,559	7,306		45,865	54,856
		Subtotal		**106,419,206**	**11,371,113**	**0**	**117,790,319**	**44,498,124**	**4,056,672**	**0**	**48,554,796**	**69,235,523**
		Less Non-Distribution Assets		**16,523**			**16,523**	**16,523**			**16,523**	**0**
		Total		**106,402,683**	**11,371,113**	**0**	**117,773,796**	**44,481,601**	**4,056,672**	**0**	**48,538,274**	**69,235,523**

Appendix 2-C
Fixed Asset Continuity Schedule

				2011													
				Cost						Accumulated Depreciation							
CCA Class	Depreication Rate	Acct Description	OEB Acct #	Opening	Additions	Disposals	Closing	Allocations	Closing After Allocations	Opening	Deprec.	Disposals	Closing	Allocations	Closing After Allocations	Net Book Value
47	2.5%	CLEARING RIGHTS OF WAY	1806	16,966,966	2,217,628		19,184,594		19,184,594	1,592,662	451,895		2,044,557		2,044,557	17,140,037
		LAND AND LAND RIGHTS	1805	853,958	54,374		908,331		908,331				0		0	908,331
47	2.0%	BUILDINGS AND FIXTURES	1808	838,778	21,749		860,528		860,528	305,887	16,685		322,572		322,572	537,956
1 & 47	3.3%	STATION EQUIPMENT	1820	11,414,798	93,342		11,508,140		11,508,140	4,517,117	324,138		4,841,255		4,841,255	6,666,885
47	4.0%	POLES TOWERS & FIXTURES	1830	40,811,076	3,884,635		44,695,711		44,695,711	16,846,893	1,548,112		18,395,005		18,395,005	26,300,706
47	4.0%	O/H CONDUCTORS & DEVICES	1835	18,797,810	1,310,655		20,108,465		20,108,465	8,469,301	684,135		9,153,436		9,153,436	10,955,029
47	4.0%	U/G CONDUCTORS & DEVICES	1845	971,137	95,698		1,066,834		1,066,834	247,254	43,658		290,912		290,912	775,923
47	4.0%	LINE TRANSFORMERS	1850	10,705,102	627,613		11,332,715		11,332,715	5,421,209	402,321		5,823,529		5,823,529	5,509,185
47	4.0%	SERVICES	1855	3,462,040	343,839		3,805,879		3,805,879	1,908,494	112,830		2,021,324		2,021,324	1,784,555
47	4.0%	METERS	1860	2,179,006	27,187		2,206,193		2,206,193	1,307,470	66,776		1,374,246		1,374,246	831,947
47	10.0%	STREET LIGHT/SIGNAL SYSTM	1875	16,523			16,523		16,523	16,523			16,523		16,523	
1 & 47	4.0%	OTHER TANGIBLE PROPERTY	1990	2,150,996			2,150,996		2,150,996	1,467,910	74,343		1,542,253		1,542,253	608,743
47	4.0%	BUILDINGS AND FIXTURES	1908	215,137			215,137		215,137	83,192	8,605		91,797		91,797	123,340
47	10.0%	OFFICE FURNITURE & EQUIP	1915	787,880	27,187		815,067		815,067	752,354	11,435		763,790		763,790	51,277
10	20.0%	TRANSPORT EQUIP	1930	4,284,906	625,297		4,910,203		4,910,203	3,354,245	398,978		3,753,223		3,753,223	1,156,980
8	10.0%	LABORATORY EQUIPMENT	1945	109,423			109,423		109,423	101,192	923		102,115		102,115	7,308
8	10.0%	TOOLS & WORK EQUIPMENT	1940	1,558,996	54,374		1,613,370		1,613,370	1,131,653	93,523		1,225,176		1,225,176	388,193
8	10.0%	COMMUNICATIONS EQUIPMENT	1955	453,917			453,917		453,917	380,702	14,321		395,023		395,023	58,894
47	10.0%	MISCELLANEOUS EQUIPMENT	1960	122,557			122,557		122,557	101,601	5,305		106,907		106,907	15,650
47& 50	10% & 20%	COMPUTER HARDWARE	1920	988,593	442,601		1,431,194	546,219	1,977,412	503,271	139,779		643,050	440,992	1,084,041	893,371
12	20.0%	COMPUTER SOFTWARE	1925	100,721	1,043,647		1,144,368	1,440,470	2,584,838	45,865	114,922		160,787	944,675	1,105,462	1,479,376
		Subtotal		**117,790,319**	**10,869,825**	**0**	**128,660,144**	**1,986,689**	**130,646,832**	**48,554,796**	**4,512,684**	**0**	**53,067,480**	**1,385,667**	**54,453,146**	**76,193,686**
		Less Non-Distribution Assets		**16,523**			**16,523**		**16,523**	**16,523**			**16,523**		**16,523**	
		Total		**117,773,796**	**10,869,825**	**0**	**128,643,621**	**1,986,689**	**130,630,310**	**48,538,274**	**4,512,684**	**0**	**53,050,957**	**1,385,667**	**54,436,624**	**76,193,686**

The 2011 continuity schedule includes the allocation of the shared IT assets as described in the BDR report, Exhibit 4, Tab 5, Schedule 1, Appendix A.

GROSS FIXED ASSETS TABLE

OEB Accoun	Description	2007 Board Approved	2007 Actual	Variance from 2007 Board Approved	2008 Actual	Variance from 2007 Actual	2009 Actual	Variance from 2008 Actual	2010 Test Year	Variance from 2009 Actual	2011 Test Year	Variance from 2010 Test
	Land and Buildings											
1805	Land	841,604	841,604	-	841,604	-	853,958	12,354	853,958	-	908,331	54,374
1806	Land Rights	9,720,877	9,976,901	256,025	13,260,761	3,283,860	14,898,554	1,637,793	16,966,966	2,068,412	19,184,594	2,217,628
1808	Buildings and Fixtures	6,832,763	6,566,898	(265,864)	6,823,071	256,173	575,618	(6,247,454)	838,778	263,161	860,528	21,749
	Sub Total - Land and Buildings	**17,395,243**	**17,385,404**	**(9,840)**	**20,925,436**	**3,540,032**	**16,328,129**	**(4,597,307)**	**18,659,702**	**2,331,573**	**20,953,453**	**2,293,751**
	DS											
1820	Distribution Station Equipment - Normally Primary below 50 k	8,495,076	9,123,967	628,891	9,860,126	736,159	9,980,389	120,263	11,414,798	1,434,409	11,508,140	93,342
	Sub Total - DS	**8,495,076**	**9,123,967**	**628,891**	**9,860,126**	**736,159**	**9,980,389**	**120,263**	**11,414,798**	**1,434,409**	**11,508,140**	**93,342**
	Poles and Wires											
1830	Poles, Towers and Fixtures	29,851,390	30,694,517	843,127	32,487,480	1,792,963	36,885,199	4,397,720	40,811,076	3,925,877	44,695,711	3,884,635
1835	Overhead Conductors and Devices	16,105,767	14,546,701	(1,559,066)	15,551,313	1,004,612	17,048,153	1,496,840	18,797,810	1,749,657	20,108,465	1,310,655
1845	Underground Conductors and Devices	460,099	460,099	-	955,688	495,589	971,137	15,449	971,137	-	1,066,834	95,698
	Sub Total - Poles and Wires	**46,417,256**	**45,701,317**	**(715,939)**	**48,994,481**	**3,293,164**	**54,904,489**	**5,910,008**	**60,580,023**	**5,675,534**	**65,871,011**	**5,290,988**
	Line Transformers											
1850	Line Transformers	8,254,433	8,772,416	517,983	9,342,244	569,828	9,762,097	419,852	10,705,102	943,005	11,332,715	627,613
	Sub Total - Line Transformers	**8,254,433**	**8,772,416**	**517,983**	**9,342,244**	**569,828**	**9,762,097**	**419,852**	**10,705,102**	**943,005**	**11,332,715**	**627,613**
	Services and Meters											
1855	Services	2,678,357	2,868,410	190,053	3,010,506	142,096	3,129,007	118,501	3,462,040	333,033	3,805,879	343,839
1860	Meters	2,220,714	2,172,783	(47,932)	2,176,593	3,811	2,010,935	(165,658)	2,179,006	168,071	2,206,193	27,187
	Sub Total - Services and Meters	**4,899,071**	**5,041,193**	**142,121**	**5,187,099**	**145,906**	**5,139,942**	**(47,157)**	**5,641,046**	**501,104**	**6,012,072**	**371,026**
	General Plant											
1908	Buildings and Fixtures	667,551	668,756	1,205	713,841	45,085	215,137	(498,705)	215,137	-	215,137	-
	Sub Total - General Plant	**667,551**	**668,756**	**1,205**	**713,841**	**45,085**	**215,137**	**(498,705)**	**215,137**	**-**	**215,137**	**-**
	Equipment											
1915	Office Furniture and Equipment	779,264	777,556	(1,708)	791,733	14,177	787,880	(3,853)	787,880	-	815,067	27,187
1930	Transportation Equipment	4,844,121	4,638,418	(205,703)	4,951,770	313,351	3,966,567	(985,203)	4,284,906	318,340	4,910,203	625,297
1940	Tools, Shop and Garage Equipment	1,368,733	1,378,186	9,453	1,443,562	65,376	1,505,940	62,377	1,558,996	53,057	1,613,370	54,374
1945	Measurement and Testing Equipment	230,701	230,701	-	100,192	(130,509)	109,423	9,231	109,423	-	109,423	-
1955	Communication Equipment	393,688	395,567	1,879	400,394	4,828	398,868	(1,526)	453,917	55,049	453,917	-
1960	Miscellaneous Equipment	111,116	111,116	-	122,557	11,441	122,557	-	122,557	-	122,557	-
	Sub Total - Equipment	**7,727,622**	**7,531,544**	**(196,078)**	**7,810,208**	**278,664**	**6,891,234**	**(918,974)**	**7,317,680**	**426,445**	**8,024,537**	**706,857**
	IT Assets											
1920	Computer Equipment - Hardware	3,971,037	3,900,689	(70,348)	4,032,298	131,609	962,064	(3,070,233)	988,593	26,528	1,977,412	988,820
1925	Computer Software	1,839,081	1,876,261	37,180	1,958,227	81,966	68,206	(1,890,021)	100,721	32,515	2,584,838	2,484,117
	Sub Total - IT Assets	**5,810,118**	**5,776,950**	**(33,168)**	**5,990,525**	**213,574**	**1,030,270**	**(4,960,254)**	**1,089,314**	**59,043**	**4,562,250**	**3,472,937**
	Other Distribution Assets											
1990	Other Tangible Assets	2,150,996	2,150,996	-	2,150,996	-	2,150,996	-	2,150,996	-	2,150,996	-
	Sub Total - Other Distribution Assets	**2,150,996**	**2,150,996**	**-**	**2,150,996**	**-**	**2,150,996**	**-**	**2,150,996**	**-**	**2,150,996**	**-**
	GROSS ASSETS TOTAL	**101,817,367**	**102,152,542**	**335,175**	**110,974,956**	**8,822,414**	**106,402,683**	**(4,572,273)**	**117,773,796**	**11,371,113**	**130,630,310**	**12,856,514**

The splitting out of the distribution assets from Great Lakes Power Limited to Great Lakes Power Distribution Inc. on July 1, 2009 did not include the building on Sackville Road in Sault Ste. Marie, certain fleet vehicles, and the information technology hardware and software. The removal of those assets was based on the net book value.

OVERVIEW OF ALLOWANCE FOR WORKING CAPITAL

The working capital allowance is forecast to be $3,930,844 for 2010 and $4,150,138 for 2011. The working capital allowance is based on the "15% allowance approach" referred to at page 8 of the Board's Filing Requirements. The calculations have been provided by account for each of 2007 Actual, 2008 Actual, 2009 Actual, 2010 Test Year and 2011 Test Year in the table on the following page.

Details of the cost of power forecast for 2010 and 2011 included in the working capital allowance calculations can be found at Exhibit 2, Tab 3, Schedule 3 (Calculation of Cost of Power).

WORKING CAPITAL CALCULATION BY ACCOUNT

	Description	2007 Actual	Allowance for Working Capital	2008 Actual	Allowance for Working Capital	2009 Actual	Allowance for Working Capital	2010 Test Year	Allowance for Working Capital	2011 Test Year	Allowance for Working Capital
Rate Used for Working Capital Allowance			15%		15%		15%		15%		15%
Power Supply Expenses											
4705	Power Purchased	11,311,727	1,696,759	10,742,579	1,611,387	11,459,959	1,718,994	13,898,956	2,084,843	14,545,555	2,181,833
4708	Charges-WMS	1,044,431	156,665	1,009,805	151,471	1,000,305	150,046	1,079,208	161,881	1,090,183	163,527
4714	Charges-NW	1,134,046	170,107	1,129,691	169,454	1,064,479	159,672	1,061,037	159,156	1,072,418	160,863
4716	Charges-CN	844,162	126,624	789,830	118,474	850,741	127,611	919,648	137,947	929,572	139,436
4730	Rural Rate Assistance Expense	205,623	30,844	196,701	29,505	263,205	39,481	207,540	31,131	209,651	31,448
	Power Supply Expenses Total	14,539,989	2,180,998	13,868,606	2,080,291	14,638,690	2,195,803	17,166,389	2,574,958	17,847,379	2,677,107
Distribution Expenses - Operation											
5005	Operation Supervision and Engineering	492,192	73,829	482,747	72,412	458,073	68,711	435,385	65,308	482,358	72,354
5010	Load Dispatching	63,221	9,483	58,011	8,702	58,139	8,721	88,075	13,211	90,497	13,575
5012	Station Buildings and Fixtures Expense	196,535	29,480	240,620	36,093	279,542	41,931	291,355	43,703	298,548	44,782
5016	Distribution Station Equipment - Operation Labour	16,888	2,533	12,087	1,813	100	15	53,709	8,056	55,186	8,278
5017	Distribution Station Equipment - Operation Supplies and Expenses	17,790	2,668	4,512	677	78	12	10,700	1,605	10,938	1,641
5020	Overhead Distribution Lines and Feeders - Operation Labour	82,412	12,362	55,814	8,372	56,803	8,520	49,866	7,480	51,237	7,686
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	13,506	2,026	24,093	3,614	44,507	6,676	13,100	1,965	13,372	2,006
5030	Overhead Subtransmission Feeders - Operation	31,679	4,752	33,596	5,039	31,327	4,699	36,458	5,469	37,406	5,611
5035	Overhead Distribution Transformers- Operation	679	102	7,911	1,187	9,540	1,431	27,598	4,140	28,357	4,254
5065	Meter Expense	262,831	39,425	252,109	37,816	254,832	38,225	290,699	43,605	298,257	44,739
5070	Customer Premises - Operation Labour	88,684	13,303	84,585	12,688	92,678	13,902	58,641	8,796	60,254	9,038
5075	Customer Premises - Materials and Expenses	24,216	3,632	24,236	3,635	32,924	4,939	35,000	5,250	35,700	5,355
5096	Other Rent	13,707	2,056	8,365	1,255	34,055	5,108	17,950	2,693	17,950	2,693
	Distribution Expenses - Operation Total	1,304,342	195,651	1,288,685	193,303	1,352,598	202,890	1,408,536	211,280	1,480,059	222,009
Distribution Expenses - Maintenance											
5110	Maintenance of Buildings and Fixtures - Distribution Stations	139,682	20,952	70,386	10,558	38,880	5,832	137,699	20,655	141,072	21,161
5112	Maintenance of Transformer Station Equipment	37,450	5,618	4,829	724	5,034	755	7,786	1,168	7,977	1,196
5114	Maintenance of Distribution Station Equipment	127,037	19,056	124,247	18,637	110,379	16,557	150,904	22,636	154,601	23,190
5120	Maintenance of Poles, Towers and Fixtures	60,346	9,052	8,841	1,326	36,792	5,519	95,374	14,306	97,639	14,646
5125	Maintenance of Overhead Conductors and Devices	1,166,993	175,049	1,061,110	159,166	922,236	138,335	1,029,706	154,456	1,054,161	158,124
5130	Maintenance of Overhead Services	832	125	87,763	13,164	198,281	29,742	156,858	23,529	160,583	24,087
5135	Overhead Distribution Lines and Feeders - Right of Way	1,785,503	267,826	1,624,944	243,742	1,844,171	276,626	2,098,331	314,750	2,600,924	390,139
5155	Maintenance of Underground Services	-	-	15,689	2,353	15,950	2,392	11,611	1,742	11,904	1,786
5175	Maintenance of Meters	50,805	7,621	(17,858)	(2,679)	11,913	1,787	29,025	4,354	29,769	4,465
	Distribution Expenses - Maintenance Total	3,368,649	505,297	2,979,950	446,992	3,183,635	477,545	3,717,293	557,594	4,258,631	638,795
Billing and Collection											
5310	Meter Reading Expense	388,106	58,216	383,925	57,589	369,039	55,356	431,331	64,700	442,222	66,333
5315	Customer Billing	448,520	67,278	381,837	57,275	516,789	77,518	521,376	78,206	534,736	80,210
5320	Collecting	76,389	11,458	90,243	13,536	104,013	15,602	120,421	18,063	123,598	18,540
5335	Bad Debt Expense	18,835	2,825	57,583	8,637	42,067	6,310	45,000	6,750	45,000	6,750
5340	Miscellaneous Customer Accounts Expenses	125,591	18,839	147,880	22,182	157,051	23,558	162,315	24,347	166,170	24,925
	Billing and Collection Total	1,057,441	158,616	1,061,466	159,220	1,188,958	178,344	1,280,443	192,066	1,311,726	196,759
Community Relations											
5420	Community Safety Program	-	-	-	-	-	-	10,000	1,500	10,000	1,500
5515	Advertising Expense	1,902	285	1,119	168	735	110	-	-	-	-
	Community Relations Total	1,902	285	1,119	168	735	110	10,000	1,500	10,000	1,500
Administrative and General Expenses											
5610	Management Salaries and Expenses	167,363	25,104	261,937	39,291	397,021	59,553	967,307	145,096	980,429	147,064
5615	General Administrative Salaries and Expenses	687,539	103,131	810,987	121,648	791,439	118,716	930,433	139,565	955,322	143,298
5620	Office Supplies and Expenses	126,108	18,916	142,821	21,423	354,677	53,202	255,836	38,375	260,953	39,143
5625	Administrative Expense Transferred/Credit	-	-	-	-	-	-	(821,003)	(123,150)	(874,329)	(131,149)
5630	Outside Services Employed	859,370	128,905	1,551,121	232,668	731,687	109,753	409,390	61,409	539,402	80,910
5635	Property Insurance	109,143	16,371	93,634	14,045	89,688	13,453	90,000	13,500	91,800	13,770
5655	Regulatory Expenses	98,387	14,758	92,447	13,867	97,382	14,607	175,000	26,250	175,000	26,250
5665	Miscellaneous General Expenses	23,200	3,480	24,500	3,675	25,000	3,750	-	-	7,500	1,125
5670	Rent	-	-	-	-	69,611	10,442	140,613	21,092	142,019	21,303
5675	Maintenance of General Plant	184,208	27,631	202,663	30,399	314,815	47,222	315,387	47,308	321,695	48,254
5680	Electrical Safety Authority Fees	26,055	3,908	19,237	2,886	18,509	2,776	10,000	1,500	10,000	1,500
	Administrative and General Expenses Total	2,281,373	342,206	3,199,346	479,902	2,889,827	433,474	2,472,964	370,945	2,609,791	391,469
Taxes											
6105	Taxes Other Than Income Taxes (Note less capital taxes)	163,402	24,510	163,956	24,593	146,241	21,936	150,000	22,500	150,000	22,500
	Taxes Total	163,402	24,510	163,956	24,593	146,241	21,936	150,000	22,500	150,000	22,500
Working Capital Allowance Total		22,717,099	3,407,565	22,563,127	3,384,469	23,400,685	3,510,103	26,205,625	3,930,844	27,667,586	4,150,138

Cost of Power Calculation

2010

Rate Category	Volume	Volume	Retail Transmission Rate		Retail Transmission Rate - Wholesale Market Service		Rural and Remote Rate		Cost of Power	
	kWh	kW	Rate	Amount	Rate	Amount	Rate	Amount	Rate	Amount
Residential - R1	115,501,565		0.0057	658,359	0.0050	577,508	0.0052	600,608	0.001	115,502	0.06697	7,735,140
Residential - R2	77,427,222	151,138	2.1218	320,685	1.7882	270,265	0.0052	402,622	0.001	77,427	0.06697	5,185,301
Seasonal	13,738,063		0.0057	78,307	0.0050	68,690	0.0052	71,438	0.001	13,738	0.06697	920,038
Street Lights	873,176	2,304	1.6002	3,687	1.3824	3,185	0.0052	4,541	0.001	873	0.06697	58,477
Total	207,540,026	153,442		1,061,037		919,648		1,079,208		207,540		13,898,956
OEB Account				**4714**		**4716**		**4708**		**4730**		**4705**

2011

Rate Category	Volume	Volume	Retail Transmission Rate		Retail Transmission Rate - Wholesale Market Service		Rural and Remote Rate		Cost of Power	
	kWh	kW	Rate	Amount	Rate	Amount	Rate	Amount	Rate	Amount
Residential - R1	117,017,625		0.0057	667,000	0.0050	585,088	0.0052	608,492	0.001	117,018	0.06938	8,118,683
Residential - R2	77,844,107	151,952	2.1218	322,412	1.7882	271,721	0.0052	404,789	0.001	77,844	0.06938	5,400,824
Seasonal	13,915,643		0.0057	79,319	0.0050	69,578	0.0052	72,361	0.001	13,916	0.06938	965,467
Street Lights	873,176	2,304	1.6002	3,687	1.3824	3,185	0.0052	4,541	0.001	873	0.06938	60,581
Total	209,650,550	154,256		1,072,418		929,572		1,090,183		209,651		14,545,555
OEB Account				**4714**		**4716**		**4708**		**4730**		**4705**

OVERVIEW OF CAPITAL PROGRAMS AND PROJECTS

API has set out descriptions of its distribution capital expenditures for each year from 2008-2011 that exceed a materiality threshold of $75,000. The year under which each capital expenditure is described, corresponds with the in-service date of each capital expenditure. As well, API has engaged in two capital programs that have resulted in capital expenditures in multiple years. Rather than provide repeated descriptions under the corresponding years, API has provided descriptions of these two capital programs below.

High-Risk Conductor Replacement Program

The High-Risk Conductor Replacement Program is a multi-year program that was initiated by Great Lakes Power Limited ("GLPL"), and was reviewed and subsequently approved by the OEB in GLPL's 2007 distribution rate application (EB-2007-0744). The following is an update of this continuing program.

It is general industry knowledge that all types of aluminum conductor steel reinforced ("ACSR") experience corrosion to the steel core as well as a loss of mechanical strength over time. Because ACSR relies on the steel core for mechanical strength, corrosion of the steel core causes it to be susceptible to breaking. Smaller diameter conductor, such as ACSR #4 and #6, do not have the same strength as larger diameter ACSR conductor sizes. ACSR core corrosion together with the inherently weaker mechanical strength of the #4 and #6 sizes, results in a significant safety risk to line workers and the public arising from the higher probability of line breaks. As a result, efforts have been made throughout the industry to replace ACSR #4 and #6.

Since internal corrosion cannot be detected by visual inspection of conductor while in operation, the only accurate method to assess the state of corrosion on a segment of ACSR #4 and #6 is to remove segments of the conductor and conduct a physical inspection.

Historically, API would assess the condition of its ACSR #4 and #6 in the field while repairing line breaks. Based on the observation of API line crews, it was concluded that the broken portions of ACSR #4 and #6 conductor were experiencing severe corrosion. Of particular concern to API was that this corrosion was also occurring on ACSR #4 and #6 existing in favourable conditions where corrosion is less likely to occur. Favourable conditions include low load (i.e. temperature of conductor is lower) and areas without salt contamination (i.e. areas other than along roads). ACSR #4 and #6 used in favourable conditions also suffered severe corrosion. One of the difficulties is that without physically sampling sections of the ACSR, corrosion cannot be detected by routine visual inspection. API does not have any ACSR #4 or #6 in service that is less than 20 years old except for sections that are repaired during restoration efforts.

In 2005, Kinectrics, Inc. was retained by API to perform analytical testing of a sample of conductor that had been replaced. The following excerpt from the Kinectrics report which summarized their analysis of a 23 year old sample of ACSR #6 that had been used in favourable conditions, confirmed API's concerns:

> "This conductor sample is considered to be in poor physical condition. The sample shows very low remaining tensile strength and poor torsional ductility. The steel core wire is 100% covered with heavy surface rust with heavy pitting indicating that corrosion has removed all of the zinc from the outer surfaces of the steel wires."

In 2007, API sent two additional conductor samples to Kinectrics for testing. The following excerpt from the report for these samples confirmed that conductor removed from various areas was experiencing deterioration similar to the 2005 sample:

> "Overall Assessment - Sample #1: This conductor sample is considered to be in poor physical condition. The sample shows very low remaining tensile strength and poor torsional ductility. The steel core wire is 100%

> covered with heavy surface rust with heavy pitting indicating that corrosion has removed all of the zinc from the outer surfaces of the steel wires.
>
> Overall Assessment – Sample #2: This conductor sample is considered to be in fair physical condition. The sample shows fair remaining tensile strength and good torsional ductility. The steel core wire is 100% covered with heavy surface rust with mild to medium pitting indicating that corrosion has removed all of the zinc from the outer surfaces of the steel wires."

A summary of the methodology and results of API's testing of #4 and #6 ACSR is included as Exhibit 2, Tab 4, Schedule 2, Appendix A.

Since severe corrosion of API's ACSR #4 and #6 was occurring on conductor in favourable conditions, it was likely that ACSR #4 and #6 corrosion was occurring on other segments throughout API's system. In API's opinion, this circumstance posed a significant safety risk to the public (not only in populated areas but also to members of the public who use API's ROWs for recreational purposes such as snowmobiling, hiking, etc.) and API's line personnel.

There have been a number of worker and public safety incidents related to failure of #4 and #6 ACSR conductors in Ontario. As an example of the significant hazard that API's ACSR #4 and #6 conductor poses to workers and the public, on February 3, 2004 there was an incident on API's distribution system whereby a line (ACSR #6) broke approximately ten feet from a pole. The conductor on the source side had come to rest against the pole, and the remaining section of conductor fell across a pickup truck parked underneath. The section of line lying across the truck was on the load side of the break and as a result was isolated. Had it not been isolated, the consequences could have been much worse.

Because of industry knowledge, historical observations, expert analysis and testing, age of the conductor and operational experience, API concluded that its system composed of #4 and #6 ACSR needed to be replaced and as a result, it commenced this program.

Concurrent with the commencement of the high-risk conductor replacement program, API gave direction to all line personnel; imposing restrictions and specific work procedures for work conducted on or near #4 and #6 ACSR conductor in order to enhance worker safety.

The contractor and project manager responsible for a majority of the conductor replacement have indicated that breakage in the conductor stranding was frequently identified, a majority of the conductor replaced was corroded to the point of exposing the steel core, and inspections of the conductor at mid-span intervals revealed severe pitting. API's concerns have been and continue to be validated by the continuation of the removal of this conductor.

The High-Risk Conductor Replacement Program was initiated in 2003, with a total of 704 km of #4 and #6 ACSR scheduled to be replaced. Approximately 50 km of ACSR conductor will be replaced during each year 2010-2012. This replacement will consist of #6 ACSR and sections of #4 ACSR deemed to be higher-risk due to a combination of public safety risk, impact on reliability, vintage, pole condition and joint-use tenancy. The entire program (both #4 and #6 ACSR) was previously targeted for completion by 2012, at a pace of approximately 100 km per year for the 2008-2012 period. API has continued to evaluate the condition of conductor being removed as the replacement program moves from areas of high-density and high airborne contamination to more remote and isolated areas. Preliminary observations of small amounts of #4 ACSR removed from these remote areas indicates that this conductor may not be experiencing the same severity of core corrosion as #6 ACSR in general and #4 ACSR in areas of higher airborne contamination. While the conductor still demonstrated overall deterioration, the loss in tensile strength was not as severe as samples previously tested. As a result of these observations, API lowered the annual replacement targets to

50 km per year (based on typical replacement levels prior to 2008) in order to achieve the replacement of substantially all of its #6 ACSR by the end of 2012. API plans to conduct testing on samples of #4 ACSR, that are representative of various geographical areas and various vintages, in order to re-evaluate its target replacement plan for #4 ACSR in remote areas beyond 2012.

As the program progresses from towns and villages to more rural and remote locations, API expects some increases in the average cost/km replacement as compared to previous years due to a combination of the following factors:

- Year over year inflationary increases in material, labour, equipment and fuel costs.
- Costs related to daily travel time, fuel consumption, contractor mobilization, design, staking and commissioning will increase.
- Less favourable soil conditions in the more remote areas increases the average cost of setting poles.
- Many existing lines in remote areas were originally constructed off-road. In many cases, relocating these lines to road allowance will result in improved reliability and will reduce future O&M costs. This relocation however requires an incremental up-front cost to clear right-of-way for the new line.
- Replacement of shorter line sections in these areas translates into an increasing number of projects per year to achieve the 50 km replacement target. While the majority of project costs are related to the distance or number of poles, some costs tend to be more project-specific.

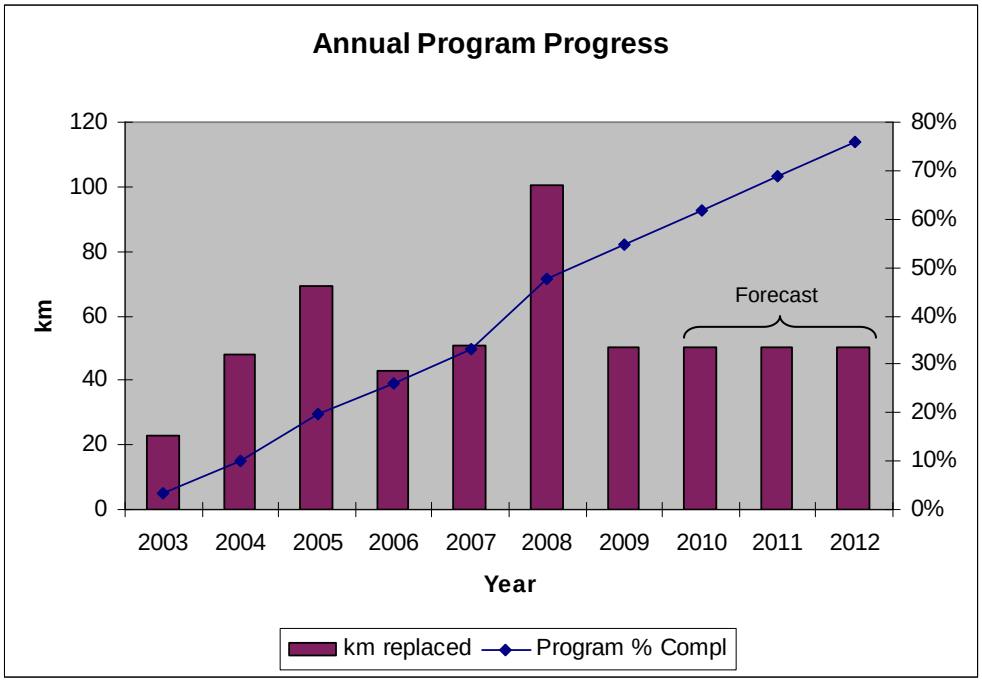
API manages its conductor replacement program with the objective of maximizing safety and reliability, while minimizing costs. API prioritizes these objectives as follows:

1. Safety (replacement in communities and where public risk is high);
2. Reliability (replacement where the load is the highest or where there is industrial or commercial impact from failure); and
3. Cost (in locations where API can logistically optimize internal resources and independent contractors).

For the reasons set out above, there is clearly a need to continue API's conductor replacement program. If API's #4 and #6 ACSR conductor is not replaced, the following can be expected to occur:

- The conductor will continue to corrode, mechanical strength will weaken and there will be an increasing amount of conductor breaks.
- As the conductor continues to corrode, API's line personnel will be exposed to increasing safety risk due to more frequent maintenance calls and the inherent danger of working on and around corroded conductor.
- Public safety risk will increase.
- Reliability will be adversely affected causing an increasing amount of outages.
- Maintenance costs to repair breaks will increase.
- The possibility of forest fires caused by broken conductor will increase.

The following chart illustrates the number of kilometres of high-risk conductor replaced annually since the start of the program, as well as the planned replacement to the end of 2012.



Right-of-way Expansion Program

The Right-of-way Expansion Program is the continuation of a multi-year program that was initiated by Great Lakes Power Limited ("GLPL"), and that was reviewed and subsequently approved by the OEB in GLPL's 2007 distribution rate application (EB-2007-0744). The following is an update of this continuing program.

Through its rights-of-way ("ROW") expansion program, API has been widening its ROW from the standard of approximately 2 meters on each side of the line (plus allowance for conductor swing) to 4 meters (plus allowance for 0.5 meters on either side conductor swing), resulting in a ROW of 9 meters. The expansion program is necessary for public and worker safety, reliability, and for API's ROW to be consistent with industry practice. The expansion program was undertaken contemporaneously with API's cycle for ROW maintenance, which is described in Exhibit 4, Tab 1, Schedule 1, Appendix B.

Being located in rural, Northern Ontario, one of the characteristics of API's distribution service area is that it is predominantly located in forest zones with dense vegetation. API's distribution service area extends through two forest zones. The southern part is in the Great Lakes - St. Lawrence forest zone, characterized by red and sugar maple, yellow birch, red oak, hemlock, red and white pine. The northern part is in the Boreal forest zone, characterized by black and white spruce, tamarack, aspen, white birch, balsam fir, and jack pine. North of Wawa and east of the Montreal River area is the approximate transition area between the two forest zones.

ROW's that run through forests are attractive to and frequented by recreational users. For API, its ROW located in forests are primarily on private property, forced roads, road allowances and Crown land. Accordingly, the level of public access on API's ROW is significant. Members of the public that access API's ROW include recreational users such as hikers, snowmobile and ATV operators, adjacent land owners, tree-trimmers/wood-harvesting operators, and other users of adjacent roads, lands, and ROW (including telephone or cable companies and highway departments).

The combination of open and public access on API's ROW and the fact that API's ROW are surrounded by trees that could come into contact with or fall on the lines is a public safety concern. Accordingly, API's ROW expansion program is necessary to protect the public as well as API's line personnel. API's ROW expansion program will reduce the likelihood of a public hazard related to trees and branches coming into contact with or falling on lines. The wider ROW standard will also increase worker safety for the following reasons:

- line workers will less frequently repair lines that have been broken by or come into contact with fallen trees or branches;
- working on lines with a wider clearance to the tree-line is inherently safer; and
- it will be safer to move equipment on the ROW's.

Hydro One's current standard ROW width is 10 meters (5 meters on either side of the line including an allowance for conductor swing). The 9 meter wide ROW standard that API adopted (4.5 meters on either side of the line including an allowance for conductor swing) is more consistent with industry practice than its previous ROW practice. Although Hydro One's ROW standard is wider than API's, API is of the view that it can minimize the safety concerns described above while using the 9 meter wide standard contained in the Electrical Safety Code (the "ESC"). Section 75 of the ESC provides for a 9 meter ROW width (4.5 meters on either side of the line including an allowance for conductor swing). Given that this standard is contained in the ESC, API believes that this ROW standard is prudent from a public and worker safety perspective.

In 2004, Ontario Regulation 22/04 came into effect and required local distribution companies to install, maintain and repair all electrical installations so as to reduce the probability of exposure to electrical safety hazards. According to Ontario Regulation 22/04, overhead distribution lines that meet the 9 meter ROW standard contained in section 75 of the ESC are deemed to reduce the probability of exposure to electrical safety hazards. Furthermore, subsection 5(2) of Regulation 22/04 reinforces API's view that the 9 meter wide ROW standard contained in the ESC is prudent from a safety

perspective. API will continue to monitor the effectiveness of maintaining a 9 meter wide ROW and will make adjustments if required.

API's 9 meter ROW standard is also consistent with the Canadian Standards Association's (the "CSA") ROW standard. Based on API's ROW maintenance cycle and the growth rates of the trees adjacent to API's ROW, CSA standards generally require a 9 meter wide ROW for API's system.[1]

In addition to the safety considerations and industry practices described above, API considered the other benefits that would result from adopting the 9-meter standard. With a wider ROW, line breaks caused by falling trees and branches would be reduced, thereby reducing maintenance costs associated with repairing line breaks. The wider ROW will also lead to the following benefits to consumers: increased efficiencies to storm response; greater access for line maintenance; locating and accessing equipment in problem areas; and the ability to restore power quicker. A larger ROW width standard will remove more hazardous trees and allow for better tree species selection along the backline of the ROW (slower growing, stronger trees i.e. cedar), to create a more stable backline.

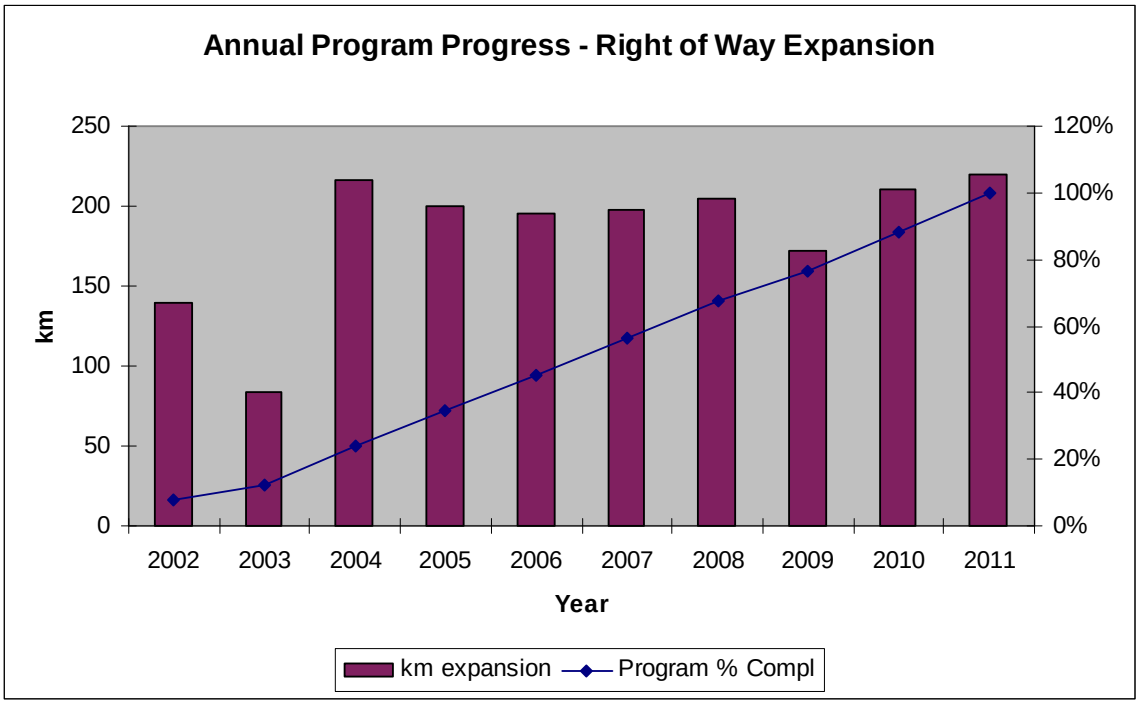
API has conducted its ROW expansion program in conjunction with its ROW maintenance program. Working on the ROW expansion program concurrent with API's regular ROW maintenance program has resulted in the following efficiencies:

- utility arborists with necessary expertise are already mobilized, so there is no need to duplicate efforts;
- API is able to deal with landowners, affected First Nations and Métis, municipalities, and ministries on one occasion in regard to issues such as property easements, cutting rights, heritage trees, environmental concerns, use of herbicides and gaining access to the ROW through private property;

[1] In certain areas where growth rates are high, CSA standards require API to either expand the ROW beyond 9 meters or maintain the areas on a more frequent cycle.

- fewer planned outages (i.e. separate outages for both ROW maintenance and expansion is avoided);
- more efficient work environment for patrolling lines, accessing hardware, and movement of equipment; and
- decreased response time to unplanned outages.

The following chart illustrates the number of kilometres of right-of-way expansion completed annually since the start of the program, as well as the planned completion to the end of the program.



CAPITAL PROJECTS 2007-2011

The tables on the following pages provide an overview of capital spending for the 2007 to 2011 time period excluding the Smart Metering program. 2007 actual spending is compared to amounts previously identified in the 2007 rate application (EB-2007-0744). Actual spending for 2008 and 2009, as well as forecasted spending for 2010 and 2011 is also included.

On subsequent pages, explanations are provided for projects exceeding $75,000 that were not included in API's 2007 rate application. Explanations are also provided for 2008-2011 projects exceeding $75,000. Information Technology Strategy and Major Projects expenditures are described separately in Exhibit 2, Tab 4, Schedule 5, Appendix A.

Algoma Power Inc.
Analysis of Actual CapEx vs. Approved CapEx 2007

Project	Approved	2007 Actual	2008 Actual*	Total	Variance
Approved Projects >$75k					
Conductor Replacement	2,573,300	2,351,538	-	**2,351,538**	**(221,762)**
Right-Of-Way Expansion	2,015,000	2,082,247	-	**2,082,247**	**67,247**
Transportation and Work Equipment	600,000	658,901	-	**658,901**	**58,901**
Rebuild 34.5 kV Circuit East	372,000	290,330	6,928	**297,258**	**(74,742)**
Voltage Conversion	281,700	270,469	6,412	**276,881**	**(4,819)**
Transformers	220,000	206,175	-	**206,175**	**(13,825)**
Garden River DS Increase Capacity	181,500	222,015	19,859	**241,874**	**60,374**
Goulais Substation Breaker Replacement	144,900		135,435	**135,435**	**(9,465)**
Subtotal >$75k in Rate Application	6,388,400	6,081,675	168,634	**6,250,309**	**(138,091)**
Other Spending					
AM/FM	-	120,395	-	**120,395**	**120,395**
Padmount Transformer Inventory	-	80,460	-	**80,460**	**80,460**
Total of other 2007 Capital Projects	2,194,270	1,942,566	-	**1,942,566**	**(251,704)**
Note: $2,194,270 is the result of $8,582,670 Total Capital identified in 2007 rate application less the $6,388,400 total of projects > $75k.					
Total 2007 CapEx	8,582,670	8,225,096	168,634	**8,393,730**	**(188,940)**

*In this table, “2008 Actual” represents the amounts capitalized in 2008 for projects >$75k that were identified in the 2007 rate application (EB-2007-0744). 2008 total capital expenditures are detailed in the table on the following page.

Algoma Power Inc.
Actual and Forecast CapEx 2008-2011

	2008 Actual	2009 Actual	2010 Forecast	2011 Forecast
Project / Program				
Conductor Replacement	2,255,252	4,107,674	3,874,575	4,078,021
Right-Of-Way Expansion	2,897,574	1,620,024	2,051,423	2,191,257
Transformers (Total)	427,733	295,914	620,643	283,772
Transportation and Work Equipment	112,347	570,701	323,909	625,297
IT Hardware	-	-	-	415,414
IT Software	-	-	-	934,900
Wawa #1 DS Rebuild	838,587	2,445	-	-
St. Joseph Island - New Submarine Cables	495,589	14,331	-	-
Waltonen Rd. Loop Feed	175,639	-	-	-
Insulator Replacement No. 4 Circuit	164,885	233,038	-	-
Goulais Substation Breaker Replacement	135,435	-	-	-
Hawk Junction Switch Replacement	117,838	-	-	-
Garden River DS Oil Containment	96,752	-	-	-
Wawa Voltage Conversion	-	320,572	242,892	-
Pole Replacement - No. 2 Wawa 34.5 kV	-	102,393	4,226	-
Refurbish Bar River Regulating Station	-	92,916	-	-
Replacement Supply to St. Joeseph Island	-	-	1,861,165	-
Wawa 34.5 kV Line Relocation	-	-	269,240	-
HVAC Replacement	-	-	213,780	-
2nd Feeder Desbarats DS	-	-	161,084	-
Richmont Mines Upgrades			116,340	
Goudreau DS Structure Replacement	-	-	91,774	-
Buttermilk Ski Hill Line Relocation	-	-	91,558	
Bellevue Valley Line Relocation	-	-	-	269,693
Submarine Cable to Michipicoten Lighthouse	-	-	-	95,698
Subtotal >$75k	**7,717,631**	**7,360,008**	**9,922,609**	**8,894,052**
Total of other 2008-2011 Capital Projects	**1,370,457**	**2,022,682**	**1,448,505**	**1,975,773**
Total 2008-2011	**9,088,088**	**9,382,690**	**11,371,114**	**10,869,825**

Pad-Mount Transformer Inventory - $80,460: In previous years, almost all of API's service connections were either connected overhead, or were of a size that API did not supply transformation. As a result, API did not maintain a large inventory of pad-mount transformers. With an increasing percentage of new service requests considering underground options, API was required to acquire a sufficient inventory of pad-mount transformers to meet the connection timelines stipulated in the DSC and its Conditions of Service.

AM/FM - $120,395: API's current mapping software requires custom programming for the majority of product support and development. The majority of these costs related to custom programming to support API's outage management system, its CableCAD mapping system and integration between the two systems. Costs were also incurred to purchase additional software viewer licenses to improve efficiencies in operations and engineering processes.

Capital Projects 2008

API's total capital expenditures were $9,088,088 for 2008. Projects exceeding the $75,000 materiality threshold are described in more detail below.

High Risk Conductor Replacement Program (100 km) - $2,255,252: Please refer to the description of API's conductor replacement program described above. Although the 100km of replacement projects were in-service by late 2008, the accounting transfer from Work in Progress to Rate Base for many projects was completed in early 2009. This resulted in approximately $1.87M of the $4.06M total being capitalized in 2009 as opposed to 2008.

Right-of-Way Expansion Program - $2,897,574: Please refer to the description of API's right-of-way expansion program described above.

Wawa #1 DS Rebuild - $841,032:

- Contractor costs for rebuild (excl transformer costs) - $394,755
- Transformer purchase, delivery, installation and commissioning - $250,899
- Major Equipment (reclosers, imbiber) - $41,718

- API costs (engineering, project management, labour, mat'l, equipment) - $153,660

This substation previously contained three end-of-life single phase transformers supplying a small portion of the 4.8 kV Delta configured distribution system in the town of Wawa. The transformers were installed in the early 1960's and the overall rating of the transformer bank was insufficient to supply the town's entire load. The transformers were showing signs of oil staining on the transformer surface. The overall condition of the transformers combined with the absence of secondary oil containment and sub-standard equipment clearances within the substation presented considerable safety, environmental and reliability risks. The substation rebuild consisted of removal and disposal of the three end-of-life transformers and other obsolete equipment, construction of oil containment and a transformer foundation, installation of a new 3-phase power transformer, and construction of a new station ground grid. Existing fencing, steel structures and switches that were determined to be in good condition were incorporated into the new station design. The rebuild has reduced the safety, environmental and reliability risks previously associated with this site. The substation rebuild was also a necessary starting point for the overall voltage conversion in the town of Wawa from 4.8 kV Delta to 4.8/8.3 kV Wye (see description in 2009).

<u>St. Joseph Island – New 34.5 kV Submarine Cables - $509,920</u>:

- Submarine Cable - $170,739
- Electrical Contractor Costs - $70,736
- Cable-laying Contractor Costs - $64,054
- Switching Kiosks - $30,240
- Dip Pole Cables, Terminations & Accessories - $28,145
- Craning Costs - $5,407
- API costs (engineering, project management, labour, mat'l, equipment) - $140,599

Existing PILC cables installed in 1961, and a spare cable installed in 1975 were the single source of supply to an island with almost 1800 customers. Two of these cables required emergency repairs due to failure near the cable terminations in the late 1990's. The cable termination structures were installed in 1961 and these wooden structures were showing signs

of deterioration. It would not have been practical to replace the existing structures while maintaining supply to the island, nor to relocate the existing cables to a newly constructed structure. Also, running the existing cables to failure was not an option as the allowable installation window during any given year is quite small due to a combination of weather and environmentally sensitive areas. As a result, new submarine cables were installed and terminated to new pad-mounted kiosks on either side of the water crossing. The larger conductor size of the new cables as compared to the original cables will make it possible to supply the island directly at 25 kV, allowing the St. Joseph Island DS to be retired in 2010 (see 2010 project description for more detail).

Transportation and Work Equipment - $112,347:

- Purchase of two pick-up trucks (replace two pickups approx. 10 years old) – $54,929
- Purchase new brush chipper for forestry – $30,244
- Purchase two new snow-machines – $19,890
- Miscellaneous - $7,284

Waltonen Rd. Loop-feed - $175,639: Due to a large amount of upcoming conductor replacement and ROW expansion work in the area, a tie-line was constructed between two feeders in this area. This has minimized the number and duration of outages associated with work in the area and will continue to serve as a loop-feed to minimize interruptions and improve restoration time in future years.

Insulator Replacement No. 4 Circuit - $164,885: In early 2008, API experienced four outages to a 44 kV sub-transmission circuit, all within a one month period. Analysis of outage reports dating back to 2006 revealed an increasing number of outages on this circuit, many of which were due to failed insulators. API sent three of these defective insulators to Kinectrics Inc. in order to investigate the cause of failure and to provide recommendations for further action. The Kinectrics report identified the cause of failure as poor quality porcelain that was cracked as a result of cement expansion over time. The report suggested the possibility that a combination of severe freeze-thaw cycles in this area, combined with vibration and pollution associated with the line following a railway track, caused the cracking process to accelerate. API conducted

thorough visual inspections for surface cracking as recommended in the Kinectrics report, determined that the failure was not an isolated incident, and initiated a program to replace insulators in this area during 2008 and 2009. The failing porcelain insulators were replaced with polymer insulators that are less susceptible to these methods of failure. 292 porcelain insulators were replaced in 2008 in a section of the circuit along the railway track between Hawk Junction and Goudreau.

Transformers – $427,733:

1. Annual Transformer Inventory - $176,620: This includes annual transformer purchases to connect new services and to replace in-service transformers due to failure or load growth. Due to API's lower customer density, the percentage of customers requiring transformers is higher and it is often unfeasible to group customers on the same transformers. There are approximately 6,000 transformers in service in API's distribution system. The basis for replacement is end of life where the transformer fails, or because of voltage conversions. 80 inventory transformers were purchased in 2008, at an average cost of $2,208 per transformer.

2. Transformers for Voltage Conversion and #4/#6 ACSR Replacement Projects - $251,113: A portion of the #4/#6 ACSR replacement projects scheduled for 2008 were located in areas targeted for voltage conversion in the near future. Transformers in these areas are typically replaced with dual-voltage transformers at the time of the line rebuilds in order to minimize the time and costs associated with the future conversion. 130 transformers were purchased for voltage conversion and #4/#6 ASCR replacement projects in 2008, at an average cost of $1,931 per transformer.

The transformers removed during conductor replacement and voltage conversion projects are returned to inventory if they are suitable for reuse based on overall condition and electrical ratings. The vast majority of these transformers are rated 4.8 kV, and as such are only suitable for use on small portions of API's system, mostly in the Wawa area.

Goulais Substation Breaker Replacement - $135,435: This project was described in the 2007 rate application (EB-2007-0744), with forecasted spending of $144,900 in 2007. The project was substantially completed in 2007, however due to adverse weather and the impact that the final power outage would have had on customers in late 2007, the new reclosers were not placed in service until early 2008.

Hawk Junction Switch Replacement - $117,838: Due to the construction and condition of three existing switches associated with a 44 kV voltage regulator at the Hawk Junction DS, the switches could not be operated under load or used as isolation points for work protection. As a result, routine maintenance activities and switching often required complete isolation of the 44 kV circuit from the upstream transmission supply points, resulting in outages to large industrial customers. These switches were replaced with 44 kV load break switches in 2008 to improve the operability and reliability of this circuit.

Garden River Oil Containment - $96,752: This project follows from the installation of a second transformer (T2) and associated oil containment during the Garden River DS capacity increase in late 2007. The oil containment that had surrounded the original station transformer (T1) was constructed at the same time as the station and did not meet current MOE requirements for Sewage Works in terms of drainage and provisions for effluent sampling. As a result, API could not obtain a Certificate of Approval from the MOE for the overall site. This required the original T1 oil containment to be re-designed and re-built to current standards. API decided to rebuild the existing containment while the contractor and project manager were already mobilized in the area, resulting in cost saving compared to a future rebuild. The re-design of the T1 containment concurrent with the T2 containment construction in late 2007 also allowed the two containment systems to be linked together, requiring less material and equipment for the substation overall. As a result of the rebuild, the environmental risks associated with this site have been reduced and the entire site meets MOE requirements for secondary oil containment systems.

Capital Projects 2009

API's total capital expenditures were $9,382,690 for 2009. Projects exceeding the $75,000 materiality threshold are described in more detail below.

High Risk Conductor Replacement Program (50 km) - $4,107,674: Please refer to the description of API's conductor replacement program described above. As noted in the 2008 program description, the accounting transfer from Work in Progress to Rate Base was completed in early 2009 for many of the projects placed in service late in 2008. As a result, approximately $1.87M of the $4.11M total above relates to 2008 projects.

Right-of-Way Expansion Program - $1,620,024: Please refer to the description of API's right-of-way expansion program described above.

Wawa Voltage Conversion - $563,464: The distribution system in the town of Wawa was originally constructed as a 4.8 kV Delta system. As the load increased and the infrastructure aged on this system, API had faced a number of challenges due to the Delta configuration. The absence of a system neutral posed significant challenges with feeder protection and effective load balancing. With completion of the Wawa #1 DS rebuild in 2008, API's converted the entire town of Wawa from 4.8 kV Delta to a 4.8/8.3 kV Wye configuration. This work was completed entirely by internal API crews and the project costs also include reconfiguration of a large transformer at the Wawa #2 DS that was required to restore a second point of supply to the town following completion of the voltage conversion. This conversion has mitigated many of the safety concerns surrounding protection of the Delta system and will eliminate wide-spread outages resulting from attempts to balance safety and reliability with the protections on the delta configured circuits. The higher phase-to-phase voltage will also reduce future line losses. Selection of the 4.8/8.3 kV voltage level for the wye configuration provided the following additional benefits:

- Enabled most of the existing transformers in Wawa to be re-used with a simple reconnection of the transformer bushings

- Enabled re-use of an existing substation transformer at the Wawa #2 DS by changing the internal links on the transformer to allow operation at the new voltage level.
- Enabled pole-top transformers in good condition that were removed during voltage conversion programs in other areas to be transferred to inventory in Wawa rather than being scrapped.

Transportation and Work Equipment - $570,701

- Purchase of a Radial Boom Derrick ("RBD") to replace existing 1993 RBD that was at end-of-life - $268,201. This RBD was ordered in early 2008, however due to lengthy lead times on these types of vehicles and a delay in delivery, it was not received until early 2009.
- Purchase of 6 Pick-Up Trucks - $266,363. Three were replacements of older vehicles, and the other three were purchased to address vehicle shortages and reduce the need for long-term leases/rentals for regular full time employees.
- Two new Snow-machines for winter access to off-road rights-of-way in Sault lines area - $24,619.
- Two new trailers, one for off-road vehicles and one for snow-machines - $11,518

Transformers - $295,914

1. Annual Transformer Inventory - $107,831: This includes annual transformer purchases to connect new services and to replace in-service transformers due to failure or load growth. Due to API's lower customer density, the percentage of customers requiring transformers is higher and it is often unfeasible to group customers on transformers. There are approximately 6,000 transformers in service in API's distribution system. The basis for replacement is end of life where the transformer fails, or because of voltage conversions. 46 inventory transformers were purchased in 2009, at an average cost of $2,344 per transformer.

2. Transformers for Voltage Conversion and #4/#6 ACSR Replacement Projects - $188,083: A portion of the #4/#6 ACSR replacement projects scheduled for 2009

were located in areas targeted for voltage conversion in the near future. Transformers in these areas are typically replaced with dual-voltage transformers at the time of the line rebuilds in order to minimize the time and costs associated with the future conversion. 61 transformers for voltage conversion and #4/#6 replacement projects were purchased in 2009, at an average cost of $3,083 per transformer. The higher cost per transformer as compared to other years is due to a number of large 3-phase pad-mount transformers required for the voltage conversion in Wawa. The entire town of Wawa was converted in 2009. While most existing 4.8 kV transformers were re-used by reconnecting the bushings, some 3-phase transformers and 3-phase banks required replacement.

The transformers removed during conductor replacement and voltage conversion projects are returned to inventory if they are suitable for reuse based on overall condition and electrical ratings. The vast majority of these transformers are rated 4.8 kV, and as such are only suitable for use on small portions of API's system, mostly in the Wawa area.

Insulator Replacement No. 4 Circuit - $233,038: This is the second portion of insulator replacement on this circuit. Please see the detailed description 2008 capital projects. 171 insulators were replaced in 2009 between Hawk Junction and Goudreau. The higher cost per insulator as compared to 2008 replacements is due to the requirement of external contractors and specialized equipment to access structures that are not accessible by road or rail.

Pole Replacement – No. 2 Wawa 34.5 kV - $106,619: Routine circuit inspections revealed that a number of poles on this distribution feeder were in poor condition and required replacement. A section of 40 poles in the poorest overall condition were replaced in 2008.

Refurbish Bar River Regulating Station – $92,916: The condition of the site surrounding this voltage regulator presented a number of public and worker safety risks as fencing was in poor condition and electrical clearances between obsolete equipment and a 34.5 kV bypass circuit were less than required. The bypass circuit was re-located, allowing obsolete equipment to be removed and new fencing to be rebuilt around a smaller overall station footprint.

Capital Projects 2010

API's total capital expenditures for 2010 are forecasted to be $11,371,114. It is expected that all projects listed below will be placed in service in 2010. Projects exceeding the $75,000 materiality threshold are described in more detail below.

Conductor Replacement Program (50 km) - $3,874,575: Please refer to the description of API's conductor replacement program described above. The increase in program cost from 2009 to 2010/2011 is due to increasing cost/km required to complete the program in rural areas for the reasons listed in the detailed program overview above.

Right-of-Way Expansion Program - $2,051,423: Please refer to the description of API's right-of-way expansion program described above.

Replacement Supply to St. Joseph Island - $1,861,165

The existing substation on St. Joseph Island was constructed in 1961. Three of the transformers currently in service were installed between 1968 and 1973, with a fourth unit added in 1985. Analyses of oil samples from the three older transformers are showing increasing levels of moisture content. Dissolved gas analysis on the newer fourth transformer shows high levels of carbon monoxide, indicating that the insulation has been overheated due to prolonged overloading or corona. Due to the age, condition and capacity of the existing St. Joseph Island substation structure and transformers, the risk of catastrophic failure is increasing in probability. Failure could result in significant safety, reliability or environmental impacts. The existing single-phase transformers making up the three-phase bank are mismatched in all electrical ratings, leading to significant circulating current and higher than average transformer losses. One of the transformers is now weeping small amounts of oil and while the issue is currently controlled and contained, the fact that there is no secondary oil containment presents an increasing environmental risk if replacement is delayed. Crowded conditions on site make installation of a system spare transformer difficult and hazardous.

There is clearly a need to replace the existing substation on St. Joseph Island due to increasing safety, environmental, and reliability risks. API plans to reconfigure its subtransmission system in the Desbarats to St. Joseph Island area to allow the St. Joseph Island load to be supplied directly from another nearby substation. The overall plan will effectively eliminate two existing antiquated distribution substations, resulting in improved operability, maintainability and reliability of the system. The individual projects descriptions below provide details of how each project supports this overall plan.

New Desbarats DS – New Supply to St. Joseph Island: API's plan for 2010 involves installing a new supply to St. Joseph Island from the existing New Desbarats DS and retiring the existing St. Joseph Island DS. In evaluating alternatives for replacing the existing St Joseph Island DS, API determined that this option would prove more economical and provide more operational benefits in terms of reducing future substation maintenance requirements, when compared to the option of constructing a new substation on St. Joseph Island. This plan will involve the installation of a new 34.5/25 kV transformer and significant civil and electrical modifications to the New Desbarats DS. Upon completion of this work, the existing 34.5 kV submarine cables between Desbarats and St. Joseph Island will be operated at 25 kV, and the St. Joseph Island DS will be bypassed, allowing it to be retired. This project is dependent on the voltage conversion project and the installation of voltage regulators as described below.

Voltage Conversion – Desbarats Area: There is a small amount of 4.8/8.3 kV load on the existing Old Desbarats DS. The transformers were installed in 1976 and oil analysis is showing increasing levels of moisture content. Equipment in the substation is prone to salt-spray contamination resulting from its location along a major highway. This substation is electrically connected to the 34.5 kV feeder between the New Desbarats DS and the St. Joseph Island DS. As a result of the plan to convert this portion of the 34.5 kV feeder to 25 kV for the new supply to St. Joseph Island, API plans to retire this substation by converting most portions of the load to 7.2/12.5 kV to allow transfer to the 12.5 kV feeders supplied from the New Desbarats DS. A small amount of the 4.8 kV single-phase load in more rural

areas will not be converted to 7.2 kV at this time and will be supplied with the use of step-down transformers.

Voltage Regulators - St. Joseph Island: API has determined that supplying St. Joseph Island at 25 kV directly from the Desbarats area will require installation of voltage regulators on the 25 kV system in order to maintain acceptable voltage profiles at the end of long, single-phase feeders. Installation of these voltage regulators will also resolve some voltage concerns that were present before the change in supply.

Transformers - $620,643

1. Annual Transformer Inventory - $116,866: This includes annual transformer purchases to connect new services and to replace in-service transformers due to failure or load growth. Due to API's lower customer density, the percentage of customers requiring transformers is higher and it is often unfeasible to group customers on the same transformers. There are approximately 6,000 transformers in service in API's distribution system. The basis for replacement is end of life where the transformer fails, or because of voltage conversions.

2. Transformers for Voltage Conversion and #4/#6 ACSR Replacement Projects - $503,777: A large number of the #4/#6 ACSR replacement projects scheduled for 2010 are located in areas targeted for voltage conversion in the near future. Transformers in these areas are typically replaced with dual-voltage transformers at the time of the line rebuilds in order to minimize the time and costs associated with the future conversion.

The 2010 voltage conversion projects are targeted towards the Desbarats area. This will allow the entire remaining load on the Old Desbarats DS to be transferred to the New Desbarats DS. The retirement of the Old Desbarats DS is required to allow the new 25 kV supply to St. Joseph Island from the New Desbarats DS, as described above. This voltage conversion will require a large number of replacement transformers. It should be noted that

on a number of lines supplied from the Old Desbarats DS, the voltage conversion work is occurring in conjunction with replacement of #4/#6 ACSR in order to achieve efficiencies (i.e. the line is being converted to the new voltage at the same time as it is being rebuilt to replace the conductor). 211 transformers are required for voltage conversion and #4/#6 ACSR replacement projects in 2010, at an average cost of $2,388 per transformer.

The transformers removed during conductor replacement and voltage conversion projects are returned to inventory if they are suitable for reuse based on overall condition and electrical ratings. The vast majority of these transformers are rated 4.8 kV, and as such are only suitable for use on small portions of API's system, mostly in the Wawa area.

Transportation and Work Equipment - $323,909:

- Purchase Line Truck to replace a 2002 Line Truck with over 300,000 km - $310,000
- Miscellaneous Equipment - $13,909

Wawa 34.5 kV Line Relocation - $269,240: There are currently two 34.5 kV subtransmission circuits connecting the Wawa #1 DS and the Wawa #2 DS. The structures are primarily back-lot construction and were installed in the 1950's. Their condition and proximity to fences and buildings on residential properties constitutes an increasing public safety risk. With the decommissioning of a large mine previously supplied from these circuits and the 2008 re-build of the Wawa #1 DS, one of the two circuits is no longer required. The remaining 34.5 kV feeder will primarily be relocated as over-build construction on an existing 8.3 kV feeder, which will allow the existing back-lot structures to be removed.

HVAC Replacement - $213,780: The existing HVAC system in the Sault Ste. Marie office building is at end-of-life. While replacement of end-of-life equipment is the primary driver, this project is also expected to improve the overall energy efficiency of API's office facilities.

2nd Feeder – Desbarats DS - $161,084: In preparation for load transfers from the Old Desbarats DS to the New Desbarats DS, a second feeder egress was constructed from the New Desbarats DS to pick up the load in the town of Desbarats. This feeder will be placed into service at the

time of conversion in 2010. This will allow the town and rural feeders to be unaffected by faults on the other feeder and will also provide a second supply during some planned outages.

Richmont Mines Upgrades - $116,340: Load increases and requests for additional service location on a mining property required changes to primary metering and the addition of a 44 kV load-break switch as well as some minor modifications to the 44 kV line. An economic evaluation consistent with the DSC determined that no capital contribution would be required from the customer for the necessary upgrades to API's system. In addition, the resulting changes in metering and switching configurations will be operationally beneficial to API.

Goudreau DS Structure Replacement - $91,774: The two-pole structure and platform support a 44/4.8 kV step-down transformer to supply a small 4.8 kV feeder. The structure, platform and transformer were installed in 1964 and are showing visible signs of deterioration. Replacement is required prior to failure of this structure, which could result in environmental impact from spilled transformer oil as well as a prolonged outage to local customers.

Buttermilk Ski Hill Line Relocation - $91,558: Safety concerns identified by the customer and the Electrical Safety Authority require replacement of conductors on a portion of the existing line as well as construction of a new line in a different location due to the hazardous location of the existing line in relation to the ski hill.

Capital Projects 2011

API's total capital expenditures for 2011 are forecasted to be $10,869,825. It is expected that all projects listed below will be placed in service in 2011. Projects exceeding the $75,000 materiality threshold are described in more detail below.

Conductor Replacement Program (50 km) - $4,078,021: Please refer to the description of API's conductor replacement program described above. The increase in program cost from 2009 to 2010/2011 is due to increasing cost/km required to complete the program in rural areas for the reasons listed in the detailed program overview above.

Right-of-Way Expansion Program - $2,191,257: Please refer to the description of API's right-of-way expansion program described above.

IT Hardware and Software - $1,350,314: Please refer to Exhibit 2, Tab 4, Schedule 5, for a detailed description of 2011 IT capital.

Transportation and Work Equipment - $625,297:

- Replacement of one Line Truck - $299,055
- Replacement of other equipment (trucks, snow-machines, off-road vehicles, etc.) - $163,121: Many lines are not road accessible, particularly some critical subtransmission circuits. A variety of equipment is required to allow for inspections, patrols and emergency response through various seasons and ground conditions.
- Off-road Radial Boom Derrick - $163,121: API currently rents a Nodwell several times per year for construction or emergency repairs in off-road areas that are inaccessible to line trucks. Cost per rental is approximately $9000. Time required to arrange the rental and to mobilize to site results in extremely long response times during emergencies. In 2009, there were five rentals (three for emergency repairs, two for planned work).

Transformers - $283,772: Includes annual inventory as well as transformers used for voltage conversion and #4/#6 ACSR Conductor Replacement projects. Please refer to detailed descriptions from prior years. Fewer projects involving voltage conversion are expected in 2011 as compared to previous years and as a result total spending on transformers is expected to be less than 2008-2010 on average.

Bellevue Valley Line Relocation - $269,693: The existing 3-phase line is located off-road in a swampy area. Access is extremely difficult and hazardous to workers. The majority of this line was constructed in 1961 and the majority of poles have not been replaced since this time. Many of the poles are severely leaning due to poor soil conditions. Single phase taps downstream of this line go on to supply power to a number of customers as well as two important communications towers. A new line consisting of 28 poles will be built along a nearby

road allowance to allow the existing line to be retired. The relatively high cost per pole of $9,632 can be attributed to the following factors:

- The requirement to establish a new Right of Way along the nearby road allowance, which involves costs for surveying, acquisition of easements, staking and forestry.
- The large number of anchors and stub poles required due to the curvature of the road allowance (more than three quarters of the new poles require anchoring).

Submarine Cable to Michipicoten Lighthouse - $95,698: The existing line was constructed around a bay in 1970 to supply power to a lighthouse and cottage. The line consists of 14 poles spanning a total distance of approximately 1.5 km. There is no road access to this portion of line and the Right of Way consists mainly of large rock and overgrown trees. Access is hazardous to workers, especially during emergency response at night or in inclement weather. API plans to run approximately 750 metres of submarine cable across the bay in order to allow the existing line to be retired.

Geographic Information System Implementation: (Note that the following project is not expected to exceed $75,000 in any particular year, however API has added a description of the need for a GIS system as it expects annual capital expenditure in the range of $50,000-$75,000 per year in future years for implementation, development and system integration activities.)

API manages its distribution lines (conductor and devices, poles, pole-mounted transformers, rights-of-way, etc.) and distribution substations (transformers, voltage regulators, communications, civil structures, etc.) with its Automated Mapping Facilities Management ("AM/FM") system and corporate databases.

API's AM/FM system identifies information on the individual pieces of equipment that comprise API's distribution system (i.e. poles, circuits, transformers, etc.), and provides geographic information on each piece of equipment. The information tracked by API's AM/FM system includes, to the extent possible, installation dates and equipment specifications.

The combination of the AM/FM system, corporate databases, and additional observations, assist API's engineering staff in proposing which facilities require capital improvements in order to maintain reliability.

Prioritization of capital projects supporting improved reliability is based on a number of factors, including:

- reliability considerations;
- health and safety considerations;
- environmental considerations; and
- location relative to other projects (i.e. coordination of crews for multiple projects within proximity).

The current AM/FM system which was implemented in the early 1990's, has reached its end of useful life. Any current integration efforts with upgraded corporate systems would require specialized programming knowledge, which is increasingly difficult to source. Limited program flexibility caused by proprietary software, are impacting the maintenance costs of the current software.

Advances in the software field of Geographic Information Systems (GIS) have provided improvements in user interfaces, customer information requirements, work management, maintenance and capital planning, corporate database integration, external data acquisitions and exchanges, information retrieval, data analysis, reporting, and application integrations such as outage management, SMART Grid and asset management.

There are many industry studies and reports that highlight the value of geographic information systems. In the November 2009 KEMA published a report for the OEB entitled "Leveraging Network Utility Asset Management Practices for Regulatory Purposes" the following reference to the value of GIS was provided:

"In recent years there have been numerous initiatives within electricity distribution and transmission utilities to improve the efficiency of inspection and maintenance activities whereby

trained operational staff receive instructions in the field and record their inspection activities via portable devices capable of two way communications with central databases and work scheduling systems. Further sophistication is possible by interfacing asset registers with Geographic Information Systems (GIS) to enable staff to identify particular assets from maps on hand held devices."

Another report entitled "Review of Asset Management Practices in the Ontario Electricity Distribution Sector – March 10 2009', submitted to the OEB by KPMG identifies GIS as improving the effectiveness of the utility's inspection and maintenance processes.

The implementation of GIS at API will be a multi-year endeavor ensuring both the utility and stakeholder requirements have been addressed. During 2010, API expects to identify utility requirements, stakeholder interests, define the project scope for 2011 and subsequent years, set long term objectives, and develop the long term plan for the project.

ACSR CONDUCTOR TESTING

Overview

This appendix describes the methodology used by API in assessing the condition of its #4 and #6 ACSR conductors and how these assessments have driven the High-Risk Conductor Replacement Program.

Techniques for Condition Assessment

In general, mechanical failure of #4 and #6 ACSR conductors occurs due to the corrosion, and resulting loss of tensile strength in the conductor's steel core. As a result, the condition of an in-service conductor often cannot be accurately determined through routine visual inspections. Since initiating its conductor replacement program, API has relied on the following two methods to assess the condition of the conductor being replaced:

Laboratory Testing: Samples of some conductors that have been removed are sent to Kinectrics for detailed physical testing and analysis. Kinectrics are renowned specialists in the energy industry with comprehensive capabilities for scientific evaluation and advanced testing. Their reports provide a detailed overview of the testing methodology, the test results and an analysis of the overall condition of the conductor sample.

Field Observation of Conductors During Restoration or Following Removal: While the condition of conductor cannot be readily assessed with the conductor in service, conductors that have failed or have been removed from service can be observed physically. While not as accurate as laboratory testing, factors affecting loss of strength are readily identifiable (e.g. core steel is severely rusted/pitted, conductor breaks easily with little force applied, conductor snaps when being coiled onto reels, etc.).

Testing Methodology

It is not generally practical to remove portions of in-service #4/#6 lines for testing to determine if each individual line section should be replaced. As a result, API's condition assessment tends to focus on the condition of conductor being replaced to ensure that the program is prudent, to justify annual replacement targets, and to determine common elements that should factor into prioritization of replacement (e.g. age, location, proximity to highways, etc.). Occasionally, samples of in-service conductor are removed to determine if areas scheduled to be replaced in future years must be brought forward due to immediate safety concerns.

API primarily uses field observations to assess the condition of conductors being removed. The intent is to continually verify that the program is justified and to determine whether the average condition of the conductors being removed justifies any change to the program replacement targets in future years. A small number of these conductors are sent to Kinectrics in order to have an independent third party perform detailed testing and analysis of these samples and to compare the results against visual inspections. In the samples tested to date, API has observed that there is a close correlation between the overall condition in the test results from Kinectrics and the assessment resulting from the visual observation of the conductor after it is removed from service. Due to this correlation and the cost of testing, API has concluded that visual observations in the field, supplemented by a small amount of laboratory testing provide a prudent and reasonable balance to verifying the effectiveness of the condition assessment process.

Summary of Test Results

The table below summarizes the results of testing performed by Kinectrics to date:

Test Year	**Kinectrics Rpt #**	**Test**					
		Torsion	Elongation	Zinc	Tension	**Visual**	**Overall**
2005	422131	Poor	-	None	Poor	**Poor**	**Poor**
2007	422274	Poor	Below Requirement	None	Poor	**Poor**	**Poor**
2007	422274	Good	Below Requirement	None	Fair	**Poor**	**Fair**
2008	419026	Fair	Below Requirement	None	Very Good	**Poor**	**Marginal**
2008	419023	Good	Below Requirement	None	Good	**Marginal**	**Fair**
2008	419023	Marginal	Below Requirement	None	Marginal	**Poor**	**Poor**
2009	419130	Very Good	Al: Below St: Above	None	Good	**Good**	**Good**
2009	419030	Very Good	Al: Below St: Above	Very Good	Very Good	**Very Good**	**Very Good**
2009	419030	Poor	Below Requirement	None	Poor	**Poor**	**Poor**
2009	419030	Marginal	Below Requirement	None	Marginal	**Poor**	**Poor**

Impact of Test Results on Program Targets

The High-Risk Conductor Replacement Program was initiated in 2003. 23 km of conductor was replaced in the first year, predominantly #6 ACSR in high-population, high-load areas. In 2004, the amount of conductor replaced was approximately doubled (48 km) as a result of field observations of conductor removed in 2003 and a public

safety incident early in 2004. From 2004-2007, the program continued with an average replacement of approximately 50 km per year. In 2005, typical samples of conductor was removed for laboratory testing in order to confirm that the replacement continued to be justified and this testing confirmed poor condition in all categories.

In 2007, two samples of conductor were tested. The first was a sample that appeared visually to be in the worst overall condition of all conductors removed that year. The second sample was still observed to be in poor condition, but appeared less corroded and less brittle than the average conductor removed that year. Since the tests showed that even one of the better conductors removed in 2007 had only a "Fair" overall condition, it was decided to double the replacement targets for 2008 to 100 km and to conduct further testing in 2008.

In 2008, three representative samples of conductors were removed from service were sent to Kinectrics for testing. The test results revealed that all three samples were of "Fair" to "Poor" overall condition. The results did indicate however that as the program moved from lines located in high-load, high-pollution areas to areas with more favourable conditions, the rated tensile strength ("RTS") was higher in general than samples from previous years. Since remaining RTS is a good indication of the probability of failure, the annual program replacement targets for future years were returned to pre-2008 levels of 50 km per year.

In 2009, two of the four samples sent for testing showed results similar to previous test results. The other two samples were tested from a feeder in an area that had experienced a number of outages where the conductor had failed, but appeared to be in relatively good condition from visual observations during restoration. These two samples involved removal of two sample spans from the line section for testing to determine whether it would be justified to advance this particular project forward within the replacement program due to reliability and safety concerns. The test results showed these two samples to be in "Good" and "Very Good" condition, and it was concluded that the most likely cause of conductor failure was tree contact. The ROW for this circuit was expanded later in 2009 through the Right-of-Way Expansion Program and there have been no conductor failures on the line in question since that time.

SYSTEM EXPANSIONS THROUGH CAPITAL CONTRIBUTIONS

A description of API's capital contribution methodology for the New Customer Connections and Roadway Relocations follows below:

New Customer Connections

These projects involve the installation of API facilities to connect new commercial, industrial, or residential customers. The primary driver in this category is residential and seasonal connections. The volume of work and level of capital contributions estimated for budgeting purposes are based on evaluating historical spending and known anticipated projects.

API capital costs are for the installation of overhead and underground distribution lines, transformers, and accessories as well as for inspecting work performed by the developer's contractor. These facilities may be new installations on the distribution system or upgrades to the system to increase capacity to meet the customer load demand. API performs an economic evaluation of the costs of these service projects based on the OEB's prescribed valuation methodologies provided for in the DSC. The economic evaluation includes a discounted cash flow analysis to determine whether the stream of future customer revenues from the new service is sufficient to cover the net present value of capital and ongoing maintenance costs of the distribution system expansion. If there is a shortfall between the present value of the projected costs and revenues, the customer pays the difference as a capital contribution in accordance with the DSC.

Roadway Relocations

The primary drivers for these projects are requests by municipalities and road authorities for plant relocation or modifications. These projects generally occur due to road widening, ditching, resurfacing, and or realignment. The work estimated for this category in a given year is derived from historical values. Often municipal work projects

receive funding on short notice, which requires API to relocate facilities within a limited time period.

The *Public Service Works on Highways Act* provides for a cost sharing arrangement whereby the Road Authority contributes 50% of the cost of labour for the project. API is responsible for the remaining 50% of the labour costs, and 100% of the material costs for the project.

CAPITALIZATION POLICY

Description

At a macro level the capitalization policy of API follows the Board's Accounting Procedures Handbook (the "Handbook"). Specifically, Article 410 provides the guidance, which API applies as its accounting practices related to decisions of capitalization versus expense, betterments versus repairs of assets, types of expenditure included as asset costs, and other capital related determinations. In addition, due to their high cost, meters and distribution transformers are capitalized once received from the supplier in accordance with Article 510 of the Handbook. All plant materials and operating supplies, including poles and conductors, are treated as inventory in accordance with Article 420 of the Handbook.

Allocation of Costs to Capital

The capital cost of construction includes the cost of labour, materials and overhead associated with such work.

Labour Costs

Labour is charged to capital at a fully loaded labour rate. The fully loaded labour rate is comprised of direct labour, payroll burden, vehicle charges and small indirect costs such as meals and small tools. All non-administration supervisors and managers have their time allocated to capital projects.

Capitalized Overhead Costs

API capitalizes costs that are directly attributable to capital projects and is requesting the approval to capitalize overhead costs associated with capital work. Capitalized overhead costs represent the amount of overhead costs that are required to support capital projects in a given year. Overhead costs will be capitalized for the administrative departments based

on the prorating of unionized labour costs between capital and operating expenditures. The administration departments will include finance, information technology, human resources, health, safety & environmental, materials management and management.

Overhead Capitalized
2010 and 2011 Test Years

2010		2011	
Capitalization Rate[(1)]	Amount Capitalized ($'000)	Capitalization Rate[(1)]	Amount Capitalized ($'000)
7.2%	$821	8.0%	$874

(1) Based on amount capitalized over total capital spend.

The methodology proposed is consistent with the methodology used by CNPI and approved by the Board in EB-2008-0222.

Material Supplies

Materials and supplies are charged to capital based on actual costs for non-stock materials and at the weighted average price for stock materials.

Materiality

As a practical matter, items of a capital nature less than $500 in value are charged to operating expenses as incurred.

INFORMATION TECHNOLOGY CAPITAL ADDITIONS

Asset Management

API's IT assets include hardware and software. The main components of the IT hardware include servers, switches, network equipment, and workstations (desktops and laptops). The software that is used in conjunction with this hardware includes: email applications and file/print services. There are other specific software applications that are used within API that are unique to departmental needs. For a discussion of IT Strategy and Major Projects, please refer to Exhibit 2, Tab 4, Schedule 5, Appendix A.

Hardware

Workstations

API maintains approximately fifty (50) workstations (both desktops and laptops) within the primary service centre and satellite locations. The lifecycle of these assets has been set at five years, which generally coincides with the warranty coverage and useful life of the assets.

Servers

The server assets will also be managed using a five-year lifecycle. API currently does not maintain any servers. The server side data is currently maintained pursuant to the IT services agreement.

The following is a discussion of the IT hardware for the two forward test years 2010 and 2011. Material, contracted labour and overhead are included in these costs including the hardware costs for the SAP migration.

2010 Test Year Hardware

The following IT equipment is scheduled for purchase:

- New workstations - $26,528

2011 Test Year Hardware

The following IT equipment is scheduled for purchase:

- New Workstations - $43,500
- New Servers - $63,073 (VMware, File/Print, Citrix and Firewall)
- Storage - $54,374 (Ax4-5F File Server Storage)
- Switches - $32,624 (HP Procure Core Network Switches)
- Telephone System - $108,747 (VoIP Primary System, Automated Call Distribution System, Related Switches)
- Network Printer - $10,875 (Billing Printer)
- Intrusion/Virus Prevention - $21,749 (Barracuda Web Filter, Citrix VPN Appliance)
- Backup Technology - $21,749 (Tape Drive, Media)
- Other Equipment - $11,962 (Cat5e cabling, Cable tester, Data Centre Air Removal Door)
- Migration of Messaging, File/Print - $46,761 (Migration from Legacy Systems)

Software

Computer software encompasses all applications that are installed and run on API workstations. This includes the following:

- Operating system
  - Microsoft Windows 7 (workstation)
  - Microsoft Windows Server 2008 (server)
- Client specific office productivity
  - Microsoft Office 2007
  - Adobe Acrobat – pdf creation and viewing application
  - WinZip – file compression application
  - SnagIt – screen capture application

Generally, API's software is replaced in conjunction with the vendor's maintenance schedule and lifecycle schedule. Updates and upgrades of software are normally implemented upon the vendor's recommendations.

The following is an overview of software for the years 2010 and 2011 Test Years. Material, contracted services, labour and overhead are included in these costs including those relating to the SAP migration, which is discussed in the IT Strategy and Major Projects document.

2010 Test Year

The following software has been scheduled for purchase:

- Client specific office productivity
  - Microsoft Office 2007 - $2,159
  - Additional Productivity Software (Adobe, SnagIt, WinZip) - $3,239

2011 Test Year

In 2011 Test Year, the following costs will be allocated to software:

- Client specific office productivity
  - Microsoft Windows 7 - $10,875
  - Microsoft Office 2007 - $7,232
  - Microsoft Productivity Software - $1,195
  - AutoCAD - $16,312
  - Additional Productivity Software (Adobe, SnagIt, WinZip) - $10,875
- Server Specific Software
  - Microsoft Windows Server 2008 - $1,087
  - Microsoft SQL Server 2008 - $544
  - DoubleTake Replication Software - $10,875
  - Utility Software (Citrix, VmWare) - $10,875
  - Phone System Software/Licensing/Configuration - $54,374
  - Firewall - $27,187
- SAP Specific

- Customer Information System ("CIS") Migration - $381,485
- Enterprise Resource Planning ("ERP") Migration - $401,984

INFORMATION TECHNOLOGY STRATEGY AND MAJOR PROJECTS

The goal of API's information technology ("IT") strategy is to invest in technology to improve customer service and operating efficiency. This will be achieved through a variety of initiatives ranging from the development of automations, building in-house technical competence and a migration from legacy to new technology.

The key components of API's IT Strategy are as follows:

- Maintain business continuity including system reliability and integrity;
- Provide capabilities for regulatory initiatives and future business requirements; and
- Manage capital and support costs associated with the technology.

To realize this strategy, the major projects will include moving from API's existing legacy customer service and accounting systems to CNPI's integrated Customer Information System ("CIS") and back office Enterprise Resource Planning ("ERP") SAP system. The consolidation of API into this corporate standard will facilitate efficiencies that will benefit customers. A new phone system is also being installed. An overview of these projects is set out below.

CIS and ERP MIGRATION

API is currently running their primary business functions related to customer service, work management and financials within a legacy system that will no longer be available beyond October, 2011. In 2009, in conjunction with the sale of the distribution assets to GLPD, certain functional IT services were provided to GLPD on a transitional basis. Subsequently, additional support services were negotiated and are also being provided by GLPT. These IT services are collectively referred to as the IT services agreement, which terminates in October, 2011. API will not have an operational IT system capable of meeting its business needs beyond this date. In addition, it is important that API's business information is consolidated into a standard technology currently in use by all operating affiliates; in this case SAP. Considering these two factors, a migration strategy for API's legacy system to CNPI's CIS and ERP SAP system has been determined to be an efficient technical solution compared to acquiring a new stand alone system. By sharing the same system with

operating affiliates, costs can also be shared for future IT improvements and upgrades that will benefit consumers. The costs of the CIS Migration in 2011 Test Year is $381,485. The cost of the ERP Migration in 2011 Test Year is $401,984.

CIS SUBCOMPONENTS

The CIS portion of SAP contains all front office functions related to interactions with the customer and external parties. The following is a description of the subcomponents, of CIS.

- Bill-to-Cash Management

  Manage the meter-to-cash cycle from billing through collections by reducing day payment outstanding and improving credit checking, bill accuracy and presentment.

- Deregulated Compliance

  Support data exchange among all participants in the energy/utilities market sector to minimize operational costs and effectively manage deregulation processes such as change of supplier, reconciliation and settlement, and grid usage.

- Smart Meter Compliance

  The Ontario government is requesting that Ontario local distribution companies (LDCs) begin billing customers based on Time-of-Use (TOU) rates in 2011. In conjunction with this Provincial mandate, LDCs will also be required to synchronize hourly meter data for smart metered customers with a provincially owned and managed Meter Data Management/Repository (MDM/R) system. This system will be responsible for estimating consumption where required as well as for providing TOU billing quantities to LDCs for the purposes of billing customers.

ERP SUBCOMPONENTS

The ERP portion of SAP contains all back office functions related to financials, work order and asset management. The following is a description of the subcomponents of ERP:

- Financials & Controlling (FI/CO)

  The Finance module (FI) contains the basic configuration and processes required to utilize SAP's general ledger, accounts payable, accounts receivable, and various other basic accounting functions. The FI module closely integrates with SAP's Controlling (CO) module, which provides the necessary functions for allocating costs, labour, and other activities to cost centres, capital and maintenance orders, and general ledger accounts. Both the FI and CO modules also contain various tools for generating financial reports, including trial balances and income statements.

- Sales & Distribution (SD)

  The Sales & Distribution module (SD) contains the necessary configuration and processes to allow work orders (both capital and non-capital) to be billed directly to customers. It is also responsible for the integration of quotes and estimates with the billing system and the generation of bills for non-distribution work performed by the utility for customers.

- Plant Maintenance (PM)

  The Plant Maintenance (PM) module is responsible for managing capital and non-capital work orders and integrating equipment, inventory, labour, and other resources for the purposes of completing various types of transmission and distribution system construction and maintenance. The module also interacts directly with the SD module to allow third-party billing of this work when required.

- Materials Management (MM)

  The Materials Management (MM) module is responsible for all inventory management activities, purchase order creation, goods issues and receipts, and all other functions involving stock and warehouse equipment. It is tightly integrated with both the SD and PM modules, providing stock information to work order planners and managing moving-average prices, which help to accurately plan and bill for material costs.

SAP MIGRATION PROJECT PHASES

The following is an outline of the SAP migration project phases necessary to migrate API business data and processes to SAP:

- Project Planning and Management

  A project manager creates a project plan for the migration and integration project, complete with time lines and resource requirements. This document will be used as a basis to retain the required internal and external resources for the durations specified in the project plan. Once assembled, the project team will meet to discuss the project plan and begin working on the initial phases of the project.

  As the migration project progresses, regular status updates will be provided to stakeholders. If issues are encountered at any point during the project, it will be the responsibility of the project manager to meet with the required parties, reach a resolution, and communicate any changes to the project team and stakeholders.

- Data Cleansing, Interpretation, and Extraction

  The first operational phase of the migration project will require project team members to develop an understanding of how the legacy system's relational database model is designed and how various data correlates to SAP data. To do this, operational team members complete migration templates that map data fields from the legacy system to SAP.

  As migration templates are completed, developers will work to design extraction scripts to query the legacy system database and retrieve data in a format that SAP can accept as input to its migration workbench. Through this process, missing required fields can be identified and decisions can be made regarding necessary information that is not contained in the legacy system database. In some cases, data may only require cleansing, meaning that missing data in the legacy system is completed and

inconsistencies amongst fields eliminated in order to ensure that only accurate and useful data is migrated to SAP.

- SAP System Configuration for API

As data interpretation and extractions are carried out by the technical team members, functional team members and SAP consultants will work towards setting up the basic configuration in API's new environment in SAP. This will include defining company codes, chart of accounts, billing rates, meter reading organization, and a collection of other configuration settings. These activities will prepare the new system to receive the migrated data as well as to allow unit testing of business processes.

- Process Mapping in SAP

To be certain that API's business continues to run in accordance with best-practices, all existing business processes will be mapped to the new SAP-centric processes before the final migration and adoption of SAP functions can occur. This exercise will involve project team members from both the technical and functional units as well as end-users, and will involve carrying out end-to-end work processes in the legacy system and SAP, ensuring that both old and new processes yield similar, compliant results.

- End-User Training

From the early phases of the SAP migration project and up until go-live, end users will be involved both to help extract data and process information from the legacy system and to learn the new processes and functions in SAP. Training will take place on site at either API or at the location of an operating affiliate and will be conducted either on a one-on-one basis or in small groups. Additionally, API users will be encouraged to offer feedback and process ideas to the trainers, who in turn may use this information to enhance or improve a process currently in use.

- Go-live Blackout Window

Leading up to the final data migration to SAP, a number of business processes must cease in the legacy system and an organized approach to commencing these processes in SAP should be planned. Meter reading, billing, and various other customer activities should be ended in a way that makes them easy to transition to the new system. Strategies for ensuring that this cutover process runs smoothly will be shared with the API staff during go-live planning.

- Data Migration from Advanced Legacy System to SAP

When data extraction scripts are complete and tested, base system configuration has been accepted, and all processes are defined and agreed on, the final data migration will take place. This process will commence at the end of business on a Friday and complete by mid-day on Saturday. This provides the project team with one and a half days during the go-live weekend to validate data loads and ensure that all objects have been created and connected to one another successfully.

INFRASTRUCTURE MIGRATION

In addition to CIS and ERP, a third component of the technical environment within API is the IT infrastructure. This consists of technology that supports and provides access to the CIS and ERP systems as well as messaging (email) and file/print systems. Infrastructure technology also includes the networking components that link workstations, servers and printers as well as protect those assets from external internet based threats.

In conjunction with the CIS and ERP migration, IT infrastructure will also need to be migrated to API consistent with the corporate standard utilized by all operating affiliates.

IT infrastructure includes hardware and software. The main components of the IT hardware include servers, switches, network equipment, and workstations (desktops and laptops). The software that is used in conjunction with this hardware includes: email applications, file/print services, and the HTE legacy system. The cost of the Infrastructure Migration in 2011 Test Year is $432,960.

PHONE SYSTEM PROJECT

API currently utilizes a phone system that will no longer be available beyond October, 2011. This includes the telephone assets as well as the service. As the business relies on a phone system for customer service and operations, it is necessary to carry out a replacement of this system in 2011.

API will implement a phone system similar to that of its operating affiliates in order to transition to a common platform. Automated Call Distribution ("ACD") functionality will be deployed to route calls to available customer service representatives. The ACD enables customer service representatives to respond to customer calls in compliance with OEB quality standards. In the event of storm or unplanned outage situations, high volume calls may be rerouted to other operating affiliates, which would provide customers with information that may be relevant during restoration efforts. The cost of the phone system in 2011 Test Year is $163,121.

ASSET MANAGEMENT PROCESS

API's approach to asset management involves managing existing infrastructure and optimizing the replacement of assets.

Managing Existing Infrastructure

API performs routine inspections of its facilities to meet or exceed the minimum inspection requirements of Appendix C of the Distribution System Code (the "DSC"). API also maintains existing infrastructure according to a combination of good utility practice and manufacturer recommendations. Most inspection and maintenance activities are performed by API crews; however, outside contractors are employed where specialized equipment or expertise is required (e.g. infra-red scanning, detailed pole testing).

Distribution Lines

For API's distribution lines, regular visual inspections are carried out by qualified internal crews on a six-year cycle to meet the requirements of the DSC for rural areas. Where these inspections identify immediate deficiencies or potential hazards, API undertakes further inspection and testing, maintenance or replacement as appropriate. Line equipment such as switching and protective devices are inspected and/or maintained according to manufacturer's recommendations and/or good utility practice. This typically involves visual inspection, mechanical and electrical testing, as well as part replacement or equipment overhauls when necessary.

In 2009, API retained an external contractor to perform detailed pole testing on a small sample of its poles. This testing provides valuable details on the condition of the poles, the remaining pole strength and expected remaining life, as well as observations of any conditions that could potentially have an impact on remaining life of the poles. This information is provided in a searchable database that could be used for long-term planning of line rebuilds and pole replacements. Over the next eight years (2010-2017), API plans to extend this testing to all poles that have been in service for more than ten

years. This will ensure that as the High-Risk Conductor Replacement program (referred to in Exhibit 2, Tab 4, Schedule 1) comes to an end, future line rebuilds can consider accurate pole condition information as part of the prioritization process.

Distribution Substations

For its distribution substations, a range of inspection and maintenance activities are carried out bi-annually to meet the requirements of the DSC. Activities such as monthly visual inspections of oil containment systems and quarterly effluent sampling are also conducted to meet environmental requirements imposed by the MOE. Inspection and maintenance activities include visual inspections, functional tests, infra-red inspections, oil sampling and dissolved gas analysis. These activities are conducted primarily by API crews, and supplemented by external consultants as required (e.g. infra-red scanning and laboratory testing of oil samples). As with line inspections, API takes appropriate remedial action when deficiencies or hazards are identified.

Optimizing Asset Replacement

In order to optimize replacement of existing infrastructure, the information gathered through the above-mentioned inspection and planned maintenance programs are reviewed and assessed. Where detailed testing and analysis has been conducted (either by qualified API staff or by independent third parties), the results of these tests are also considered in prioritization of replacements. Where large replacement programs are developed to resolve critical issues, third party testing is often undertaken to support the program's justification (e.g. laboratory testing of #4/#6 ACSR conductor to support the High-Risk Conductor Replacement Program). Prioritization of projects in any given year is based on consideration of a number of factors including the following:

<u>Health and Safety:</u>

- exposure to the public and employees;
- likelihood of an event occurring; and
- the consequences of an event.

Environment:

- exposure to the public and employees;
- likelihood of an event occurring; and
- the consequences of an event.

Reliability:

- reliability indices;
- history/impact of failure; and
- specific system events (e.g. faults, equipment overloading, etc.).

Regulatory:

- applicable standards as per the DSC, RSC, etc;
- environmental protection (e.g. oil containment); and
- applicable regulations (e.g. Green Energy Act, Electricity Act, etc.).

Resourcing:

- resource adequacy – equipment and labour;
- market conditions – contractors and raw materials; and
- timelines and budget constraints.

Synergies:

- location relative to other projects (e.g. coordination of crews for multiple projects within close proximity reduces travel costs, combining projects reduces contractor mobilization and contract administration costs).

Stakeholder Feedback:

- suggestions and feedback from annual stakeholder sessions.

Enhancements to API's Asset Management Plan

API's comprehensive approach to asset management and capital budgeting provides API with an effective means of identifying capital expenditures based on condition assessment through inspections and testing. It also provides for project prioritization based on a number of factors that are important to relevant stakeholders. API is continually improving its overall asset management plan. As a result, API has identified a number of areas for future development that will refine and improve its asset management processes. These include development and integration of geographic information systems ("GIS"), asset management tools, vegetation management tools, as well as document management and work management systems.

Forecast of Capital Expenditures

The table below provides a 3-year forecast of API's capital expenditures, grouped by the following categories (excluding Smart Metering costs):

<u>Demand Work</u>

- Primarily non-discretionary spending to meet DSC and other legislated requirements.
- Includes New Customer Additions, Small Upgrades, Storm Damage, Transformers, Meters, Road Relocations, etc.
- Spending forecast is based on average of historical spending, adjusted for inflation.

<u>Right of Way Expansion / Conductor Replacement</u>

- Please see Exhibit 2, Tab 4, Schedule 1 for a more detailed description of these programs.

<u>Subtransmission / Substation</u>

- Includes rebuilds and refurbishments of substation and subtransmission assets. These projects are prioritized according the asset replacement strategy identified above.

Other Replacements and System Improvements

- Includes individual voltage conversion projects, line relocations, and smaller replacement programs (e.g. certain types/vintages of insulators, crossarms, etc.)

Buildings and Yards, Land Rights

- Includes capital expenses related to office buildings and work centres as well as acquisition of easements.

IT Hardware and Software

- Please see Exhibit 2, Tab 5, Schedule 1, for a detailed overview of costs.

Business Systems and SCADA

- Includes SCADA development as well as costs associated with implementation and development of certain business systems (GIS, Asset Management, Vegetation Management, MDM/R Integration)

Transportation and Work Equipment

- Includes line trucks, vehicles, off-road equipment and snow-machines.

Small Tools and Office Equipment

- Includes tools for trades groups and large office equipment (scanner/copier).

The following table sets out API's forecasted capital costs based on the preceding categories:

Category	**2010**	**2011**	**2012**
Demand Work	$2,033,187	$1,710,372	$1,733,833
Right of Way Expansion	$2,047,857	$2,191,257	$220,478
Conductor Replacement	$3,867,839	$4,078,021	$4,133,958
Sub-Transmission / Substation	$1,752,144	-	$2,315,016
Other Replacements and System Improvements	$971,661	$620,947	$479,539
Buildings and Yards, Land Rights	$267,299	$76,123	$77,167
IT Hardware and Software	$53,891	$1,350,314	$55,119
Business Systems and SCADA	-	$135,934	$110,239
Transportation and Work Equipment	$323,346	$625,297	$468,515
Small Tools and Office Equipment	$53,891	$81,560	$55,119
Total	**$11,371,114**	**$10,869,825**	**$9,648,983**

Capital costs are expected to decrease in 2012, primarily due to the completion of the Right of Way Expansion project in 2011.

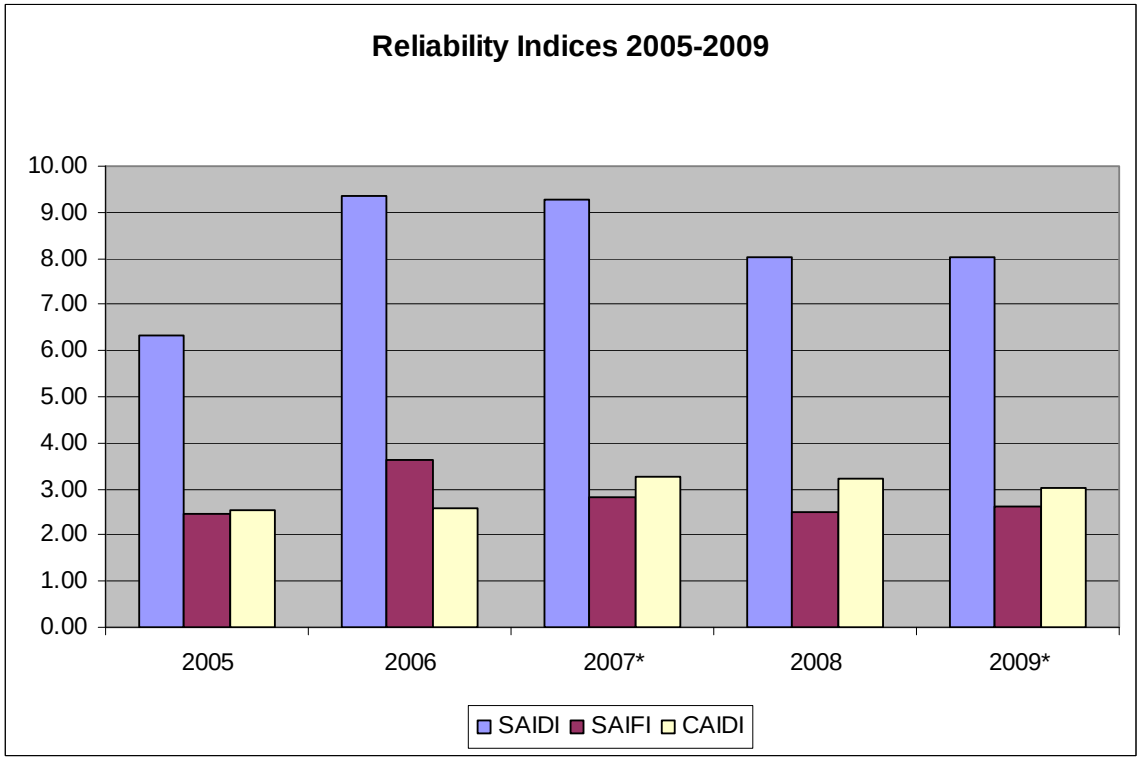
SERVICE QUALITY AND RELIABILITY PERFORMANCE

Service Quality Indicators

Reliability Indices for API for the five-year period 2005-2009 are shown in the table and chart below:

Year	2005	2006	2007	2007*	2008	2009	2009*	5-year Avg	5-year Avg*
SAIDI	6.32	9.34	9.35	9.29	8.04	9.87	8.03	8.58	8.20
SAIFI	2.47	3.64	3.32	2.84	2.49	3.42	2.64	3.07	2.82
CAIDI	2.56	2.57	2.82	3.27	3.23	2.88	3.04	2.81	2.93

***** indicates loss of supply (transmission) outages excluded.



NOTE: During upgrades to its outage database in 2009, API performed an audit of previously entered data. A number of records were found to be missing certain data and were subsequently updated. As a result of this data cleansing process, the above 2005-

2008 figures reflect revisions to those previously submitted by API through RRR annual filings.

Reliability Performance

The reliability indices show an increase in SAIDI and SAIFI from 2005 to 2006, followed by a declining trend from 2006-2009. CAIDI is relatively constant, with small increases from 2005-2007, followed by small decreases from 2007-2009.

API's outage tracking database allows analysis of outage information according to the cause of the outage. The charts on the following page are extracted from information in this database to illustrate trends that impact reliability indices.

From 2005 to 2009, the charts show that the total number of forced outages has decreased year over year. Long duration outages in 2006 which were due to a number of storms as well as a substation equipment failure contributed to the noticeable jump in SAIDI from 2005 to 2006.

From 2007 to 2009, the indices remain above 2005 levels due to an increase in the frequency and duration of planned outages required to support API's Right-of-Way Expansion and Conductor Replacement programs. To enhance worker and public safety, API has required an increased number of planned interruptions for any construction or Right-of-Way clearing activities in proximity to distribution lines containing #4 or #6 ACSR. Also, as the conductor replacement program progresses to more rural areas, an alternate supply is often not available and planned outages are required in order to complete the work safely.

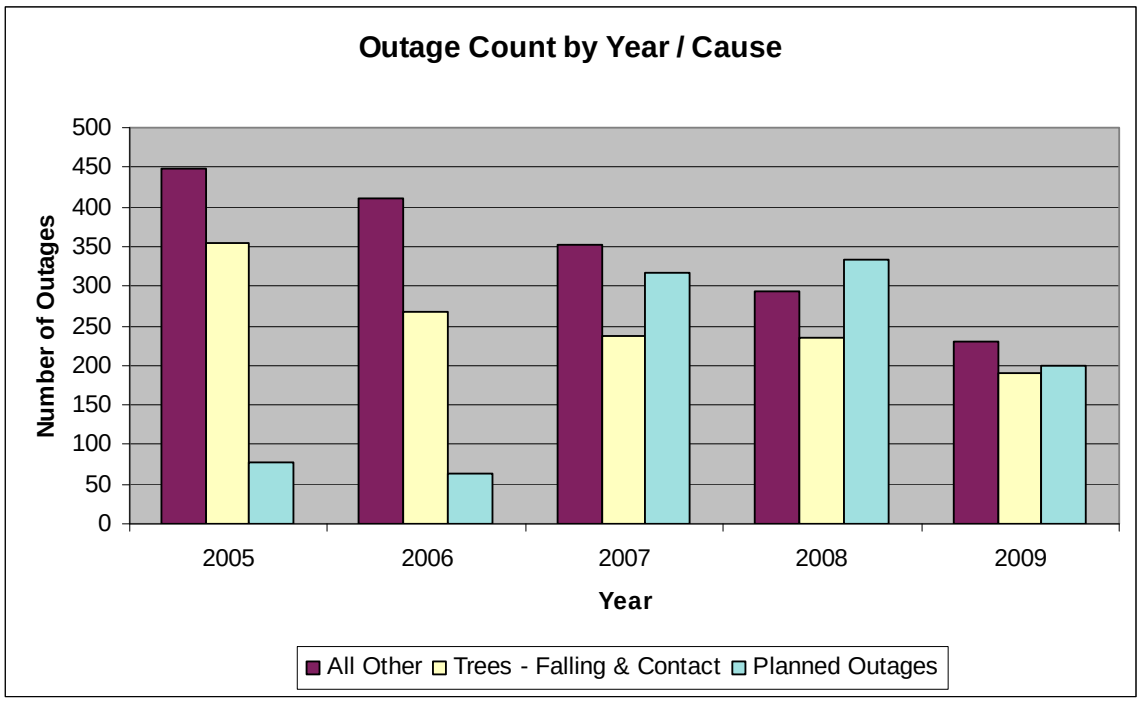


Figure 1: Outage Counts by Year 2005-2009

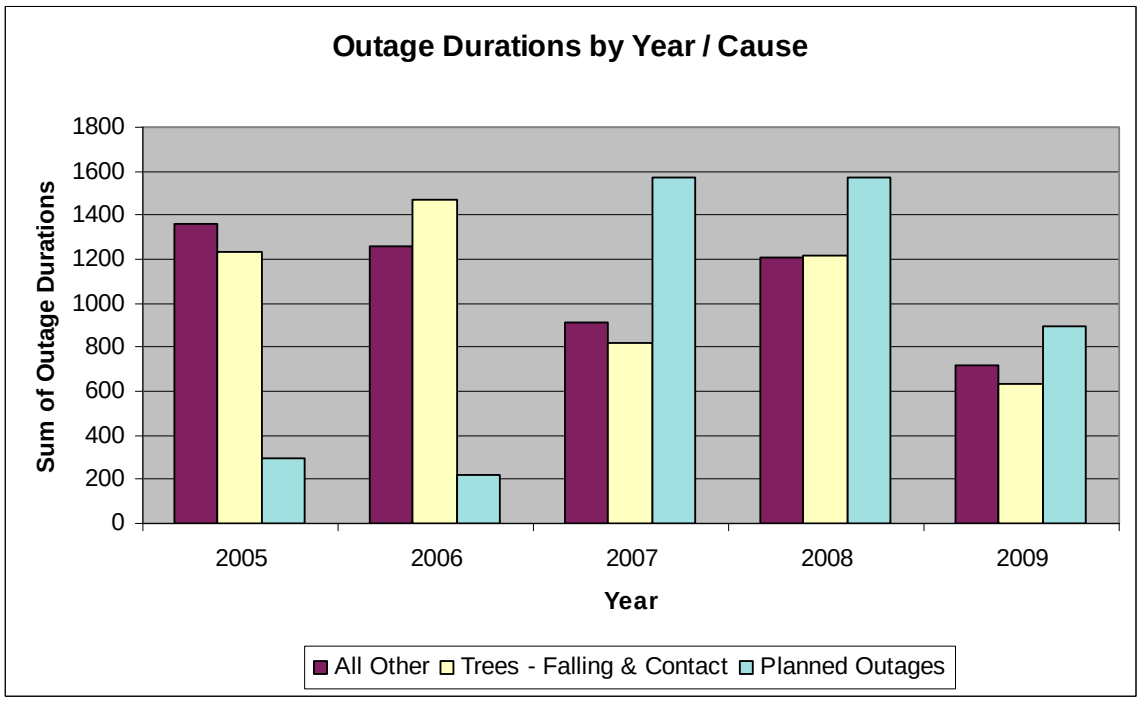


Figure 2: Outage Sum of Durations by Year 2005-2009

One of the key API operational objectives is to continuously enhance system reliability. Capital investments are aimed at improving or maintaining reliability by proactively upgrading deteriorating facilities and adding system capacity to avoid overloads. The Right-of-Way Expansion and High-Risk Conductor Replacement programs will result in a reduction in the number of outages caused by tree contact or conductor failure. It is expected that this benefit will continue to increase as these programs progress towards completion in the coming years. Where technically and economically feasible, investments are also made to enable redundancy of supply so that customers can be supplied from alternate paths in emergency or planned outage situations. Due to the extremely rural, low-density nature of much of API's service territory, redundant supplies are not always available or feasible to construct.

In addition to capital investments, maintenance programs and operational practices are aimed at maintaining or improving reliability. API's right-of-ways are located predominantly in high-density vegetation areas, and in conjunction with progress being realized in its Right-of-Way Expansion program, API maintains appropriate, systematic vegetation management programs to ensure that adequate clearances are maintained between power lines and surrounding vegetation. In forced outage situations, outage response efforts focus on locating and isolating faulted areas quickly so that as many of the affected customers can be restored from alternate paths, where available. As alternate supply paths are not available in many areas, API makes use of a large number of feeder reclosers to attempt to clear temporary faults without outages. In future years, API expects to be able to leverage its investment in its Smart Metering infrastructure to support SCADA functionality and to supplement its outage management system in order to further improve reliability.

OVERVIEW OF OPERATING REVENUE

In its Decision and Order, EB-2007-0744, the Board approved a tariff of rates and charges effective September 1, 2007, but implemented January 1, 2009, for electricity consumed or estimated to have been consumed on or after January 1, 2009. API had foregone recovery of its incremental revenue requirement from the effective date of the new rates to the implementation date of the new rates. Rather than recovering this incremental revenue requirement through a rate rider, it was used to offset the balance in account 1590.

Decision and Order, EB-2007-0744, established new customer classification and resulted in certain reclassified customers being overbilled distribution delivery charges for the period from the effective date, September 1, 2007, to the implementation date, January 1, 2009. Electricity revenues from delivery charges were credited back to these customers. In the intervening period from the 2007 test year to January 1, 2009, the implementation date, API (or its predecessor) appropriately continued to bill its customers and record its revenues on the basis of historical rate classifications.

Historical customer classifications were as follows:

- Residential
- General Service Less Than 50 kW
- General Service Greater Than 50 kW
- Large Customer
- Seasonal
- Street Lighting

The new customer classifications are as follows:

- Residential - R1 (subject to RRRP funding)
- Residential - R2 (subject to RRRP funding)
- Seasonal Customers (not currently receiving RRRP funding)
- Street Lighting (not currently receiving RRRP funding)

Where, Residential R -1 is comprised of the former Residential and General Service Less Than 50 kW classifications; Residential R - 2 is comprised of the former General Service Greater Than 50 kW classification; Seasonal remains unchanged, and; Street Lighting remains unchanged. Due to the previous assignment of certain customer types to the Street Lighting classification and the reclassification of customer classes in EB-2007-0744, it was necessary to reclassify approximately 67 customers from Street Lighting to the Residential R - 1 classification. This is discussed more fully in Exhibit 3 Tab 2 Schedule 1.

The discontinuities from 2007 to 2009 include the following:

- the customer classification changes described above[1],
- the Board's direction related to foregone revenues[2], and
- applicable over-collected distribution revenues from certain reclassified customers that realized a rate reduction from these reclassification of classes were returned to the customers in 2009 for previous years[3].

The aggregate effect of the above factors render a meaningful year-over-year variance analysis of distribution revenues impractical.

The following Table 1 provides a summary of billed and forecasted distribution revenues for the period of the 2007 Board Approved to the 2011 Test Year.

[1] Decision and Order, EB-2007-0744, page 27
[2] Decision and Order, EB-2007-0744, page 48
http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/rec/88205/view/GLPL_dec_order_20081030.PDF
[3] Great Lakes Power Limited, Draft Rate Order, EB-2007-0744, Exhibit D page 4 of 12

Table 1 Exhibit 3 Tab 1 Schedule 1

Summary of Distribution Revenues							
Customer Classification	Billing Metric	2007 Board Approved	2007 Actual	2008 Actual	2009 Actual	2010 Forecast	2011 Forecast
Residential R - 1	kWh	4,821,500			5,054,329	5,241,978	5,396,032
Residential	kWh		6,848,693	8,230,032			
General Service < 50	kWh		1,279,758	1,311,440			
Residential R - 2	kW	834,900			891,879	753,685	770,910
General Service > 50	kW		552,694	535,319			
Large Use	kW		517,569	295,498			
Seasonal	kWh	1,880,500			1,862,280	2,288,029	2,129,732
Street Lighting	kWh	44,200	18,595	29,463	39,204	114,695	188,510
		7,581,100	9,217,310	10,401,752	7,847,692	8,398,387	8,485,184

Although the 2007 Board Approved revenues were established on the premise of the re-classified customer classes, actual billing and record keeping were maintained using the conventional methodology until the implementation of EB-2007-0744 in January 2009. These new rates were made effective September 2007[4]. The discontinuities evidenced from the Board Approved 2007 revenues through to the 2009 actuals result from the numerous adjustments and reclassifications arising from the Board's Decision and Order, EB-2007-0744.

In addition, EB-2007-0744 together with the adoption of Regulation 445/07 (the reclassification regulation) and the amendment of Regulation 442/01 (the RRRP regulation) allowed significant funding of the revenue requirement attributable to Residential – R1 and Residential – R2 customers.

The 2010 and 2011 forecasted revenues flow from the application of the distribution rate adjustment factor based on year over year percentage change in the simple average of the "Delivery" component of other utilities for the same year[5] applied to forecasted volumes. API has used the simple average of the delivery component of other utilities in the current rate year to be 5.5% for 2010 and 2.0% for 2011 as provided by Board staff. This is discussed in more detail in Exhibit 8, Rate Design.

[4] Rate Order, EB-2007-0744
[5] Decision and Order, EB-2007-0744, page 30

The following Table 2 compares the 2007 Board Approved to actual recorded and forecasted amounts through to 2011. This table is subject to the same issues as evidenced in Table 1 above. Actual record keeping for 2007 and 2008 were on the conventional customer classifications, new formats were begun in January 2009.

Table 2 Exhibit 3 Tab 1 Schedule 1

Summary of Distribution Throughput (kWh)							
Customer Classification	Billing Metric	2007 Board Approved	2007 Actual	2008 Actual	2009 Actual	2010 Forecast	2011 Forecast
Residential R - 1	kWh	101,468,266			103,758,019	104,754,767	106,119,297
Residential	kWh		92,360,867	87,951,272			
General Service < 50	kWh		29,212,744	27,331,222			
Residential R - 2	kW	191,492			150,499	151,138	151,952
General Service > 50	kW		133,252	125,458			
Large Use	kW		60,469	30,740			
Seasonal	kWh	11,657,297			12,341,792	12,459,994	12,622,297
Street Lighting	kWh	891,877	841,490	957,415	791,996	791,996	791,996

CUSTOMER AND LOAD FORECAST

In its Decision and Order, EB-2007-0744, the Board encouraged the applicant to include a multi-year weather normalized load forecast in any future rate applications. API has maintained its historical consumption and customer data and has provided this data to Elenchus Research Associates ("ERA"). ERA, in consultation with API, has developed a weather normal load forecast for 2010 and 2011 as well as weather normalized historical consumption for the available years. This report entitled "Weather Normalized Distribution System Load Forecast: 2010 – 2011", is provided in Exhibit 3, Tab 2, Schedule 2.

The Table below provides a summary of the API customer and load forecast.

Exhibit 3, Tab 2, Schedule1, Table 1

Algoma Load and Customer Forecast Information								
	2005	2006	2007 Forecast	2007	2008	2009 Actual	2010 Test Year	2011 Test Year
R1								
Number of Customers	7,758	7,740	7,740	7,815	7,923	7,997	8,024	8,049
Change in Customer Count	(5)	(18)		75	109	74	27	25
Kilowatt-hours	103,661,767	99,478,516	104,428,306	100,674,579	103,691,076	103,761,012		
Weather Normalized Kilowatt-hours						103,317,932	104,754,767	106,119,297
Average per Customer - kWh	13,362	12,853	13,492	12,883	13,087	12,975		
Normalized Average - kWh						12,920	13,055	13,184
Seasonal								
Number of Customers	3,652	3,707	3,707	3,718	3,688	3,643	3,654	3,665
Change in Customer Count	6	55		11	(30)	(45)	11	11
Kilowatt-hours	11,678,117	11,746,043	11,746,043	11,665,351	11,591,418	12,341,792		
Weather Normalized Kilowatt-hours						12,289,090	12,459,994	12,622,297
Average per Customer - kWh	3,198	3,169	3,169	3,138	3,143	3,388		
Normalized Average - kWh						3,373	3,410	3,444
Residential - R2								
Number of Customers	47	45	47	47	48	48	48	48
Kilowatt-hours	66,360,103	68,290,099	50,139,889	75,340,938	66,017,652	69,931,763		
Kilowatts	182,693	180,802	197,392	191,492	159,280	150,499		
Weather Normalized Kilowatt-hours						69,808,980	70,228,773	70,606,900
Weather Normalized Kilowatts						150,235	151,138	151,952
Average per Customer - kWh	1,411,917	1,517,558	1,066,806	1,602,999	1,375,368	1,456,912		
Average per Customer - kW	3,887	4,018	4,200	4,074	3,318	3,135		
Normalized Average - kWh						1,454,354	1,463,099	1,470,977
Normalized Average - kW						3,130	3,149	3,166
Street Light								
Number of Customers	100	99	99	32	32	32	32	32
Kilowatt-hours	1,046,222	1,056,913	1,010,306	816,298	791,996	791,996	791,996	791,996
Kilowatts					2,304	2,304	2,304	2,304
Totals								
Number of Customers	11,557	11,591	11,593	11,611	11,691	11,720	11,758	11,794
Kilowatt-hours	182,746,209	180,571,571	167,324,544	188,497,166	182,092,142	186,826,563		
Kilowatts	182,693	180,802	197,392	191,492	161,584	152,803		
Weather Normal Kilowatt-hours						186,207,998	188,235,530	190,140,490
Weather Normal Kilowatts						152,539	153,442	154,256

In Table 1, the volumes for 2007 and 2008 were derived from the values reported under the conventional rate classifications and discussed in Exhibit 3, Tab 1, Schedule 1.

A more comprehensive discussion of the customer and load forecast methodology is contained in Exhibit 3, Tab 2, Schedule 2.

The following is a discussion of each of the Rate Classes.

Residential Customers

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.

The Residential R1 Class shows a significant increase in customer count from the 2007 Board Approved count to the 2008 count. The primary reason for the change is the reclassification of customers that were previous recorded in the Street Light Class. Prior to the introduction of the current customer class structure, EB-2007-0744, certain customers recognized as safety and traffic signals, small scattered loads were included in the Street Light Class. Subsequent to EB-2007-0744, the customers were appropriately associated with the former GS < 50 kW customers and assigned to the Residential R1 Class.

There has been a modest number of Seasonal Customers that have migrated from the Seasonal Class to the Residential R1 Class. These are primarily retired persons who have converted their cottages to year round residences and now occupy the premise on a year round basis.

Otherwise there has been very modest growth in the R1 Class and this has been reflected in the customer forecast for 2010 and 2011. Interestingly, the load forecast model has yielded a small increase in the average use per customer in the R1 Class for 2010 and 2011 as compared to 2009. There may be a number of reasons for this. First, API suggests that there is an increasing infiltration of electronic products into the home and business. These include home entertainment products and personal computing. Second, with the low amount of new building stock being introduced the average age of the building stock is increasing and likely consuming more energy over time. The third is believed to be related to the local economy. Closures in the forestry industry and a depressed economy in general suggest that more people are at home during the daytime. This changing demographic may be contributing to increased energy usage.

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.

These are the customers formerly described as GS > 50 kW and Large Customer B. There is no change forecasted in the customer count for the Residential R2 Class. Beginning in 2008, there has been significant reduction in the energy consumption and demand associated with this class. The reductions are primarily associated with the downturn in the forestry industry.

API is not forecasting an increase in the customer count of the Residential R2 Class but is recognizing a modest increase in throughput and demand. These increases are attributable to increased activity in the mining sector.

Seasonal Customers

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.

There was a slight decline in the Seasonal Customer count in 2008 and 2009. This is attributable to some migration to the Residential R1 Class as well as some disconnections. A modest growth has been predicted for the class as well as modest increases in average customer throughput. The average increase in throughput is likely for the same reasons as discussed in the Residential R1 Class. A further contributor is that increasingly these seasonal residences are becoming retirement retreats.

Street Lighting

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

Street Lighting Class, subsequent to the customer reclassifications discussed with the Residential R1 Class above, has been consistent and no changes are forecasted (subject to API's reclassification discussion in Exhibit 8).

LOAD FORECASTING AND WEATHER NORMALIZATION METHODOLOGY

In its Decision and Order, EB-2007-0744, the Board encouraged the applicant to include a multi-year weather normalized load forecast in any future rate applications. API has maintained its historical consumption and customer data and has provided this data to Elenchus Research Associates ("ERA"). ERA, in consultation with API, has developed a weather normal load forecast for 2010 and 2011 as well as weather normalized historical consumption for the available years. This report entitled "Weather Normalized Distribution System Load Forecast: 2010 – 2011", is provided in Exhibit 3, Tab 2, Schedule 2, Appendix A.

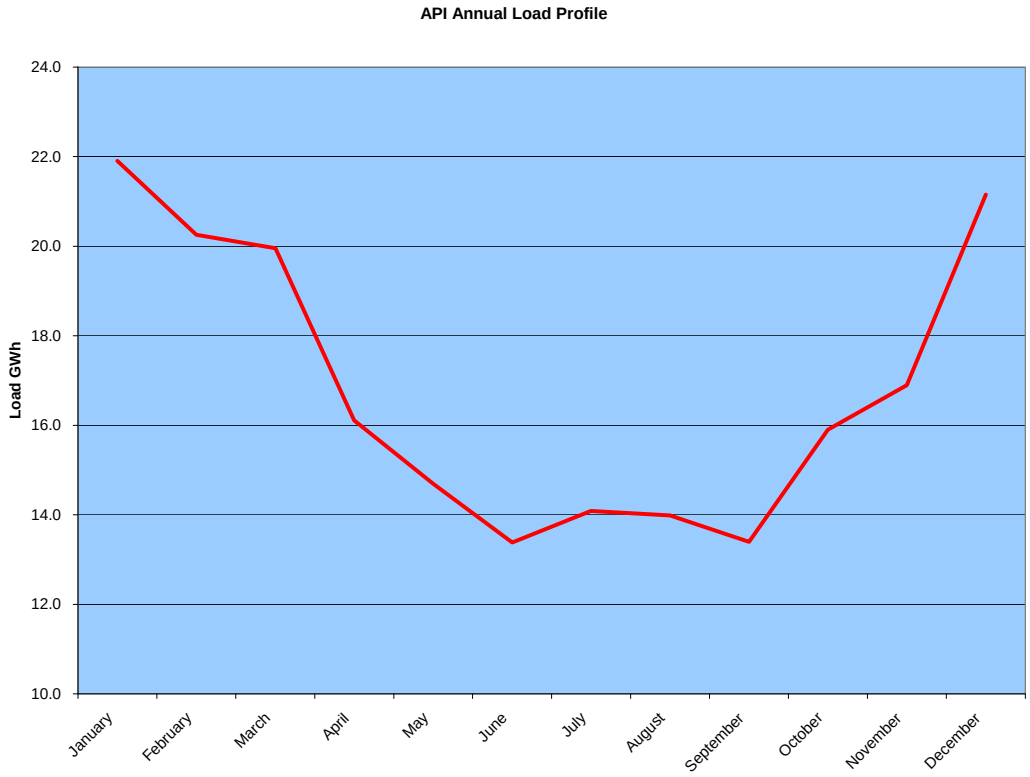
The API service territory encompasses an area of approximately 14,200 square kilometers in a remote area of Northern Ontario extending north and east of the city of Sault Ste. Marie. The economic wellbeing of the region is closely aligned to the forestry and mining industries. This is exemplified by the presence of a single large forestry sector customer, that historically has represented as much as 15 per cent of the energy throughput. API through its interactions with its industrial customers is not forecasting a rebound in the forestry industry in the forecast period. The mining sector has been maintaining consistent levels of consumption and demand in recent years. Again through discussions with its customers, API expects the trend in the mining sector to continue in the forecast period with the possibility of modest increases in consumption and demand.

Historically, growth in the Residential and Seasonal sectors has been very modest with little new construction and the average age of the building stock increasing. This aging building stock is believed to be a contributing factor in an increasing consumption per customer evidenced in the customer and load forecast. API has experienced a small amount of migration from the Seasonal Class to the Residential R1 Class. Discussions with these customers indicate that retiring residents are winterizing their cottages and utilizing them as year round residences thus qualifying as Residential R1 customers. This conversion to year round residences may along with other demographic changes be contributing to an increase

in average customer consumption. Secondly, the trend of an increasing infiltration of electronic products including home entertainment products and personal computers is likely also a contributing factor. The third factor is believed to be related to the local economy. Closures in the forestry industry and a depressed economy suggest that more people are home during the daytime further contributing to the increase energy consumption.

API is a winter peaking utility and peak period energy consumption is influenced by the use of secondary fuels such as wood burning heat sources. The graph shown in the Chart 1 below demonstrates the significance of the winter peak.

Chart 1 Exhibit 3 Tab 2 Schedule 2



The significance of this chart is to illustrate the seasonality of the API throughput and its susceptibility to influence of secondary fuel usage. This profile is the average of 2006 to 2009 inclusive with very little variability from year to year. There is no evidence to suggest

to API that this profile will not continue into the forecast period. The Weather Normalized Distribution System Load Forecast: 2010 – 2011 filed with the application is consistent with the API's empirical knowledge of the region and its customers.

Late in the preparation of this Application, API has become aware of a possible new customer. The customer and associated demand and throughput are very speculative at this time and have not been included in the 2011 forecast. The customer is described as a large rock-crushing quarry that is presently operating using onsite diesel generation. Speculation is that the operation, currently peaking at 750 kW under self generation, would require a capacity of approximately 2.5 MW. The operation is weather dependent and would operate during non-winter periods, possibly April to November. Should matters related to this customer become firm during the review period, API will update its load and revenue forecast accordingly.

Forecast revenues are provided here.

Shown below is the 2010 revenues based on exiting rates. The Volumetric rate has been uplifted to simulate recovery of the RRRP.

Exhibit 3, Tab 2, Schedule 2, Table 1

2010 Weather Normalized Forecasted Revenue Recovery Summary								
Customer Class	**Billing Metric**	**No. of Cust.**	**Charge Determinant**	**Simulated Rates**		**Revenue**		
				Fixed	*Volumetric*	*Fixed*	*Volumetric*	*Total*
Residential								
R1 Energy Rate	kWh	8,012	104,754,767	20.41	0.1069	1,962,238	11,195,280	13,157,517
R2 Demand Rate	kW	48	151,138	596.12	7.3375	343,365	1,108,977	1,452,342
Total Residential						*2,305,603*	*12,304,256*	14,609,859
Seasonal	kWh	3,649	12,459,994	24.00	0.1412	1,050,960	1,758,968	2,809,928
Street Lights (conn.)	kWh	1,052	791,996	-	0.0602	-	47,686	47,686
						3,356,563	14,110,911	17,467,474

Shown below is the 2011 revenues based on exiting rates. The Volumetric rate has been uplifted to simulate recovery of the RRRP.

Exhibit 3, Tab 2, Schedule 2, Table 2

2011 Weather Normalized Forecasted Revenue Recovery Summary								
Customer Class	**Billing Metric**	**No. of Cust.**	**Charge Determinant**	**Rates**		**Revenue**		
				Fixed	*Volumetric*	*Fixed*	*Volumetric*	*Total*
Residential								
R1 Energy Rate	kWh	8,039	106,119,297	20.41	0.1069	1,968,810	11,341,109	13,309,919
R2 Demand Rate	kW	48	151,952	596.12	7.3375	343,365	1,114,949	1,458,315
Total Residential						*2,312,175*	*12,456,058*	14,768,233
Seasonal	kWh	3,660	12,622,297	24.00	0.1412	1,054,008	1,781,880	2,835,888
Street Lights (conn.)	kWh	1,052	791,996	-	0.0602	-	47,686	47,686
						3,366,183	14,285,625	17,651,808

Shown below are the 2010 revenues for those classes subject to the RRRP based on proposed rates. The RRRP has been calculated separately.

Exhibit 3, Tab 2, Schedule 2, Table 3

2010 Distribution Base Rate Determination											
Customer Class	**Metric**	**Average # of Customers**	**Billing Determinant**		**F/V Split**		**Distribution Rates**		**Revenues**		
			kWh	**kW**	**Fixed Allocation**	**Variable Allocation**	**Monthly Service Charge**	**Variable Charge**	**Fixed**	**Variable**	**Total Revenue**
Residential - R1	kWh	8012	104,754,767		14.1%	85.9%	20.41	0.1142	1,962,238	11,959,152	13,921,390
Residential - R2	kW	48		151,138	15.2%	84.8%	596.12	12.6873	343,365	1,917,529	2,260,894
									2,305,603	**13,876,682**	**16,182,284**
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 2010 using the Board Approved Methodology, EB-2007-0744											**5.50%**
Customer Class	**Metric**	**Average # of Customers**	**Billing Determinant**		**F/V Split**		**Distribution Rates**		**Revenues**		
			kWh	**kW**	**Fixed Allocation**	**Variable Allocation**	**Monthly Service Charge**	**Variable Charge**	**Fixed**	**Variable**	**Total Revenue**
Residential - R1	kWh	8012	104,754,767		39.5%	60.5%	21.53	0.0303	2,070,161	3,171,817	5,241,978
Residential - R2	kW	48		151,138	48.1%	51.9%	628.91	2.5899	362,250	391,435	753,685
									2,432,411	**3,563,252**	**5,995,664**
The Rural and Remote Rate Protection Amount Required for 2010											**$ 10,186,621**

Shown below are the 2011 revenues for those classes subject to the RRRP based on proposed rates. The RRRP has been calculated separately.

Exhibit 3, Tab 2, Schedule 2, Table 4

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		13.5%	86.5%	20.41	0.1193	1,968,810	12,657,722	14,626,532
Residential - R2	kW	48		151,952	10.9%	89.1%	596.12	18.3868	343,365	2,793,915	3,137,280
									2,312,175	**15,451,637**	**17,763,812**
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 2011using the Board Approved Methodology, EB-2007-0744											**2.00%**
			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%	21.96	0.0309	2,118,636	3,277,396	5,396,032
Residential - R2	kW	48		151,952	47.9%	52.1%	641.48	2.6417	369,495	401,414	770,910
									2,488,131	**3,678,810**	**6,166,942**
The Rural and Remote Rate Protection Amount Required for 2011											**$ 11,596,870**

Shown below are the 2010 revenues for those classes not subject to the RRRP.

Exhibit 3, Tab 2, Schedule 2, Table 5

2010 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	3649	12,459,994		45.9%	54.1%	24.00	0.0993	1,050,960	1,237,069	2,288,029
Street Lighting	kWh	1052	791,996		10.8%	89.2%	0.98	0.1292	12,372	102,323	114,695
									1,063,332	**1,339,392**	**2,402,724**

Shown below are the 2011 revenues for those classes not subject to the RRRP.

Exhibit 3, Tab 2, Schedule 2, Table 6

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
Seasonal	kWh	3660	12,622,297		49.5%	50.5%	24.00	0.0852	1,054,008	1,075,724	2,129,732
Street Lighting	kWh	1052	791,996		7.2%	92.8%	1.08	0.2208	13,634	174,876	188,510
									1,067,642	**1,250,600**	**2,318,242**

Weather Normalized Distribution System Load Forecast: 2010 - 2011

Prepared for

Algoma Power Inc.

April 29, 2010

1 INTRODUCTION

This document outlines the results and methodology used to derive the 2010 and 2011 load forecast for Algoma Power Inc. (API). A weather normal load forecast is developed for 2010 and 2011 as well as weather normalized historical consumption for the available years.

There are several characteristics that make Algoma Power rather unique compared to other distribution utilities. Algoma Power serves a very large, sparsely populated rural area north and east of Sault Ste. Marie. Customers include residential households, cottages and farms, but also industrial concerns such as mines, sawmills and forestry operations. As well, customers include institutional and commercial customers such as schools, hospitals, stores, tourist operators and embedded distributors that also include embedded generation. Some of the larger industrial and commercial customers are seasonal operations (for example, forestry operations and tourist operations such as ski hills and summer camps).

Algoma Power has four customer rate classes: R1, R2, Seasonal and Street lighting. The R1 class is made up of residential customers and smaller general service accounts (GS<50) and accounts for roughly 50 per cent of wholesale purchases of the utility. The R2 class consists of GS>50 kW customers and larger users. The Seasonal class consists primarily of cottages and residences that are not used year-round. Historical class billing data is generally available only on an annual basis, although more recent data (e.g., 2009) is available monthly for some customer classes. Some larger R2 customers do have monthly data available from late 2005. Customer counts are available on a monthly basis from 2008, but earlier data are available on a year-end basis only.

Due to the unusual load profile of some large customers in the R2 class resulting from seasonal operations, and taking into account that these types of customers are not degree-day dependent (for example, sawmill/forestry operations and mining operations), and that the monthly consumption of these customers is a significant

proportion of total purchases in some months, the consumption for 5 of the largest R2 customers has been removed from the monthly wholesale purchases. The remaining wholesale kWh purchases are referred to as WSL kWh, or "weather sensitive load". Due to the fact that monthly data are not available for Street Lighting, the Street Lighting consumption has not been removed from the monthly WSL, even though the consumption is not degree-day dependent. However, Street Light consumption represents less than 1% of WSL kWh. Therefore, this should not materially affect the analysis.

Monthly consumption for the 5 largest R2 customers is available from November 2005 to December 2009. Therefore, the weather normal forecast for API is based on monthly WSL kWh data from November 2005 to December 2009 (50 monthly observations). The next section describes the details of the WSL regression equation.

2 ENERGY FORECAST USING WSL KWH DELIVERIES

In order to determine the relationship between observed weather and energy consumption, monthly weather observations describing the extent of heating or cooling required within the month are necessary. Environment Canada publishes monthly observations on heating degree days (HDD) and cooling degree days (CDD) for selected weather stations across Canada. Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18°C. For Algoma Power, we have used monthly HDD and CDD as reported at Sault Ste Marie Airport.

In addition to degree-days, we have used the number of "peak-days" in the month as well as a time-trend to capture other consumption changes over time that are not related to weather or peak-days. Generally, consumption is also sensitive to economic conditions. API's WSL consumption was tested against economic data for North-Eastern Ontario and Ontario as a whole. No discernible relationship was observed. This could be explained by several factors. Firstly, the load most sensitive to economic

conditions has been removed from the WSL kWh consumption (the 5 largest R2 customers). The almost 20 per cent decline in consumption for these 5 customers is attributable to the economic conditions they operate in (weak forestry sector). Secondly, API serves an area that has seen very little growth. In the 5 years since year-end 2003, only 160 R1 and 66 Seasonal customers have been added.

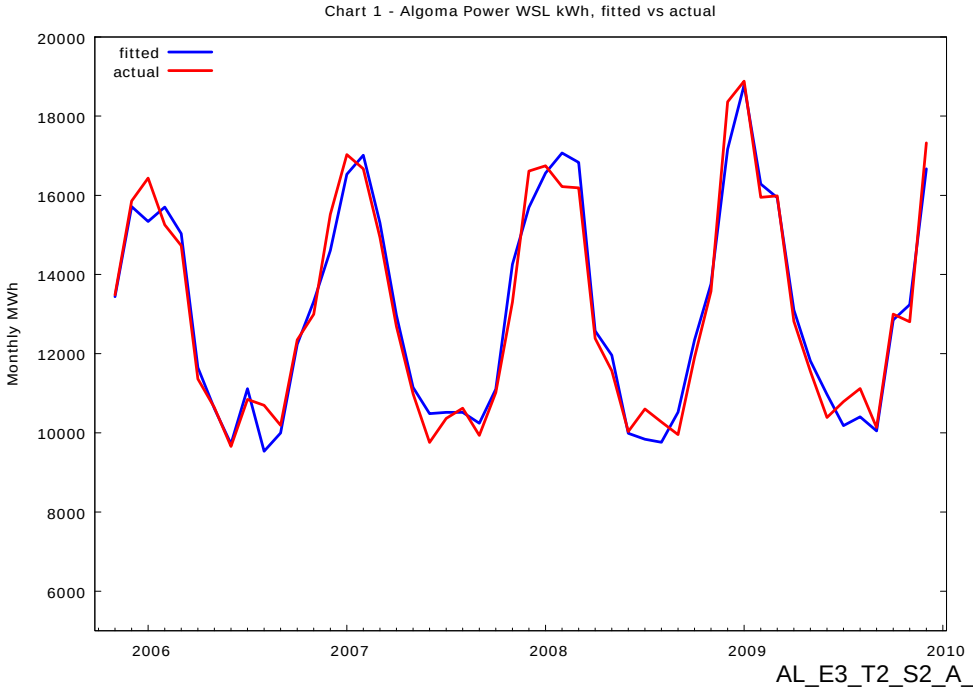
Using the data discussed, a multiple regression analysis was used to develop an equation describing the relationship between monthly actual WSL kWh and the explanatory variables.

The resulting equation, estimated using the 50 observations from 2005:11-2009:12 is displayed in Table 1 below:

Table 1: OLS, using observations 2005:11-2009:12 (T = 50)
Dependent variable: *WSL kWh*

variable	coefficient	t-ratio	
const	5,832,335.7	3.873	
HDD	10,302.9	28.833	
CDD	36,054.8	5.291	
PeakDays	112,020.1	1.608	
time	15,458.6	2.845	
R-squared	0.962	*Adj R-squared*	0.959
F(4, 45)	287.8	*P-value(F)*	2.00E-31
Theil's U			0.29929
Durbin-Watson			1.89

Fitted vs. actual observations are plotted in Chart 1 below:



Annual estimates using actual weather are compared to actual values in Table 2 below. Mean absolute percentage error (MAPE) for annual estimates for the period is 0.8%.

Table 2: Actual Deliveries vs. Estimates, Algoma Power

Year	*Actual WSL kWh*	*Predicted kWh*	*Absolute % Error*
2006	150,668,796	148,875,593	1.2%
2007	153,919,598	155,783,582	1.2%
2008	157,822,157	158,386,411	0.4%
2009	160,752,853	160,303,661	0.3%
	Mean Absolute Percentage Error (annual)		***0.8%***

2.1 WEATHER NORMALIZATION AND FORECASTED KWH

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells "average" out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. The OEB has considered and approved several different approaches to what constitutes "weather normal" over the past several years. For gas utilities, the Board has approved a five-year moving average for NRG (RP-2004-0167), a weighted average of 20 year and 30 year for Union Gas (RP-2003-0063), and a combination of methods including a 20 year trend, weighted average 20 year and 30 year, and variations of the so-called "de Bever" method depending upon location for Enbridge Gas Distribution (EB-2006-0034). For electric LDCs, Hydro One Networks Inc. (HONI) has used a 31 year average for their definition of weather normal (EB-2005-0378 and EB-2007-0681). On the other hand, Toronto Hydro Electric System Limited (THESL) has used the most recent 10 year average as a definition of weather normal (EB-2005-0421 and EB-2007-0680) as have many of the LDCs that filed for cost-of-service rebasing for 2009 rates. API has adopted the 10 year average from 2000 to 2009 as the definition of weather normal. Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the "average" weather experienced in recent years. Many other LDCs have also adopted this definition for the purposes of cost-of-service rebasing.

For Algoma Power, the most recent 10-year average monthly HDD and CDD for Sault Ste Marie Airport has been used to define "normal weather". The actual monthly values and 10-yr averages are displayed in a table in an appendix to this report.

Incorporating the 10-yr weather normal heating and cooling degree days, and the other explanatory variables, the following weather corrected consumption and forecast values are calculated:

Table 3: Weather Corrected WSL kWh, Algoma Power

			10-yr (1999-2008)	
Year	Actual WSL kWh	%chg	Weather Normal	%chg
2006	150,668,796		153,388,309	
2007	153,919,598	*2.2%*	155,838,381	*1.6%*
2008	157,822,157	*2.5%*	157,952,394	*1.4%*
2009	160,752,853	*1.9%*	160,066,406	*1.3%*
2010			162,292,439	*1.4%*
2011			164,406,451	*1.3%*

3 CLASS SPECIFIC WEATHER NORMALIZATION AND CONSUMPTION FORECASTS

Table 4 presents annual (weather actual) class data which has been adjusted for unbilled amounts (e.g., amounts billed for previous year consumption or unbilled current year consumption). The table also shows the share of class consumption in WSL (exclusive of distribution losses). R2 Net refers to R2 class consumption exclusive of 5 larger users, consistent with the definition of WSL. The "Large Users" category consists of the balance of R2 class consumption.

Table 4: Weather Actual Class kWh Throughput, Algoma Power

Year	WSL kWh	R1	share	R2 Net	share	Larger Users	R2 Total	Seasonal	share	Street	share
2006	150,668,796	99,478,516	0.6602	21,993,996	0.1460	46,296,103	68,290,099	11,746,043	0.08		
2007	153,919,598	100,674,579	0.6541	25,127,897	0.1633	50,213,041	75,340,938	11,665,351	0.08		
2008	157,822,157	103,691,076	0.6570	26,848,443	0.1701	39,169,209	66,017,652	11,591,418	0.07	791,996	0.005
2009	160,752,853	103,761,012	0.6455	28,753,392	0.1789	41,178,371	69,931,763	12,341,792	0.08	791,996	0.005

For the weather sensitive consumption classes (R1, R2 Net, Seasonal), historic weather normal class specific kWh consumption is allocated based on each class' historic share in WSL kWh (both weather actual), exclusive of distribution losses.

Forecast class values are allocated based on the class share for 2009. Forecast class kWh for Streetlighting is based on consumption in 2009 as no new streetlights are anticipated. For the larger use customers in the R2 class, consumption for 2010 and 2011 are estimated at an annual throughput of 41.2 GWh, consistent with the volume in 2009. The expectation is that the volume for these customers is not likely to change in the next 24 months unless the forest sector completely collapses. Risk factors include a higher Canadian/US dollar exchange rate, high fuel and electricity costs, and a feeble economic recovery. Some recent negative local news (closure of St. Mary's Paper in Sault Ste Marie with approximately 300 direct layoffs) does not bode well for the sector. However, at this time, the forecast is that 2009 consumption levels will hold.

Table 5: 10-yr (2000-2009) Weather Normal kWh Throughput, Algoma Power

	WSL kWh	R1	% chg	R2	% chg	Seasonal	% chg
2006	153,388,309	*101,274,064*		*68,687,082*		*11,958,054*	
2007	155,838,381	*101,929,603*	*0.6%*	*75,654,186*	*10.1%*	*11,810,773*	*-1.2%*
2008	157,952,394	*103,776,643*	*1.8%*	*66,039,808*	*-12.7%*	*11,600,983*	*-1.8%*
2009	160,066,406	*103,317,932*	*-0.4%*	*69,808,980*	*5.7%*	*12,289,090*	*5.9%*
2010F	162,292,439	*104,754,767*	*1.4%*	*70,228,773*	*0.6%*	*12,459,994*	*1.4%*
2011F	164,406,451	*106,119,297*	*1.3%*	*70,606,900*	*0.5%*	*12,622,297*	*1.3%*

CLASS KW

Actual, normalized and forecast kW for the R2 class are summarized in Table 6 below. Historical normalized values are calculated based on the annual ratio of class kW to class kWh. Forecast kW is based on the class kW to class kWh ratio in 2009.

Table 6: R2 Class kW (Actual, Normalized, and Forecast)

Year	**Actual kW**	**Class kW/kWh ratio**	**Normalized kW**	**% change**
2006	180,802	0.00265	*181,853*	
2007	191,492	0.00254	*192,288*	*5.7%*
2008	159,280	0.00241	*159,333*	*-17.1%*
2009	150,499	0.00215	*150,235*	*-5.7%*
2010F			*151,138*	*0.6%*
2011F			*151,952*	*0.5%*

A summary of the historic (2009), and forecast (2009 and 2010) years is displayed in Table 7 below.

Table 7: Load Forecast Summary (Historic and Test Years).

	2009 Actual	2009 Normalized	2010f Normalized	2011f Normalized
R1 (kWh)	103,761,012	103,317,932	104,754,767	106,119,297
R2 (kWh)	69,931,763	69,808,980	70,228,773	70,606,900
(kW)	150,499	150,235	151,138	151,952
Seasonal (kWh)	12,341,792	12,289,090	12,459,994	12,622,297
Street Lights (kWh)	791,996	791,996	791,996	791,996
Total Retail kWh	186,826,563	186,207,998	188,235,529	190,140,490

4 CUSTOMER FORECAST

The following table (Table 8) develops the customer forecast for Algoma Power. Annual year-end customer counts by customer class are available from 2003 with the exception of street lights. Annual average customer counts are developed by averaging year-end customer counts. No new customer attachments (or customer losses) are expected in the R2 and Streetlight classes. R1 and Seasonal are expected to continue to grow at the long term growth rate of roughly 0.3 per cent per annum.

Table 8 – Algoma Power Customer Count, Historic and Forecast

Year-End Customer Count

	R1 - Res	*% chg*	R2 - Res	*% chg*	Seasonal	*% chg*	Streetlights
2003	7,837		49		3,577		
2004	7,763	*-0.9%*	48	*-2.0%*	3,646	*1.9%*	
2005	7,758	*-0.1%*	46	*-4.2%*	3,652	*0.2%*	
2006	7,740	*-0.2%*	44	*-4.3%*	3,707	*1.5%*	
2007	7,815	*1.0%*	50	*13.0%*	3,718	*0.3%*	
2008	7,923	*1.4%*	47	*-5.4%*	3,688	*-0.8%*	32
2009	7,997	*0.9%*	48	*2.1%*	3,643	*-1.2%*	32
2010	8,024	*0.3%*	48		3,654	*0.3%*	32
2011	8,049	*0.3%*	48		3,665	*0.3%*	32

Average Customer Count

	R1 - Res	R2 - Res	Seasonal	Streetlights
2004	7,800	49	3,612	
2005	7,761	47	3,649	
2006	7,749	45	3,680	
2007	7,777	47	3,712	
2008	7,869	48	3,703	32
2009	7,960	48	3,666	32
2010	8,011	48	3,649	32
2011	8,037	48	3,660	32

AVERAGE USE

Actual use per customer and normalized use per customer (based on average annual customer count) resulting from the load forecast are displayed below.

Table 9

Actual Use Per Customer

	R1	R2	Seasonal	Streetlights
2006	12,838	1,517,558	3,192	
2007	12,945	1,608,131	3,142	
2008	13,178	1,365,412	3,130	24,750
2009	13,035	1,472,248	3,367	24,750

Normalized Use Per Customer

	R1	R2	Seasonal	Streetlights
2006	13,069	1,526,380	3,250	
2007	13,106	1,614,817	3,182	
2008	13,188	1,365,870	3,133	24,750
2009	12,980	1,469,663	3,353	24,750
2010f	13,077	1,463,099	3,415	24,750
2011f	13,205	1,470,977	3,449	24,750

APPENDIX

Heating and Cooling Degree Days, SSM Airport

HDD

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	**avg**
Jan	893	781.9	721.4	920.6	1006	925.1	689.8	776.9	761.9	970.4	**844.7**
Feb	699.1	786.6	685.7	902.6	707	693.6	734.6	843.5	831.3	747.8	**763.2**
Mar	538.2	704.2	778.6	745.5	652.7	744.9	635.4	654.6	795.5	680.7	**693.0**
Apr	427.2	399.6	470.5	497.2	457.4	369.1	360	459.1	391.8	425.5	**425.7**
May	234.7	195.9	326	236.5	297.9	259	185.1	204.6	320	298.9	**255.9**
Jun	124.6	89.5	93.1	112.8	151.4	31.7	81.2	67.8	99.8	126.1	**97.8**
Jul	49.9	53	19.1	28	54.7	34.9	8.4	38	34.8	87.7	**40.9**
Aug	50.6	33	28.9	32.2	83	23.7	35	33.8	29	69.3	**41.9**
Sep	176	152	89.9	123.1	84.1	82.6	151.9	127.6	140.1	93.1	**122.0**
Oct	318.1	319.3	409.8	348.5	307.3	273.6	375.3	233.5	334.5	381.1	**330.1**
Nov	499.7	414.9	574.4	494.7	462.7	497.6	467.9	541	496.8	416.7	**486.6**
Dec	891.4	593.9	686.5	657.8	796.9	738.6	624.3	711.6	814.7	748.5	**726.4**
Total	**4902.5**	**4523.8**	**4883.9**	**5099.5**	**5061.1**	**4674.4**	**4348.9**	**4692**	**5050.2**	**5045.8**	**4828.21**

CDD

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	**avg**
Jan	0	0	0	0	0	0	0	0	0	0	**0.0**
Feb	0	0	0	0	0	0	0	0	0	0	**0.0**
Mar	0	0	0	0	0	0	0	0	0	0	**0.0**
Apr	0	0	0	0	0	0	0	0	0	0	**0.0**
May	1.7	0	0.2	0	0.2	0	8.4	12.5	0	0	**2.3**
Jun	6.7	29.9	21	11.9	2.2	41.8	12.9	35.9	7.8	19.2	**18.9**
Jul	37.1	41.8	79	27.9	15.4	78.8	78.2	41.7	18.7	8	**42.7**
Aug	18.3	59.4	33.3	48.6	13.5	40.6	20.1	42.5	24	25.2	**32.6**
Sep	8.6	9.3	36	14.2	24.3	22.3	5.2	17	9.8	5	**15.2**
Oct	0.4	0	0.8	0	0	9.6	0	0.8	1.3	0	**1.3**
Nov	0	0	0	0	0	0	0	0	0	0	**0.0**
Dec	0	0	0	0	0	0	0	0	0	0	**0.0**
Total	**72.8**	**140.4**	**170.3**	**102.6**	**55.6**	**193.1**	**124.8**	**150.4**	**61.6**	**57.4**	**112.9**

OVERVIEW OF OTHER DISTRIBUTION REVENUE OFFSET

Other distribution revenue is comprised of charges for pole rental, specific services charges and other miscellaneous revenues. Other distribution revenue will be used as an offset to the service revenue requirement. API is requesting Board approval for additional specific service charges not previously requested. The table below summarizes the revenues from the 2007 Board Approved to the 2011 Test Year. Explanations for variances are explained in detail in Exhibit 3, Tab 3, Schedule 3.

Exhibit 3, Tab 3, Schedule 1, Table 1

Other Distribution Revenue Offset Table

OEB Account	Description	2007 Board Approved	2007 Actual	2008 Actual	2009 Actual	2010 Test Year	2011 Test Year
4080	Distribution Services Revenue (SSS Revenue)	(38,731)	(36,907)	(37,282)	(37,060)	(35,236)	(35,335)
4210	Rent from Electric Property	(238,178)	(279,314)	(154,696)	(236,989)	(195,321)	(217,247)
4225	Late Payment Charges	(5,700)	(12,326)	(3,054)	(7,614)	(7,500)	(7,500)
4235	Miscellaneous Service Revenues	(101,275)	(96,491)	(41,944)	(102,657)	(105,000)	(110,000)
4325	Revenues from Merchandise, Jobbing, Etc.	(403,861)	(345,366)	(453,936)	(743,532)	(206,679)	(206,679)
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	403,861	353,026	443,114	741,116	206,679	206,679
4355	Gain on Disposition of Utility and Other Property	-	(565)	-	-	-	-
4360	Loss on Disposition of Utility and Other Property	-	22,231	18,777	32,667	-	-
4405	Interest and Dividend Income	-	-	(497,803)	(21,293)	-	-
	Other Distribution Revenue Offset	(383,884)	(395,713)	(726,826)	(375,362)	(343,057)	(370,082)

Distribution Services Revenue (OEB Account 4080)

This amount represents revenues generated from the $0.25 charge per customer, per month for SSS billing.

Rent from Electric Property (OEB Account 4210)

This amount represents revenues generated from joint use pole sharing agreements with telecommunication and cable television providers.

Late Payment Charges (OEB Account 4225)

This amount represents revenues generated from late payment charges (1.5% monthly, or 19.56% per annum) resulting from non-payment of overdue accounts, as well as collection fees for processing and delivering final collection notices. API proposes to continue this practice.

Miscellaneous Service Revenues (OEB Account 4235)

This amount represents revenues generated from other specific service charges. API is requesting Board approval for additional specific service charges, as listed in Exhibit 3, Tab 3, Schedule 4. The previous Board Approved service charges also remain in effect.

Revenues from Merchandise, Jobbing, etc. (OEB Account 4325)

This amount represents revenues generated from third party job orders.

Costs and Expenses of Merchandising, Jobbing, etc. (OEB Account 4330)

This amount represents offsetting costs associated with revenues generated from third party job orders.

Gain on Disposition of Utility and Other Property (OEB Account 4355)

This amount represents gains related to the disposal of utility property, plant and equipment.

Loss on Disposition of Utility and Other Property (OEB Account 4360)

This amount represents losses related to the disposal of utility property, plant and equipment.

Interest and Dividend Income (OEB Account 4405)

This amount represents interest earned on Canadian and US bank accounts and carrying charges applied to regulatory accounts.

Appendix 2-D
Other Distribution Revenue Offset Table

OEB Account	Description	2007 Board Approved	2007 Actual	2008 Actual	2009 Actual	2010 Test Year	2011 Test Year
4080	Distribution Services Revenue (SSS Revenue)	(38,731)	(36,907)	(37,282)	(37,060)	(35,236)	(35,335)
4210	Rent from Electric Property	(238,178)	(279,314)	(154,696)	(236,989)	(195,321)	(217,247)
4225	Late Payment Charges	(5,700)	(12,326)	(3,054)	(7,614)	(7,500)	(7,500)
4235	Miscellaneous Service Revenues	(101,275)	(96,491)	(41,944)	(102,657)	(105,000)	(110,000)
4325	Revenues from Merchandise, Jobbing, Etc.	(403,861)	(345,366)	(453,936)	(743,532)	(206,679)	(206,679)
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	403,861	353,026	443,114	741,116	206,679	206,679
4355	Gain on Disposition of Utility and Other Property	-	(565)	-	-	-	-
4360	Loss on Disposition of Utility and Other Property	-	22,231	18,777	32,667	-	-
4405	Interest and Dividend Income	-	-	(497,803)	(21,293)	-	-
	Other Distribution Revenue Offset	(383,884)	(395,713)	(726,826)	(375,362)	(343,057)	(370,082)
Specific Service Charges		(101,275)	(96,491)	(41,944)	(102,657)	(105,000)	(110,000)
Late Payment Charges		(5,700)	(12,326)	(3,054)	(7,614)	(7,500)	-
Other Distribution Revenues		(276,909)	(316,222)	(191,978)	(274,049)	(230,557)	(260,082)
Other Income and Expenses		-	29,325	(489,849)	8,959	(0)	(0)
Total		(383,884)	(395,713)	(726,826)	(375,362)	(343,057)	(370,082)

Specific Service Charges: Account 4235
Late Payment Charges: Account 4225
Other Distribution Revenues: Accounts 4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses: Accounts 4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390,

VARIANCE ANALYSIS ON OTHER DISTRIBUTION REVENUE OFFSET

The total other distribution revenue offset has been consistent since the 2007 Actual with the exception of the 2008 Actual, which is related to account 4405 and is explained in more detail below. The following analysis explains the variances in the other distribution revenue offset.

Rent from Electric Property (OEB Account 4210)

The variance from 2007 Actual to 2008 Actual is the result of a timing issue for the billing of three joint use tenants. Pole rental charges for these tenants was delayed in 2006 and accounted for in 2007 instead, increasing the amount of revenue recorded in 2007. Furthermore, the 2008 pole rental charges for these three tenants were billed early and also recorded in 2007, resulting in even higher revenues for 2007 and lower than normal revenues for 2008.

Miscellaneous Service Revenues (OEB Account 4235)

Specific service charges have remained consistent from the 2007 Actual to the 2011 Test Year with the exception of the 2008 Actual. The 2007 Actual incorrectly includes an adjustment of approximately $62,000. Excluding the adjustment, the 2007 Actual and 2008 Actual amounts are comparable. The increase in the 2009 Actual relates to the implementation of the specific service charges approved in the 2008 Decision and Order. A slight increase in the 2010 and 2011 Test Years is a result of the forecasted implementation of new Specific Service Charges outlined in Exhibit 3, Tab 3, Schedule 4. The forecasted annual volumes and revenues relating to the new services charges are outlined in Exhibit 3, Tab 3, Schedule 4.

Revenues from Merchandise, Jobbing, etc. (OEB Account 4325)

The variances from year to year are dependent upon and explained by varying demand of third parties.

Costs and Expenses of Merchandising, Jobbing, etc. (OEB Account 4330)

The variances from year to year are dependent upon and explained by varying demand of third parties.

Interest and Dividend Income (OEB Account 4405)

Carrying charges on all regulatory assets approved with API's 2007 cost of service application, resulted in a large variance between the 2007 Actual and the 2008 Actual. The carrying charge amounts, totaling $454,931, relate to prior years, were not recorded until 2008 after receiving the Decision and Order.

Specific Service Charges: Standard Amounts (not previously applied for)

Requested Specific Service Charges – Summary

Rate Code	Standard Name	Std	Amt	Calculation Method - Check box: Standard Formula (attach calculation & justification)	Other Formula (attach calculation & justification)	Time & Materials
1	Arrears certificate	$15	x			
2	Statement of account	$15	x			
3	Pulling post dated cheques	$15	x			
4	Duplicate invoices for previous billing	$15	x			
5	Request for other billing information	$15	x			
6	Easement letter	$15	x			
7	Income tax letter	$15	x			
9	Account history	$15	x			
12	Charge to certify cheque	$15	x			
17	Collection of account charge - no disconnection - after regular hours	$165	x			
20	Disconnect/Reconnect at meter - after regular hours	$185	x			
21	Install/Remove load control device - after regular hours	$185	x			
23	Disconnect/Reconnect at pole - after regular hours	$415	x			
25	Service call - customer-owned equipment	$30	x			
26	Service call - after regular hours	$165	x			
27	Temporary service install & remove - overhead - no transformer	$500	x			
28	Temporary service isntall & remove - underground - no transformer	$300	x			
29	Temporary service install & remove - overhead - with transformer	$1,000	x			
Additional Charges - Please be Specific						

SPECIFIC SERVICE CHARGES: STANDARD AMOUNTS (NOT PREVIOUSLY APPLIED FOR)

Forecasted Annual Volumes and Revenue

FORECAST VOLUME	DESCRIPTION OF CHARGE	UNIT CHARGE	TOTAL OTHER REVENUE
0	Arrears Certificates	$15.00	$0.00
0	Statement of Account (Account history is where we collect our #s)	$15.00	$0.00
10	Pulling Post Dated Cheques	$15.00	$150.00
15	Duplicate Invoice for previous billing	$15.00	$225.00
50	Request for other billing information	$15.00	$750.00
0	Easement Letter (Lawyer's Letter are where we collect our #s/already an approved charge)	$15.00	$0.00
0	Income Tax Letter (Account history is where we collect our #s)	$15.00	$0.00
60	Account History	$15.00	$900.00
0	Charge to certify cheques	$15.00	$0.00
0	Collection of account charge - no disconnect - after regular hours	$165.00	$0.00
10	Disconnect/Reconnect Charges at meter - after regular hours	$185.00	$1,850.00
10	Disconnect/reconnect at pole - after regular hours	$415.00	$4,150.00
10	Install/remove load control device - after regular hours	$185.00	$1,850.00
0	Service call - customer owned equipment	$30.00	$0.00
0	Service call - after regular hours	$165.00	$0.00
0	Temporary service install & remove - overhead - no transformer	$500.00	$0.00
0	Temporary service install & remove - underground - no transformer	$300.00	$0.00
0	Temporary service install & remove - overhead - with transformer	$1,000.00	$0.00
	Total Revenue		$9,875.00

OVERVIEW OF OPERATING COSTS

This Exhibit 4, Tab 1, Schedule 1 (Overview of Operating Costs) sets out an overview of API's operating costs forecasted for the 2010 and 2011 Test Years including the following: operations, maintenance, and administration expenses ("OM&A expenses"), amortization expense, income tax, property taxes and Ontario capital taxes. A summary of the OM&A expenses is provided in Appendix 2-F.

Summary of OM&A Costs Table

Description	2007 Board Approved	2007 Actual	2008 Actual	2009 Actual	2010 Test Year	2011 Test Year
Operating	1,410,195	1,312,953	1,288,685	1,352,598	1,408,536	1,480,059
Maintenance	2,865,774	3,368,649	2,979,950	3,183,635	3,717,293	4,258,631
Billing and Collection	1,144,440	1,057,441	1,061,466	1,188,958	1,280,443	1,311,726
Community Relations	8,000	1,902	1,119	735	10,000	10,000
Administrative and General	2,736,565	2,465,274	3,370,454	3,052,844	2,642,964	2,779,791
Total	8,164,974	8,206,220	8,701,673	8,778,771	9,059,236	9,840,207

Exhibit 4, Tab 1, Schedule 2 (Departmental Overview) provides a background on the following departments: customer service, information technology, finance, regulatory, human resources, health, safety and environment, community involvement and operations. Details of the maintenance and vegetation management programs are included in Appendix A and Appendix B.

Please refer to Exhibit 4, Tab 5, Appendix 2-M for a discussion of Shared Services.

Exhibit 4, Tab 4, Appendix 2-L (Employee Compensation) reviews the employee compensation and other benefits for API.

Exhibit 4, Tab 7 details amortization expenses used to determine revenue required for the 2010 and 2011 Test Years.

Exhibit 4, Tab 8 calculates income taxes and Ontario capital taxes used to determine the revenue requirement for the 2010 and 2011 Test Years.

COSTS ARISING FROM THIS APPLICATION

API is requesting a recovery of regulatory expenses in the amount of $75,000 in 2010. This amount is one third of the total forecasted regulatory costs for this Application. API has undertaken to prepare, submit and defend this Application relying, for the most part, on its own resources.

Exhibit 4, Tab 1, Schedule 1, Table 1

Regulatory Costs Arising from the 2010 EDR	
Legal Review and Regulatory	$ 80,000
External Consultation	$ 50,000
Backfilling Internal Resources	$ 25,000
Intervenors	$ 50,000
Travel	$ 20,000
Total	$225,000
One Third Claim in 2010 Test Year	$ 75,000

APPENDIX A

Maintenance Programs

Expenditures on maintenance programs are an integral aspect of good utility practice. Effectively maintaining existing line and substation equipment is necessary to keep equipment in good working condition, maximize equipment lifespan, and reduce the probability of failure. Maintenance programs optimize the value of capital investments. Maintaining equipment in proper working condition reduces the probability of equipment failure, enhances safety and increases reliability of supply to customers.

Maintenance activities on distribution lines and substations in API's service area can be subdivided into three basic categories:

Predictive Maintenance: to identify equipment deficiencies that may lead to failure. Examples of predictive maintenance activities are visual inspections, equipment testing, and substation transformer dissolved gas analysis.

Corrective Maintenance: to repair equipment as a result of deficiencies identified through visual inspections or testing.

Preventive Maintenance: to service or repair equipment on a regular schedule to ensure that equipment remains in good working condition. Maintenance is systematically undertaken at specific time intervals. Examples of preventive maintenance activities are loadbreak switch maintenance, protective device maintenance, and substation equipment maintenance.

These maintenance activities are described in more detail below. Line and substation maintenance activities are described separately. A separate discussion of vegetation management is described in more detail in Exhibit 4, Tab 1, Schedule 1, Appendix B.

LINE MAINTENANCE ACTIVITIES

API establishes its various maintenance cycles to achieve a number of objectives:

- Maintenance cycles for inspections will meet or exceed the minimum regulatory requirements.
- Critical assets may be inspected more frequently and may make use of more sophisticated inspection methods (e.g. thermographic scans at substations).
- Preventive maintenance activities are scheduled on cycles that attempt to optimize the life-cycle costs of equipment considering manufacturer's recommendations, good utility practice as well as API past experience.
- Preventive maintenance activities that are scheduled cycles greater than one year will be scheduled with a goal of levelizing expenditures from year-to-year.

To the extent possible, scheduling of preventive maintenance activities on cycles greater than one year will be scheduled with a goal of levelizing the amount of work assigned to each service centre from year-to-year. This ensures adequate resource availability to complete the planned program and minimizes travel costs associated with crews traveling between service centres.

The three major types of maintenance activity for lines are described as follows:

Predictive Line Maintenance

Predictive maintenance on overhead and underground distribution systems in API's service area takes the form of visual inspections, which are part of API's distribution system inspection program. Normally on an annual basis, all overhead and underground lines scheduled to be inspected during that year are patrolled and detailed inspections carried out on most equipment. This includes poles, crossarms, guy wires, transformers (overhead and padmounted), conductors and cables, insulators, arrestors, bushings, terminations, switching devices (fused cutouts, loadbreak and disconnect switches, live-line openers, etc). Civil facilities, such as transformer pads and cable chambers, are also inspected. As a result, most

overhead and underground line components are normally inspected on a 6-year cycle. This conforms to the 6-year cycle for rural facilities laid out in the DSC, Appendix C, *Minimum Inspection Requirements*.

The results of these inspections and any identified deficiencies are documented for follow-up and are archived. Deficiencies are assessed on the basis of the potential for failure and consequential impact on safety or reliability and then prioritized for corrective action. The first classification indicates that urgent repair or replacement is required to address an imminent failure or safety hazard, while the second indicates that the deficiency is of a minor nature and action can be deferred. Examples of priority deficiencies would be broken poles/crossarms or floating conductors, while a less critical deficiency would be a blown lightning arrestor. Patrols are carried out by line crews, which allow some critical deficiencies to be addressed during these patrols. Repairs to less critical deficiencies are typically planned so that a group of deficiencies within a given area can be addressed by a single crew in an efficient timeframe.

In addition to the 6-year cycle inspections described above, various substation components are inspected on monthly, quarterly, and biannual cycles, with any deficiencies being noted and prioritized for correction. Thermographic scans of substations are also conducted annually. Deficiencies observed outside of scheduled line patrols are also recorded and corrected.

In 2009, API retained an external contractor to perform detailed pole testing on a small sample of its poles. This testing provides valuable details on the condition of the poles, the remaining pole strength and expected remaining life, as well as observations of any conditions that could potentially have an impact on remaining life of the poles. This information is provided in a searchable database that can be used for long-term planning of line rebuilds and pole replacements. The results of the 2009 testing have already proven valuable in that a small number of poles on a critical circuit were identified as requiring short-term replacement due to condition, while the remainder of poles had more remaining life than expected and replacement could be delayed. Over the next eight years (2010-2017), API plans to extend

this testing to all poles that have been in service for more than ten years. The rural nature of API's service area results in many pole replacements being driven by asset end-of-life as opposed to line upgrades or replacements to accommodate the connection of new services.

Corrective Line Maintenance

Any deficiencies identified during or outside of scheduled inspections are recorded and prioritized as described above. Repairs or replacements are carried out accordingly and completion is tracked through API's work management system.

Preventive Line Maintenance

Three major preventive maintenance activities are conducted on distribution lines and equipment: Vegetation Management (See Exhibit 4, Tab 1, Schedule 1, Appendix B), Switch Maintenance, and Protective Device and Voltage Regulator Maintenance. The latter two activities are described below.

Switch Maintenance

API maintains switches located in its substations and on its subtransmission feeders on a 6-year cycle. This minimizes the likelihood of widespread outages due to switch failure and ensures that switches will operate effectively in the event of planned or forced outages elsewhere on the system. Switch maintenance includes the following main activities:

- Visual inspection of switch components, such as contacts, insulators and arc horns, to identify any broken or deteriorated parts and evidence of surface tracking or corrosion.
- Opening and closing switches to verify proper and efficient operation of blades and gang-operating mechanisms, where applicable.
- Cleaning and greasing of electrical connections and moving parts.
- Replacement of worn components, or the entire switch if necessary.

Protective Device and Voltage Regulator Maintenance

API performs routine maintenance of its Reclosers, Sectionalizers and Voltage Regulators, generally on a 6-year cycle. Maintenance activities are typically based on manufacturer's recommendations and include the following main activities:

- Determination of number of operations since date of last maintenance to verify that existing maintenance intervals are adequate.
- Visual inspection of tanks, bushings, contacts, operating mechanisms, control boxes, etc… to identify any broken or deteriorated parts and evidence of surface tracking or corrosion.
- Testing of operations, both manually and using electrical test equipment to ensure proper operation.
- Electrical testing (ratio, resistance, etc.) to verify electrical integrity of device and all components.

The results of any tests performed are documented on equipment test forms and kept on file for trending and comparison purposes.

SUBSTATION MAINTENANCE ACTIVITIES

Predictive Substation Maintenance

Predictive substation maintenance is integral to maintaining reliability and detecting potential equipment failure. Since substation equipment typically requires large investments for installation and since failure of substation components can affect large numbers of customers, detecting potential failures before they occur is very important. There are presently three key predictive maintenance activities conducted in API substations: visual inspections, power transformer dissolved gas analysis, and thermographic scanning. These activities are performed on regular schedules and are described below.

Visual Inspections

Visual Inspections are essential for assessing the condition of substation components and identifying deterioration or areas where attention is required. The DSC provides for different inspection intervals for substations based on various criteria and location. API conducts detailed inspections on each of its substations every 6 months in compliance with the DSC requirements for rural areas. Substation buildings, fences, and electrical components (buswork, switches, insulators, batteries, transformers, ground conductors, etc.) are inspected and any deficiencies recorded. In addition, data such as relay targets, breaker counters, direct current system voltage, and power transformer gauge readings are recorded. The condition of ancillary equipment such as lighting, eyewash stations, first-aid kits, and oil spill kits is also inspected. API also performs monthly inspections of its oil containment facilities and quarterly sampling of effluent from the oil containment in accordance with Ministry of Environment requirements. During these monthly inspections of oil containment, the remainder of the substation is visually inspected at a high level and deficiencies requiring immediate correction are identified.

Any deficiencies noted during inspections are recorded, reported, and prioritized for corrective action.

Transformer Dissolved Gas Analysis

Dissolved gas analysis ("DGA") is an effective tool for assessing the condition of power transformers and identifying deterioration in transformer oil or insulation. DGA can also identify whether arcing or acid build up is occurring inside the transformer. DGA tests for the presence of dissolved gas and water in transformer insulating oil, and based on the level of gas or moisture present, assesses the condition of the transformer. An important aspect of DGA is the trend analysis, which reviews the history of dissolved gas levels in the transformer.

DGA is scheduled annually on all power transformers and in API substations, whether in-service or spare. API uses a qualified contractor to perform the analysis, provide reports on transformer condition, and recommend any required actions if gassing is above normal levels

or if acids are detected. Corrective action to deal with abnormalities is essential to prevent failure and extend the life of the transformer.

Thermographic Scanning

Thermographic (infra-red) scanning is scheduled annually for all substations in API's service area. Thermography captures the temperature of components compared to surrounding equipment and ambient temperature, and high relative temperatures can be indicative of overloaded or deteriorated components. These scans are performed by a contractor on most buswork, switchgear, and transformers and detailed results are reported to API, along with a summary of priority findings.

Corrective Substation Maintenance

Corrective maintenance is a reactive activity that takes place when deficiencies in substation components are identified. Defective components are prioritized for repair or replacement on the basis of the severity of the condition, the criticality of the equipment, and the potential impact of failure on safety or service reliability.

Preventive Substation Maintenance

Preventive maintenance on substation components is conducted on a regularly scheduled basis and is integral to keeping equipment in good working condition. Substation components in API's service area undergo preventive maintenance on a 6-year cycle, including inspecting, cleaning, lubricating, and testing. The following major activities are included in this program:

- Breaker / Recloser / Circuit Switcher maintenance – inspection, cleaning of bushings, connections, contacts and moving parts, contact resistance and insulation testing.
- Switch maintenance – inspection and cleaning of bushings, connections, contacts, arc horns, and operating mechanisms, insulation testing.
- Relays – testing to ensure appropriate response, and recalibration of electromechanical relays as required.

- Power and potential transformers – inspection and cleaning of gauges, tap changers, access ways, bushings, and connections.
- Oil renewal – replacing insulating oil in power transformers and oil-insulated circuit breakers and potential transformers as needed ensuring insulating oil is clear of contaminants.
- Accessories – other equipment such as motor operators and heating elements are inspected, cleaned, and maintained.

APPENDIX B

Vegetation Management

Vegetation management has both an O&M component and a capital component. The costs associated with maintaining and controlling vegetation within a right-of-way ("ROW") are a maintenance expense. The cost of expanding ROW's is a capital cost. This Appendix B (Vegetation Management) discusses the maintenance expense portion of API's Vegetation Management Program. Please refer to Exhibit 2, Tab 4, Schedule 1 for a discussion on API's capital expenditures related to ROW expansion.

The objective of vegetation maintenance is to manage vegetation clearances to electrical equipment on a regular schedule to enhance and sustain reliability and worker accessibility to the system, while minimizing hazards created by vegetation in proximity to energized equipment. Although this maintenance activity could be categorized in the corrective and preventive maintenance sections of this Application (Exhibit 4, Tab 1, Schedule 1, Appendix A), given the importance of the activity, API has chosen to categorize this item separately.

The vegetation management program is an integral part of API's preventive maintenance program. Vegetation can interfere with the safe and reliable operation of API's electrical system. Examples of interference include tree caused outages on power lines resulting in disruptions to service. Vegetation can also impede the efforts of staff to locate, inspect, maintain, and repair disruptions to electrical service. In addition, trees and brush growing in the vicinity of electrical wires increase the risk of injury to the public and API's employees. The vegetation management program mitigates tree caused outages and hazards created by trees in proximity to energized equipment, improves reliability and worker access to the system, and enhances public safety.

Being a rural and remote distributor in Northern Ontario, one of the characteristics of API's distribution service area is that it is located predominantly in forest zones with dense

vegetation. API's distribution service area extends through two forest zones. The southern part is in the Great Lakes - St. Lawrence forest zone, characterized by red and sugar maple, yellow birch, red oak, hemlock, red and white pine. The northern part is in the Boreal forest zone, characterized by black and white spruce, tamarack, aspen, white birch, balsam fir, and jack pine. North of Wawa and east of the Montreal River area is the approximate transition area between the two forest zones.

API has sufficient ROWs to support its 1,845 kilometers of distribution line. They require tree trimming or removal and brush control, and 10 substations require total vegetation control. The service area is divided into three geographical zones: Wawa, Sault and Desbarats, which are shown of the map in Figure 1 at the end of this section. The vegetation management program is administered using these three zones, as well as system criticalities, and ROW characteristics (i.e. on-road, off-road) to manage smaller parts and different work activities within the entire system. To meet its ROW vegetation management challenges with greater effectiveness, API has steadily improved its vegetation management program. API's ROW maintenance program is being implemented to operate on the basis of a 6-year cycle whereby a portion of the system's ROW's is inspected and maintained each year so that, over the course of the entire cycle, all ROW's in all three zones on API's system are maintained. The goal of API's vegetation management program is to control vegetation utilizing a 6-year cycle to cover all three zones. The 6-year cycle was initiated by Great Lakes Power Limited ("GLPL"), and was reviewed and approved by the OEB as part of GLPL's 2007 distribution rate application (EB-2007-0744).

Vegetation management work activities include line clearing (trimming and removals), brush control (removal of undergrowth on the floor of the ROW), landowner notifications, vegetation conditional assessments and demand work (customer request to remove hazardous trees, hazardous reports, and other unplanned maintenance).

The maintenance portion of API's vegetation work is currently separated into five categories as listed in the table below.

Exhibit 4, Tab 1, Schedule 1, Appendix B, Table 1

API Vegetation Maintenance Program

	2009	2010	2011
Line Clearing & Brush Control (with Expansion Program)	1,217,000	1,352,000	1,540,000
Cycle Maintenance (on previously expanded ROW)	471,000	527,000	820,000
Demand Work	83,000	90,000	100,000
Condition Assessment	15,000	17,000	30,000
Station Total Vegetation Control	14,000	14,000	10,000
Total	**$1,800,000**	**$2,000,000**	**$2,500,000**

Right Of Way Maintenance Program

Line Clearing/Brush Control in conjunction with Expansion Program

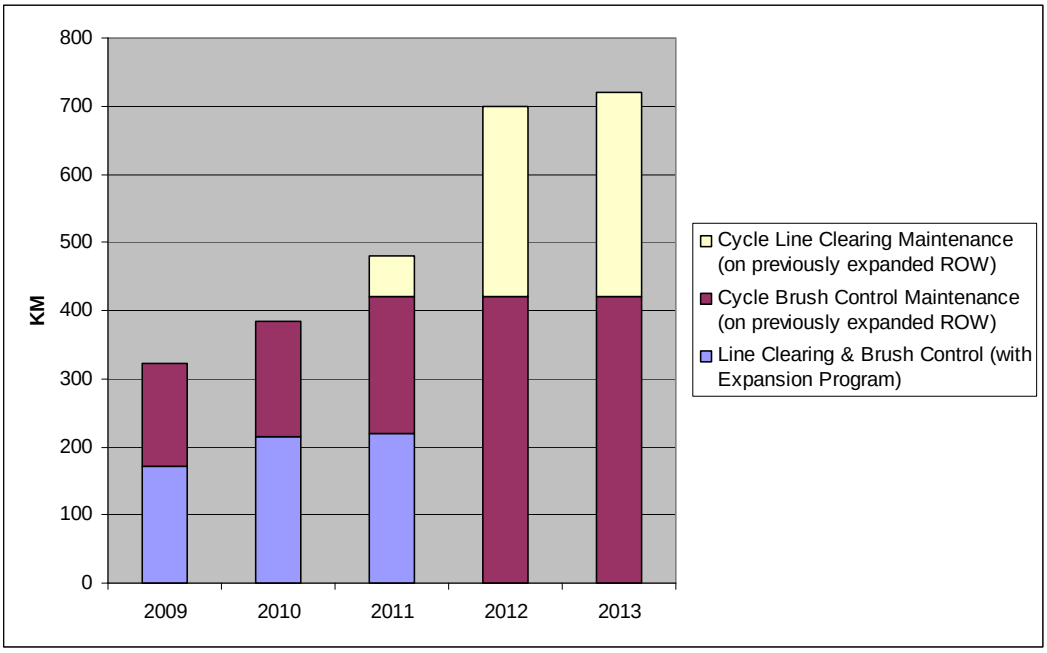
The maintenance costs identified in this line item are O&M costs of clearing existing ROWs concurrently with the work carried out on the capital expansion program of expanding ROWs. A detailed explanation of the capital ROW expansion program, as well as a list of the cost savings and efficiencies gained by working on this program concurrently with line clearing and brush control can be found in Exhibit 2, Tab 4, Schedule 1. The ROW expansion program is currently forecasted to be completed in 2011, after which line clearing and brush control will continue as an independent program, working towards a 6-year cycle.

Cycle Maintenance

With the focused efforts to complete the capital ROW expansion program contemporaneously with the maintenance program to achieve the above noted benefits, the maintenance program has covered less ROW distance per year as compared with the 6-year cycle to be implemented by API. However, API has planned for this and has been increasing its ROW maintenance program to ensure efficiency has not been lost in areas where the expansion program has occurred. For example, on St Joseph Island the expansion program occurred between 2002 and 2004. In 2007, the floor of the ROW was retreated in order to address the brush and put the approximate 250 km of ROW on the same brush control cycle. If API chose not to return with the brush control program in 2007,

and instead waited until 2012 to return, the brush on those ROWs would have grown back into an unsafe clearance from electrical equipment. This would create an increase in maintenance cost due to a higher volume of vegetation material to be removed, requiring a greater skilled worker expense and possible outages to perform the work. Deferring this maintenance work would also decrease accessibility and visibility of the system, negatively affect conditional patrols for line and forestry concerns, storms response and regular maintenance work, while increasing the potential of injury to the public and API's employees. API has continued this brush control program in other areas for subsequent years.

As depicted in the chart below, API is managing its transition from the combined expansion/maintenance program to a fully operational 6-year vegetation maintenance cycle. In doing so, a ramping up of the maintenance expenditure to cover off the additional ROW distance is required over the next few years. While the line clearing and brush control on the narrower ROW will be eliminated upon completion of the program, it will offset the increase in line clearing and brush control required on the expanded ROW on an ongoing basis.



Demand Work

Within the vegetation management program there is an annual budget to address hazardous trees identified by external stakeholders such as customers, landowners, municipalities, government agencies and other interest groups and internally identified concerns through hazard reports, line patrols, interruption reports and/or trouble calls. The demand work program is based on historical expenditures and number of reports.

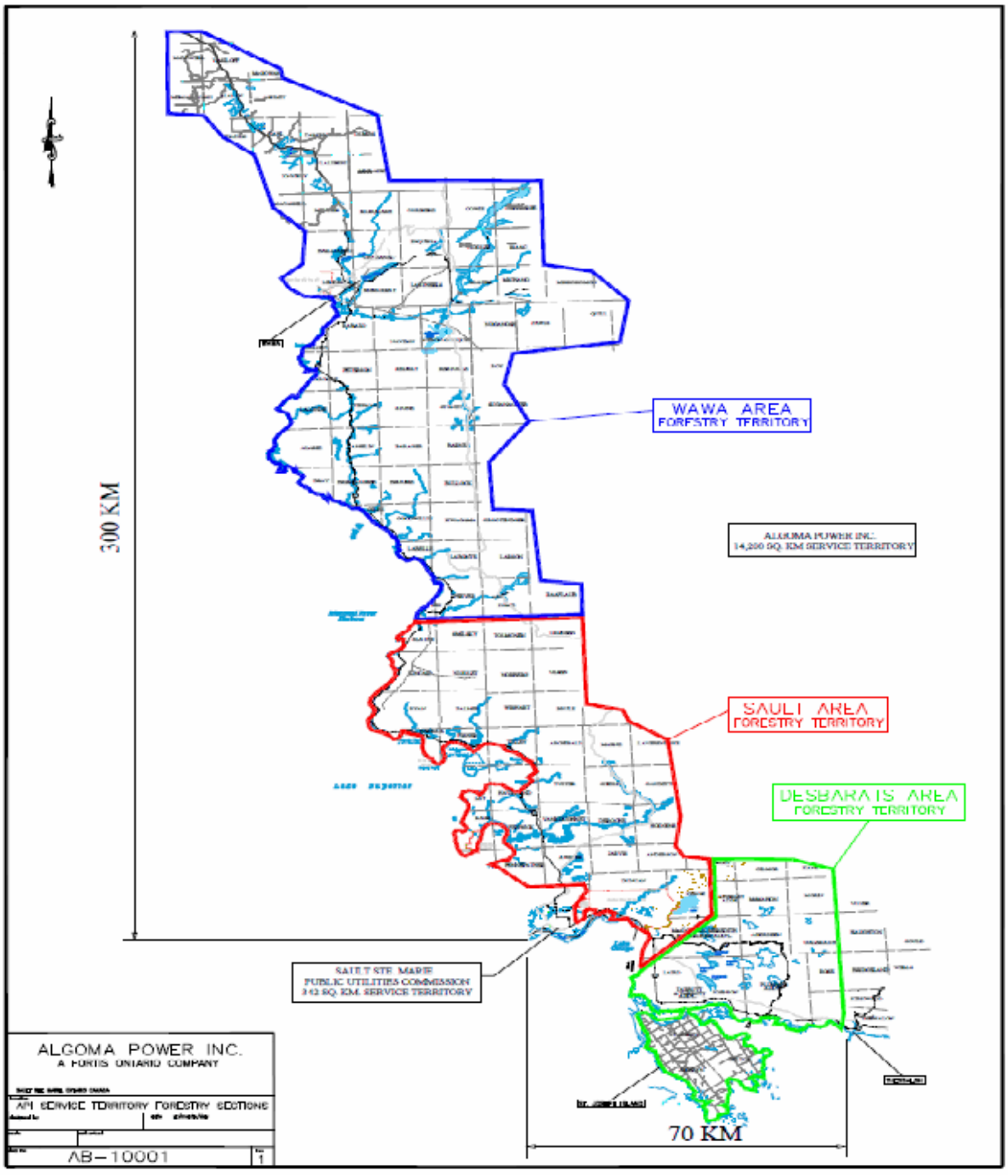
Condition Assessment

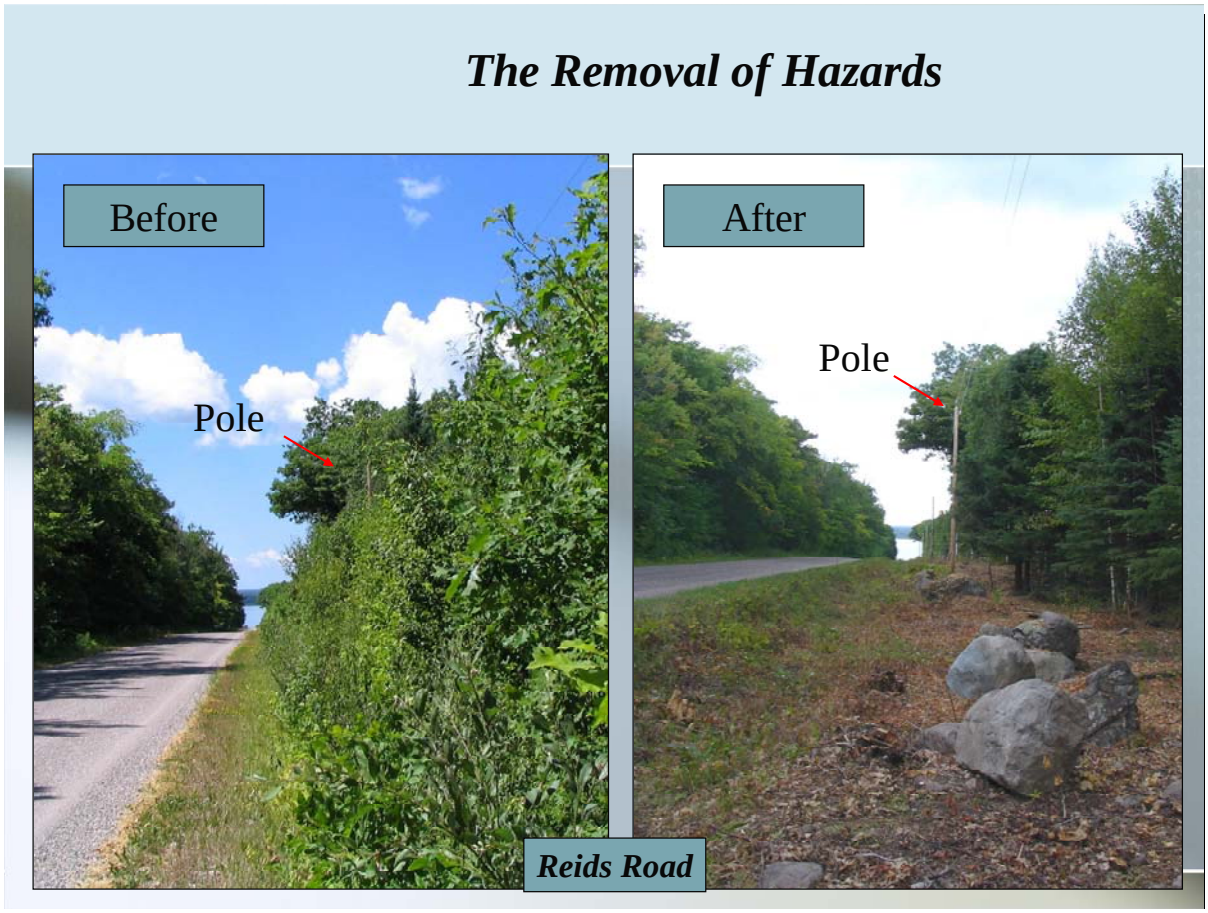
API has established a vegetation condition assessment program which is following the ROW expansion program typically 2 to 3 years prior to the cycle maintenance program. Data is collected based on tree condition (i.e. disease, damage, dead, leaning, shallow rooted) and proximity of vegetation (both trees and brush) to the energized equipment. The number of occurrences, density and severity are recorded and this information in combination with outage statistics, and hazardous tree reports are used to prioritize future work programs and to evaluate the need for any off-cycle work.

Distribution Station Vegetation Management

Station maintenance includes hazardous tree management outside the perimeter of the station and total vegetation control, where sites must be kept free of vegetation to reduce the risk of electrical injury and fires due to vegetation cover. The total vegetation control is annual work, administered through API's vegetation management program and conducted on the 10 of the substations covering approximately 2 hectares. The hazardous tree management around the station is performed in conjunction with the ROW cycled vegetation management work.

Exhibit 4, Tab 1, Schedule 1, Appendix B, Figure 1




The Removal of Hazards
Before
Pole
After
Pole
Reids Road

DEPARTMENTAL OVERVIEW

In order to provide a more comprehensive understanding of API's operations and operating expenses, a brief overview of the functional departments within the organization is set out below.

Customer Service

The Customer Service department is responsible for all customer related functions including:

- Call centre activities
- Credit and collections
- Accounts receivable/payment processing
- Two-Way Automatic Communications System ("TWACS") meter reading, comprehensive meter reading schedules and administration
- Billing activities
- Retail settlement
- New services, upgrades and other customer demand work
- Planned and forced outage management
- Customer communication
- Community relations

Staffing

Customer service activities for API are performed centrally out of the Sault Ste. Marie service centre. There are three regional customer service staff who perform all call centre activities, day-to-day payment processing, credit and collections, billing and electronic business transactions. There are also two employees who manage the administration, customer demand work, reporting, and forced/planned outage co-ordination. In addition, one part-time communication clerk manages the website, outbound calls and customer communication. The regional call centre supports the operations of the entire service area covering 14,200 square kilometers, as required.

The customer service supervisor manages staff, communications, customer claims, co-ordination of operational and customer service functionality, plans/co-ordinates compliance to OEB regulations within the department.

Call Centre Activities

Call centre activities constitute all incoming and outgoing customer interactions via telephone, internet, mail and walk-in traffic. In 2009, the call centre fielded a total of 14,975 telephone calls. Of these calls 72% were answered within 30 seconds or less, which exceeds the OEB minimum service level. Call centre activities primarily deal with customer inquiries, processing customer moves, payment arrangements and other miscellaneous activities.

The following chart outlines the number of calls answered annually since 2006 and the percentage answered within 30 seconds:

Year	Number of Calls Answered	% Answered within 30 seconds
2006	19,515	69%
2007	21,907	71%
2008	16,125	78 %
2009	14,975	72 %

Credit and Collections

Credit and collection activities include managing all accounts receivable related to customer billing, in compliance with the Distribution System Code and API's Conditions of Service. The collections process includes mailing notices, incoming and outgoing telephone calls, registered final notices and the eventual disconnection of electrical services for overdue amounts.

The Customer Service department works with customers to make payment arrangements and installment plans to ensure timely payment and avoid interruption of electrical supply.

Payment Processing

Customers have a variety of methods available to pay their invoice. Customers can pay via pre-authorized payment, credit cards, telephone and internet banking, at financial institutions, by mail and in-person in the office or at any of five API authorized agents.

Meter Reading and Billing Activities

All general service meters >50kW are read monthly. General service meters <50kW and residential are read bi-monthly. Seasonal service meters are read annually. Meter reading services are conducted by three in-house staff and 2745 meters east of Sault Ste. Marie are read via electric lines through the TWACS.

Inserting and mailing of invoices and other communication is contracted with a local mailing house in Sault Ste. Marie.

Billing activities consist of standard supply and distributor-consolidated billing. The number of customers enrolled with retailers has increased each year since deregulation. The following chart sets out the number of retailer-enrolled customers since 2006.

Rate Category	2006	2007	2008	2009
Total	433	504	538	548

Retail Settlement

Retail settlement includes the processing of all retailer transaction requests. A significant amount of processes are manual and the Company is working to automate them within the IT system. Nevertheless, there are still a number of exceptions that require labour hours from customer service staff. Retail settlement also includes the processing of the Regulated Price Plan ("RPP") variance and required reporting as well as the quarterly Ontario Power Generation rebate.

Stakeholder Relations

An employee delegation from API attends 15 annual stakeholder meetings in communities within its service area, delivering information about customer service initiatives, maintenance/capital programs, and answering questions raised by stakeholders.

Information Technology

The business has recently transitioned from an integrated distribution and transmission business to a stand-alone distribution business. On an interim basis, API will continue to utilize the IT system of Great Lakes Power Limited's transmission business and receive support through a services agreement plus limited support from CNPI. Pursuant to this agreement, all hardware and software applications will remain in place for 24 months. While API continues to utilize this system, an implementation plan has been developed for the migration to an SAP IT system. For a discussion of this project, please refer to Exhibit 2, Tab 4, Schedule 5, Appendix A (IT Strategy and Major Projects).

Finance

The Finance department supports all back office operations of API. Located in the Sault Ste. Marie office, the Finance department is responsible for all company accounts payable, and other receivables, payroll and financial reporting. In addition, the department is responsible for OEB data collection and reporting as well as monthly financial statements. Limited finance support is provided by CNPI to API primarily by the Chief Financial Officer of CNPI.

Regulatory

In the past, the regulatory functions were completed utilizing shared resources with the formerly integrated transmission business. Since the acquisition by FortisOntario, the regulatory department of CNPI, an affiliate, provides regulatory support to API and assists

with maintaining compliance with its regulatory requirements. API will continue to rely on the internal resources of its affiliates to develop in-house regulatory competency rather than contracting this out to consultants in order to optimize regulatory compliance.

Human Resources

API does not have a dedicated Human Resources department. Health plan cost management, workplace safety and insurance board administration, and other benefit related activities are managed by API with the assistance of its affiliates. CNPI provides limited human resources support in areas of labour relations, and pensions. The company maintains a modified return to work program and regularly tracks, reports and manages human resources in an effort to remain aligned with corporate objectives.

API maintains positive labour relations with its represented employees and has a cooperative working relationship with the Power Workers Union.

Further human resources services will be provided from API's affiliates as the integration of the utility evolves. For example, further shared corporate services may be required to support API's human resource priorities to ensure adequate staffing levels, succession planning with a focus on employee development and on-going labour relations.

Health, Safety and Environment

API has an internal Health, Safety and Environment department responsible for promoting safe operations and implementing and maintaining API's health and safety and environmental management systems. Limited health, safety and environmental support is provided by CNPI. API promotes healthy and safe work practices through many elements of the system including regular workplace inspections and observations.

API is working towards the integration of the HS&E system utilized by its FortisOntario affiliates. The result will include the establishment of an integrated occupational health,

safety and environmental management system consistent with OHSAS 18001 and ISO 14001, developed within the context of the FortisOntario structure. It is anticipated that this integration will be completed by 2011.

API has consistently achieved high levels of success in the area of health and safety as evidenced by its safety record. As of February 1, 2010, API has gone almost 6 years without a lost time accident.

Community Involvement (Community Relations) and Conservation

Community involvement and public relations have been and remain an important core value of API. Continued local community involvement in selective focus areas will aid in achieving the goal of being a valued member of the community.

API has participated in a number of energy conservation and demand management programs in conjunction with provincial programs. For over 20 years, API has presented school powerline safety and energy conservation programs for elementary students across the District.

Operations

The Operations department is comprised of the following functional areas:

Line Services

The line department is responsible for the operation and maintenance of the distribution line network. All responses to outages, system events, line maintenance programs and select capital construction programs are delivered by line department personnel located in Sault Ste. Marie, Wawa and Desbarats service centres. These service centres house line trucks, fleet vehicles and all stores inventory including conductors, poles and distribution transformers. Managerial and supervisory functions associated with the line services are located at the Sault Ste. Marie service centre.

Forestry Services

The forestry department is responsible for the maintenance of the distribution rights of way throughout the system. The department also oversees the right of way expansion program. In addition to performing field line clearing activities, the department ensures all land issues and permissions are granted prior to the field work. The field work completed by API staff is performed for the most part by skilled utility arborist tradespersons. In addition to internal staff, a large portion of the field work is contracted out. Accordingly, the support to manage, administer and monitor these contracts is also performed by this department.

Electrical Services

The electrical services department is responsible for the monitoring, testing and maintenance of all substation and control equipment. The department maintains the power transformers, reclosers, regulators, and switches of the 13 distribution substations serving the API customer base. The two employees in this department are based at the Sault Ste. Marie service centre. Given the small department and the relative location of the work requirements in this area, it is most efficient to locate in Sault Ste. Marie.

Metering Services

The meter services department is responsible for meter reading, installations, power quality checks, meter verification, testing and ensuring metering compliance with Industry Canada. The department also responds to customer revenue meter disputes. Personnel in this department are based at Sault Ste. Marie, Wawa and Desbarats service centres.

Property/Procurement/Fleet

The property and procurement department is responsible for tendering and purchasing all inventory, supplies and contracted services required by API to provide service. This department is also responsible for the maintenance of all company buildings and fleet. In respect of API, personnel in this department provide their services from the Sault Ste. Marie service centre.

Engineering

The engineering and planning department, with assistance from its affiliates, is responsible for asset management, engineering design, and planning and scheduling of all capital projects for the distribution systems. Capital projects include new services, system expansions, distribution rebuilds, system voltage conversions, system additions, rights of way and land or easement procurements. Personnel in this department are centrally located at the Sault Ste. Marie service centre. Limited engineering support is provided by CNPI to API. Their main priorities are to ensure that service is provided pursuant to API's Conditions of Service and OEB regulations and that the distribution system is designed, constructed, and maintained in compliance with the requirements of the Provincial Electrical Safety Authority and other applicable codes and regulations.

Appendix 2-F

Summary of OM&A Expenses

	2007 Board Approved	2007 Actual	Variance from 2007 Board Approved	2008 Actual	Variance from 2007 Actual	2009 Actual	Variance from 2008 Actual	2010 Test Year	Variance from 2009 Actual	2011 Test Year	Variance from 2010 Test
Operation	1,410,195	1,312,953	(97,242)	1,288,685	(24,268)	1,352,598	63,913	1,408,536	55,938	1,480,059	71,523
Maintenance	2,865,774	3,368,649	502,875	2,979,950	(388,700)	3,183,635	203,686	3,717,293	533,658	4,258,631	541,338
Billing and Collecting	1,144,440	1,057,441	(86,999)	1,061,466	4,025	1,188,958	127,492	1,280,443	91,485	1,311,726	31,282
Community Relations	8,000	1,902	(6,098)	1,119	(784)	735	(384)	10,000	9,265	10,000	-
Administrative and General	2,736,565	2,465,274	(271,291)	3,370,454	905,180	3,052,844	(317,610)	2,642,964	(409,880)	2,779,791	136,827
Total OM&A Expenses	8,164,974	8,206,220		8,701,673		8,778,771		9,059,236		9,840,207	
Variance from previous year			**41,246**		**495,453**		**77,098**		**280,466**		**780,971**
Percent change (year over year)			**0.5%**		**6.0%**		**0.9%**		**3.2%**		**8.6%**
Percent Change 2010 Test Year vs. Most Current Actuals (2009A)	**3.2%**										
Percent Change 2010 Test Year vs. Last Board Approved Rebasing Year (2007A)	**10.4%**										
Average for 2008,2009	**3.5%**										
Compound Annual Growth Rate (for 2007A,2008,2009)	**7.0%**										

Appendix 2-E and 2-G
OM & A Detailed Costs Table

OEB Account	Expense Description	2007 Board Approved	2007 Actual	2008 Actual	2009 Actual	2010 Test Year	2011 Test Year
	Distribution Expenses - Operation						
5005	Operation Supervision and Engineering	445,999	492,192	482,747	458,073	435,385	482,358
5010	Load Dispatching	61,343	63,221	58,011	58,139	88,075	90,497
5012	Station Buildings and Fixtures Expense	256,673	196,535	240,620	279,542	291,355	298,548
5016	Distribution Station Equipment - Operation Labour	37,245	16,888	12,087	100	53,709	55,186
5017	Distribution Station Equipment - Operation Supplies and Expenses	36,853	17,790	4,512	78	10,700	10,938
5020	Overhead Distribution Lines and Feeders - Operation Labour	38,748	82,412	55,814	56,803	49,866	51,237
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	14,420	13,506	24,093	44,507	13,100	13,372
5030	Overhead Subtransmission Feeders - Operation	42,189	31,679	33,596	31,327	36,458	37,406
5035	Overhead Distribution Transformers- Operation	9,477	679	7,911	9,540	27,598	28,357
5060	Street Lighting and Signal System Expense	-	8,611	-	-	-	-
5065	Meter Expense	335,377	262,831	252,109	254,832	290,699	298,257
5070	Customer Premises - Operation Labour	69,576	88,684	84,585	92,678	58,641	60,254
5075	Customer Premises - Materials and Expenses	43,660	24,216	24,236	32,924	35,000	35,700
5096	Other Rent	18,635	13,707	8,365	34,055	17,950	17,950
	Distribution Expenses - Operation Total	1,410,195	1,312,953	1,288,685	1,352,598	1,408,536	1,480,059
	Distribution Expenses - Maintenance						
5110	Maintenance of Buildings and Fixtures - Distribution Stations	67,995	139,682	70,386	38,880	137,699	141,072
5112	Maintenance of Transformer Station Equipment	2,076	37,450	4,829	5,034	7,786	7,977
5114	Maintenance of Distribution Station Equipment	90,689	127,037	124,247	110,379	150,904	154,601
5120	Maintenance of Poles, Towers and Fixtures	14,221	60,346	8,841	36,792	95,374	97,639
5125	Maintenance of Overhead Conductors and Devices	1,029,623	1,166,993	1,061,110	922,236	1,029,706	1,054,161
5130	Maintenance of Overhead Services	11,309	832	87,763	198,281	156,858	160,583
5135	Overhead Distribution Lines and Feeders - Right of Way	1,600,000	1,785,503	1,624,944	1,844,171	2,098,331	2,600,924
5155	Maintenance of Underground Services	-	-	15,689	15,950	11,611	11,904
5160	Maintenance of Line Transformers	32,861	-	-	-	-	-
5175	Maintenance of Meters	17,000	50,805	(17,858)	11,913	29,025	29,769
	Distribution Expenses - Maintenance Total	2,865,774	3,368,649	2,979,950	3,183,635	3,717,293	4,258,631
	Billing and Collection						
5310	Meter Reading Expense	313,031	388,106	383,925	369,039	431,331	442,222
5315	Customer Billing	481,643	448,520	381,837	516,789	521,376	534,736
5320	Collecting	112,686	76,389	90,243	104,013	120,421	123,598
5335	Bad Debt Expense	67,000	18,835	57,583	42,067	45,000	45,000
5340	Miscellaneous Customer Accounts Expenses	170,080	125,591	147,880	157,051	162,315	166,170
	Billing and Collection Total	1,144,440	1,057,441	1,061,466	1,188,958	1,280,443	1,311,726
	Community Relations						
5420	Community Safety Program	-	-	-	-	10,000	10,000
5515	Advertising Expense	8,000	1,902	1,119	735	-	-
	Community Relations Total	8,000	1,902	1,119	735	10,000	10,000
	Administrative and General Expenses						
5610	Management Salaries and Expenses	218,476	167,363	261,937	397,021	967,307	980,429
5615	General Administrative Salaries and Expenses	748,647	687,539	810,987	791,439	930,433	955,322
5620	Office Supplies and Expenses	169,800	126,108	142,821	354,677	255,836	260,953
5625	Administrative Expense Transferred/Credit	-	-	-	-	(821,003)	(874,329)
5630	Outside Services Employed	855,532	859,370	1,551,121	731,687	409,390	539,402
5635	Property Insurance	115,760	109,143	93,634	89,688	90,000	91,800
5655	Regulatory Expenses	120,100	98,387	92,447	97,382	175,000	175,000
5665	Miscellaneous General Expenses	32,300	23,200	24,500	25,000	-	7,500
5670	Rent	-	-	-	69,611	140,613	142,019
5675	Maintenance of General Plant	285,000	184,208	202,663	314,815	315,387	321,695
5680	Electrical Safety Authority Fees	21,700	26,055	19,237	18,509	10,000	10,000
6105	Taxes Other Than Income Taxes (Note less capital taxes)	164,250	163,402	163,956	146,241	150,000	150,000
6205	Donations	5,000	20,499	7,152	16,776	20,000	20,000
	Administrative and General Expenses Total	2,736,565	2,465,274	3,370,454	3,052,844	2,642,964	2,779,791
	Total Operating, Maintenance and Administrative Expenses	8,164,974	8,206,220	8,701,673	8,778,771	9,059,236	9,840,207

Appendix 2-H
OM & A Cost Driver Table

OM&A	2007 Actual	2008 Actual	2009 Actual	2010 Test Year	2011 Test Year
Opening Balance	8,164,974	8,206,220	8,701,673	8,778,771	9,059,236
Right of ways	185,503	(160,560)	219,228	254,160	502,593
Outage & system events	126,893	(18,952)	(28,357)	66,047	28,181
Plant Maintenance	(100,793)		112,152		
Administative & general*	($340,757)	$378,410	($17,138)	$288,143	$173,139
Maintenance activities		(189,465)	26,216	174,513	
Customer Billing		(66,683)	134,952		
Office Building Rent			69,611	71,003	
Capitalized overheads				(821,003)	
Regulatory	532,697	200,224	(474,905)	77,618	
Meter Reading				62,292	
MSP Credit (one-time)	(366,225)	347,853			
Other	3,928	4,626	35,339	107,693	77,058
Closing Balance	8,206,220	8,701,673	8,778,771	9,059,236	9,840,207

*Includes salaries, expenses, supplies, & certain outside services. Changes primarily relate to inflation, FTE increases, wage/benefits changes, stand-alone structure, FortisOntario allocations as explained in variance analysis.

Algoma Power Inc.

Appendix 2-l
Regulatory Cost Schedule

Regulatory Cost Category	Ongoing or One-time Cost?	2007 Actual	2009 Actual Year	2010 Test Year	% Change in 2010 vs. 2007	2011 Test Year	% Change in 2010 vs. 2011
1. OEB Annual Assessment	ongoing	90,089	90,377	95,566	6%	95,566	0%
2. OEB Hearing Assessments (applicant initiated)							
3. OEB Section 30 Costs (OEB initiated)	ongoing	4,522	4,194	4,434	-2%	4,434	0%
4. Expert Witness cost for regulatory matters							
5. Legal costs for regulatory matters *	one-time	532,697	258,015	26,000	-95%	75,000	188%
6. Consultants costs for regulatory matters *	one-time			18,000			
7. Operating expenses associated with staff resources allocated to regulatory matters							
8. Operating expenses associated with other resources allocated to regulatory matters (please identify the resources) *	one-time			31,000			
9. Other regulatory agency fees or assessments							
10. Any other costs for regulatory matters (please define)							

*API estimates the cost of the 2010/2011 rate application will be $225,000. It is proposed the costs will be recovered over a three period (i.e. 2010, 2011 & 2012) as API expects to rebase again in 2013. The details of the costs are included in Exhibit 1, Tab 1, Schedule 1.

Appendix 2-J
OM&A Cost per Customer and FTEE

	2007 Actual	2008 Actual	2009 Actual	2010 Test Year	2011 Test Year
Number of Customers	11,611	11,691	11,720	11,758	11,794
Total OM&A	$ 8,022,318	$ 8,530,565	$ 8,615,754	$ 8,889,236	$ 9,670,207
OM&A cost per Customer	$ 691	$ 730	$ 735	$ 756	$ 820
Number of FTEEs	62.23	64.45	68.28	77.68	77.68
FTEEs/Customer	0.0054	0.0055	0.0058	0.0066	0.0066
OM&A cost per FTEE	$ 128,914	$ 132,359	$ 126,183	$ 114,434	$ 124,488

The number of FTEEs for 2010 and 2011 Test Years is based on the BDR report in Exhibit 4, Tab 5, Appendix A.

OPERATING COSTS VARIANCE ANALYSIS

VARIANCES FROM 2007 BOARD APPROVED TO 2010 TEST YEAR

Explanations are provided for increases that surpassed a materiality threshold of $75,000.

Maintenance of Poles, Towers and Fixtures (OEB Account 5120)

The increased cost of $81,153 is primarily the result of introducing annual diagnostic pole testing program which is based on an eight year cycle. The program is forecast to cost $75,000 in 2010 and $76,500 in 2011 and is further described in Exhibit 4, Tab 1, Schedule 1, Appendix A

Maintenance of Overhead Conductors and Devices (OEB Account 5125)
Maintenance of Overhead Services (OEB Account 5130)

The maintenance of overhead conductors, devices and services accounts have been used interchangeably and thus, should be considered in total. The increase cost of $145,632 reflects historical spending in this category which predominately captures the expenses related to unplanned outage and system restoration. Over the actual period outlined, the costs in these accounts have ranged from approximately $1.1 million to $1.2 million reflecting the impact of outage and restoration events and general cost increases.

Overhead Distribution Lines and Feeders – Right of Way (OEB Account 5135)

The increased cost of $498,331 is primarily the result of moving to a six year maintenance cycle and the resulting increase in the total number of kilometers maintained per year. The vegetation management program is described in Exhibit 4, Tab 1, Schedule 1, Appendix B.

Meter Reading Expense (OEB Account 5310)

The increased costs of $118,300 is primarily related to additional meter reading resources that will be required in 2010 and 2011 prior to the implementation of Smart Meters. API has utilized an Automated Meter Reading system since early 2000 for all of its residential meters east of Sault Ste. Marie. With the deployment of Smart Meters in 2010, API will lose the

ability to remotely read the meters in that geographic area, and as a result will be required to temporarily increase the manual reading efforts through contracted labour until the Smart Meter remote reading capabilities are implemented in late 2011. The API Smart Meter Project is fully described in Exhibit 10.

Administrative Expense Transferred/Credit (OEB Account 5625)

The cost variance of $821,003 relates to the proposed change in methodology for the capitalization of overhead costs as requested in Exhibit 1, Tab 2, Schedule 3.

Rent (OEB Account 5670)

This new cost is related to the assumption of a sub-lease, negotiated at arm's length and on market based lease rates, with GLPT for the office building located at 2 Sackville Road. In 2009, in conjunction with the sale of distribution assets to GLPD, GLPL determined that it would continue its ownership of the 2 Sackville Road complex which it would lease to GLPT which in turn subleases a portion to API. As shown in the Exhibit 4, Tab 3, Schedule 1, Table 1 below, there is an offsetting benefit in the total cost of service and cost of capital resulting from the reduction from rate base of the same building. As a result, the total impacts to expense in 2010 and 2011 are less than the 2007 Board Approved expenses.

Exhibit 4, Tab 3, Schedule 1, Table 1

	2007 Board Approved	2008 Actual	2009 Actual	2010 Test Year	2011 Test Year
Asset Related Costs					
2 Sackville Rd Office *					
Complex Rate Base ($ thousands)	5,060	4,921	4,782	-	-
Cost of Capital (7.34%)	371,436	361,218	175,499	-	-
Depreciation	139,221	139,221	69,611		
Lease from GLPT	-	-	34,800	140,613	142,019
Operating Costs					
Operating Costs - Total	476,092	507,862	308,890		
Allocated from GLPT			229,980	315,387	321,695
	476,092	507,862	538,870	315,387	321,695
Allocated to GLP Generation	(237,027)	(247,839)	-	-	-
Allocated to GLPT	(54,858)	(57,360)	(154,445)		-
API Net Operating Cost Total	184,208	202,663	384,425	315,387	321,695
Total Building Costs	**694,865**	**703,101**	**664,335**	**456,000**	**463,714**
* Estimated for 2007 & 2008					

VARIANCE ANALYSIS ADMINSTRATION AND GENERAL EXPENSES

API has undergone a significant transformation since the last Board Approved revenue requirement and over the last year. This change has impacted API's administration and general expenses as a result of the splitting of the three operations of GLPL (i.e., generation, transmission, and distribution) into three stand alone operations. This separation has limited the sharing of staff and services which has resulted in lost synergies. This is especially true for the splitting of the transmission and distribution operations by GLPL in 2009 to become compliant with Section 71 of the OEB Act. These operations essentially shared management, staff, and services where individuals often worked for both operations prior to the mandated separation.

In late 2009, API was also acquired by FortisOntario. API and FortisOntario have begun to share services in the areas of executive, human resources, health and safety, engineering, regulatory, and some finance areas. The focus has been on supporting the operations of

API as it transforms from being previously integrated with the transmission operations of GLPL. Some areas that were previously outsourced are now being supported by FortisOntario. For example, the previous extensive use of external legal counsel to prepare rate applications has been replaced with support from FortisOntario. The same methodology used by CNPI in its cost of service application to allocate shared services has been updated to include API.

The variances of the administrative and general expense accounts need to be considered with the above transformation in mind.

Management Salaries and Expenses (OEB Account 5610)
General Administrative Salaries and Expenses (OEB Accounts 5615)
Office Supplies and Expenses (OEB Accounts 5620)
Outside Services Employed (OEB Account 5630)

The above accounts need to be reviewed as a group and not individually due to the transformation. The impacts of the above noted transformation primarily affects these accounts and cannot be isolated to any individual account.

Expense Description	2007 Board Approved	2009 Actual	2010 Test Year	Variance from 2007 Board Approved		Variance from 2009 Actual	
Management Salaries and Exp	218	397	967				
General Adm Salaries and Exp	749	791	930				
Office Supplies and Exp	170	355	256				
Outside Services Employed	856	732	409				
	1,992	2,275	2,563	571	28.6%	288	12.7%

The increase in costs of $571,000 from 2007 Board Approved to 2010 Test Year is the result of the following: increase in FTE's and corresponding compensation costs associated with the split from the transmission business, an increase in FTE's as a result of bringing contracted work in house, and increased wages and employee benefit costs. Certain allocations from FortisOntario also contributed to the increase. These increases have been partially offset by the reduction in outside services employed, the elimination of cost sharing of general management salaries and expense with transmission, and the removal of Ontario Operations Allocation from Brookfield Renewable Power. The 2010 Test Year allocation from FortisOntario is $581,342 and is based on the allocation methodology as described by in Exhibit 4 Tab 5. Outside services employed have been reduced as a result of reductions in regulatory and IT support.

The increase in costs of $288,000 from the 2009 Actual to the 2010 Test Year is primarily attributable to the reasons described above for the 2007 Board Approved variance.

VARIANCES FROM 2009 ACTUAL TO 2010 TEST YEAR

Explanations are provided for increases that surpassed a materiality threshold of $75,000.

Maintenance of Buildings and Fixtures – Distribution Stations (OEB Account 5110)

The increase cost of $98,819 is primarily attributable to a maintenance project related to a land remediation at the St. Joseph's Island substation. The estimate on this project is $100,000. The St. Joseph's Island substation, as described in Exhibit 2, Tab 4, Schedule 2, will be decommissioned in 2010.

Maintenance of Overhead Conductors and Devices (OEB Account 5125)

Maintenance of Overhead Services (OEB Account 5130)

The maintenance of overhead conductors, devices and services accounts have been used interchangeably and thus, should be considered in total. The increased cost of $66,047 reflects historical spending in this category which predominately captures the expenses related to unplanned outage and system restoration. Over the actual period outlined, the costs in these accounts have ranged from approximately $1.1 million to $1.2 million reflecting the impact of outage and restoration events and general cost increases.

Overhead Distribution Lines and Feeders – Right of Way (OEB Account 5135)

The increased cost of $254,160 is primarily the result of moving toward a six year maintenance cycle and the resulting increase in the total number of kilometres maintained per year. The vegetation management program is described in Exhibit 4, Tab 1, Schedule 1, Appendix B.

Administrative Expense Transferred/Credit (OEB Account 5625)

The cost variance of $821,003 relates to the proposed change in methodology for the capitalization of overhead costs as requested in Exhibit 1, Tab 2, Schedule 3.

Regulatory Expenses (OEB Account 5655)

The cost increase of $77,618 relates to one third of the budgeted external costs (including legal, consulting, intervenors, and travel) associated with API's 2010/2011 cost of service application. The external resources and associated costs have been reclassed to this account from 2010 forward.

VARIANCES FROM 2010 TEST YEAR TO 2011 TEST YEAR

Explanations are provided for increases that surpass a materiality threshold of $75,000.

Overhead Distribution Lines and Feeders – Right of Way (OEB Account 5135)

As described in Exhibit 4, Tab 1, Schedule 1, Appendix B, the maintenance program has been increasing to achieve the 6 year cycles on the previously expanded ROW. Accordingly, the costs have increased as the total number of kilometres maintained per year has increased. As a result, compared to 2010 Test Year cost, the expenses will have increased $502,593. At this level of spending, API will continue to achieve less than the target 6 year maintenance cycle and as a result will expect that spending will increase in 2012 as a final tranche to achieve sustainability in this integral program. With the exception of a few small areas, it is expected that the ROW expansion program will be completed in 2011. This is fully described in Exhibit 2, Tab 4, Schedule 1.

Outside Services Employed (OEB Account 5630)

Costs in this account show a variance of $130,012 between 2010 Test Year and 2011 Test Year. This variance is primarily related to an increase in external communications and IT software maintenance costs as they relate to the implementation of an integrated Information Technology platform as noted in Exhibit 2, Tab 4, Schedule 5.

Appendix 2-K
OM & A Detailed Costs Table

Quantitative Variance Analysis

OEB Account	Expense Description	2007 Board Approved	2007 Actual	2008 Actual	2009 Actual	2010 Test Year	Variance from 2007 Board Approved $	Variance from 2007 Board Approved %	Variance from 2009 Actual $	Variance from 2009 Actual %	2011 Test Year	Variance from 2010 Test Year $	Variance from 2010 Test Year %
	Distribution Expenses - Operation												
5005	Operation Supervision and Engineering	445,999	492,192	482,747	458,073	435,385	(10,614)	-2%	(22,688)	-5%	482,358	46,973	11%
5010	Load Dispatching	61,343	63,221	58,011	58,139	88,075	26,732	44%	29,936	51%	90,497	2,422	3%
5012	Station Buildings and Fixtures Expense	256,673	196,535	240,620	279,542	291,355	34,682	14%	11,814	4%	298,548	7,192	2%
5016	Distribution Station Equipment - Operation Labour	37,245	16,888	12,087	100	53,709	16,464	44%	53,608	53534%	55,186	1,477	3%
5017	Distribution Station Equipment - Operation Supplies and Expenses	36,853	17,790	4,512	78	10,700	(26,153)	-71%	10,622	13653%	10,938	238	2%
5020	Overhead Distribution Lines and Feeders - Operation Labour	38,748	82,412	55,814	56,803	49,866	11,118	29%	(6,937)	-12%	51,237	1,371	3%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	14,420	13,506	24,093	44,507	13,100	(1,320)	-9%	(31,407)	-71%	13,372	272	2%
5030	Overhead Subtransmission Feeders - Operation	42,189	31,679	33,596	31,327	36,458	(5,731)	-14%	5,130	16%	37,406	948	3%
5035	Overhead Distribution Transformers- Operation	9,477	679	7,911	9,540	27,598	18,121	191%	18,058	189%	28,357	759	3%
5060	Street Lighting and Signal System Expense	-	8,611	-	-	-	-		-		-	-	
5065	Meter Expense	335,377	262,831	252,109	254,832	290,699	(44,678)	-13%	35,867	14%	298,257	7,558	3%
5070	Customer Premises - Operation Labour	69,576	88,684	84,585	92,678	58,641	(10,935)	-16%	(34,037)	-37%	60,254	1,613	3%
5075	Customer Premises - Materials and Expenses	43,660	24,216	24,236	32,924	35,000	(8,660)	-20%	2,076	6%	35,700	700	2%
5096	Other Rent	18,635	13,707	8,365	34,055	17,950	(685)	-4%	(16,105)	-47%	17,950	-	0%
	Distribution Expenses - Operation Total	1,410,195	1,312,953	1,288,685	1,352,598	1,408,536	(1,659)	0%	55,938	4%	1,480,059	71,523	5%
	Distribution Expenses - Maintenance												
5110	Maintenance of Buildings and Fixtures - Distribution Stations	67,995	139,682	70,386	38,880	137,699	69,704	103%	98,819	254%	141,072	3,374	2%
5112	Maintenance of Transformer Station Equipment	2,076	37,450	4,829	5,034	7,786	5,710	275%	2,752	55%	7,977	191	2%
5114	Maintenance of Distribution Station Equipment	90,689	127,037	124,247	110,379	150,904	60,215	66%	40,525	37%	154,601	3,697	2%
5120	Maintenance of Poles, Towers and Fixtures	14,221	60,346	8,841	36,792	95,374	81,153	571%	58,582	159%	97,639	2,265	2%
5125	Maintenance of Overhead Conductors and Devices	1,029,623	1,166,993	1,061,110	922,236	1,029,706	83	0%	107,470	12%	1,054,161	24,456	2%
5130	Maintenance of Overhead Services	11,309	832	87,763	198,281	156,858	145,549	1287%	(41,423)	-21%	160,583	3,725	2%
5135	Overhead Distribution Lines and Feeders - Right of Way	1,600,000	1,785,503	1,624,944	1,844,171	2,098,331	498,331	31%	254,160	14%	2,600,924	502,593	24%
5155	Maintenance of Underground Services	-	-	15,689	15,950	11,611	11,611		(4,339)	-27%	11,904	293	3%
5160	Maintenance of Line Transformers	32,861	-	-	-	-	(32,861)	-100%	-		-	-	
5175	Maintenance of Meters	17,000	50,805	(17,858)	11,913	29,025	12,025	71%	17,112	144%	29,769	744	3%
	Distribution Expenses - Maintenance Total	2,865,774	3,368,649	2,979,950	3,183,635	3,717,293	851,519	30%	533,658	17%	4,258,631	541,338	15%
	Billing and Collection												
5310	Meter Reading Expense	313,031	388,106	383,925	369,039	431,331	118,300	38%	62,292	17%	442,222	10,891	3%
5315	Customer Billing	481,643	448,520	381,837	516,789	521,376	39,733	8%	4,587	1%	534,736	13,360	3%
5320	Collecting	112,686	76,389	90,243	104,013	120,421	7,735	7%	16,409	16%	123,598	3,176	3%
5335	Bad Debt Expense	67,000	18,835	57,583	42,067	45,000	(22,000)	-33%	2,933	7%	45,000	-	0%
5340	Miscellaneous Customer Accounts Expenses	170,080	125,591	147,880	157,051	162,315	(7,765)	-5%	5,264	3%	166,170	3,855	2%
	Billing and Collection Total	1,144,440	1,057,441	1,061,466	1,188,958	1,280,443	136,003	12%	91,485	8%	1,311,726	31,282	2%
	Community Relations												
5420	Community Safety Program	-	-	-	-	10,000	10,000		10,000		10,000	-	0%
5515	Advertising Expense	8,000	1,902	1,119	735	-	(8,000)	-100%	(735)	-100%	-	-	
	Community Relations Total	8,000	1,902	1,119	735	10,000	2,000	25%	9,265	1261%	10,000	-	0%
	Administrative and General Expenses												
5610	Management Salaries and Expenses	218,476	167,363	261,937	397,021	967,307	748,831		570,286	144%	980,429	13,122	1%
5615	General Administrative Salaries and Expenses	748,647	687,539	810,987	791,439	930,433	181,786	24%	138,994	18%	955,322	24,889	3%
5620	Office Supplies and Expenses	169,800	126,108	142,821	354,677	255,836	86,036	51%	(98,841)	-28%	260,953	5,117	2%
5625	Administrative Expense Transferred/Credit	-	-	-	-	(821,003)	(821,003)		(821,003)		(874,329)	(53,326)	6%
5630	Outside Services Employed	855,532	859,370	1,551,121	731,687	409,390	(446,142)	-52%	(322,297)	-44%	539,402	130,012	32%
5635	Property Insurance	115,760	109,143	93,634	89,688	90,000	(25,760)	-22%	312	0%	91,800	1,800	2%
5655	Regulatory Expenses	120,100	98,387	92,447	97,382	175,000	54,900	46%	77,618	80%	175,000	-	0%
5665	Miscellaneous General Expenses	32,300	23,200	24,500	25,000	-	(32,300)	-100%	(25,000)	-100%	7,500	7,500	
5670	Rent	-	-	-	69,611	140,613	140,613		71,003	102%	142,019	1,406	1%
5675	Maintenance of General Plant	285,000	184,208	202,663	314,815	315,387	30,387		573		321,695	6,308	
5680	Electrical Safety Authority Fees	21,700	26,055	19,237	18,509	10,000	(11,700)	-54%	(8,509)	-46%	10,000	-	
6105	Taxes Other Than Income Taxes (Note less capital taxes)	164,250	163,402	163,956	146,241	150,000	(14,250)	-9%	3,759	3%	150,000	-	0%
6205	Donations	5,000	20,499	7,152	16,776	20,000	15,000	300%	3,224	19%	20,000	-	
	Administrative and General Expenses Total	2,736,565	2,465,274	3,370,454	3,052,844	2,642,964	(93,601)	-3%	(409,880)	-13%	2,779,791	136,827	5%
	Total Operating, Maintenance and Administrative Expenses	8,164,974	8,206,220	8,701,673	8,778,771	9,059,236	894,263	11%	280,466	3%	9,840,207	780,971	9%

OM&A Detailed Costs Table
Year Over Year Variance

OEB Accoun	Expense Description	2007 Board Approved	2007 Actual	Variance from 2007 Board Approved	2008 Actual	Variance from 2007 Actual	2009 Actual	Variance from 2008 Actual	2010 Test Year	Variance from 2009 Actual	2011 Test Year	Variance from 2010 Test
	Distribution Expenses - Operation											
5005	Operation Supervision and Engineering	445,999	492,192	46,193	482,747	(9,445)	458,073	(24,674)	435,385	(22,688)	482,358	46,973
5010	Load Dispatching	61,343	63,221	1,878	58,011	(5,210)	58,139	128	88,075	29,936	90,497	2,422
5012	Station Buildings and Fixtures Expense	256,673	196,535	(60,138)	240,620	44,084	279,542	38,922	291,355	11,814	298,548	7,192
5016	Distribution Station Equipment - Operation Labour	37,245	16,888	(20,357)	12,087	(4,802)	100	(11,987)	53,709	53,608	55,186	1,477
5017	Distribution Station Equipment - Operation Supplies and Expenses	36,853	17,790	(19,063)	4,512	(13,278)	78	(4,434)	10,700	10,622	10,938	238
5020	Overhead Distribution Lines and Feeders - Operation Labour	38,748	82,412	43,664	55,814	(26,598)	56,803	989	49,866	(6,937)	51,237	1,371
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	14,420	13,506	(914)	24,093	10,587	44,507	20,414	13,100	(31,407)	13,372	272
5030	Overhead Subtransmission Feeders - Operation	42,189	31,679	(10,510)	33,596	1,917	31,327	(2,269)	36,458	5,130	37,406	948
5035	Overhead Distribution Transformers- Operation	9,477	679	(8,798)	7,911	7,231	9,540	1,630	27,598	18,058	28,357	759
5060	Street Lighting and Signal System Expense	-	8,611	8,611	-	(8,611)	-	-	-	-	-	-
5065	Meter Expense	335,377	262,831	(72,546)	252,109	(10,722)	254,832	2,723	290,699	35,867	298,257	7,558
5070	Customer Premises - Operation Labour	69,576	88,684	19,108	84,585	(4,100)	92,678	8,093	58,641	(34,037)	60,254	1,613
5075	Customer Premises - Materials and Expenses	43,660	24,216	(19,444)	24,236	20	32,924	8,688	35,000	2,076	35,700	700
5096	Other Rent	18,635	13,707	(4,928)	8,365	(5,343)	34,055	25,691	17,950	(16,105)	17,950	-
	Distribution Expenses - Operation Total	1,410,195	1,312,953	(97,242)	1,288,685	(24,268)	1,352,598	63,913	1,408,536	55,938	1,480,059	71,523
	Distribution Expenses - Maintenance											
5110	Maintenance of Buildings and Fixtures - Distribution Stations	67,995	139,682	71,687	70,386	(69,296)	38,880	(31,507)	137,699	98,819	141,072	3,374
5112	Maintenance of Transformer Station Equipment	2,076	37,450	35,374	4,829	(32,622)	5,034	206	7,786	2,752	7,977	191
5114	Maintenance of Distribution Station Equipment	90,689	127,037	36,348	124,247	(2,790)	110,379	(13,868)	150,904	40,525	154,601	3,697
5120	Maintenance of Poles, Towers and Fixtures	14,221	60,346	46,125	8,841	(51,506)	36,792	27,951	95,374	58,582	97,639	2,265
5125	Maintenance of Overhead Conductors and Devices	1,029,623	1,166,993	137,370	1,061,110	(105,883)	922,236	(138,874)	1,029,706	107,470	1,054,161	24,456
5130	Maintenance of Overhead Services	11,309	832	(10,477)	87,763	86,931	198,281	110,517	156,858	(41,423)	160,583	3,725
5135	Overhead Distribution Lines and Feeders - Right of Way	1,600,000	1,785,503	185,503	1,624,944	(160,560)	1,844,171	219,228	2,098,331	254,160	2,600,924	502,593
5155	Maintenance of Underground Services	-	-	-	15,689	15,689	15,950	261	11,611	(4,339)	11,904	293
5160	Maintenance of Line Transformers	32,861	-	(32,861)	-	-	-	-	-	-	-	-
5175	Maintenance of Meters	17,000	50,805	33,805	(17,858)	(68,663)	11,913	29,772	29,025	17,112	29,769	744
	Distribution Expenses - Maintenance Total	2,865,774	3,368,649	502,875	2,979,950	(388,700)	3,183,635	203,686	3,717,293	533,658	4,258,631	541,338
	Billing and Collection											
5310	Meter Reading Expense	313,031	388,106	75,075	383,925	(4,182)	369,039	(14,886)	431,331	62,292	442,222	10,891
5315	Customer Billing	481,643	448,520	(33,123)	381,837	(66,683)	516,789	134,952	521,376	4,587	534,736	13,360
5320	Collecting	112,686	76,389	(36,297)	90,243	13,854	104,013	13,770	120,421	16,409	123,598	3,176
5335	Bad Debt Expense	67,000	18,835	(48,165)	57,583	38,748	42,067	(15,515)	45,000	2,933	45,000	-
5340	Miscellaneous Customer Accounts Expenses	170,080	125,591	(44,489)	147,880	22,288	157,051	9,171	162,315	5,264	166,170	3,855
	Billing and Collection Total	1,144,440	1,057,441	(86,999)	1,061,466	4,025	1,188,958	127,492	1,280,443	91,485	1,311,726	31,282
	Community Relations											
5420	Community Safety Program	-	-	-	-	-	-	-	10,000	10,000	10,000	-
5515	Advertising Expense	8,000	1,902	(6,098)	1,119	(784)	735	(384)	-	(735)	-	-
	Community Relations Total	8,000	1,902	(6,098)	1,119	(784)	735	(384)	10,000	9,265	10,000	-
	Administrative and General Expenses											
5610	Management Salaries and Expenses	218,476	167,363	(51,113)	261,937	94,574	397,021	135,084	967,307	570,286	980,429	13,122
5615	General Administrative Salaries and Expenses	748,647	687,539	(61,108)	810,987	123,448	791,439	(19,548)	930,433	138,994	955,322	24,889
5620	Office Supplies and Expenses	169,800	126,108	(43,692)	142,821	16,713	354,677	211,856	255,836	(98,841)	260,953	5,117
5625	Administrative Expense Transferred/Credit	-	-	-	-	-	-	-	(821,003)	(821,003)	(874,329)	(53,326)
5630	Outside Services Employed	855,532	859,370	3,838	1,551,121	691,751	731,687	(819,435)	409,390	(322,297)	539,402	130,012
5635	Property Insurance	115,760	109,143	(6,617)	93,634	(15,510)	89,688	(3,946)	90,000	312	91,800	1,800
5655	Regulatory Expenses	120,100	98,387	(21,713)	92,447	(5,941)	97,382	4,935	175,000	77,618	175,000	-
5665	Miscellaneous General Expenses	32,300	23,200	(9,100)	24,500	1,300	25,000	500	-	(25,000)	7,500	7,500
5670	Rent	-	-	-	-	-	69,611	69,611	140,613	71,003	142,019	1,406
5675	Maintenance of General Plant	285,000	184,208	(100,793)	202,663	18,455	314,815	112,152	315,387	573	321,695	6,308
5680	Electrical Safety Authority Fees	21,700	26,055	4,355	19,237	(6,818)	18,509	(728)	10,000	(8,509)	10,000	-
6105	Taxes Other Than Income Taxes (Note less capital taxes)	164,250	163,402	(848)	163,956	553	146,241	(17,715)	150,000	3,759	150,000	-
6205	Donations	5,000	20,499	15,499	7,152	(13,347)	16,776	9,624	20,000	3,224	20,000	-
	Administrative and General Expenses Total	2,736,565	2,465,274	(271,291)	3,370,454	905,180	3,052,844	(317,610)	2,642,964	(409,880)	2,779,791	136,827
	Total Operating, Maintenance and Administrative Expenses	8,164,974	8,206,220	41,246	8,701,673	495,453	8,778,771	77,098	9,059,236	280,466	9,840,207	780,971

EMPLOYEE COMPENSATION

OVERVIEW

This Exhibit 4, Tab 4, Schedule 1 (Employee Compensation) provides an overview of API's compensation framework including an outline of API's approach to employee incentive pay. Appendix 2-L (Employee Costs) that appears in Exhibit 4, Tab 4, Schedule 2 provides a summary of total compensation costs from 2007 Actual to the 2010 and 2011 Test Years. Exhibit 4, Tab 4, Schedule 3 (Compensation Variance Analysis) provides an explanation of significant year-over-year variances. Exhibit 4, Tab 4, Schedule 4 (Pension Expense and Post Retirement Benefits) outlines the status of API's pension funding and assumptions used in the analysis.

BASE PAY COMPENSATION

Overall compensation for all non-union employees of API is designed to be competitive so as to attract and retain qualified personnel. Overall compensation, includes base pay and a portion of pay which is at risk (ie. incentive compensation).

Salary increases for 2010 and 2011 were based on market information, including adjustments for performance and economic market conditions. Management and Non-union staff are not paid overtime compensation.

SHORT-TERM INCENTIVE COMPENSATION AVAILABLE TO MANAGEMENT AND NON-UNION STAFF

Description

One element of API's overall compensation package for non-union employees is incentive compensation.

Incentive compensation for all non-union employees of API reflects an element of compensation put at risk to elicit and sustain continued and improved performance. The more senior the employee, the greater the percentage of overall compensation, which is put at risk.

Application

The short-term incentive plan is available to all regular Management and Non-union staff of API. Unionized employees do not participate in the short-term incentive plan and do not receive incentive compensation.

Format

The short-term incentive program includes both an individual and a corporate component for all Management and Non-union staff. Key aspects of this plan together with the targets are outlined below.

Minimum Corporate Performance Criterion

Prior to any incentive payments being made, a minimum corporate performance criterion, or trigger, must be reached. API must achieve a pre-determined corporate threshold/target as approved by the board of directors; otherwise, no incentive payments will be made. For more information on these criterion, see “Corporate Targets” below.

Payout Summary

Basis

The target incentive compensation ranges from 5% to 25% of base salary. An additional payment of up to 50% of the target bonus may be awarded at the board of directors’ discretion in recognition of response to exceptional challenges or opportunities. There is no payout if performance falls below the 50% target level.

The individual performance component was designed to better reflect the degree of opportunity which employees in each management group have to influence corporate performance. The weighting for the individual component will vary by position level.

Position	Corporate Targets	Individual Targets
Regional Manager	50%	50%
Other Management/Non-union	25%	75%

The incentive regime is structured in a manner that emphasizes the greater ability of the more senior individuals to affect corporate performance by making a greater portion of their compensation dependent on corporate as opposed to individual performance. For the Regional Manager, the split is 50% corporate and 50% individual. For Management and Non-union staff, the split is 25% corporate and 75% individual.

Corporate Targets

Corporate targets may include the following: cost reduction, capital project completion, customer service, safety and environment, regulatory compliance, employee training, and reliability. Accordingly, all corporate incentive payments included in the 2010 and 2011 Test Years relate to benefits to ratepayers as described below. Corporate measures have three performance levels, and are reflective of key corporate targets or goals.

Each of the corporate targets benefits the ratepayers. In particular, the cost reduction measures set targets for maintaining or reducing operating costs. The capital project measure sets targets for meeting budgeted capital project costs, and completing projects with respect to scope and schedule. These measures are primarily customer-related as they represent a cost reduction or maintenance target that directly benefits ratepayers through lower rates or rates that would otherwise be higher. Customer service corporate measures benefit ratepayers by ensuring efficient and effective levels of service that meet Board standards and service quality indices. Safety and environmental measures benefit ratepayers by minimizing high risk incidents and promoting a proactive approach to

managing safety and the environment. Furthermore, rate payers also benefit from a safe supply of electricity at lower costs. Regulatory compliance primarily benefits ratepayers as it ensures reliable supply of electricity, and efficient customer service at approved rates. Employee training primarily benefits ratepayers, by ensuring that ratepayers receive appropriate service levels from employees that keep abreast of various job related skills including regulatory, safety and environmental, technical and customer service related policies and procedures. Reliability measures primarily benefit the ratepayer by ensuring a reliable supply of electricity.

Individual Targets

Individual targets, like the corporate targets, support the broader design objective of aligning the interests of all stakeholder groups in API with an overall focus on efficient delivery of service to customers. Individual measures were developed in consultation with the individuals and their immediate superiors. Each measure has three performance levels, is reflective of key projects or goals and focuses on departmental or divisional priorities. Individual measures may include the following: human resources, safety and environment, reliability, regulatory compliance, customer service, efficiencies, cost reduction, capital project completion and training targets. These measures primarily benefit ratepayers for the reasons discussed herein. Human resources targets primarily benefit the ratepayer by ensuring that skilled personnel are recruited and retained to provide safe and reliable service, and to maintain service levels. Cost reduction and efficiency measures relate to maintaining or reducing operating costs which flow directly to the ratepayer through stable rates. Safety and environment, reliability, regulatory compliance, and customer service measures directly benefit ratepayers in the form of a safe and reliable supply of electricity in compliance with regulations and established customer service levels.

Assessment and Payment

The board of directors of FortisOntario, API's parent company, approves the corporate targets for all participants. Actual corporate performance is assessed and approved

annually by the board of directors of FortisOntario. Actual performance against individual targets is evaluated by the individual's immediate superior for Non-union staff and Management. The Chief Executive Officer of API assesses and approves the Regional Manager's performance.

Payments will be made generally in February, once all corporate and individual performance measures for the financial year have been finalized. API budgets for incentive payments at target payment levels.

OTHER BENEFITS

Other benefits include such items as pension contributions, health and dental insurance benefits, vehicle benefits, interest benefits, share purchase plan benefits, and health and wellness membership. These are calculated at year end based on information available or provided at that time.

COMPENSATION FOR UNIONIZED EMPLOYEES

Unionized employees of API are represented by Power Workers' Union CUPE Local 1000 (the "Union"). The terms of employment, including compensation, overtime and benefits are set out in the collective agreement between API and the Union, which is for a three-year term (January 1, 2010 to December 31, 2012). The wage increases under the new collective agreement are as follows:

Year 1 – 1% Jan. 1, 2010, 2% Jul. 1, 2010
Year 2 – 2.75% Jan. 1, 2011
Year 3 – 3% Jan. 1, 2012

The wage increases under the previous collective agreement were as follows:

Year 1 - 3.5%, Jan. 1, 2007
Year 2 – 3%, Jan 1, 2008
Year 3 – 3%, Jan. 1, 2009

Employee Compensation & Benefits

Appendix 2-L
Employee Costs

	2007 ACTUAL	2008 ACTUAL	2009 ACTUAL	2010 TEST YEAR	2011 TEST YEAR
Number of Employees (FTEs including Part Time)					
Union	39.23	39.14	40.79	40.94	40.94
Non-Union	23.00	25.31	27.49	30.86	30.86
Total	62.23	64.45	68.28	71.80	71.80
Number of Part Time Employees					
Union	6.84	5.23	5.86	4.98	4.98
Non-Union	5.27	5.55	4.88	3.62	3.62
Total	12.11	10.78	10.74	8.60	8.60
Total Salary & Wages					
Union	2,692,319	2,796,363	2,958,174	3,023,774	3,106,928
Non-Union (Excludes Incentive Pay)	1,367,668	1,618,052	1,794,411	2,047,587	2,103,896
Total	4,059,988	4,414,415	4,752,585	5,071,361	5,210,823
Total Benefits					
Union	1,000,970	1,003,925	1,299,547	1,351,066	1,377,930
Non-Union	456,120	525,812	598,168	793,023	849,162
Total	1,457,090	1,529,737	1,897,715	2,144,089	2,227,092
Total Compensation (Salary, Wages & Benefits)					
Union	3,693,290	3,800,288	4,257,721	4,374,840	4,484,858
Non-Union (Incentive Pay Included)	1,947,844	2,283,817	2,582,797	3,040,725	3,158,658
Total	5,641,133	6,084,105	6,840,518	7,415,565	7,643,516
Compensation - Average Yearly Base Wages					
Union	58,979	59,311	60,519	61,906	63,608
Non-Union (Excludes Incentive Pay)	59,464	63,929	65,287	66,351	68,175
Compensation - Average Yearly Overtime					
Union	9,650	12,134	12,003	11,957	12,286
Non-Union	-	-	-	-	-
Compensation - Average Incentive Pay					
Union	-	-	-	-	-
Non-Union	6,997	7,083	8,413	7,346	7,548
Compensation - Average Yearly Benefits					
Union	25,515	25,650	31,859	33,003	33,659
Non-Union	19,831	20,775	21,763	25,697	27,517
Total Compensation	**5,641,133**	**6,084,105**	**6,840,518**	**7,415,565**	**7,643,516**
Total Compensation charged to OM&A	**4,188,852**	**4,302,421**	**5,078,712**	**5,080,158**	**5,241,209**
Total Compensation Capitalized	**1,452,281**	**1,781,685**	**1,761,806**	**2,335,407**	**2,402,307**

COMPENSATION VARIANCE ANALYSIS

For the purpose of completing Appendix 2-L Employee Costs, API used hours and dollars allocated to the various categories as a basis for calculating FTE's and OM&A and capital allocations over the years shown.

FTE's

The total increase in FTE's over the period 2007 Actual to the 2011 Test Year is 9.57 or 15.4%. Non-Union staff account for the major portion of the overall increase; 7.86 FTE's or 12.6%.

There are four main factors that contribute to the non-union FTE increase over the period:

(i) The separation of the transmission and distribution businesses contributed since a few new positions were required:

a. General Manager and Assistant – Upon the split of the business, the new distribution operation required an onsite, Regional Manager and Administrative Assistant;

b. Health, Safety & Environmental Specialist and Assistant were assigned to manage this vital aspect of API's stand alone operation; and

c. Accounting and IT positions that were shared between the two operating divisions are now stand-alone. Accordingly, certain job positions were required in the new API operation.

(ii) There was a replacement of three externally contracted positions with three regular employee positions:

a. Engineering technician – This was needed to support the increased capital programs;

b. Metering supervisor – This was required to oversee the existing metering and electrical departments as well as establish the ongoing operational requirements of the extensive Smart Meter system which is being deployed during the 2010 and 2011 Test Years; and

c. Accountant – This position replaced a long term external contract resource.

(iii) There was an increase in land and land-rights operational requirements associated with a move to the 6 year ROW maintenance cycle requiring a new position of Land Technician.

(iv) The re-assignment of part time duties to full time staff.

The total increase in union FTE's over the period remain relatively flat with an increase of only 1.71 staff. The changes that arise over the period resulted in increases arising primarily in the two main trades, Lines and Forestry.

PTE's

The total decrease in PTE's over the period is a result in the re-assignment of part time duties to full time staff.

Total Salary and Wages

Total salary and wages over the period have increased as a result of the addition of FTE's noted above. In addition, to the factors noted above regarding non-union FTE's, individual progressions, and staff mix also contribute to the overall dollar increase.

Other contributors in addition to normal negotiated collective bargaining increases impacting the union increase would include such items as (i) overall increase in FTE's; (ii) individual progressions, and (iii) changes in staff mix.

Total Benefits

Total benefits over the period 2007 to 2010 reflect a notable increase. The primary contributing factor in the latter years is the funding of pension and retiree benefits. In

addition, there are the general and collective bargaining increases that result in areas such as health, dental, vision and insurance.

PENSION EXPENSE AND POST RETIREMENT BENEFITS EXPENSE

Defined Benefit Pension Plan

API sponsors the Retirement Fund of API. The pension plan is a contributory, defined-benefit pension plan whereby the members contribute an amount equal to 5% of gross earnings per plan year up to and including the YMPE and 7% of gross earnings if any, in excess of the YMPE. The members comprise of current represented employees of the Power Workers Union, pensioners (previous employees) and beneficiaries of employees or pensioners. Currently there are 35 active members and a total of 33 pensioners/beneficiaries receiving a pension.

Effective July 1, 2009 employees of the 'distribution' division of the Great Lakes Power Limited were transferred to API. The employees were members of the Retirement Fund of GLPL prior to July 1, 2009. A Retirement Fund of API was established for employees transferred to API. An application has been submitted to the Financial Services Commission of Ontario ("FSCO") for approval of the transfer of these assets and liabilities from the GLPL Plan to the Retirement Fund of API, as well as benefits in the GLPL Plan for inactive members formerly employed by the 'distribution' division of GLPL.

The most recent actuarial valuation for the Retirement Fund of API was as at July 1, 2009. The actuarial valuation was filed with the FSCO. The valuation showed that the Plan had a deficit of $2,086,800 million, on a going-concern basis.

DB Pension	2010 Test Year
Pension expense	654,383
Significant assumptions used:	
Discount rate	6.40%
Expected long-term rate of return on plan assets	6.25%
Rate of compensation increase	4.00%

The defined benefit pension expense amounts are prepared for API by Mercer (Canada) Limited ("Mercer"). In February 2010, Mercer provided an updated estimate of the 2010 pension expense amount. For the 2011, the 2010 pension expense amount has been increased by rolling forward the 2010 expense as a part of the labour increases noted in Exhibit 4, Tab 4 (Employee Compensation Breakdown).

Defined Contribution Pension Plan of Algoma Power Inc.

This plan is available to full time, permanent, non-unionized employees after completing 3 months of employment. Currently, there are 19 members in the plan. Members of the plan may make contributions ranging from 0% to 5% percent of their basic earnings. API is required to contribute an amount equal to 3% of earnings, in addition to matching the employee's contributions to a maximum of 8%. Contributions cannot exceed the overall maximum under the Income Tax Act (Canada).

DC Pension	2010 Test Year
Pension premiums	103,702

POST RETIREMENT BENEFITS EXPENSE

API provides certain health, dental, and life insurance benefits, under unfunded defined benefits plans, on behalf of its retired employees.

The post retirement benefit expense amounts are prepared for API by Mercer. In February 2010, Mercer provided updated estimates of the 2010 post retirement benefit expense amounts. For the 2011, the 2010 post retirement expense amount has been increased by rolling forward the 2010 expense as a part of the labour increases noted in Exhibit 4, Tab 4, (Employee Compensation Breakdown).

Post-retirement Benefits	**2010 Test Year**
Post-retirement benefit costs	587,078
Significant assumptions used:	
Discount rate	6.60%

SERVICES FROM (TO) AFFILIATES

FortisOntario owns and operates five regulated electric distribution business units and a regulated transmission business unit, as well as an unregulated co-generation plant in Cornwall (Cornwall District Heating), which is owned directly by FortisOntario.

The business units of the FortisOntario group are as follows:

- FortisOntario (includes Executive and Cornwall District Heating);
- Cornwall Electric;
- CNPI – Fort Erie / Gananoque;
- CNPI – Port Colborne;
- CNPI – transmission; and
- Algoma Power Inc.

Services Agreements

Services Agreements between FortisOntario and its Board licensed affiliates have been previously filed and are due to expire in September 2010. Upon expiry, FortisOntario will enter renewed service agreements with all of its business units including API. In the interim, API and its affiliates abide by the terms of the agreements files with the Board.

Corporate and Administrative Services - Shared Services

In order to maximize efficiencies of scale and avoid duplication, certain administrative and corporate services are shared by the business units. The full integration of API with the FortisOntario business units is expected to take place over time. For example, as outlined in the capital program at Exhibit 2, Tab 4, Schedule 5, Appendix A, API will be migrated onto CNPI's IT system in 2011. This process will include the sharing of corporate services with FortisOntario including the following: executive, finance, information technology, human resources, health, safety and environmental, regulatory and engineering design management

for capital projects through the use of Shared Service Agreements. These Shared Service Agreements utilize a cost-based pricing approach. Each of the individual functions identified above were reviewed to determine the appropriate allocations ultimately resulting in the assignment of full time equivalents to each business unit. BDR was engaged by FortisOntario to review the cost allocation methodology and computations used for the allocation of shared services and to provide its opinion as to the reasonableness thereof. A copy of the BDR Report confirming BDR's opinion is attached as Appendix A.

Since the acquisition of API on October 8, 2009, there have been a number of initiatives undertaken to advance the business plans of API, in support of the ongoing integration of API as an affiliate of FortisOntario. Recognizing that the oversight of the business had changed to FortisOntario, a number of corporate wide policies were rolled out to employees within the first month of the acquisition beginning with Health, Safety and Environment, Code of Conduct and Whistleblower policies.

With a view to mutually benefit both FortisOntario and API, the integration of Health Safety and Environmental systems have been progressing. Incident and monthly statistics reporting was also implemented in January 2010.

Corporate Services - Fortis Inc.

Fortis Inc. charges FortisOntario, and other Fortis owned companies, for specific costs incurred related to the listing of Fortis shares on the Toronto Stock Exchange, investor reporting costs, charges related to the administration of share purchase plans, and other miscellaneous costs. Consumers benefit from these services by providing API with access to capital which supports the required capital investment in the API's distribution system to ensure reliable and safe distribution of electricity. These charges are allocated to FortisOntario and based on assets and share purchase plan participants. These costs are then allocated to FortisOntario's operating subsidiaries. Cost-based pricing is used to properly allocate these charges reviewed by an internal audit function provided by Fortis based on time and costs.

Interest Expense

Please see Exhibit 5, Tab 1, Schedule 1 for a discussion of affiliated debt.

The tables below summarize API's forecasted affiliated expenses (recoveries) for the 2010 and 2011 Test Years.

Appendix 2-M
2010 Shared Services/Corporate Cost Allocation
($'000)

From	To	Services Offered*	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
FortisOntario	API	Corporate	Cost-based	373	373	19.4
Fortis Inc.	API	Corporate	Cost-based	56	56	28.0
CNPI	API	Administration	Cost-based	134	134	5.3
CNPI	API	Rent Allocation	Market-based	19	19	3.9

*See descriptions above.

Appendix 2-M
2011 Shared Services/Corporate Cost Allocation
($'000)

From	To	Services Offered*	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
FortisOntario	API	Corporate	Cost-based	373	373	19.4
Fortis Inc.	API	Corporate	Cost-based	59	59	28.0
CNPI	API	Administration	Cost-based	134	134	5.3
CNPI	API	Rent Allocation	Market-based	19	19	3.9

*See descriptions above.

STUDY OF AFFILIATE SERVICE COSTS AND COST ALLOCATION

BDR
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BDR

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1 SUMMARY OF STUDY AND FINDINGS

FortisOntario Inc. ("FortisOntario") owns and operates five Ontario electricity distribution business units and a transmission business unit, all of which are regulated by the Ontario Energy Board ("OEB"), as well as unregulated generation assets. Included among the five distribution business units is Algoma Power Inc. ("Algoma"), which was acquired from Brookfield Renewable Power Inc. in October 2009. To maximize available efficiencies of scale for all the business units, certain general plant and administrative, general and customer service functions are shared by FortisOntario and its operating subsidiaries. Since acquiring Algoma, FortisOntario has taken steps to integrate certain management and administrative functions, where appropriate given the existing staffing, facilities and operational structure of Algoma, and its remote location. In order to prepare appropriate revenue requirements for Algoma's 2010/2011 distribution rate application, FortisOntario conducted a study to allocate the shared costs among its business units. If approved by the OEB, the costs allocated to the regulated distribution business units will become part of the revenue requirement for Algoma in 2010 and 2011.

FortisOntario requested BDR NorthAmerica Inc. ("BDR") to review the methodology and computations in its study to allocate the shared costs, based on BDR's extensive experience in cost allocation for energy utilities.

Based on the information provided by FortisOntario, BDR has concluded that the approach is reasonable and consistent with acceptable methods of allocation of shared costs for regulated utilities.

2 INTRODUCTION AND SCOPE

FortisOntario is a holding company that owns and operates primarily electricity transmission and distribution business units in Ontario. As well as Algoma, the rate-regulated distribution business units include Canadian Niagara Power Inc. ("CNPI") with service territories in Fort Erie, Port Colborne and Gananoque. FortisOntario also serves electricity distribution customers in Cornwall, through a subsidiary, Cornwall Electric.

Within the FortisOntario organization, management and specialist staff, and certain key systems and facilities are shared to maximize efficiencies of scale, avoid duplication, and provide the required skills and expertise to each business function. Examples of these shared functions are executive management, administrative support functions (finance, human resources, health, safety and environment and information technology) and asset management. These activities support and provide benefits to all of FortisOntario's regulated business units and to its unregulated business activities. The costs are shared by the business units based on allocation.

In order to recover the allocated portion of shared costs through the rates of the rate-regulated transmission and distribution business units, approval is required from the OEB. The allocated portion of shared costs must be supported by documentation of the costs involved, the services performed, and the methodology used for the allocation.

In 2008, CNPI applied to the OEB for approval of the 2009 rates of its three distribution territories located in Fort Erie, Port Colborne and Gananoque. At that time, a study to allocate the shared costs was prepared. CNPI retained the services of BDR to perform a review of the methodology used to determine cost responsibility for each distribution service territory, and to provide an opinion as to the reasonableness of the overall approach and the specific allocation treatment of each cost function. The cost allocation study and BDR's report supporting the reasonableness of the methodology used were filed with the OEB in connection with those rate applications, and a revenue requirement was approved for each of the three distribution territories reflecting the results of the study.

In October 2009, FortisOntario acquired Algoma, and since then, has begun taking steps to integrate the operations of that territory with its other business units in order to work towards realizing available cost savings in the interest of all customers. This transition will take time, given its recent reorganization and remote location. An application to the OEB for approval of rates for the Algoma service territory is now being filed. This necessitated an updated cost allocation study to reflect services rendered to Algoma and support the inclusion of the allocated costs in Algoma's revenue requirement.

FortisOntario retained the services of BDR to review the methodology of the updated cost allocations and to provide an opinion as to the reasonableness of the overall approach and the specific allocation treatment of each cost function. Computations and background data were provided for BDR's review. BDR was not requested to comment on the overall level of the costs or on the degree to which operational synergies are or will be achieved by this arrangement.

3 CONSULTANT QUALIFICATIONS

BDR is a leading management consulting firm specializing in advising the electricity industry and related affiliates on strategic, financial and regulatory matters. Our client base includes electric utilities of all ownership categories and interested policy makers/stakeholders such as governments, regulators, consumers, generators, transmission and distribution companies and their affiliates.

BDR's key areas of practice are:

Business and Strategic Planning: BDR staff has completed strategic business plans and options analyses for well over 100 clients in the electricity and related sectors. These plans include consideration of the strengths and weaknesses of the client in a range of business options.

Mergers and Acquisitions: A changing industry requires basic reassessments and decisions to merge and/or acquire businesses and to expand some businesses and exit others. BDR has managed the process of merger, divestment and acquisition of both generation and "wires" facilities in the electricity industry and related affiliates. Key in these assignments is the development of a valuation for the enterprise(s).

Regulatory: BDR advises clients who are regulated entities in all aspects of dealing with regulators. This includes supporting applications for mergers and acquisitions, studies in support of rates and revenue requirements, such as cost of capital, cost allocation and working capital analysis. Services include analysis and expert testimony where required.

This assignment was carried out by Paula Zarnett, Vice President of BDR. She is a Certified Management Accountant, and has an MBA (Finance) from the University of Calgary. Ms. Zarnett's three decades of cost allocation experience include:

- Fully allocated cost of service studies for natural gas utilities in Manitoba and Alberta;
- Leading a cross-functional team in a one-year project to develop Toronto Hydro's first cost allocation study;

- Membership in the Municipal Electric Association cost allocation sub-committee which studied a generic approach to cost allocation for small, medium and large utilities in Ontario;
- Two cost allocation studies for Saint John Energy, a municipal electric utility in New Brunswick;
- A cost allocation and rate design study for Enwave, a district steam system serving a commercial and institutional customer base in Toronto;
- Participation in the OEB's 2003 Cost Allocation Working Group;
- Participation in the OEB's 2005-2006 Cost Allocation Review for electricity distribution utilities; and
- Expert review of New Brunswick Power Distribution and Customer Service's cost allocation study in its 2005 application to the New Brunswick PUB.

Ms. Zarnett presented the Advanced Cost Allocation and Rate Design module at CAMPUT's annual Energy Regulation Course in 2006, 2007 and 2008.

4 APPROACH TO THE ASSIGNMENT

The purpose of this study was to allocate the costs of staff and facilities, the benefits of which are shared by Algoma, as a FortisOntario operating subsidiary, with FortisOntario's other business units. The costs involved are costs that *cannot be directly attributed to a single business unit*, and therefore must be attributed based on some fair and reasonable methodology. The essence of the methodology is, for each type of cost, to attempt to identify an objectively measurable variable (or a combination of variables) that is (a) causally related to the incurrence of the cost, and/or (b) related to the value that is created by the incurrence of the cost; such a variable is generally termed a "cost driver". Each type of cost is then allocated to each business unit based on its share of the identified cost driver. The selection of cost drivers is the key area for management's professional judgment since, once the cost drivers are selected, the related computations are straightforward.

During the early part of 2010, management of FortisOntario undertook the work of identifying and quantifying the cost of functions that are shared among its affiliates and gathering cost driver data to support allocations. The selection of cost drivers follows the precedent of previous allocations of FortisOntario and CNPI costs. FortisOntario then computed the cost responsibility of each affiliate. The data and computations were provided to BDR in May, 2010 for review. BDR did not make any independent audit either of financial information or of the data related to cost drivers.

The review focuses on the types of costs for which FortisOntario is proposing to make an allocation to be recovered in the revenue requirement of Algoma. All of the cost types involved are cost types for which FortisOntario's subsidiary, CNPI, has previously

received approval to include an allocation for the revenue requirement of its distribution service territories. Because of this, BDR has treated the issue of the appropriateness of sharing and allocating such costs within the FortisOntario group of business units as already determined to be acceptable.

5 SHARED SERVICES SUPPLIED TO ALGOMA

Algoma has a direct staff complement of 75. Except for the local senior manager, who will now spend 10% of his time on work that will be treated as a cost at the FortisOntario level, all are fully dedicated to the local operations of the Algoma service territory, and their costs, along with the related costs of local facilities, are being treated as direct costs of Algoma. During the forecast period, Algoma will neither receive from nor provide to its affiliates, any services in such functions such as customer service or the operations and maintenance of its distribution system. Therefore, while the FortisOntario overall shared cost study addresses the allocation of such costs among the CNPI service territories and transmission, and Cornwall Electric, these cost functions were not reviewed for purposes of this report.

Therefore, the only shared corporate services that FortisOntario proposes to provide to Algoma during 2010 and 2011, and for which a cost is allocated, are:

- Executive Services
- Finance
- Information Technology
- Human Resources
- Health, Safety and Environment
- Regulatory, and
- Engineering Design management for capital projects.

The services listed above are also shared by CNPI transmission, CNPI's Gananoque, Fort Erie and Port Colborne distribution service territories, and Cornwall Electric, and (except for engineering design) by FortisOntario itself.

6 DISCUSSION OF METHODOLOGY BY COST FUNCTION

6.1 *Executive*

This function consists of four senior executives and an executive assistant. Each executive was interviewed to determine the percentage of time spent on each of the business units in a representative period. The resulting percentages were averaged and used to allocate the costs of the executive group including the executive assistant.

This approach results in an allocation of 19.4% of these costs to Algoma.

On review, BDR considers that time spent is a reasonable and appropriate cost driver, and that this approach is consistent with acceptable methods of cost allocation.

6.2 *Finance*

FortisOntario staff reviewed each of the sub-activities that comprise the finance function. This approach is consistent with the approach used to allocate the costs submitted for CNPI's Fort Erie, Port Colborne, and Gananoque service territories in their applications for 2009 rates. The sub-activities are:

- Accounts Payable and Receivable;
- Payroll;
- Financial Reporting;
- Financial Analysis; and
- Supervision.

No component of Accounts Payable and Receivable or Payroll were allocated to Algoma, as these functions will continue to be carried out by local staff.

Only financial reporting, analysis and supervision services are intended to be provided to Algoma in the forecast period. The employees involved estimated that 10% of their work will be for Algoma. Supervision was allocated in proportion to the allocation of supervised FTEs in the function.

The result is that the overall proportion of finance cost allocated to Algoma is 3.3%.

On review, BDR considers this approach reasonable and consistent with acceptable methods of shared cost allocation.

6.3 *Information Technology*

6.3.1 Expenses

At present, the Information Technology ("IT") function for Algoma is contracted out under an agreement that expires late in 2011. Until that time, only minimal IT services (related primarily to corporate email) will be provided as shared corporate services by FortisOntario. Therefore, FortisOntario anticipates that one employee in this function will spend 10% of their time providing services to Algoma. This results in 1.4% overall of corporate IT expenses being allocated to Algoma. This allocation is proposed for both 2010 and 2011.

6.3.2 Assets

During 2011, FortisOntario will devote resources to the process of integrating Algoma with CNPI's system, so that on expiration of the existing contract for services near the end of 2011, IT services can commence to be supplied to Algoma as a shared corporate service. FortisOntario therefore proposes for purposes of the allocation of *assets* (but not *expenses*) commencing in 2011, to follow the same methodology for Algoma as for all its business units. Within FortisOntario, the corporate information systems and workstation assets support the work of the employees in all functions. The methodology therefore uses the number of FTEs (excluding IT, Human Resources and Health and Safety) as the cost driver and allocation base for the IT function[1]. On the basis of Algoma's FTEs, Algoma would be allocated 40% of the costs by this method.

Within the IT function, four out of seven employees will provide services to Algoma based on the system becoming integrated. The other three employees in the corporate IT function provide services to other business units, which will be provided to Algoma by local staff. For these three employees, therefore, no allocation to Algoma is proposed.

The proposed allocation is therefore (40% x 4/7) or 22.9% of the IT *assets* for 2011. This allocation has been included for purposes of *assets in rate base*, but not for *expenses*. Treatment of expenses is described in the previous section of this report.

For clarity, no allocation of IT *assets* is proposed for 2010.

On review, BDR considers this treatment of expenses and of assets to be reflective of the present conditions of operation and of the planned transition to shared corporate IT services near the end of 2011, and therefore consistent with acceptable methods of shared cost allocation.

6.4 *Health, Safety and Environment*

Most health, safety and environmental functions will continue to be carried out for Algoma through local facilities and staff. Therefore, FortisOntario anticipates that one employee in this function will spend 10% of their time providing services to Algoma. This results in 5% overall of corporate health, safety and environment costs being allocated to Algoma.

On review, BDR considers this treatment to be reflective of the present conditions of operation, and therefore consistent with acceptable methods of shared cost allocation.

[1] Since the Human Resource and Health and Safety functions also support the employees, IT and these two functions were grouped for purposes of allocation in the study prepared for purposes of CNPI's 2009 rates.

6.5 *Human Resources*

FortisOntario's general approach to allocation of Information Technology, Health, Safety and Environment and Human Resource functions is to consider that these functions provide a benefit by serving and supporting staff across the FortisOntario corporate organization, including both staff representing a direct operating cost and staff providing shared services. Therefore, the proportionate direct and allocated FTEs *other than* Information Technology, Health, Safety & Environment, and Human Resources for each business were used as the basis to allocate these costs across the business units except for the treatment of Algoma with respect to Information Technology and Health, Safety and Environment described in the preceding two sections.

Application of this methodology would result in an allocation of approximately 40% of the Human Resources costs to Algoma, reflecting its complement of 75 local staff. FortisOntario is proposing to make a reduction of 50% in the proportionate allocation, to reflect the fact that Algoma will continue to provide some of these services locally over a transitional period. The result is that in total, Algoma will be allocated 20% of the total corporate Human Resources cost.

On review, BDR considers this treatment to be reflective of the present conditions of operation, and therefore consistent with acceptable methods of shared cost allocation.

6.6 *Regulatory*

A small allocation is made to FortisOntario, as the holding company for the regulated businesses on a judgment basis. Based on the judgment of the staff involved, each regulated business unit other than Cornwall Electric and CNPI Transmission have the same regulatory requirements, and have therefore received equal allocations. Cornwall Electric and CNPI transmission presently require a lower level of rate development and regulatory activity. They therefore received reduced allocations based on staff judgment.

FortisOntario's regulatory staff represents the regulated business units at regulatory stakeholder events and prepares required filings. This means that much of the effort applies to the benefit of all FortisOntario's regulated business units at once. On the basis that regulatory requirements for all Ontario rate-regulated distributors are essentially the same, the approach of equal allocations to the three CNPI distribution business units and Algoma is, in our view, reasonable.

On this basis, Algoma is allocated 18.75% of the total costs of the regulatory function.

Therefore on review, BDR considers this approach reasonable and consistent with acceptable methods of cost allocation.

6.7 *Engineering Design for Capital Programs*

The general approach taken in the allocation of this cost function is to allocate to all business units proportionately based on capital spending. In the case of Algoma, that approach has been applied to allocate the time of two FTEs in a department of eight, and no allocation has been made to Algoma for the time of the other six employees. This reflects the fact that some engineering design services will be provided by Algoma's local staff, rather than by the shared staff.

Since Algoma is expected to have 31.5% of FortisOntario's total capital spending, the result is that 7.88% of these costs (31.5% x 2/8) have been allocated to Algoma.

On review, BDR considers this treatment to be reflective of the present conditions of operation, and therefore consistent with acceptable methods of shared cost allocation.

6.8 *Service Centre Building Costs*

FortisOntario staff advised BDR that the Fort Erie service centre building is owned by FortisOntario and rented by CNPI Fort Erie. Appropriate total rent for the building was determined by an independent appraisal as an estimate of market value. Based on area utilized, the total rent was disaggregated into the office, warehouse and garage components.

As part of the study, all (78) staff occupying space in the office part of the Fort Erie service centre building were identified, and their efforts allocated among the business units. The allocated shares of each FTE were summed, and the proportion of the total of 78 FTEs allocated to each business unit was computed as a percentage. This percentage was used to allocate the office-related rental cost. Maintenance costs were in proportion to the allocation of service centre rent. Since the warehouse and garage components serve the Fort Erie and Port Colborne and the CNPI transmission business units only, no share of rent cost related to those sections of the building was allocated to Algoma.

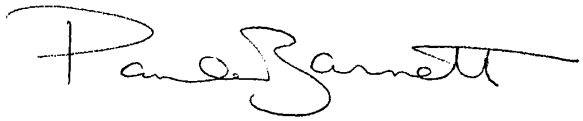
On this basis, 3.9% of the total cost of use of the Fort Erie service centre building is allocated to Algoma.

On review, BDR considers this approach reasonable and consistent with acceptable methods of cost allocation.

7 AUTHORSHIP AND USE

This report was written and submitted by me, Paula Zarnett, Vice President, BDR following a review of information provided to me by FortisOntario, and is intended for use by FortisOntario in support of the application to the Ontario Energy Board of its subsidiary, Algoma Power Inc., for approval of 2010 and 2011 rates and charges.

Dated at Toronto, Ontario, this 1st day of June, 2010.



Paula Zarnett

APPENDIX A – SUMMARY OF ALLOCATION DATA AND FACTORS

Department/Function	Total FTEs	FTEs Allocatd to Algoma Power	Percentage Allocation
Executive	5.00	0.97	19.4%
Regulatory	2.00	0.38	18.8%
Finance	9.00	0.30	3.3%
Engineering	8.00	0.63	7.9%
Health & Safety	2.00	0.10	5.0%
IT - Expense	7.00	0.10	1.4%
Human Resources	1.50	0.30	20.1%
Cost of Fort Erie Service Centre	78.00	3.08	3.9%
IT Assets	7.00	1.60	22.9%

APPENDIX B : STUDY OF AFFILIATE SERVICE COSTS AND COST ALLOCATION FOR ALGOMA POWER INC. – TERMS OF REFERENCE FOR ENGAGEMENT

(ATTACHED)

BDR
34 King Street East,
Suite 1000, 10th Floor,
Toronto, Ontario
M5C 2X8
416-214-4848

May 19, 2010

Douglas Bradbury, P.Eng.,
Director Regulatory Affairs,
FortisOntario Inc.
By Email to: doug.bradbury@FortisOntario.com

Dear Mr. Bradbury:

Re: Study of Affiliate Service Costs and Cost Allocation
For Algoma Power Inc. – Terms of Reference for Engagement

Thank you for engaging BDR NorthAmerica Inc. ("BDR") to review the methodology by which FortisOntario proposes to allocate the costs of shared corporate services to its operating subsidiary, Algoma Power Inc. ("Algoma"), and to provide an opinion as to the reasonableness of the overall approach and the specific allocation treatment of each cost function.

As we discussed by telephone, FortisOntario is presently preparing to file supporting information for Algoma's application to the OEB for approval of 2010/2011 rates. The purpose of affiliate service cost allocation study is to support the inclusion of an appropriate allocation of the costs of services that FortisOntario provides to Algoma on a shared basis. You have collected cost data for each of the shared corporate service functions, as well as data for the proposed allocation factors, and have prepared a computation of the allocated amounts for inclusion in Algoma's proposed revenue requirement.

FortisOntario staff performed similar studies for filing with the OEB in support of the allocation of costs of shared corporate services in 2005 for 2006 rates, and in 2008 for 2009 rates of the distribution service territories of Canadian Niagara Power Inc. In both cases, BDR was retained to provide a review and opinion, and BDR's report formed part of the evidence in the proceedings.

The purpose of this letter is to set out BDR's understanding of the scope of this engagement for FortisOntario. If you concur in this understanding, our signatures below will formalize our agreement.

Terms of Reference

BDR will review the data and computations that you have provided in Excel spreadsheet form, and prepare a report ("the BDR report") which:

- Describes the methodology used in the allocation of the cost of each type of shared corporate service to Algoma; and
- Provides an opinion, based on BDR's experience in the electricity distribution sector and in cost allocation, as to the reasonableness of the overall approach and the specific allocation treatment of each cost function.

BDR has not been requested to comment on the overall level of the costs or on the degree to which operational synergies are or will be achieved by the service sharing arrangement.

The BDR report is intended to be filed by FortisOntario with the OEB in support of Algoma's application for approval of its 2010/2011 rates. The review will therefore be confined to the methodology as it applies specifically to Algoma.

The BDR report will be completed and delivered to FortisOntario in time for filing with the OEB on June 1, 2010.

If requested by FortisOntario, BDR will assist FortisOntario in responding to interrogatories from parties to the proceeding related to the BDR report. In the case of an oral hearing, and if requested by FortisOntario, BDR will provide oral expert testimony.

The work on the BDR report will be performed by me or under my supervision, and I will personally provide the oral expert testimony if requested.

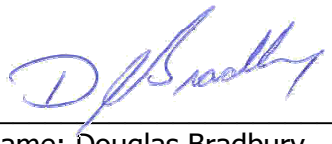
Agreement to Perform the Services

BDR agrees to perform the assignment for FortisOntario in accordance with the Terms of Reference contained in this letter. If these Terms of Reference are acceptable to FortisOntario, please have an authorized person sign below, and return a copy to us. We will commence work on the assignment immediately.

Yours truly,

Paula Zarnett
Vice President

On behalf of FortisOntario, I accept the Terms of Reference for the assignment as set out in this letter.



Name: Douglas Bradbury
Title: Director Regulatory Affairs

PURCHASE OF NON-AFFILIATE SERVICES

SUMMARY

API manages outsourcing expenses through two primary methods. As the first control measure, API has employed a purchasing agent or buyer. The buyer is responsible to seek the optimal combination of logistics activities and their attributes such as price, quality, speed and security and to manage the resulting information and monetary flows. Additional responsibilities of the buyer include overseeing the acquisition, use and disposition of goods, materials and services to fulfill internal and external customer needs. The specific duties of the buyer include:

- Prepare all aspects of simple bids, requests for quotes, and proposals, including precise specifications, supporting spreadsheets, comparisons, recommendations, and justifications; issues purchase orders.
- Assist in bid openings for competitive solicitations such as requests for quotes, bids, and proposals.
- Review and evaluate purchase orders, negotiates change orders, and determines sole source validity.
- Investigate and develop new supply sources; stay abreast of new trends and innovations in routinely purchased supplies, material, services and equipment.
- Maintain price lists on assigned commodities; negotiate prices and terms.
- Monitor usage inconsistencies, price changes, vendor back orders and make necessary adjustments with suppliers and vendors regarding replacements, incomplete orders, damaged supplies or unsatisfactory services.

The second method used by API seeks to control outsourced expenses through request for proposals (“RFP") subject to the pre-qualification of contractors in conjunction with specific safety and environmental standards.

An RFP is sent to each of the pre-qualified contractors. The responses to the RFP are assessed and evaluated by API on the basis of price, health and safety, environment, return

on investment, delivery schedule, quality, and reliability. A successful contractor is asked to provide an itemized estimate of the costs to conduct the work. Based upon the estimate, efforts are made to negotiate the price and terms on a fixed price contract basis.

Algoma Power Inc.
Third Party Services - 2007

Company Name	Nature of Service	Annual Dollar Amount	Vendor Selection Methodology
WILDERNESS VEGETATION MANAGEMENT	Vegetation Management - Line Clearing	$ 1340k	Annual agreement
ASPLUNDH CANADA INC.	Vegetation Management - Line Clearing	$ 1166k	Annual agreement
K-LINE MAINTENANCE & CONSTRUCTION	Line Construction	$ 999k	Annual agreement
OGILVY RENAULT	Legal services	$ 660k	Outside counsel
OUTLAND REFORESTATION INC.	Vegetation Management - Brush Clearing	$ 267k	Annual agreement
EPTCON LTD.	Substation Construction	$ 218k	Sole sourced
WARDROP ENGINEERING INC.	Project management services	$ 182k	Awarded
1687921-ONTARIO, INC.	Metering services	$ 162k	Contract renewed
WESLEY E. CRIGGER	Accounting Services	$ 159k	Contract renewed
KEN WRIGHTSON	Engineering Services	$ 152k	Contract renewed
GLENN R. TAYLOR	Contractor Monitoring	$ 149k	Contract renewed
POLLARI CONTRACTING	Backhoe / snow removal	$ 106k	Annual agreement
CASE CONSTRUCTION	Backhoe / snow removal	$ 103k	Annual agreement

Algoma Power Inc.
Third Party Services - 2008

Company Name	Nature of Service	Annual Dollar Amount	Vendor Selection Methodology
K-LINE MAINTENANCE & CONSTRUCTION	Line Construction	$ 1601k	Annual agreement
WILDERNESS VEGETATION MANAGEMENT	Vegetation Management - Line Clearing	$ 1418k	3 year agreement negotiated
ASPLUNDH CANADA INC.	Vegetation Management - Line Clearing	$ 1351k	Annual agreement
OUTLAND REFORESTATION INC.	Vegetation Management - Brush Clearing	$ 856k	Annual agreement
OGILVY RENAULT	Legal services	$ 613k	Outside counsel
POWERTEL UTILITIES CONTRACTORS LTD.	Substation Construction	$ 612k	Tender
WARDROP ENGINEERING INC.	Project management services	$ 179k	Contract renewed
WESLEY E. CRIGGER	Accounting Services	$ 155k	Contract renewed
1687921-ONTARIO, INC.	Metering services	$ 151k	Contract renewed
KEN WRIGHTSON	Engineering Services	$ 147k	Contract renewed
GLENN R. TAYLOR	Contractor Monitoring	$ 147k	Contract renewed
EPTCON LTD.	Substation Construction	$ 124k	Existing agreement
POLLARI CONTRACTING	Backhoe / snow removal	$ 122k	Annual agreement
DELOITTE & TOUCHE LLP	Auditing services	$ 107k	External auditor

Algoma Power Inc.
Third Party Services - 2009

Company Name	Nature of Service	Annual Dollar Amount	Vendor Selection Methodology
WILDERNESS VEGETATION MANAGEMENT	Vegetation management - line clearing	$ 1336k	3 year contract
K-LINE MAINTENANCE & CONSTRUCTION	Line construction	$ 829k	Tendered
TORYS LLP	Legal services	$ 781k	Outside counsel
ASPLUNDH CANADA INC.	Vegetation management - line clearing	$ 716k	Annual agreement
OUTLAND REFORESTATION INC.	Vegetation management - brush clearing	$ 390k	Annual agreement
OGILVY RENAULT	Legal services	$ 296k	Outside counsel
WARDROP ENGINEERING INC.	Project management services	$ 196k	Agreement renewal
POLLARI CONTRACTING	Backoe / Snow removal	$ 195k	Agreement renewal
LAIDLAW, PACIOCCO, MELVILLE,	Legal services	$ 158k	Outside counsel
KEN WRIGHTSON	Contractor Monitoring	$ 145k	Contract renewed
1687921-ONTARIO, INC.	Metering Services	$ 137k	Contract renewed
2181437 ONTARIO INC.	Contractor Monitoring	$ 130k	Contract renewed
GLENN R. TAYLOR	Contractor Monitoring	$ 119k	Contract renewed
EPTCON LTD.	Smart Meter TGB installations	$ 110k	Tendered
CASE CONSTRUCTION	Backhoe / Snow removal	$ 105k	Annual agreement

Algoma Power Inc.
Third Party Services - 2010

Company Name	Nature of Service	Annual Dollar Amount	Vendor Selection Methodology
K-LINE MAINTENANCE & CONSTRUCTION	Line construction	$ 1200k	Annual agreement
WILDERNESS VEGETATION MANAGEMENT	Vegetation management - line clearing	$ 1100k	3 year agreement
GREAT LAKES POWER TRANSMISSION LP	IT/Lease	$ 370k	2 & 5 year agreement
OUTLAND REFORESTATION INC.	Vegetation management - brush control	$ 500k	Annual agreement
EPTCON LTD.	Sustation construction	$ 450k	Tender
SENSUS METERING	Smart meter communication	$ 280k	Multi year agreement
2181437 ONTARIO INC.	Contractor Monitoring	$ 120k	Contract renewed
GLENN R. TAYLOR	Contractor Monitoring	$ 120k	Contract renewed
POLLARI CONTRACTING	Backhoe / snow removal	$ 100k	Annual agreement
CASE CONSTRUCTION	Backhoe / snow removal	$ 100k	Annual agreement
ANDREW TAYLOR, ENERGY LAW	Legal services	$ 100k	Outside counsel
Other contracted services, not yet selected			
	Vegetation management	$ 1000k	Annual agreement

Algoma Power Inc.
Third Party Services - 2011

Company Name	Nature of Service	Annual Dollar Amount	Vendor Selection Methodology
GREAT LAKES POWER TRANSMISSION LP	IT/Lease	$ 370k	2 & 5 year agreement
SENSUS METERING	Smart meter communication	$ 370k	Multi year agreement
Other contracted services, not yet selected			
	Vegetation management	$ 2800k	Annual agreement
	Line construction	$ 1100k	Annual agreement
	Contract monitoring	$ 200k	Annual agreement
	Backhoe / snow removal	$ 200k	Annual agreement

DEPRECIATION, AMORTIZATION AND DEPLETION

API's amortization rates used in this Application are consistent with the rates approved in API's 2008 Board Decision. Those rates are consistent with those outlined in Appendix B of the 2006 Distribution Rate Handbook, with the exception of amortization rates for vehicles. API has historically amortized its vehicles over the five year period or 20% per year.

Amortization on capital assets is calculated as follows:

- A straight line basis over the estimated remaining useful life of the assets at the end of the previous year; plus
- Amortization on capital additions during the current year commences in the month following the month the asset is capitalized.

On April 28, 2010 the Board released an *Asset Amortization Study* (the "Study") prepared by Kinectrics Inc. The Study, which is subject to further input by stakeholders, will be used to assist utilities in updating amortization rates and becoming IFRS compliant. API proposes, after finalization of the Study, that the amortization rates in the 2011 Test Year be updated based on the results of this Study. The application of these updated rates would be subject to the specific unique circumstances of API. Based on initial review of the Study, API believes the revised amortization rates will reduce the amount of depreciation in its revenue requirement.

Exhibit 4, Tab 7, Schedule 2 details amortization expense by OEB asset account.

Algoma Power Inc.
Schedule 2-N - Depreciation Expense

2010 Test Year

Account	OEB Acct	Description	Opening Balance	Fully Depreciated Assets	Net for Depreciation	Additions	Total for Depreciation (e) = (c) + 0.5 x (d)	Years	Depreciation Expense
			(a)	(b)	(c) =(a) - (b)	(d)		(f)	(g) = (e) / (f)
1141	1806	CLEARING RIGHTS OF WAY	14,898,554	-	14,898,554	2,068,412	15,932,760	40	398,319
1150	1805	LAND AND LAND RIGHTS	853,958	-	853,958	-	853,958	0	-
1151	1808	STRUCTURES & IMPROVEMENTS	575,618	15,160	560,458	263,161	692,038	50	13,841
1152	1820	STATION EQUIPMENT	9,793,387	995,461	8,797,926	1,434,409	9,515,131	30	317,171
1154	1830	POLES TOWERS & FIXTURES	36,885,199	2,902,903	33,982,296	3,925,877	35,945,235	25	1,437,809
1155	1835	O/H CONDUCTORS & DEVICES	17,048,153	1,797,920	15,250,233	1,749,657	16,125,062	25	645,002
1157	1845	UNDERGROUND CONDUCTORS	971,137	(75,598)	1,046,735	-	1,046,735	25	41,869
1158	1850	LINE TRANSFORMERS	9,762,097	795,715	8,966,381	943,005	9,437,884	25	377,515
1159	1855	SERVICES	3,129,007	763,482	2,365,525	333,033	2,532,042	25	101,282
1160	1860	METERS	2,010,935	523,695	1,487,240	168,071	1,571,275	25	62,851
1163	1875	STREET LIGHT/SIGNAL SYSTM	16,523	16,523	-	-	-	10	-
1165	1990	UNDISTRIBUTED PERM W/O's	1,872,250	13,671	1,858,579	-	1,858,579	25	74,343
1166	1920	OFFICE AND SUPPORT	586,546	-	586,546	-	586,546	10	58,655
1171	1908	STRUCTURES & IMPROVEMENTS	215,137	-	215,137	-	215,137	25	8,605
1172	1915	OFFICE FURNITURE & EQUIP	787,880	644,618	143,262	-	143,262	10	14,326
1173	1930	TRANSPORT EQUIP < 3 TONS	1,341,554	669,554	671,999	53,057	698,528	5	139,706
1174	1930	TRANSPORT EQUIP > 3 TONS	2,625,013	1,790,932	834,081	265,283	966,723	5	193,345
1176	1945	LABORATORY EQUIPMENT	109,423	100,192	9,231	-	9,231	10	923
1177	1940	TOOLS & WORK EQUIPMENT	1,505,940	628,356	877,583	53,057	904,112	10	90,411
1178	1955	COMMUNICATIONS EQUIPMENT	398,868	273,892	124,976	55,049	152,501	10	15,250
1179	1960	MISCELLANEOUS EQUIPMENT	122,557	69,504	53,053	-	53,053	10	5,305
1185	1920	COMPUTER HARDWARE	375,518	124,598	250,920	26,528	264,185	5	52,837
1186	1925	COMPUTER SOFTWARE	68,206	47,934	20,272	32,515	36,530	5	7,306
1191	1820	ELECTRICAL PLANT PRE-1950	187,002	187,002	-	-	-	1	-
1192	1990	PRE-1950 APPRAISL SURPLUS	278,746	278,746	-	-	-	1	-
			106,419,206	**12,564,259**	**93,854,946**	**11,371,113**	**99,540,503**		**4,056,672**

Algoma Power Inc.
Schedule 2-N - Depreciation Expense

2011 Test Year

Account	OEB Acct	Description	Opening Balance	Fully Depreciated Assets	Net for Depreciation	Additions	Total for Depreciation (e) = (c) + 0.5 x (d)	Years	Depreciation Expense
			(a)	(b)	(c) =(a) - (b)	(d)		(f)	(g) = (e) / (f)
1141	1806	CLEARING RIGHTS OF WAY	16,966,966	-	16,966,966	2,217,628	18,075,780	40	451,895
1150	1805	LAND AND LAND RIGHTS	853,958	-	853,958	54,374	881,144	0	-
1151	1808	STRUCTURES & IMPROVEMENTS	838,778	15,402	823,376	21,749	834,251	50	16,685
1152	1820	STATION EQUIPMENT	11,227,796	1,550,337	9,677,459	93,342	9,724,130	30	324,138
1154	1830	POLES TOWERS & FIXTURES	40,811,076	4,050,597	36,760,479	3,884,635	38,702,797	25	1,548,112
1155	1835	O/H CONDUCTORS & DEVICES	18,797,810	2,349,753	16,448,058	1,310,655	17,103,385	25	684,135
1157	1845	UNDERGROUND CONDUCTORS	971,137	(72,455)	1,043,592	95,698	1,091,441	25	43,658
1158	1850	LINE TRANSFORMERS	10,705,102	960,889	9,744,212	627,613	10,058,019	25	402,321
1159	1855	SERVICES	3,462,040	813,209	2,648,830	343,839	2,820,750	25	112,830
1160	1860	METERS	2,179,006	523,202	1,655,804	27,187	1,669,397	25	66,776
1163	1875	STREET LIGHT/SIGNAL SYSTM	16,523	16,523	-	-	-	10	-
1165	1990	UNDISTRIBUTED PERM W/O's	1,872,250	13,671	1,858,579	-	1,858,579	25	74,343
1166	1920	OFFICE AND SUPPORT	586,546	-	586,546	-	586,546	10	58,655
1171	1908	STRUCTURES & IMPROVEMENTS	215,137	-	215,137	-	215,137	25	8,605
1172	1915	OFFICE FURNITURE & EQUIP	787,880	687,121	100,759	27,187	114,352	10	11,435
1173	1930	TRANSPORT EQUIP < 3 TONS	1,394,610	811,734	582,876	326,242	745,997	5	149,199
1174	1930	TRANSPORT EQUIP > 3 TONS	2,890,296	1,790,932	1,099,364	299,055	1,248,891	5	249,778
1176	1945	LABORATORY EQUIPMENT	109,423	100,192	9,231	-	9,231	10	923
1177	1940	TOOLS & WORK EQUIPMENT	1,558,996	650,952	908,044	54,374	935,231	10	93,523
1178	1955	COMMUNICATIONS EQUIPMENT	453,917	310,706	143,211	-	143,211	10	14,321
1179	1960	MISCELLANEOUS EQUIPMENT	122,557	69,504	53,053	-	53,053	10	5,305
1185	1920	COMPUTER HARDWARE	402,047	217,727	184,320	442,601	405,620	5	81,124
1186	1925	COMPUTER SOFTWARE	100,721	47,934	52,787	1,043,647	574,611	5	114,922
1191	1820	ELECTRICAL PLANT PRE-1950	187,002	187,002	-	-	-	1	-
1192	1990	PRE-1950 APPRAISL SURPLUS	278,746	278,746	-	-	-	1	-
			117,790,319	**15,373,678**	**102,416,641**	**10,869,825**	**107,851,554**		**4,512,684**

TAX OVERVIEW

Attached as Exhibit 4, Tab 8, Schedule 2 (Tax Calculations) is the tax model used to calculate 2010 and 2011 income taxes and capital taxes. The income tax rates, Ontario capital tax rates, capital cost allowance rates and classes, and other rates used to calculate the taxes are the currently enacted rates for the forecast period.

Schedule 2 summarizes the income tax and Ontario capital taxes for the period 2007 Actual to 2010 and 2011 Test Years. The 2007 Actual and 2008 Actual highlights are based on the actual federal and provincial returns filed. The 2009 Actual and 2010 and 2011 Test Years highlights are based on forecast. The calculations are segregated between transmission operations and distribution operations to July 1, 2009. The 2010 and 2011 Test Years distribution utility earnings are based on the requested return on equity.

As a member of a group of companies, API must also share the exemptions available for Ontario Capital Tax ($15 million). For purposes of preparing the regulatory Ontario Capital Tax, these exemptions have been allocated on the basis of the actual exemptions used in the 2008 tax returns.

Exhibit 4, Tab 8, Schedule 3 (Capital Cost Allowance (CCA)) contains the capital cost allowance continuity schedules for the distribution operations of API for the period July 1, 2009 Actual to 2010 and 2011 Test Years.

Exhibit 4, Tab 8, Schedule 4 (Cumulative Eligible Capital (CEC)) discusses the cumulated eligible capital for the distribution operations of API for the period 2009 Actual to 2010 and 2011 Test Years.

Exhibit 4, Tab 8, Schedule 5 (Property Taxes) contains the property tax expense variances.

Exhibit 4, Tab 8, Schedule 6 contains the October 8, 2009 T2 Corporation Income Tax Return that was filed with Canada Revenue Agency.

TAX CALCULATIONS

Description	2007 Actual	2008 Actual	2009 Actual	2010 Regulatory	2011 Regulatory
Net income(loss) per financial statements	(189,435)	3,448,376	(9,746,950)	-	-
Utility income before taxes		-	-	2,738,660	3,028,471
Add:					
Provision for income taxes - current	76,600	1,741,800	833,310	-	-
Provision for income taxes - deferred	-	-	(2,904,829)	-	-
Provision for rate mitigation accrual			14,890,315	-	-
Amortization of tangible assets	3,559,152	3,727,967	3,651,441	4,056,672	4,512,684
Non-deductible meals and entertainment	32,058	48,672	45,450	40,000	40,000
Reserves from financial statements - EOY	184,566	332,733	963,886	990,000	990,000
Total Additions	3,852,377	5,851,171	17,479,573	5,086,672	5,542,684
Deduct:					
Gain on disposal of assets per financial statements	(22,000)	(18,777)	(32,667)	-	-
Capital cost allowance	3,336,278	3,858,385	3,688,581	4,402,571	5,435,814
Reserves from financial statements - BOY	98,281	184,566	332,733	963,886	990,000
Allowance for funds used during construction	38,310	75,969	78,704	77,000	-
Capitalized general expense	-	-	-	821,003	874,329
Total Deductions	3,450,870	4,100,144	4,067,350	6,264,460	7,300,143
Taxable Income	212,072	5,199,403	3,665,273	1,560,873	1,271,011
Corporate tax rate	36.12%	33.50%	33.00%	31.00%	28.25%
Income Tax	76,600	1,741,800	1,209,540	483,871	359,061
Grossed Up Taxes				701,262	500,433
Calculation of total taxes					
Income Tax	76,600	1,741,800	1,209,540	701,262	500,433
Ontario Capital Tax	156,771	-	140,447	49,776	-
Total taxes	**233,371**	**1,741,800**	**1,349,987**	**751,037**	**500,433**
Tax Rates					
Federal Tax	22.12%	19.50%	19.00%	18.00%	16.50%
Provincial Tax	14.00%	14.00%	14.00%	13.00%	11.75%
Total Tax Rate	36.12%	33.50%	33.00%	31.00%	28.25%
Calculation of Ontario Capital Tax					
Total Rate Base	57,774,016	62,743,449	65,485,469	69,509,146	76,864,742
Less Exemption	2,766,800	-	3,064,515	3,141,585	-
Taxable Capital/Deemed Taxable Capital	55,007,216	62,743,449	62,420,955	66,367,561	76,864,742
OCT Rate	0.285%	0.000%	0.225%	0.075%	0.000%
Ontario Capital Tax	156,771	-	140,447	49,776	-

DISTRIBUTION 2009 CCA SCHEDULE
July 1 to October 8 Actual

Class	Class Description	UCC July 1, 2009 Opening Balance	2009 Additions	2009 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2009 CCA	UCC End of 2009
1	Distribution System - post 1987	33,012,126	0	0	33,012,126	0	33,012,126	4%	361,777	32,650,349
2	Distribution System - pre 1988	0	0	0	0	0	0	6%	0	0
3		0	0	0	0	0	0	5%	0	0
8	General Office/Stores Equip	473,921	2,808	0	476,729	1,404	475,325	20%	26,045	450,684
10	Computer Hardware/ Vehicles	744,907	0	30,474	714,433	0	714,433	30%	58,720	655,712
12	Computer Software	0	0	0	0	0	0	100%	0	0
45	Computers & Systems Software acq'd post Mar 22/04	0	0	0	0	0	0	45%	0	0
47.0	New Distribution Assets	23,410,752	490,170	0	23,900,922	245,085	23,655,837	8%	518,484	23,382,438
1.3	Bldg after Mar 18/07	0	0	0	0	0	0	6%	0	0
50.0	Comp Equip after Mar 18/07	108,237		0	108,237	0	108,237	55%	16,310	91,927
	TOTAL	**57,749,943**	**492,978**	**30,474**	**58,212,447**	**246,489**	**57,965,958**		**981,336**	**57,231,110**

On July 1, 2009, the distribution assets were transferred from Great Lakes Power Limited to Algoma Power Inc. (formerly Great Lakes Power Distribution Inc.). The assets were transferred at book value. On October 8, 2009, FortisOntario Inc. acquired Algoma Power Inc. and a "change of control" income tax return was filed. (see Exhibit 4, Tab 8, Schedule 6). The opening UCC tax pools in schedule 8 are based on the book value of the capital assets transferred.

DISTRIBUTION 2009 CCA SCHEDULE
October 8 to December 31 Actual

Class	Class Description	UCC July 1, 2009 Opening Balance	2009 Additions	2009 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2009 CCA	UCC End of 2009
1	Distribution System - post 1987	32,650,349	0	0	32,650,349	0	32,650,349	4%	300,562	32,349,787
2	Distribution System - pre 1988	0	0	0	0	0	0	6%	0	0
3		0	0	0	0	0	0	5%	0	0
8	General Office/Stores Equip	450,684	79,618	0	530,302	39,809	490,493	20%	22,576	507,726
10	Computer Hardware/ Vehicles	655,712	416,971	0	1,072,683	208,485	864,198	30%	59,665	1,013,018
12	Computer Software	0	23,828	0	23,828	11,914	11,914	100%	2,742	21,086
45	Computers & Systems Software acq'd post Mar 22/04	0	0	0	0	0	0	45%	0	0
47.0	New Distribution Assets	23,382,438	4,105,530	0	27,487,968	2,052,765	25,435,203	8%	468,286	27,019,681
1.3	Bldg after Mar 18/07	0	0	0	0	0	0	6%	0	0
50.0	Comp Equip after Mar 18/07	91,927	1,801	0	93,729	901	92,828	55%	11,750	81,979
	TOTAL	**57,231,110**	**4,627,748**	**0**	**61,858,859**	**2,313,874**	**59,544,985**		**865,581**	**60,993,277**
		Total Additions 2009	**9,370,336**				**Total CCA 2009**		**3,688,581**	

DISTRIBUTION 2010 CCA SCHEDULE

Class	Class Description	UCC 2010 Opening Balance	2010 Additions	2010 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2010 CCA	UCC End of 2010
1	Distribution System - post 1987	32,349,787	0	0	32,349,787	0	32,349,787	4%	1,293,991	31,055,796
2	Distribution System - pre 1988	0	0	0	0	0	0	6%	0	0
3		0	0	0	0	0	0	5%	0	0
8	General Office/Stores Equip	507,726	50,000	0	557,726	25,000	532,726	20%	106,545	451,181
10	Computer Hardware/ Vehicles	1,013,018	300,000	0	1,313,018	150,000	1,163,018	30%	348,905	964,113
12	Computer Software	21,086	25,000	0	46,086	12,500	33,586	100%	33,586	12,500
45	Computers & Systems Software acq'd post Mar 22/04	0	0	0	0	0	0	45%	0	0
47.0	New Distribution Assets	27,019,681	10,150,111	0	37,169,792	5,075,056	32,094,737	8%	2,567,579	34,602,213
1.3	Bldg after Mar 18/07	0	0	0	0	0	0	6%	0	0
50.0	Comp Equip after Mar 18/07	81,979	25,000	0	106,979	12,500	94,479	55%	51,963	55,015
	TOTAL	**60,993,277**	**10,550,111**	**0**	**71,543,388**	**5,275,056**	**66,268,333**		**4,402,571**	**67,140,818**

DISTRIBUTION 2011 CCA SCHEDULE

Class	Class Description	UCC 2011 Opening Balance	2011 Additions	2011 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2011 CCA	UCC End of 2011
1	Distribution System - post 1987	31,055,796	0	0	31,055,796	0	31,055,796	4%	1,242,232	29,813,564
2	Distribution System - pre 1988	0	0	0	0	0	0	6%	0	0
3		0	0	0	0	0	0	5%	0	0
8	General Office/Stores Equip	451,181	50,000	0	501,181	25,000	476,181	20%	95,236	405,945
10	Computer Hardware/ Vehicles	964,113	575,000	0	1,539,113	287,500	1,251,613	30%	375,484	1,163,629
12	Computer Software	12,500	959,700	0	972,200	479,850	492,350	100%	492,350	479,850
45	Computers & Systems Software acq'd post Mar 22/04	0	0	0	0	0	0	45%	0	0
47.0	New Distribution Assets	34,602,213	8,003,796	0	42,606,009	4,001,898	38,604,111	8%	3,088,329	39,517,680
1.3	Bldg after Mar 18/07	0	0	0	0	0	0	6%	0	0
50.0	Comp Equip after Mar 18/07	55,015	407,000	0	462,015	203,500	258,515	55%	142,184	319,832
	TOTAL	**67,140,818**	**9,995,496**	**0**	**77,136,314**	**4,997,748**	**72,138,566**		**5,435,814**	**71,700,500**

CUMULATIVE ELIGIBLE CAPITAL

The OEB's Decision and Order (EB-2007-0744) dated October 30, 2008 relating to Great Lakes Power Limited's cost of service rate application denies the recovery of the balance of Regulatory Asset Account 1574 that recorded deferred mitigation amounts since 2002. In their decision the Board also awarded the benefit of the tax treatment to the shareholder as follows:

"The Board reiterates its view that the benefits of a tax loss should be realized by the party – shareholders or ratepayers – that bore the expenses or losses that gave rise to the tax loss. Since the Board has denied recovery of the amount accrued for rate mitigation in account 1574, the resulting losses should not be attributed to ratepayers but rather to Great Lakes Power Limited, which sustained those losses and should retain the related tax benefits."

API has treated the rate mitigation account losses as cumulative eligible capital deduction for income tax purposes. The associated deduction has not been included in the calculation of income tax expense included in the revenue requirement.

Property Taxes

OEB Account	Description	2007 Board Approved	2007 Actual	Variance from 2007 Board Approved	2008 Actual	Variance from 2007 Actual	2009 Actual	Variance from 2008 Actual	2010 Test Year	Variance from 2009 Actual	2011 Test Year	Variance from 2010 Test
6105	Taxes Other Than Income Taxes	164,250	163,402	(848)	163,956	553	146,241	(17,715)	150,000	3,759	150,000	-

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2010-10-08

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date		Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2009-11-08		34,862			34,862
2009-12-08		34,862			34,862
2010-01-08		34,862			34,862
2010-02-08		34,862			34,862
2010-03-08		34,862			34,862
2010-04-08		34,862			34,862
2010-05-08		34,862			34,862
2010-06-08		34,862			34,862
2010-07-08		34,862			34,862
2010-08-08		34,862			34,862
2010-09-08		34,862			34,862
2010-10-08		34,859			34,859
	Total	418,341			418,341

Quarterly instalment workchart

Date		Quarterly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2010-01-08					
2010-04-08					
2010-07-08					
2010-10-08					
	Total				

Instalment method

Indicate instalment method chosen [1-3] 1

1st Instalment base method

If payment of instalments other than quarterly instalments is delayed, indicate the MONTH in which you want them to begin (1=January, 2=February, etc.). 11

Select this box if you want the instalments to be calculated without taking the applicable thresholds into account ☐

Quarterly instalments calculation

The corporation must meet requirements 1 to 5 to be eligible for quarterly instalments for a tax year.

1 – Is the corporation a Canadian-controlled private corporation (CCPC)?	☐ Yes	☒ No
2 – Did the corporation claim any deduction under the section 125, during either the current or previous year?	☐ Yes	☒ No
3 – Is the corporation's, or any of its associated corporations', taxable income for the current or previous year less than or equal to $500,000?*	☐ Yes	☐ No
4 – Is the corporation and any associated corporations' taxable capital employed in Canada for the current or previous year less than or equal to $10,000,000?	☐ Yes	☐ No
5 – Does the corporation have a perfect compliance history in the last 12 months?	☐ Yes	☐ No

If you do not want to use the quarterly instalments option, select this box to go back to monthly instalments. ☐

*Consult the Help (F1) for information on the changes relating to years subsequent to 2008.

1 – 1st Instalment base method

1st Instalment base amount (amount N below)	418,341	÷	12	=	34,862
Monthly instalments required					34,862
Quarterly tax instalments required	418,341	÷	4	=	

2 – Combined 1st and 2nd instalment base method

Select this box if you want the first 2 payments* to be calculated without taking the applicable thresholds into account? ☐

2nd Monthly instalment base amount

Indicate:	Part I tax						
	Part VI, VI.1 and XIII.1 tax	+					
	Federal adjustment for amalgamation, winding up or transfer	+					
	Provincial tax, other than Alberta, Québec and Ontario	+					
	Ontario tax**	+					
	Provincial adjustment for amalgamation, winding up or transfer	+					
	Total	=		÷	12	=	**A**
1/12 of estimated current year credits (M below /12)		–					
Each of the first two instalment payments		=					**B**
Total tax from N below			418,341				
Amount B above x 2		–					
		=	418,341	÷	10	=	41,835
Each of the remaining ten instalment payments						=	41,835

2nd Quarterly instalment base amount

Indicate:	Part I tax						
	Part VI, VI.1 and XIII.1 tax	+					
	Federal adjustment for amalgamation, winding up or transfer	+					
	Provincial tax, other than Alberta, Québec and Ontario	+					
	Ontario tax**	+					
	Provincial adjustment for amalgamation, winding up or transfer	+					
	Total	=		÷	4	=	**A**
1/4 of estimated current year credits (M below /4)		–					
The first instalment payment		=					**B**
Total tax from N below			418,341				
Amount B above		–					
		=	418,341	÷	3	=	139,447
Each of the remaining three instalment payments						=	

* It is the first payment if the quarterly instalments are applicable.

** Use this line only to calculate instalments payable with regard to taxation years ending in 2009 and after.

3 – Estimated tax method

Instalment base amount (amount N below)		÷	12	=	
Monthly instalments required					
Quarterly tax instalments required		÷	4	=	

Instalment base calculation

Federal tax

		1st instalment base method		Estimated tax method	
Taxable income		172,192			
Calculation of tax payable					
Federal part I tax		65,433			
Federal surtax	+		+		
Recapture of investment tax credit	+		+		
Refundable tax on a CCPC's investment income	+		+		
Subtotal	=	65,433	=		**A**
Deduction					
Small business deduction					
Investment corporation deduction	+		+		
Federal tax abatement	+	17,219	+		
Manufacturing and processing profits deduction	+		+		
Non-business foreign tax credit	+		+		
Business foreign tax credit	+		+		
Tax reduction, general and accelerated	+	15,497	+		
Logging tax credit	+		+		
Federal political contribution tax credit	+		+		
Investment tax credit per Schedule 31 and resource deduction	+		+		
Qualifying environmental trust tax credit	+		+		
Subtotal	=	32,716	=		**B**
Federal tax summary					
Total part I tax payable (A minus B)		32,717			**C**
Part VI tax	+		+		**D**
Part VI.1 tax	+		+		**E1**
Part XIII.1 tax	+		+		**E2**
Parts I, VI, VI.1 and XIII.1 **Total**	=	32,717	=		**F**
Federal adjustments					
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365	x	365 / 100	x	365 / 365	
Subtotal	=	119,417	=		
Federal adjustment for amalgamation, winding up or transfer	+		+	N/A	
Total federal tax after adjustments	=	119,417	=		**G**

Provincial tax

Provincial/territorial tax, other than Alberta, Québec and Ontario			+		+	**H**
Ontario tax						
Use this section only to calculate instalments payable with regard to taxation years ending in 2009 and after (for other tax years, see the *Ontario Tax Instalments* schedule (Jump Code: **ION**)):						
Income tax		24,107				
Capital tax	+	56,287				
Corporate minimum tax paid (credited)	+	1,503				
Special additional tax on life insurance corporations	+		+			
Total Ontario tax*	=	81,897 ▶		81,897	+	**I**
Harmonized provincial tax (H + I) **Total harmonized provincial tax**			=	81,897	=	**J**
Provincial adjustments						
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365			x	365 / 100	x	365 / 365
Subtotal			=	298,924	=	
Provincial adjustment for amalgamation, winding up or transfer			+		+	N/A
Total provincial tax after adjustments			=	298,924	=	**K**
Total of tax before refundable credits** (G + K)			=	418,341	=	**L**

Instalment base calculation (continued)

Estimated current year credits

Investment tax credit refund				
Dividend refund	+		+	
Federal capital gains refund	+		+	
Provincial and territorial capital gains refund	+		+	
NRO allowable refund per Schedule 26	+		+	
Tax withheld at source	+		+	
Other estimated credits	+		+	
Total estimated current year credits	=		=	**M**
Instalment base amount (L minus M)		418,341		**N**

* Ontario tax corresponds to the amount before the application of specified Ontario tax credits.

** For instalments payable for tax years beginning before 2008, the amount on line G is not added to line L unless it exceeds $1,000. The same rule applies to line K. For instalments payable for tax years beginning after 2007, the amount on line G is not added to line L unless it exceeds $3,000. The same rule applies to line K.

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), Quebec, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 82249 4290 RC0001

Corporation's name
002 Great Lakes Power Distribution Inc.

Address of head office
Has this address changed since the last time you filed your T2 return? 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 2 Sackville Road
012

City	Province, territory, or state
015 Sault Ste Marie	016 ON
Country (other than Canada)	**Postal code/Zip code**
017	018 P6B 6J6

Mailing address (if different from head office address)
Has this address changed since the last time you filed your T2 return? 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023

City	Province, territory, or state
025	026
Country (other than Canada)	**Postal code/Zip code**
027	028

Location of books and records
Has the location of books and records changed since the last time you filed your T2 return? 030 1 Yes [X] 2 No [ ]
(If **yes**, complete lines 031 to 038.)
031 2 Sackville Road
032

City	Province,territory, or state
035 Sault Ste Marie	036 ON
Country (other than Canada)	**Postal code/Zip code**
037	038 P6B 6J6

040 **Type of corporation at the end of the tax year**

1 [ ] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [X] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 YYYY MM DD

To which tax year does this return apply?

Tax year start	Tax year-end
060 2009-07-01	061 2009-10-08
YYYY MM DD	YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 1 Yes [X] 2 No [ ]
If **yes**, provide the date control was acquired 065 2009-10-08 YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? 066 1 Yes [X] 2 No [ ]

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? 070 1 Yes [X] 2 No [ ]
Amalgamation? 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **Yes** response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150		9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173		50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	2 No X
Is the corporation inactive?	280	1 Yes	2 No X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes	2 No X

What is the corporation's major business activity? 282

(Only complete if **yes** was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale 2 Retail

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes 2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300	172,192	A
Deduct: Charitable donations from Schedule 2	311		
Gifts to Canada, a province, or a territory from Schedule 2	312		
Cultural gifts from Schedule 2	313		
Ecological gifts from Schedule 2	314		
Gifts of medicine from Schedule 2	315		
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320		
Part VI.1 tax deduction *	325		
Non-capital losses of previous tax years from Schedule 4	331		
Net capital losses of previous tax years from Schedule 4	332		
Restricted farm losses of previous tax years from Schedule 4	333		
Farm losses of previous tax years from Schedule 4	334		
Limited partnership losses of previous tax years from Schedule 4	335		
Taxable capital gains or taxable dividends allocated from a central credit union	340		
Prospector's and grubstaker's shares	350		
Subtotal		▶	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")		172,192	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C **plus** amount D)	360	172,192	
Income exempt under paragraph 149(1)(t)	370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)		172,192	Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . **400** A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . . **405** B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000 x (Number of days in the tax year before 2009 / Number of days in the tax year) x ____ / 100 = ... 1

500,000 x (Number of days in the tax year after 2008 / Number of days in the tax year) x 100 / 100 = ... 500,000 2

Add amounts at lines 1 and 2 500,000 4

Business limit (see notes 1 and 2 below) . . . . . **410** C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ____ x **415** *** ____ / 11,250 D = ... E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** F

Small business deduction

Amount A, B, C, or F whichever is the least ____ x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) x ____ / 100 x 16 % = 5

Amount A, B, C, or F whichever is the least ____ x (Number of days in the tax year after December 31, 2007 / Number of days in the tax year) x 100 / 100 x 17 % = 6

Total of amounts 5 and 6 – enter on line 9 **430** G

***** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

****** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360							A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27						B	
Amount QQ from Part 13 of Schedule 27						C	
Amount used to calculate the credit union deduction from Schedule 17						D	
Amount from line 400, 405, 410, or 425, whichever is the least						E	
Aggregate investment income from line 440						F	
Total of amounts B to F					▶		G
Amount A **minus** amount G (if negative, enter "0")							H
Amount H		x Number of days in the tax year before January 1, 2008 / Number of days in the tax year		x 7 %	=		I
Amount H		x Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year		x 8.5 %	=		J
Amount H		x Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	100 / 100	x 9 %	=		K
Amount H		x Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year		x 10 %	=		L
General tax reduction for Canadian-controlled private corporations – Total of amounts I to L							M

Enter amount M on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)							172,192 N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27						O	
Amount QQ from Part 13 of Schedule 27						P	
Amount used to calculate the credit union deduction from Schedule 17						Q	
Total of amounts O to Q					▶		R
Amount N **minus** amount R (if negative, enter "0")							172,192 S
Amount S	172,192	x Number of days in the tax year before January 1, 2008 / Number of days in the tax year		x 7 %	=		T
Amount S	172,192	x Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year		x 8.5 %	=		U
Amount S	172,192	x Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	100 / 100	x 9 %	=	15,497	V
Amount S	172,192	x Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year		x 10 %	=		W
General tax reduction – Total of amounts T to W							15,497 X

Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . . **440** _____ x 26 2 / 3 % = ... _____ A

Foreign non-business income tax credit from line 632 . . . . . _____

Deduct:

Foreign investment income from Schedule 7 . . . . . **445** _____ x 9 1 / 3 % = _____

(if negative, enter "0") _____ ▶ _____ B

Amount A **minus** amount B (if negative, enter "0") . . . . . _____ C

Taxable income from line 360 . . . . . _____

Deduct:

Amount from line 400, 405, 410, or 425, whichever is the least . . . . . _____

Foreign non-business income tax credit from line 632 . . . . . _____ x 25 / 9 = _____

Foreign business income tax credit from line 636 . . . . . _____ x 3 = _____

_____ ▶ _____

x 26 2 / 3 % = _____ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) . . . . . _____

Deduct: Corporate surtax from line 600 . . . . . _____

Net amount . . . . . _____ ▶ _____ E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . . **450** _____ F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . . **460** _____

Deduct: Dividend refund for the previous tax year . . . . . **465** _____

_____ ▶ _____ G

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . . _____

Total Part IV tax payable from Schedule 3 . . . . . _____

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . **480** _____

_____ ▶ _____ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . . **485** _____

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3 . . . . . _____ x 1 / 3 _____ I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . _____ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784) . . . . . _____

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 % . . . . . **550** 65,433 A

Corporate surtax calculation

Base amount from line A above 65,433 1

Deduct:

10 % of taxable income (line 360 or amount Z, whichever applies) 17,219 2

Investment corporation deduction from line 620 below 3

Federal logging tax credit from line 640 below 4

Federal qualifying environmental trust tax credit from line 648 below 5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360 . . . . . a

28.00 % of taxed capital gains . . . . . b

Part I tax otherwise payable (line A **plus** lines C and D **minus** line F) c

6

Total of lines 2 to 6 . . . . . 17,219 7

Net amount (line 1 **minus** line 7) 48,214 8

Corporate surtax*

Line 8 48,214 x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) x 4 % = **600** B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 . . . . . **602** C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 i

Taxable income from line 360 . . . . .

Deduct:

Amount from line 400, 405, 410, or 425, whichever is the least . . . . .

Net amount . . . . . ▶ ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . **604** D

Subtotal (**add** lines A to D) 65,433 E

Deduct:

Small business deduction from line 430 9

Federal tax abatement **608** 17,219

Manufacturing and processing profits deduction from Schedule 27 . . . . . **616**

Investment corporation deduction **620**

Taxed capital gains **624**

Additional deduction – credit unions from Schedule 17 . . . . . **628**

Federal foreign non-business income tax credit from Schedule 21 . . . . . **632**

Federal foreign business income tax credit from Schedule 21 . . . . . **636**

General tax reduction for CCPCs from amount M **638**

General tax reduction from amount X **639** 15,497

Federal logging tax credit from Schedule 21 . . . . . **640**

Federal political contribution tax credit **644**

Federal political contributions **646**

Federal qualifying environmental trust tax credit **648**

Investment tax credit from Schedule 31 . . . . . **652**

Subtotal 32,716 ▶ 32,716 F

Part I tax payable – Line E **minus** line F . . . . . 32,717 G

Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	32,717
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		32,717

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Ontario [for tax years ending before 2009], Quebec, and Alberta)	760	81,897	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		81,897 ▶	81,897
Total tax payable	770		114,614 A

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	200,000	
Total credits	890	200,000 ▶	200,000 B

Refund code 894 1 Overpayment 85,386

Balance (line A **minus** line B) -85,386

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid .....

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 King (Last name in block letters) 951 Glen (First name in block letters) 954 Chief Financial Officer (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2010-04-06 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation 956 (705) 759-7600 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☒ 2 No ☐

958 Franca Pace (Name in block letters) 959 (705) 759-7600 (Telephone number)

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

990 1

Schedule of Instalment Remittances

Name of corporation contact
Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
2009-12-04	FEDERAL TAX INSTALLMENTS	200,000

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 200,000 **A**

Total instalments credited to the taxation year per T9 200,000 **B**

Transfer

Account number	Taxation year end	Amount	Effective interest date	Description
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				

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SCHEDULE 101

Form identifier 101

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

Opening balance sheet information

Account	Description	GIFI	Amount
Assets			
	Total current assets	1599 +	
	Total tangible capital assets	2008 +	
	Total accumulated amortization of tangible capital assets	2009 –	
	Total intangible capital assets	2178 +	
	Total accumulated amortization of intangible capital assets	2179 –	
	Total long-term assets	2589 +	
	* Assets held in trust	2590 +	
	Total assets (mandatory field)	2599 =	
Liabilities			
	Total current liabilities	3139 +	
	Total long-term liabilities	3450 +	
	* Subordinated debt	3460 +	
	* Amounts held in trust	3470 +	
	Total liabilities (mandatory field)	3499 =	
Shareholder equity			
	Total shareholder equity (mandatory field)	3620 +	
	Total liabilities and shareholder equity	3640 =	
Retained earnings			
	Retained earnings/deficit – end (mandatory field)	3849 =	

* Generic item

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SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	14,678,845	
	Total tangible capital assets	2008	+	90,658,615	
	Total accumulated amortization of tangible capital assets	2009	–	42,702,405	
	Total intangible capital assets	2178	+	15,118,747	
	Total accumulated amortization of intangible capital assets	2179	–	1,170,640	
	Total long-term assets	2589	+	22,561,200	
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	99,144,362	
Liabilities					
	Total current liabilities	3139	+	3,868,747	
	Total long-term liabilities	3450	+	3,964,743	
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	7,833,490	
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	91,310,872	
	Total liabilities and shareholder equity	3640	=	99,144,362	
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	478,747	

* Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

Income statement information

Description	GIFI
Operating name	0001
Description of the operation	0002
Sequence Number	0003 01

Account	Description	GIFI		Current year	Prior year
Income statement information					
	Total sales of goods and services	8089	+	7,234,465	
	Cost of sales	8518	–	2,974,958	
	Gross profit/loss	8519	=	4,259,507	
	Cost of sales	8518	+	2,974,958	
	Total operating expenses	9367	+	3,629,725	
	Total expenses (mandatory field)	9368	=	6,604,683	
	Total revenue (mandatory field)	8299	+	7,244,933	
	Total expenses (mandatory field)	9368	–	6,604,683	
	Net non-farming income	9369	=	640,250	
Farming income statement information					
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	640,250	
Extraordinary items and income (linked to Schedule 140)					
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	161,503	
	Deferred income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	478,747	

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SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI) for Corporations* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule, and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant preparing or reporting on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant:

198

Completed an auditor's report . . . . . 1 [X]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options:

110

Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [ ] 2 No [X]

If **yes**, complete lines 102 to 107 below:

Are any values presented at other than cost? . . . . . **102** 1 Yes [ ] 2 No [ ]

Has there been a change in accounting policies since the last return? . . . . . **103** 1 Yes [ ] 2 No [ ]

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [ ] 2 No [ ]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [ ]

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [ ] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [ ] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [X]

If **yes**, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . . . **109** 1 Yes [ ] 2 No [ ]

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES — SCHEDULE 1

Corporation's name	Business Number	Tax year end (Year Month Day)
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				478,747 A
Add:				
Provision for income taxes – current	101	161,503		
Amortization of tangible assets	104	740,021		
Non-deductible meals and entertainment expenses	121	4,976		
Non-deductible company pension plans	124	67,798		
Subtotal of additions		974,298	▶	974,298
Other additions:				
Miscellaneous other additions:				
604				
Subtotal of other additions	199		▶	
Total additions	500	974,298	▶	974,298
Deduct:				
Gain on disposal of assets per financial statements	401	6,398		
Capital cost allowance from Schedule 8	403	981,337		
Cumulative eligible capital deduction from Schedule 10	405	214,176		
Contributions to deferred income plans from Schedule 15	417	59,032		
Subtotal of deductions		1,260,943	▶	1,260,943
Other deductions:				
Miscellaneous other deductions:				
700 Interest used during construction	390	19,910		
704				
Total	394			
Subtotal of other deductions	499	19,910	▶	19,910
Total deductions	510	1,280,853	▶	1,280,853
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				172,192

* For reference purposes only

T2 SCH 1 E (09)

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1); or
  - is claiming provincial or territorial tax credits or rebates (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 402 Corporations not specified Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2 (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☒	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking center; the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in computing the corporation's income under section 33.1 of the federal *Income Tax Act*.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see line 760 of the *T2 Corporation – Income Tax Guide.*
2. If the corporation has provincial or territorial tax payable, complete Part 2 on the following pages.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
172,192			24,107

Ontario basic income tax (from Schedule 500) 270 24,107

Deduct: Ontario small business deduction (from schedule 500) 402

Subtotal (if negative, enter "0") 24,107 ▶ 24,107 A6

Add:

Surtax re Ontario small business deduction (from Schedule 500) 272

Ontario additional tax re Crown royalties (from Schedule 504) 274

Ontario transitional tax debits (from Schedule 506) 276

Recapture of Ontario research and development tax credit (from Schedule 508) 277

Subtotal ▶ B6

Subtotal (amount A6 **plus** amount B6) 24,107 C6

Deduct:

Ontario resource tax credit (from Schedule 504) 404

Ontario tax credit for manufacturing and processing (from Schedule 502) 406

Ontario foreign tax credit (from Schedule 21) 408

Ontario credit union tax reduction (from Schedule 500) 410

Ontario transitional tax credits (from Schedule 506) 414

Ontario political contributions tax credit (from Schedule 525) 415

Subtotal ▶ D6

Subtotal (amount C6 **minus** amount D6) (if negative, enter "0") 24,107 E6

Ontario research and development tax credit (from Schedule 508) 416

Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0") 24,107 F6

Deduct:

Ontario corporate minimum tax credit (from schedule 510) 418

Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0") 24,107 G6

Add:

Ontario corporate minimum tax (from Schedule 510) 278 1,503

Ontario special additional tax on life insurance corporations (from Schedule 512) 280

Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies) 282 56,287

Subtotal 57,790 ▶ 57,790 H6

Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6) 81,897 I6

Deduct:

Ontario qualifying environmental trust tax credit 450

Ontario co-operative education tax credit (from Schedule 550) 452

Ontario apprenticeship training tax credit (from Schedule 552) 454

Ontario computer animation and special effects tax credit (from Schedule 554) 456

Ontario film and televison tax credit (from Schedule 556) 458

Ontario production services tax credit (from Schedule 558) 460

Ontario interactive digital media tax credit (from Schedule 560) 462

Ontario sound recording tax credit (from Schedule 562) 464

Ontario book publishing tax credit (from Schedule 564) 466

Ontario innovation tax credit (from Schedule 566) 468

Ontario business-research institute tax credit (from Schedule 568) 470

Subtotal ▶ J6

Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) 290 81,897 K6

(if a credit, enter a negative amount) Include this amount on line 255.

Summary

Enter the total net tax payable or refundable credits for all provinces and territories at line 255.

Net provincial and territorial tax payable or refundable credits **255** 81,897

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	47	Distribution Equipment	23,410,752	490,170		0	245,085	23,655,837	8	0	0	518,484	23,382,438
2.	10	Vehicles	744,907			30,474		714,433	30	0	0	58,721	655,712
3.	8	General Office/Stores Equipment	473,921	2,808		0	1,404	475,325	20	0	0	26,045	450,684
4.	50	Computer Equipment	108,237			0		108,237	55	0	0	16,310	91,927
5.	1	Pre Feb. 2005 Distribution Equip	33,012,126			0		33,012,126	4	0	0	361,777	32,650,349
		Total	57,749,943	492,978		30,474	246,489	57,965,958				981,337	57,231,110

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** A

Add:

Cost of eligible capital property acquired during the taxation year **222** 14,890,315

Other adjustments **226**

Subtotal (line 222 plus line 226) 14,890,315 x 3 / 4 = 11,167,736 B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . **228** x 1 / 2 = C

amount B minus amount C (if negative, enter "0") 11,167,736 ▶ 11,167,736 D

Amount transferred on amalgamation or wind-up of subsidiary . . . . . **224** E

Subtotal (add amounts A, D, and E) **230** 11,167,736 F

Deduct:

Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . . **242** G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** H

Other adjustments . . . . . **246** I

(add amounts G,H, and I) x 3 / 4 = **248** J

Cumulative eligible capital balance (amount F minus amount J) . . . . . 11,167,736 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249**

amount K 11,167,736

less amount from line 249

Current year deduction . . . . . 11,167,736 x 7.00 % = **250** 214,176 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 214,176 ▶ 214,176 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 10,953,560 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

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Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount) . . . . . N

Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988 . . . . . 400 1

Total of all amounts which reduced CEC in the current or prior years under subsection 80(7) 401 2

Total of CEC deductions claimed for taxation years beginning before July 1, 1988 . . . . . 402 3

Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988 408 4

Line 3 minus line 4 (if negative, enter "0") . . . . . ▶ 5

Total of lines 1, 2 and 5 6

Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400 7

Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000 8

Subtotal (line 7 plus line 8) 409 ▶ 9

Line 6 minus line 9 (if negative, enter "0") . . . . . ▶ O

Line N minus line O (if negative, enter "0") . . . . . P

Line 5 _____ x 1 / 2 = Q

Line P minus line Q (if negative, enter "0") . . . . . R

Amount R _____ x 2 / 3 = S

Amount N or amount O, whichever is less . . . . . T

Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1) 410

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SCHEDULE 15

DEFERRED INCOME PLANS

Name of corporation	Business Number	Tax year end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments,* Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) filed by: (see note 3) (EPSP only) 600
1	1	59,032				

Note 1: Enter the applicable code number:
1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP

Note 2: You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule ..... 59,032 **A**

Less:

Total of all amounts for deferred income plans deducted in your financial statements _____ **B**

Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0") ..... 59,032 **C**

Enter amount C on line 417 of Schedule 1

Note 3: T4PS slip(s) filed by: 1 – Trustee
2 – Employer

T2 SCH 15 (06)

Canada

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SCHEDULE 24

FIRST-TIME FILER AFTER INCORPORATION, AMALGAMATION, OR WINDING-UP OF A SUBSIDIARY INTO A PARENT

Name of corporation	Business Number	Tax year end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

This schedule must be filed by corporations for the first year of filing after incorporation, amalgamation, or by parent corporations filing for the first time after winding-up a subsidiary corporation(s) under section 88 of the *Income Tax Act* during the current taxation year.

Part 1 – Type of operation

100 For those corporations filing for the first time after incorporation or amalgamation, please identify the type of operation that applies to your corporation:

99 Other

Part 2 – First year of filing after amalgamation

For the first year of filing after an amalgamation, please provide the following information:

Name of predecessor corporation(s) **200**	Business Number (If a corporation is not registered, enter "NR") **300**

Part 3 – First year of filing after wind-up of subsidiary corporation(s)

For the parent corporation filing for the first time after winding-up a subsidiary corporation(s) under section 88 of the *Income Tax Act*, please provide the following information:

Name of subsidiary corporation(s) **400**	Business Number (If a corporation is not registered, enter "NR") **500**	Commencement date of wind-up (YYYY/MM/DD) **600**	Date of wind-up (YYYY/MM/DD) **700**

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- References to subsections and paragraphs are from the federal *Income Tax Act*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . 172,192 A

Ontario basic income tax: amount A **multiplied** by 14 % . . . . . 24,107 B

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount B on line 270 of Schedule 5, *Tax Calculation Supplementary - Corporations*. Otherwise, enter it on line 760 on page 8 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, from page 3 of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 2 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return) 1

Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return) 2

Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return) . . . . . x 500,000 / 500,000 (line 4 on page 4 of the T2 return) = 3

Enter the least of amounts 1, 2, and 3 C

Ontario domestic factor: Ontario taxable income * / taxable income earned in all provinces and territories ** 172,192.00 / 172,192 = ... 1.00000 D

Ontario small business income (amount C **multiplied** by amount D) . . . . . E

OSBD rate for the year . . . . . 8.5 %

Ontario small business deduction (amount E **multiplied** by OSBD rate for the year) . . . . . F

Enter amount F on line 402 of Schedule 5.

* Enter amount A from Part 1.

** Includes the offshore jurisdictions for Nova Scotia, and Newfoundland and Labrador.

Part 3 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD, and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction*.

Adjusted taxable income *	628,501 G		
Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501)	H		
Aggregate adjusted taxable income (amount G **plus** amount H)	628,501	▶ 628,501	I
Deduct:			
Ontario business limit		500,000	
Subtotal (amount I **minus** Ontario business limit) (if negative, enter "0" on this line and on line M)		128,501	J
Small business surtax rate for the year	4.25 %		
Multiply: Line J x small business surtax rate for the year =		5,461	K

Amount K x (Ontario small business income (amount E in Part 2) / 500,000) / 500,000 = L

Ontario surtax re Ontario small business deduction: lesser of amount L and OSBD (amount F in Part 2) M

Enter amount M on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Amount C in Part 2 . . . . . N

Surtax payable (amount M in Part 3) _____ = ... O
Ontario domestic factor (amount D in Part 2) x 8.5 %

Ontario adjusted small business income (amount N **minus** amount O) (if negative, enter "0") . . . . . P

Enter amount P on line R in Part 5 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D in Part 3 of Schedule 17 . . . . . Q

Deduct:

Ontario adjusted small business income (amount P in Part 4) . . . . . R

Subtotal (amount Q **minus** amount R) (if negative, enter "0") . . . . . S

OSBD rate for the year . . . . . 8.5 %

Amount S **multiplied** by the OSBD rate for the year . . . . . T

Ontario domestic factor (amount D in Part 2) . . . . . 1.00000 U

Ontario credit union tax reduction (amount T **multiplied** by amount U) V

Enter amount V on line 410 on Schedule 5.

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SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario).
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	99,144,362
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	
Total assets (total of lines 112 to 116)		99,144,362
Total revenue of the corporation for the tax year **	142	26,444,005
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	
Total revenue (total of lines 142 to 146)		26,444,005

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations exceed $5,000,000 or the total revenue for the year of the corporation or the associated group of corporations exceeds $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations exceed $50,000,000 or the total revenue for the year of the corporation or the associated group of corporations exceeds $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or has SAT payable in the year.

* **Rules for total assets**
- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Exclude unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s) and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the *Taxation Act, 2007* (Ontario) and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the *Taxation Act, 2007* (Ontario).

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the *Taxation Act, 2007* (Ontario) and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the *Taxation Act, 2007* (Ontario).

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements *		210	478,747
Add (to the extent reflected in income/loss):			
Provision for current income taxes/cost of current income taxes	220	161,503	
Provision for deferred income taxes (debits)/cost of future income taxes	222		
Equity losses from corporations	224		
Financial statement loss from partnerships and joint ventures	226		
Dividends paid/payable to shareholders (other than dividends paid by credit unions)	230		
Other additions (see note below):			
Share of adjusted net income of partnerships and joint ventures **	228		
Total patronage dividends received, not already included in net income/loss	232		
281	282		
283	284		
Subtotal		161,503 ▶	161,503 A
Deduct (to the extent reflected in income/loss):			
Provision for recovery of current income taxes/benefit of current income taxes	320		
Provision for deferred income taxes (credits)/benefit of future income taxes	322		
Equity income from corporations	324		
Financial statement income from partnerships and joint ventures	326		
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330		
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332		
Gain on donation of listed security or ecological gift	340		
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342		
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344		
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346		
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348		
Other deductions (see note below):			
Share of adjusted net loss of partnerships and joint ventures **	328		
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334		
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336		
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338		
381	382		
383	384		
385	386		
387	388		
389	390		
Subtotal		▶	B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)		490	640,250

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note:
Under Other additions, enter any realized or unrealized mark-to-market losses and foreign currency losses on assets that are included in income for accounting purposes but not in income for tax purposes, in accordance with *Ontario Regulation 37/09*. Under Other deductions, enter any realized or unrealized mark-to-market gains and foreign currency gains on assets that are included in income for accounting purposes but not in income for tax purposes, in accordance with *Ontario Regulation 37/09*.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.
- Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture was a corporation and the tax year of the partnership or joint venture was its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the *Taxation Act, 2007* (Ontario).

*** A joint election will be considered made under subsection 60(1) of the *Taxation Act, 2007* (Ontario) if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the *Taxation Act, 2007* (Ontario) if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the *Taxation Act, 2007* (Ontario) if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – Calculation of CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive) **515** 640,250

CMT loss available (amount R from Part 7) . . . . . _____

Minus: Adjustment for an acquisition of control * . . . . . **518** _____

Adjusted CMT loss available . . . . . _____ ▶ _____ C

Net income subject to CMT calculation (if negative, enter "0") **520** 640,250

Amount from line 520: 640,250 x (Number of days in the tax year before July 1, 2010: 100 / Number of days in the tax year: 100) x 4 % = 25,610 1

Amount from line 520: 640,250 x (Number of days in the tax year after June 30, 2010: _____ / Number of days in the tax year: 100) x 2.7 % = _____ 2

Subtotal (amount 1 **plus** amount 2) 25,610 3

Gross CMT: amount on line 3 above x OAF ** **540** 25,610

Deduct:

Foreign tax credit for CMT purposes *** . . . . . **550** _____

CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") . . . . . 25,610 D

Deduct:

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 24,107

Net CMT payable (if negative, enter "0") . . . . . 1,503 E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations* and complete Part 4.

* Portion of CMT loss available that exceeds the adjusted net income for the tax year from business(es) continued from before the acquisition of control. See subsection 58(3) of the *Taxation Act, 2007* (Ontario).

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** = _____

Ontario allocation factor . . . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*****Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year * . . . . . G

Deduct:

CMT credit expired * **600**

CMT credit carryforward at the beginning of the current tax year * (see note below) . . . . . ▶ **620**

Add:

CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) **650**

CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) . . . . . H

Deduct:

CMT credit deducted in the current tax year (amount P from Part 5) I

Subtotal (amount H **minus** amount I) J

Add:

Net CMT payable (amount E from Part 3) 1,503

SAT payable (amount O from Part 6 of Schedule 512) . . . . .

Subtotal 1,503 ▶ 1,503 K

CMT credit carryforward at the end of the tax year (amount J **plus** amount K) . . . . . **670** 1,503 L

* For the first harmonized T2 Return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600.
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)* for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4) . . . . . M

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 24,107 1

For a corporation that is not a life insurance corporation:

CMT after foreign tax credit deduction (amount D from Part 3) . . 25,610 2

For a life insurance corporation:

Gross CMT (line 540 from Part 3) 3

Gross SAT (line 460 from Part 6 of Schedule 512) 4

The **greater** of amounts 3 and 4 5

Deduct: line 2 or line 5, whichever applies: 25,610 6

Subtotal (if negative, enter "0") ▶ N

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 24,107

Deduct:

Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) . . . . .

Subtotal (if negative, enter "0") 24,107 ▶ 24,107 O

CMT credit deducted in the current tax year (least of amounts M, N, and O) . . . . . P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? . . . . . **675** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the *Taxation Act, 2007* (Ontario).

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if you are reporting a CMT credit carryforward at the beginning of the tax year on line 620, or a CMT credit carryforward transferred on an amalgamation or the windup of a subsidiary on line 650. For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Year of origin		CMT credit balance *
10th previous tax year	680	
9th previous tax year	681	
8th previous tax year	682	
7th previous tax year	683	
6th previous tax year	684	
5th previous tax year	685	
4th previous tax year	686	
3rd previous tax year	687	
2nd previous tax year	688	
1st previous tax year	689	
Total **		

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . ▶ 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . 770 T

* For the first harmonized T2 Return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700.
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)* for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not transfer a loss on a vertical amalgamation under subsection 87(2.11) of the federal Act or other amalgamation of a parent and its subsidiary.
Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if you are reporting a CMT loss carryforward at the beginning of the tax year on line 720 or a CMT loss transferred on an amalgamation on line 750. For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Year of origin	Balance earned in a tax year ending before March 24, 2007 *	Balance earned in a tax year ending after March 23, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 24, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 23, 2007, and has not been deducted.

*** The total of these 2 columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 515

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

- Complete this schedule for a corporation with a permanent establishment in Ontario at any time in the tax year and that is a corporation other than a financial institution. The Ontario capital tax on other than financial institutions is levied under section 64 of the *Taxation Act, 2007* (Ontario).
- To complete this schedule, you have to complete Schedule 33, *Part I.3 Tax on Large Corporations*. File completed copies of both schedules with the *T2 Corporation Income Tax Return* within six months of the end of the tax year.
- A corporation is exempt from Ontario capital tax if it was one of the following:
  1) a corporation that is liable to the special additional tax according to section 74 of the *Corporations Tax Act* (Ontario);
  2) a credit union;
  3) a deposit insurance corporation according to section 137.1 of the federal *Income Tax Act*;
  4) a family farm corporation for the year as defined by subsection 64(3) of the *Taxation Act*, 2007 (Ontario), other than a corporation for which a determination has been made under subsection 31(2) of the federal Act;
  5) a family fishing corporation, as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario); or
  6) a corporation exempt from income tax according to section 149 of the federal Act.

Part 1 – Taxable capital of a corporation resident in Canada other than a financial institution

Amount A from Part 1 of Schedule 33	100	91,310,872	
Add:			
Accumulated other comprehensive income at the end of the year	105		
Subtotal		91,310,872 ▶	91,310,872 A
Deduct:			
Amount B from Part 1 of Schedule 33	110		
Amount on line 490 from Part 2 of Schedule 33	115		
Subtotal		▶	B
Taxable capital (amount A **minus** amount 8) (if negative, enter "0")	120		91,310,872

Part 2 – Capital deduction

Complete this part only if the corporation is associated.

Are you electing under subsection 83(2) of the *Taxation Act, 2007* (Ontario)? 190 1 Yes ☐ 2 No ☐

If you answered **no** to the question at line 190, complete line 220. If you answered **yes** to the question at line 190, complete line 305 by using Schedule 516, *Capital Deduction Election of Associated Group for the Allocation of Net Deduction*, to calculate the amount to be entered on line 300.

Taxable capital (from line 120) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (from line 790 in Part 4 of Schedule 33) / Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year * — 200 / 210 _____ x 15,000,000 $ = **Capital deduction** 220 _____

* This amount includes the filing corporation's taxable capital or taxable capital employed in Canada. Do not include an amount from a financial institution or corporation that is exempt from capital tax under Division E of the *Taxation Act, 2007* (Ontario) or Part III of the *Corporations Tax Act* (Ontario).

Allocation of net deduction (from line 600 for the filing corporation from Schedule 516) / Ontario allocation factor (OAF) (amount I in Part 3) — 300 _____ = **Capital deduction** 305 _____

Part 3 – Ontario capital tax payable

Taxable capital (enter amount from line 120 in Part 1) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (enter amount from line 790 in Part 4 of Schedule 33), whichever applies **320** 91,310,872

Deduct:

Capital deduction (Enter $15,000,000 if the corporation is not associated. Otherwise, enter the amount from line 220 or line 305, whichever applies, from Part 2) . . . . . B

Net amount (line 320 **minus** amount B) (if negative, enter "0") . . . . . 91,310,872 C

Amount C 91,310,872 x (Number of days in the tax year before January 1, 2010 / Number of days in the tax year) 100/100 x 0.00225 = 205,449 D

Amount C 91,310,872 x (Number of days in the tax year after December 31, 2009 and before July 1, 2010 / Number of days in the tax year) ____/100 x 0.00150 = E

Subtotal (amount D **plus** amount E) 205,449 F

Amount F 205,449 x OAF (amount on line I) 1.00000 = ... 205,449 G

Amount G 205,449 x (Number of days in the tax year * / 365) 100/365 = ... 56,287 H

Deduct:

Capital tax credit for manufacturers (enter amount J from Part 4) **350**

Ontario capital tax payable (amount H **minus** line 350) (if negative, enter "0") **400** 56,287

Enter amount from line 400 on line 282 of Schedule 5, *Tax Calculation Supplementary - Corporations*.

* Enter either 365 if there are at least 51 weeks in the tax year, or the number of days in the year, whichever applies.

Calculation of the Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line I.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line I:

(Ontario taxable income ** / Taxable income ***) ____ = ____

Ontario allocation factor . . . . . 1.00000 I

** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*** Enter the taxable income amount from line 360 or line Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Capital tax credit for manufacturers

(Ontario manufacturing labour cost* / Total Ontario labour cost**) **405**/**410** ____ x 100 = ... **420** ____ %

If the percentage on line 420 is 20% or less, enter "0" on line J.

If the percentage on line 420 is at least 50%, enter amount H from Part 3 on line J.

If the percentage on line 420 is more than 20% but less than 50%, complete the following calculation and enter the result on line J:

(percentage from line 420) – 20% / 30% ____ % / 30.000 % x 56,287 Amount H from Part 3 = ____

Capital tax credit for manufacturers . . . . . J

Enter amount J on line 350 in Part 3

* As defined in subsection 83.1(4) of the *Taxation Act, 2007* (Ontario)

** As defined in subsection 83.1(5) of the *Taxation Act, 2007* (Ontario)

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 524

ONTARIO SPECIALTY TYPES

Name of corporation	Business Number	Tax year-end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

- Use this schedule to identify the specialty type of a corporation carrying on business in the province of Ontario through a permanent establishment if:
  – its tax year includes January 1, 2009;
  – the tax year is the first year after incorporation or an amalgamation; or
  – there is a change to the specialty type.
- If none of the listed specialty types applies, tick box 99 "Other."
- Unless otherwise noted, references to sections, subsections, and clauses are from the *Taxation Act, 2007* (Ontario).

Specialty types

100 Identify the specialty type that applies to your corporation:

- ☐ 01 Family farm corporation – See subsection 64(3).
- ☐ 02 Family fishing corporation – See subsection 64(3).
- ☐ 03 Mortgage investment corporation – See subsection 130.1(6) of the federal *Income Tax Act*.
- ☐ 04 Credit union – See subsection 137(6) of the federal Act.
- ☐ 06 Bank – See subsection 248(1) of the federal Act.
- ☐ 08 Financial institution prescribed by regulation only – See clause 66(2)(f).
- ☐ 09 Registered securities dealer – See subsection 248(1) of the federal Act.
- ☐ 10 Farm feeder finance co-operative corporation
- ☐ 11 Insurance corporation – See subsection 248(1) of the federal Act.
- ☐ 12 Mutual insurance – See subsection 27(2) of the *Taxation Act, 2007* (Ontario) and paragraph 149(1)(m) of the federal Act.
- ☐ 13 Specialty mutual insurance
- ☐ 14 Mutual fund corporation – See subsection 131(8) of the federal Act.
- ☐ 15 Bare trustee corporation
- ☐ 16 Professional corporation (incorporated professional only) – See subsection 248(1) of the federal Act.
- ☐ 17 Limited liability corporation
- ☐ 18 Generator of electrical energy for sale, or producer of steam for use in the generation of electrical energy for sale – See subsection 33(7).
- ☐ 19 Hydro successor, municipal electrical utility, or subsidiary of either – See subsection 91.1(1) and section 88 of the *Electricity Act, 1998* (Ontario).
- ☐ 20 Producer and seller of steam for uses other than for the generation of electricity – See subsection 33(7).
- ☐ 21 Mining corporation
- ☐ 22 Non-resident corporation
- ☐ 99 Other (if none of the previous descriptions apply)

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Great Lakes Power Distribution Inc.	82249 4290 RC0001	2009-10-08

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the *Business Corporations Act* (BCA) or *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the Ontario *Corporations Information Act.*
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up to date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
Great Lakes Power Distribution Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2009-01-26	2196355

Part 2 – Head or registered office address (P.O. box not acceptable)

200 Care of (if applicable)

210 Street number	**220** Street name	**230** Suite number
2	Sackville	

240 Additional address information

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Sault Ste Marie	ON	CA	P6B 6J6

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS with respect to names, addresses for service, and the date elected/appointed and date ceased of the directors and five most senior officers, or the corporation's mailing address or language of preference? Obtain a Corporation Profile Report to review the information shown for the corporation on the public record maintained by the MGS. For more information, visit **www.ServiceOntario.ca**.

300 [1] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 King (Last name) **451** Glen (First name)

454 _____ (Middle name(s)),

460 [3] Please enter one of the following numbers in this box for the above-named person: enter **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | **530** Street name | **540** Suite number

550 Additional address information

560 Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communication with the corporation. This may be different from line 990 on the T2 return.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . . Great Lakes Power Distribution Inc.

Taxation Year . . . . . 2009-07-01 to 2009-10-08

Jurisdiction . . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	X	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated . . . . . N

Corporation is related . . . . . N

Number of associated corporations . . .

Type of corporation . . . . . Corporation Controlled by a Public Corporation

Total amount due (refund) federal and provincial* . . . . . -85,386

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income	172,192
Taxable income	172,192
Donations	
Calculation of income from an active business carried on in Canada	172,192
Dividends paid	
Balance of the low rate income pool at the end of the previous year	
Balance of the low rate income pool at the end of the year	
Balance of the general rate income pool at the end of the previous year	
Balance of the general rate income pool at the end of the year	
Part I tax (base amount)	65,433
Surtax	

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I	32,717	ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	200,000
Political contributions		Other*		Surtax credit	
Investment tax credits		Provincial or territorial tax	81,897	Other*	
Abatement/Other*	32,716				

Balance due/refund (–) -85,386

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryback amounts

Investment tax credits	
Non-capital loss	
Capital loss	
Farm loss	
Restricted farm loss	
Surtax credit	
Part I tax credit (Schedule 42)	
Federal foreign non-business income tax credit	

Carryforward balances

RDTOH	
Charitable donations	
Gifts to Canada, a province or a territory	

Summary of federal carryforward/carryback information (continued)

Gifts of certified cultural property	
Gifts of certified ecologically sensitive land	
Gifts of medicine	
Investment tax credits	
Non-capital losses	
Capital/L.P.P. losses	
Farm losses	
Restricted farm losses	
Current year's balance of SR&ED expenditures (T661)	
Foreign business tax credit	
Unused surtax credit (Schedule 37)	
Capital dividend amount	
Part I tax credit (Schedule 42)	
Cumulative eligible capital	10,953,560
Capital gains reserves	
Financial statement reserve	
Other reserves	
Balance of patronage dividends	
Continuity of exemption of accumulated income	

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	N/A		
Taxable income	N/A		
% Allocation	100.00		
Attributed taxable income			
Surtax		N/A	N/A
Tax payable before deduction*	24,107		
Deductions and credits			
Net tax payable	24,107		
Attributed taxable capital	91,310,872		N/A
Capital tax payable**	56,287		N/A
Total tax payable***	81,897		
Instalments and refundable credits			
Balance due/Refund (-)	81,897		

* For Québec, this includes special taxes and logging operations.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

	British Columbia	Saskatchewan	Manitoba
% Allocation			
Attributed taxable income			
Tax payable before deduction*			
Deductions and credits			
Tax payable or refundable credit			
Attributed taxable capital			
Capital tax payable**			
Instalments and refundable credits			
Balance due/Refund (-)			

* For British Columbia, this includes the Logging Tax Payable.

** For Manitoba, this includes the Outstanding Balance Excluding Instalments.

Summary of provincial information – provincial income tax payable (continued)

	Newfoundland and Labrador	Prince Edward Island	Nova Scotia	New Brunswick
% Allocation				
Attributed taxable income				
Tax payable before deduction				
Deductions and credits				
Tax payable or refundable credit				
Attributed taxable capital				
Capital tax payable				
Instalments and refundable credits				
Balance due/Refund (-)*				

* Only applies in the case of bank, a loan corporation or a trust corporation.

	Yukon	Northwest Territories	Nunavut
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			

Summary of provincial carryforward amounts

	Québec	Alberta
Non-capital losses		
Net capital/L.P.P. losses		
Farm losses		
Restricted farm losses		
Donations		
Capital gains reserves		
Financial statement reserves		
Other reserves		
Eligible capital	10,953,560	10,953,560
Other carryforward amounts		
Ontario		
Transitional tax credit – Schedule 506		
Ontario research and development tax credit – Schedule 508		
Corporate minimum tax credit that can be carried forward over 20 years – Schedule 510		1,503
Corporate minimum tax credit that can be carried forward over 10 years – Schedule 510		
Corporate minimum tax loss that can be carried forward over 20 years – Schedule 510		
Corporate minimum tax loss that can be carried forward over 10 years – Schedule 510		
Ontario political contributions tax credit that can be carried forward over 20 years – Schedule 525		
Québec		
R&D expenditures not deducted at the end of the year – RD-222		
Tax credit for fees and dues paid to a research consortium – RD-1029.8.9.03		
Foreign non-business income tax credits – CO-17S.39		
Non-refundable tax credit for resources – 1029.8.36.EM		
Investment Tax Credit – CO-1029.8.36.IN		
Development work expenses – FM220.3		
Excess development work expenses – FM220.3		
Balance of patronage dividends – CO-786		
Alberta		
Unclaimed SR&ED expenditure pool deduction balance – A16		
British Columbia		
Scientific research and experimental development – Schedule 425		
Manufacturing and processing – Schedule 426		
Manitoba		
Research and development – Schedule 380		
Manufacturing investment – Schedule 381		
Co-op education and apprenticeship – Schedule 384		
Odour control – Schedule 385		
Community enterprise investment – Schedule 387		
Saskatchewan		
Royalty tax rebate – Schedule 400		
Manufacturing and processing investment – Schedule 402		
Research and development – Schedule 403		
Newfoundland and Labrador		
Direct equity tax – Schedule 303		
Prince Edward Island		
Investment – Schedule 321		
Nova Scotia		
Energy efficiency tax credit – Schedule 342		
Manufacturing and processing investment – Schedule 344		
New Brunswick		
Research and development – Schedule 360		
Nunavut		
Investment – Schedule 480		

CAPITAL STRUCTURE AND COST OF CAPITAL

Overview

The purpose of this evidence is to summarize the capital structure, method and cost of financing API's capital requirements for the 2010 and 2011 Test Years.

Capital Structure

API's current OEB-approved capital structure for rate making purposes is 50.0% debt and 50.0% equity. The Applicant proposes a 2010 and 2011 Test Year deemed capital structure for rate making purposes of 60.0% debt and 40.0% equity. This capital structure was determined by the OEB in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* dated December 20, 2006 (the "Board Report"). The 60.0% debt component is comprised of 4.0% deemed short-term debt and 56.0% deemed long-term debt.

API's capital structure consists of affiliated debt and common equity. The actual capital structure is managed to approximate the Board Report.

API Capital Structure

	2009		2010		2011	
($'000)	Actual		Test Year		Test Year	
Debt	45,600	58%	50,000	60%	50,000	61%
Common equity	32,570	42%	33,332	40%	32,574	39%

At the end of 2011, API pro forma financial statements include bank indebtedness of approximately $7.3 million due to the growth in property, plant and equipment, and significant amount of regulatory assets excluding the impact of increased revenue requirement. The company expects to reduced the bank indebtedness with long-term debt and possibly additional equity.

As required in the Filing Guidelines, Appendix 2-O has been completed for each year and is filed as Exhibit 5, Schedules 2.

Return on Equity

API has used a return on equity ("ROE") of 9.85% in the 2010 and 2011 Test Years as established by the Board for cost of service applications with a May 1, 2010 implementation date. The Applicant recognizes that the ROE will be updated in accordance with Board guidelines.

Cost of Debt

In October 2009, API issued a Demand Promissory Note to FortisOntario in the amount $45.6 million which bears interest at 7.62%. A copy of the Demand Promissory Note is included in the Exhibit 5, Tab 1, Schedule 3. The Board Report states "for new affiliated debt, the Board has determined that the allowed rate will be the lower of the contracted rate and the deemed long-term debt rate"[1]. API has used a deemed long-term debt rate of 5.87% in the 2010 and 2011 Test Years as established by the Board for cost of service applications with a May 1, 2010 implementation date. The Applicant recognizes that the deemed long-term debt rate will be updated in accordance with the Board guidelines. Furthermore, API has engaged CIBC World Markets to assist with the private placement of approximately $45-$50 million in senior unsecured third party debt to replace the existing affiliated debt. API expects the private placement to be completed during 2010. The company also expects the cost of debt for the Test Years for API to be established using the interest rate from the third party debt and related debt issue costs. API will update the evidence once the third-party debt has been issued and the associated rate is known. Specifically, the average weighted cost of debt will be provided for the Test Years.

The above mentioned third party debt is being issued by API and not by FortisOntario. However, management is contemplating a strategy to issue future debt for regulated utilities at the parent company level, i.e., FortisOntario, in order to pool the third party debt. CNPI and Cornwall Electric both have senior unsecured third party debt outstanding which matures in 2018 with a combined balance of $52 million. CIBC World Markets has advised that issuing $100 million of private placement should result in a lower interest rate then a $45-50 million issue because the number of interested debt investors increases at the $100 million threshold. Furthermore, debt investors expect a liquidity premium for issues of less than $100 million. FortisOntario would likely be required to establish a credit rating from a credit rating agency.

[1] Board Report, page 13

The lower interest rate obtained by pooling the debt at FortisOntario, including the debt issue costs and administration fees, would be passed onto the ratepayers of API, CNPI, and Cornwall Electric.

The Board has determined in the Board Report that "the short-term debt amount will be fixed at 4% of rate base"[2]. API has used a deemed short-term debt rate of 2.07% for the 2010 and 2011 Test Years as established by the Board for cost of service applications with a May 1, 2010 implementation date. The Applicant recognizes that the short-term debt rate will be updated with Board guidelines.

Cost of Capital

API's 2010 cost of capital is $5,081,000 which results in a return on rate base of 7.31%.

2010 Cost of Capital

($'000)

	Amount	**%**	**Cost Rate**	**Return**
Long-term debt	38,925	56.0%	5.87%	2,285
Short-term debt	2,780	4.0%	2.07%	58
Common equity	27,804	40.0%	9.85%	2,739
Total	**69,509**	**100%**	**7.31%**	**5,081**

2011 Cost of Capital

($'000)

	Amount	**%**	**Cost Rate**	**Return**
Long-term debt	43,044	56.0%	5.87%	2,527
Short-term debt	3,075	4.0%	2.07%	64
Common equity	30,746	40.0%	9.85%	3,028
Total	**76,865**	**100%**	**7.31%**	**5,619**

[2] Board Report, page 9

Appendix 2-O – 2011 Test Year

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($'000)	(%)	($'000)
	Debt					
1	Long-term Debt	56.00%		$43,044	5.87%	$2,527
2	Short-term Debt	4.00%	(1)	$3,075	2.07%	$64
3	**Total Debt**	60.0%		$46,119	5.62%	$2,590
	Equity					
4	Common Equity	40.00%		$30,746	9.85%	$3,028
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$30,746	9.85%	$3,028
7	**Total**	100.0%		$76,865	7.31%	$5,619

Notes

(1) 4.0% unless an applicant utility has proposed or been approved for a different amount.

Appendix 2-O – 2010 Test Year

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($000)	Cost Rate (%)	Return ($000)
	Debt					
1	Long-term Debt	56.00%		$38,925	5.87%	$2,285
2	Short-term Debt	4.00%	(1)	$2,780	2.07%	$58
3	**Total Debt**	60.0%		$41,705	5.62%	$2,342
	Equity					
4	Common Equity	40.00%		$27,804	9.85%	$2,739
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$27,804	9.85%	$2,739
7	**Total**	100.0%		$69,509	7.31%	$5,081

Notes

(1) 4.0% unless an applicant utility has proposed or been approved for a different amount.

Appendix 2-O – 2009 Actual

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($000)	Cost Rate (%)	Return ($000)
	Debt				
1	Long-term Debt	50.00%	$32,743	6.10%	$1,997
2	Short-term Debt	(1)	$ -		$ -
3	**Total Debt**	50.0%	$32,743	6.10%	$1,997
	Equity				
4	Common Equity	50.00%	$32,743	8.57%	$2,806
5	Preferred Shares		$ -		$ -
6	**Total Equity**	50.0%	$32,743	8.57%	$2,806
7	**Total**	100.0%	$65,485	7.34%	$4,803

Notes

(1) 4.0% unless an applicant utility has proposed or been approved for a different amount.

Appendix 2-O – 2008 Actual

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($000)	Cost Rate (%)	Return ($000)
	Debt				
1	Long-term Debt	50.00%	$31,372	6.10%	$1,914
2	Short-term Debt	(1)	$ -		$ -
3	**Total Debt**	50.0%	$31,372	6.10%	$1,914
	Equity				
4	Common Equity	50.00%	$31,372	8.57%	$2,689
5	Preferred Shares		$ -		$ -
6	**Total Equity**	50.0%	$31,372	8.57%	$2,689
7	**Total**	100.0%	$62,743	7.34%	$4,602

Notes

(1) 4.0% unless an applicant utility has proposed or been approved for a different amount.

Appendix 2-O – 2007 Actual

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($000)	Cost Rate (%)	Return ($000)
	Debt				
1	Long-term Debt	50.00%	$28,887	6.10%	$1,762
2	Short-term Debt	(1)	$ -		$ -
3	**Total Debt**	50.0%	$28,887	6.10%	$1,762
	Equity				
4	Common Equity	50.00%	$28,887	8.57%	$2,476
5	Preferred Shares		$ -		$ -
6	**Total Equity**	50.0%	$28,887	8.57%	$2,476
7	**Total**	100.0%	$57,774	7.34%	$4,238

Notes

(1) 4.0% unless an applicant utility has proposed or been approved for a different amount.

Appendix 2-O – 2007 Board Approved

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($000)	(%)	($000)
	Debt					
1	Long-term Debt	50.00%		$28,760	6.10%	$1,754
2	Short-term Debt	0.00%	(1)	$ -	0.00%	$ -
3	**Total Debt**	50.0%		$28,760	6.10%	$1,754
	Equity					
4	Common Equity	50.00%		$28,760	8.57%	$2,465
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	50.0%		$28,760	8.57%	$2,465
7	**Total**	100.0%		$57,519	7.34%	$4,219

Notes

(1) 4.0% unless an applicant utility has proposed or been approved for a different amount.

EXHIBIT 5, TAB 1, SCHEDULE 3

Algoma Power Inc.

PROMISSORY NOTE

$45,600,000 **DUE: ON DEMAND**

RATE: 7.62% ANNUALLY

FOR VALUE RECEIVED Algoma Power Inc. ("API") hereby promises to pay on demand to or to the order of FortisOntario Inc. ("FortisOntario") at 1130 Bertie Street, P.O. Box 1218, Fort Erie, ON L2A 5Y2, the principal amount of $45,600,000 in lawful money of Canada and to pay interest both before and after demand, default and judgement at the rate of 7.62% per annum calculated quarterly not in advance on the principal amount, said interest to be payable on November 30, February 28, May 31 and August 31, in each year commencing on the 30th day of November, 2009.

The principal amount outstanding under this promissory note from time to time and all accrued interest thereon shall become due and be paid in full upon demand being made by FortisOntario therefore.

API hereby waives demand and presentment for payment, notice of non-payment, protest, notice of protest, notice of dishonour, bringing of suit and diligence in taking any action.

DATED at Fort Erie, Ontario, as of this 8th day of October, 2009.

ALGOMA POWER INC.

W. J. Daley

WILLIAM J. DALEY
PRESIDENT AND CHIEF EXECUTIVE OFFICER

GLEN KING
VICE PRESIDENT, FINANCE AND CHIEF FINANCIAL OFFICER

Tor#: 2444739.1

CALCULATION OF REVENUE REQUIREMENT AND REVENUE DEFICIENCY/SUFFICIENCY

Introduction

This Exhibit 6 provides a summary of the revenue required by Algoma Power in the 2010 and 2011 Test Years in order to continue distributing electricity safely and reliably. The Total Service Revenue Requirement is offset by revenues obtained by sources other than distribution rates, i.e., other revenue. The calculation of the revenue deficiency/sufficiency does not include the recovery of Regulatory Assets (Exhibit 9). As directed in the Filing Requirements, costs and revenues related to the cost of power are kept separate from the determination of the distribution revenue deficiency/sufficiency.

The revenue deficiency/sufficiency for the 2010 and 2011 Test Years was calculated using the following inputs:

- 2007 approved rates;
- 2010 and 2011 load forecast and forecast of customers and connections, as developed using the methodology described in Exhibit 3 (Operating Revenue); and
- The base revenue requirement calculation is shown in Table 1 below.

The revenue deficiency/sufficiency was then determined by calculating what the revenue would have been with 2007 rates (not including the smart meter adder and the Regulatory Asset rider) and the forecasted 2010 and 2011 load and customer numbers.

REVENUE DEFICIENCY/SUFFICIENCY

Description		2007 Board Approved	2007 Actual	2008 Actual	2009 Actual	2010 Test Year	2011 Test Year
Distribution Revenue		17,631,884	13,184,373	18,535,556	17,566,544	17,619,307	17,708,704
Operation, Maintenance & Administrative		7,995,724	8,022,318	8,530,565	8,615,754	8,889,236	9,670,207
Depreciation & Amortization		3,607,303	3,559,152	3,727,967	3,651,441	4,056,672	4,512,684
Property Taxes		164,250	163,402	163,956	146,241	150,000	150,000
Capital Taxes (2010 and 2011 Tax Model Output)		123,167	52,047	(39,436)	200,226	49,776	
Total Costs		11,890,444	11,796,920	12,383,051	12,613,662	13,145,684	14,332,891
Utility Income before Taxes		5,741,441	1,387,453	6,152,505	4,952,882	4,473,623	3,375,813
Income tax (2010 and 2011 Tax Model Output)		1,492,000	96,587	1,580,251	833,310	701,262	500,433
Utility Income	**A**	4,249,441	1,290,866	4,572,254	4,119,572	3,772,361	2,875,380
Rate Base	**B**	57,518,786	57,774,016	62,743,449	65,485,469	69,509,146	76,864,742
Indicated Rate of Return	**C=A/B**	7.34%	2.23%	7.29%	6.29%	5.43%	3.74%
Approved/Requested Rate of Return	**D**	7.34%	7.34%	7.34%	7.34%	7.31%	7.31%
(Deficiency)/Sufficiency in Return	**E=C-D**	0.00%	-5.11%	-0.05%	-1.05%	-1.88%	-3.57%
Revenue (Deficiency)/Sufficiency	**F=B*E**	-	(2,949,747)	(33,115)	(687,062)	(1,308,758)	(2,743,432)
Service Revenue Requirement		17,631,884	16,134,120	18,568,672	18,253,606	18,928,065	20,452,136
Less Revenue Offset		(383,884)	(395,713)	(726,826)	(375,362)	(343,057)	(370,082)
Base Revenue Requirement		17,248,000	15,738,406	17,841,846	17,878,244	18,585,008	20,082,054
Add Transformer credit		34,300	46,766	47,885	51,078	51,942	51,942
Less RRRP as Board approved		(8,861,847)	(4,509,821)	(8,861,847)	(8,861,847)	(8,861,847)	(8,861,847)
Revenue to collected in rates		8,420,453	11,275,351	9,027,884	9,067,475	9,775,103	11,272,149

NUMERICAL DESCRIPTION OF DEFICIENCY/SUFFICIENCY

Based upon current rates, the chart below demonstrates that Algoma Power will experience a revenue deficiency in the amount of $1,308,758 in 2010 and $2,743,432 in 2011:

NUMERICAL DESCRIPTION OF REVENUE DEFICIENCY/SUFFICIENCY

	2010		2011	
Cost of Capital				
Rate Base	69,509,146		76,864,742	
Requested Rate of Return	7.31%	5,081,119	7.31%	5,618,813
Cost of Service				
Operation, Maintenance & Administrative	8,889,236		9,670,207	
Depreciation & Amortization	4,056,672		4,512,684	
Property Taxes	150,000		150,000	
Capital Taxes	49,776		-	
Income Taxes	701,262	13,846,946	500,433	14,833,324
Service Revenue Requirement		18,928,065		20,452,136
Operating Revenue				
Distribution Revenue	17,619,307	(17,619,307)	17,708,704	(17,708,704)
Revenue (Deficiency)/Sufficiency		(1,308,758)		(2,743,432)

CAUSES OF REVENUE DEFICIENCY

The table below provides a summary of the causes of the identified revenue deficiency in 2010 Test Year, how much each cause impacts the revenue requirement and the references provide further details:

CAUSES OF REVENUE DEFICIENCY FOR 2010

CAUSE	IMPACT ON REVENUE REQUIREMENT	REFERENCE		
		Exhibit	Tab	Schedule
Increase in Amortization Expense	(449,369)	2	1	1
		4	7	1
		4	7	2
Increase in OM&A Expenses	(893,512)	4	2	2
		4	2	3
		4	3	1
		4	3	2
Change in Income, Capital and Property Taxes	878,379	4	8	1
		4	8	2
		4	8	3
		4	8	4
Increase in Return on Capital	(859,240)	2	1	1
		2	1	2
		2	2	1
		2	2	2
		2	3	1
		2	3	2
		2	3	3
		2	4	1
		2	4	2
		2	4	3
Load Growth	14,984	3	2	1
		3	2	2
Total Deficiency	(1,308,758)			

The main contributors to the increase in the revenue requirement are as follows:

- Increase in amortization expense as a result of additions to the rate base in 2008, 2009 and 2010;

- The increase for OM&A is primarily a result of increased vegetation management and FTE increases over the period from the 2007 Board Approved to the 2010 Test Year;

- The decrease in income taxes is primarily a result of the elimination of the Ontario Capital Tax, lower tax rates from the 2007 Board Approved and the deduction of capitalized overhead for tax purposes;

- An increase in the Return on Capital is a result of continued investment in the distribution infrastructure; and

- The revenue deficiency is reduced by the impact of the forecasted load growth.

COST ALLOCATION OVERVIEW

API's previous Cost of Service rate application, EB-2007-0744, did not include a cost allocation study. In that application, electricity distribution delivery charges continued to be allocated on the basis of historic distribution of revenues to the then existing customer classes.

For this Application, API has commissioned Elenchus Research Associates Inc. ("Elenchus") to prepare a cost allocation. The API Cost Allocation Model is provided with this Application in live Excel Format, API 2010 CA Model_20100601. The cost allocation model follows the format of the 2006 Cost Allocation Methodology for Electricity Distributors (the "guidelines"). Output Sheet O1 Revenue to cost | RR of the Cost Allocation Model has been provided below as Table 4.

API utilized the services of Hydro One Networks Inc. to provide customer load profile information consistent with the Board's guidelines. Weather normalized load forecasts and customer forecasts were provided by Elenchus and are discussed in Exhibit 3.

Table 1 below provides data related to 2010 revenue shares of the customer classes on the basis of historic allocations

Exhibit 7, Tab 1, Schedule 1, Table 1

Customer Class	2010 Forecast of Throughput - kWh	Percentage of Revenue
Residential – R1	104,754,767	73.8%
Residential – R2	70,228,773	10.2%
Seasonal	12,459,994	15.7%
Street Lighting	791,996	0.3%

The Board's guidelines establish targets for class specific revenue-to-cost ratios. These are provided in Table 2.

Exhibit 7, Tab 1, Schedule 1, Table 2

Class Specific Revenue to Cost Ratios Board's Guidelines	
Classification	**Range**
Residential	85% to 115%
General Service Less Than 50 kW	80% to 120%
General Service Greater Than 50 kW	80% to 180%
Street Lighting	70% to 120%

As discussed in Exhibit 7, Tab 1, Schedule 1, (Cost Allocation Overview) it is necessary to align these class specific targets with API's customer classifications. Table 3 below compares the target ranges that were assigned by API consistent with the guidelines, with the results of the Cost Allocation Model.

Exhibit 7, Tab 1, Schedule 1, Table 3

Classification	**Target Range**	**Cost Allocation Model**
Residential - R1	85% to 115%	118.22%
Residential - R2	80% to 180%	36.45%
Seasonal	85% to 115%	151.81%
Street Lighting	70% to 120%	18.97%

The results of the Cost Allocation Study indicate that the Residential – R1 class is over contributing at a revenue-to-cost ratio of 118.22%, but may be considered reasonable when compared to the Board's guidelines for Residential and General Service less than 50 kW which are 115% and 120% respectively.

The Cost Allocation Model indicates that the Seasonal class is over contributing at a revenue-to-cost ratio of 151.81%. This is supported conceptually by its relative contribution to revenue requirement. Seasonal rates were a matter of consideration in the 2007 EDR, EB-2007-0744. In that application, a Seasonal Deferral account was created and an estimated annual shortfall in rates was established to mitigate rate impacts. This deferral account was recognition that the proportion of revenue requirement assigned to the Seasonal class may have been too large.

The Residential – R2 class which is akin to the General Service greater than 50 kW is under contributing with a revenue-to-cost ratio of 36.45%. Contrary to what is evident in the Seasonal class, revenue from the Residential – R2 class accounts for only 10% of the revenue requirement based on historically proportioned revenue shares, despite the fact that it accounts for 38% of throughput and has a significant contribution to peak.

The Street Lighting class is also under contributing with a revenue-to-cost ratio of 18.97%.

Redistribution of the revenue shares and proposed revenue-to-cost ratios are determined and stated in Exhibit 8, Tab 1, Schedule 2, (Rate Design Discussion).

Exhibit 7, Tab 1, Schedule 1, Table 4

2006 Cost Allocation Information Filing

Algoma Power Inc.
EB-2010-0278
Tuesday, June 01, 2010
Sheet O1 Revenue to Cost Summary Worksheet - First Run

Rate Base Assets		Total	1 R1	2 R2	7 Street Light	12 Seasonal
crev	Distribution Revenue (sale)	$17,467,474	$13,157,517	$1,452,342	$47,686	$2,809,928
mi	Miscellaneous Revenue (mi)	$343,057	$217,490	$88,133	$5,003	$32,431
	Total Revenue	**$17,810,531**	**$13,375,007**	**$1,540,474**	**$52,689**	**$2,842,360**
	Expenses					
di	Distribution Costs (di)	$4,762,863	$2,866,301	$1,306,234	$87,720	$502,608
cu	Customer Related Costs (cu)	$1,693,808	$1,394,715	$91,659	$11,235	$196,199
ad	General and Administration (ad)	$2,652,964	$1,737,897	$590,030	$40,563	$284,474
dep	Depreciation and Amortization (dep)	$4,056,672	$2,563,128	$975,345	$70,644	$447,555
INPUT	PILs (INPUT)	$751,038	$456,888	$209,628	$11,219	$73,304
INT	Interest	$2,342,000	$1,424,736	$653,693	$34,985	$228,587
	Total Expenses	**$16,259,345**	**$10,443,665**	**$3,826,589**	**$256,366**	**$1,732,726**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$1,430,361	$870,148	$399,239	$21,367	$139,608
	Revenue Requirement (includes NI)	**$17,689,706**	$11,313,812	$4,225,828	$277,732	$1,872,334
		Revenue Requirement Input equals Output				
	Rate Base Calculation					
	Net Assets					
dp	Distribution Plant - Gross	$101,557,858	$61,697,989	$27,444,170	$1,706,422	$10,709,276
gp	General Plant - Gross	$10,530,382	$6,406,067	$2,939,214	$157,302	$1,027,799
accum dep	Accumulated Depreciation	($46,509,937)	($28,210,059)	($12,079,334)	($884,122)	($5,336,422)
co	Capital Contribution	$0	$0	$0	$0	$0
	Total Net Plant	**$65,578,302**	**$39,893,997**	**$18,304,050**	**$979,602**	**$6,400,653**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$17,166,389	$9,553,250	$6,404,606	$72,227	$1,136,306
	OM&A Expenses	$9,109,635	$5,998,913	$1,987,923	$139,518	$983,281
	Directly Allocated Expenses	$0	$0	$0	$0	$0
	Subtotal	***$26,276,024***	***$15,552,163***	***$8,392,529***	***$211,745***	***$2,119,587***
	Working Capital	**$3,941,404**	**$2,332,825**	**$1,258,879**	**$31,762**	**$317,938**
	Total Rate Base	**$69,519,706**	**$42,226,821**	**$19,562,929**	**$1,011,364**	**$6,718,591**
			Rate Base Input equals Output			
	Equity Component of Rate Base	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income on Allocated Assets	**$1,551,185**	**$2,931,343**	**($2,286,114)**	**($203,676)**	**$1,109,633**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$1,551,185**	**$2,931,343**	**($2,286,114)**	**($203,676)**	**$1,109,633**
	RATIOS ANALYSIS					
	REVENUE TO EXPENSES %	100.68%	118.22%	36.45%	18.97%	151.81%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$120,824	$2,061,195	($2,685,353)	($225,043)	$970,025
	RETURN ON EQUITY COMPONENT OF RATE BASE	0.00%	0.00%	0.00%	0.00%	0.00%

Variation of Cost Allocation Output to Rate Design

The Cost Allocation Study undertaken for API by Elenchus and provided here in Exhibit 7, Tab 1, Schedule 2 discusses, in Section 3.1.5, a variation between API's derivation of revenue requirement and the Cost Allocation Model's derivation of revenue requirement. As discussed in Section 3.1.5, Elenchus adjusted for this variation and produced revenue-to-cost ratios provided in Table 7, Section 4 of its Report. API, in its rate design has used the unadjusted revenue-to-cost ratios which have a 100.68% revenue-to-expense ratio. The differences do not impact the rate design strategy.

The differences are summarized in the table below.

Exhibit 7, Tab 1, Schedule 1, Table 5

Variation in Revenue-to-Cost Ratios		
Class	Elenchus	Rate Design
Residential – R1	117.42%	118.22%
Residential – R2	36.42%	36.45%
Seasonal	150.78%	151.81%
Street Lighting	18.84%	18.97%

Appendix 2-P of the Board's Filing requirements is provided below.

Appendix 2-P
Cost Allocation

Revenue to Cost Ratio (%)

Customer Class	(1) From Cost Allocation Model	(2) Column 1 Revised (Transformer Ownership Allowance)	(3) Proposed for Test Year 2010	(3) Proposed for Test Year 2011	(4) Board Target Range
Residential – R1	118.22%	N/a	117.1%	113.9%	85 – 115
Residential – R2	36.45%	N/a	51.0%	65.5%	80 – 180
Seasonal	151.81%	N/a	116.1%	100.0%	85 – 115
Street Lights	18.97%	N/a	39.3%	59.7%	70 – 120

2010 Test Year Revenue Impacts

Customer Class	Current Revenue	Test Year Revenue Assuming Current Revenue to Cost Ratios	Test Year Revenue Assuming Proposed Revenue to Cost Ratios
Residential – R1	12,748,300	13,999,309	1,3921,390
Residential – R2	1,769,900	1,545,260	2,260,894
Seasonal	2,710,100	2,989,702	2,288,029
Street Lights	53,700	50,737	114,695

2011 Test Year Revenue Impacts

Customer Class	Current Revenue	Test Year Revenue Assuming Current Revenue to Cost Ratios	Test Year Revenue Assuming Proposed Revenue to Cost Ratios
Residential – R1	12,748,300	15,142,387	14,626,532
Residential – R2	1,769,900	1,659,091	3,137,280
Seasonal	2,710,100	3,226,325	2,129,732
Street Lights	53,700	54,251	188,510

COST ALLOCATION STUDY

Following is the Report prepared by Elenchus Research Associates.

Algoma Power Inc.
2010 Cost Allocation Study

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Algoma Power Inc.

May 2010

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1 INTRODUCTION

Algoma Power Inc. ("Algoma") has prepared its 2010 EDR Application as a cost of service rate application based on a forward test year. The relevant filing requirements for this Application are set out in Chapter 2 of the May 27, 2009 update to the *Ontario Energy Board, Filing Requirements for Transmission and Distribution Applications* ("Filing Requirements").

Section 2.8 of the Filing Requirements sets out the expectations of the Board with respect to Exhibit 7: Cost Allocation. The Filing Requirements state:

> *A completed cost allocation study using the Board approved methodology must be filed whether the applicant proposes to use it or not. This filing must*
>
> - *reflect future loads and cost and be supported by appropriate explanations;*
> - *be corrected for transformer ownership allowance ..., and*
> - *be presented in the form of an Excel spreadsheet.*[1]

The Filing Requirements also state that:

> *The Board expects the filings made by the applicant will follow the cost allocation policies reflected in the Board's report of November 28, 2007, Application of Cost Allocation for Electricity Distributors (EB-2007-0667).*

Algoma asked Elenchus Research Associated (Elenchus)[2] to assist it by preparing an appropriate cost allocation study for its 2010 cost of service rate application. In addressing this issue, Elenchus was guided by the Filing Requirements and the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors".[3]

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[1] *Ontario Energy Board, Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, May 27, 2009,* p. 19.

[2] John Todd, President of Elenchus Research Associates, was the lead consultant for the development and implementation of the methodology used by Algoma and documented in this report. John Todd's curriculum vitae are available at www.elenchus.ca.

[3] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

The CA Application Report observes at page 2 that:

> *The Board is cognizant of factors that currently limit or otherwise affect the ability or desirability of moving immediately to a cost allocation framework that might, from a theoretical perspective, be considered the ideal. These influencing factors include data quality issues and limited modelling experience, and are discussed in greater detail in section 2.3 of this Report.*

The "influencing factors" discussed in section 2.3 of the report are:

- **Quality of the data:** The Board notes "that accounting and load data can be improved." (p. 5)
- **Limited modelling experience:** The Board observed that "the cost allocation model is complex, and the data required for the model was not always readily available for modelling." (p. 6)
- **Status of current rate classes:** The Board points out that "Any changes in customer classification or load data could have a significant impact on future cost allocation studies" (p. 6).
- **Managing the movement of rates closer to allocated costs:** The Board notes:

> *The Board considers it appropriate to avoid premature movement of rates in circumstances where subsequent applications of the model or changes in circumstances could lead to a directionally different movement. Rate instability of this nature is confusing to consumers, frustrates their energy cost planning and undermines their confidence in the rate making process. (p. 6)*

In utilizing the Board's cost allocation model for Algoma's 2010 cost allocation study, Elenchus has been cognizant of these "influencing factors" as they apply to Algoma. In particular, Algoma is filing its 2010 CA Model as its first Cost Allocation Model. It is not possible for Algoma to produce a comparable 2006 CA Model given the changes to its rate structure in 2009 arising from the implementation of Ontario Regulation 445/07 "Reclassifying Certain Classes of Consumers as Residential Class Customers: Section 78 of the Act.

1.1 PURPOSE OF THE COST ALLOCATION STUDY

In the context of a cost of service rate application based on a 2010 forward test year, the primary purpose of the cost allocation study ("CA Study") is to determine the

proportions of a distributor's total revenue requirement that are the "responsibility" of each rate class.

In addition, cost allocation studies provide revenue to cost ratios for each customer class that can be examined to ensure that they generally fall within the Board-specified ranges (or move toward those ranges where appropriate to mitigate rate impacts) and generally are not moving away from 100%.

Conceptually, the desired results can be achieved in either of two ways.

- **Prospective Year CA Study:** A cost allocation study for the 2010 test year can be based on an allocation of the 2010 test year costs (i.e., the 2010 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc. By definition, this approach will result in a total revenue to cost ratio at proposed rates of 100%. Assuming there is a revenue deficiency for the test year, the total revenue to cost ratio at current rates will be somewhat below 100%.

- **Historic Year CA Study:** As an alternative, an historic year cost allocation study can be prepared that determines the proportion of costs allocated to each class for the most recent historic year. In this case, the CA Study would rely on actual historic year costs, weather adjusted loads, customer counts, etc. that are not affected by forecast errors. Assuming the costs and loads are relatively stable so that the proportionate cost responsibility of each rate class in the historic year is a reasonable proxy for the 2010 test year cost responsibility, the resulting proportionate cost responsibilities could be used to allocate the 2010 revenue requirement to the various classes.

The Algoma CA Study uses the first of these methods in order to ensure compliance with the Board's direction in the Filing Requirements that the CA Study should "reflect future loads and cost". Relying on a Prospective Year CA Study is also appropriate at this time since the Ontario economy has suffered in recent years and, as a result, many distributors have experienced significant changes in the load profiles of their customer classes. These changes could have a significant impact on the allocation of costs to the classes and the resulting revenue to cost ratios. This approach implicitly assumes that

the economic recovery will be slow and, as a result, the relative loads of customer classes are more likely to reflect 2010 loads than 2008 loads during the next IRM cycle.

1.2 ALGOMA'S 2006 COST ALLOCATION INFORMATION FILING

Previously Great Lakes Power Distribution Inc., Algoma did not complete a 2006 Cost Allocation Information Filing ("CAIF") consistent with the current classification of customers. Given the acquisition and change in management, it is not longer practical to create a 2006 CAIF. Therefore, Algoma is filing a 2010 CAIF without a prior CAIF for comparison.

1.3 STRUCTURE OF THE REPORT

The remainder of this report is divided into three additional sections. Section 2 provides an overview of the Algoma CA Study, explaining each of the model runs (or version of the CA model) included in the study, as well as the load and cost information used for each run. Section 3 explains the methodology used to develop the 2010 Algoma model by documenting each step taken in completing the model. Section 4 summarizes the results of the Algoma CA Study, showing the class revenue requirements and revenue to cost ratios generated.

2 OVERVIEW OF THE ALGOMA 2010 CA STUDY

2.1 MODELS RUNS INCLUDED IN THE ALGOMA COST ALLOCATION STUDY

Section 2.8.3 of the updated Filing Requirements specifies that "three sets of revenue to cost ratios for each customer class" are to be provided based on:

- "the initial cost allocation model" which is the 2006 cost allocation information filing ("CAIF");
- "the initial cost allocation model revised with the adjusted transformer ownership allowance" which is the 2006 cost allocation information filings, adjusted in accordance with section 2.8.2 of the updated Filing Requirements; and
- "the updated cost allocation model" which is the appropriate 2010 model.

However, since Algoma has not previously filed a CAIF, and it was not feasible to create a retrospective CAIF, only one version of the model is provided.

- **API-2010: Algoma 2010 Model**: The 2010 CAIF created as per Chapter 2 of the May 27, 2009 update to the Filing Requirements.

2.2 LOAD AND CUSTOMER INFORMATION

The updated Filing Requirements specify that "the updated model must be consistent with the load forecast and costs in the test year ... If updated load profiles are not available, the load profiles of the classes may be the same as those used in the information filing scaled to match the load forecast." (Section 2.8.1, pp. 19-20)

The Algoma 2010 model has been prepared using the following load and load profile information:

- **Annual Loads (kW and kWh, as appropriate) and customer counts:** The 2010 load forecast and customer counts by class being used by Algoma in its application were also used for the 2010 CA models. Algoma's load forecast was prepared by Elenchus.

- **Hourly load profile:** The hourly load profiles prepared by Hydro One for the 2006 CAIF were used with one necessary modification: two of the classes included in the Hydro One analysis have been combined to reflect the class structure used by Algoma for the test year. The R1 class is composed of the customers classified as Residential as well as those classified as GS < 50 in the earlier Hydro One analysis. Hence, the R1 load profile was derived by combining the load profiles contained in the Hydro One file for those classes. Similarly, the R2 class is composed of the customers classified as GS > 50 and Large User by Hydro One, so the R2 load profile was taken to be the sum of those two classes.

The hourly load profiles provided by Hydro One for all of the remaining classes for the 2006 model were considered to be appropriate for use in the 2010 models for the following reasons.

1. Elenchus explored alternatives for updating the hourly load profiles by rate class comparable to the estimated load profiles that Hydro One prepared for the LDCs for their 2006 CA Models. Hydro One advised that they no longer have the capacity to produce a significant number of LDC-specific hourly load profiles. As far as Elenchus is aware, no other entity has the necessary information and models to produce comparable quality hourly load profiles for Ontario LDCs. It therefore was not practical for distributors to update their hourly load profiles by class except in exceptional circumstances.

2. There would be little point in investing in updated load profiles without also investing in updated saturation surveys for the residential class in each service area. These are expensive and time consuming to undertake as they involve a survey of a statistically significant sample of customers.

3. With the widespread rollout of smart meters and the collection of smart meter data, Ontario distributors will have better hourly load profile by class data than the Hydro One estimates. Unless there is evidence of a significant change in circumstances, investing in new hourly load profile by class estimates would be a questionable use of ratepayer funds when superior hourly load profile information will be available in the next few years at minimal incremental cost.

4. Both time-of-use commodity pricing and changes to the design of distribution rates can be expected to alter the hourly load profiles of the affected classes.

5. The revenue-to-cost ratio bands set out in the CA Application Report appear to recognize the lack of precision in cost allocation studies at this time.

2.3 COST INFORMATION

As noted earlier, Elenchus's preferred methodology for preparing 2010 cost allocation models is to use the prospective 2010 test year as the basis for the CA Study, assuming appropriate expense and asset information is available for the 2010 test year. In the case of Algoma, the financial information for the forecast year has been prepared at the USoA level consistent with the level of detail embedded in the OEB's cost allocation model. [4]

[4] Some information (i.e., late payment charges) that is used in the Board's CA Model is not explicitly forecasted for the test year. These values were estimated using scaling factors based on prior year ratios. For example, the proportion of late payment charges assigned to each class was assumed to be constant. The portion of the total costs accounted for in this manner was too small for any plausible estimation errors to have a significant impact on the test year revenue to cost ratios.

3 ALGOMA COST ALLOCATION STUDY METHODOLOGY

This section documents Elenchus's methodology for the Algoma Cost Allocation Study.

3.1 2010 ALGOMA CA MODEL

3.1.1 HOURLY LOAD PROFILE (HONI FILE)

HONI provided data files with three worksheets that were to be used as input to the 2006 CAIF, although the 2006 CAIF was not completed by the Great Lakes Power:

- **Data Summary:** actual and weather normalized monthly kWh by class, disaggregated by weather sensitive and non-weather sensitive load for relevant classes.
- **Hourly Load Shape by Class:** GWh by class for each hour in 2004.
- **Input to Cost Allocation Model**: The 1CP, 4CP, 12CP, 1NCP, 4NCP, 12NCP allocators are derived from the hourly load profiles.

The Algoma hourly load shapes derived by Hydro One for the 2006 CAIF were not updated. However, the demand allocators derived by Hydro One for the 2006 CAIF were revised to reflect changes in the relative loads for the classes from 2004 to 2010. This was done by scaling the hourly load profiles of each class on the Hourly Load Shape by Class worksheet of the HONI file to levels consistent with the 2010 load forecast while maintaining the hourly load shapes.

3.1.2 DEMAND ALLOCATORS (HONI FILE)

The demand allocators used in the API-2010 CA model were derived using the same methodology as Hydro One used for the 2006 file; however, they were re-determined using the forecast 2010 hourly load profiles resulting from the preceding step. Using the 2010 hourly load profiles by class, the 12 monthly coincident and non-coincident peaks for the rate classes were determined on the Hourly Load Shape by Rate Class worksheet. The allocators were then derived as follows for the current class structure (i.e., combining previous classes as discussed above).

- The 1, 4 and 12 NCP values for each class were calculated by selecting the peak in the year (1 NCP), summing the four highest monthly peaks (4 NCP) and summing the 12 monthly peaks for each class (12 NCP), respectively.
- The total 1, 4 and 12 NCP values are the totals of the corresponding class NCP values.
- The 1, 4 and 12 CP values for each class were derived by identifying the hour in each month when the coincident peak occurred and then selecting the peak in the year (1 CP), adding the demands during the four highest coincident peak hours (4 CP) and summing the demand for each class during the 12 monthly coincident peak hours (12 CP), respectively.
- The total 1, 4 and 12 CP values are the totals of the corresponding class CP values, which are the values used to identify the relevant coincident peak hours.

3.1.3 2010 Demand Data (API-2010 Model)

The demand allocators derived in the updated Hydro One file as described in the preceding section were input at the appropriate cells at sheet I8 Demand Data of the 2010 Algoma CA Model. However, the Line Transformer and Secondary 1NCP, 4NCP and 12NCP values (rows 57-58, 63-64, 69-70) for GS > 50 are not equal to the full class NCP values since not all R2 customers use these facilities. The Line Transformer and Secondary 1NCP, 4NCP and 12NCP values were therefore determined from the full load data NCP values using the ratio of values in the 2006 CA Model.

3.1.4 2010 Customer Data (API-2010 Model)

The 30 year weather normalized kWh by rate class which was an input from the Hydro One file at Sheet I6 Customer Data row 27 in the 2006 CA model was populated with the 2010 load forecast in the 2010 CA Model.

In addition, the demand data (kW and kWh) in rows 21, 22, 23, 25, and 56 of Sheet I6 Customer Data were populated with the forecasted values.

The 2010 Distribution Revenue in row 29 was derived by Algoma using the forecast demand (kW and kWh) and customer counts by rate class, the proposed 2010 rates plus the allocated revenue associated with Rural or Remote Electricity Rate Protection ("RRRP").

3.1.5 2010 Revenue to Cost Ratios

Since Algoma is proposing to set rates that recover its full revenue requirement, the total revenue to cost ratio at proposed rates will be 100% in 2010. Due to a minor variance between Algoma's derivation of its revenue requirement for rate setting purposes and the Cost Allocation model's determination of the revenue requirement, the total revenue to cost ratio at proposed rates across all classes derived by the cost allocation model exceeds 100%. An adjustment has therefore been made on I6, Line 79 to correct for the understatement of the revenue requirement in the cost allocation model so that the class specific revenue to cost ratios are consistent with a total revenue to cost ratio of 100%.

4 SUMMARY OF REVENUE TO COST RATIOS

The class revenue to cost ratios as determined in the Algoma cost allocation model are shown in Table 7, below.

Table 7: Revenue to Cost Ratios

Customer Class	API-2010	Board Target Range
R1	117.42	85-115
R2	36.21	80-180
Street Lighting	18.84	70-120
Seasonal	150.78	85-115
Total	100.00	

The API-2010 ratios reflect the 2010 forecast throughput by class, allocated costs and revenues at proposed rates.

Table 8 presents the revenue responsibility (i.e., allocation of the total revenue requirement to the rate classes). This revenue responsibility is presented in both dollar and percentage terms.

Table 8: Revenue Responsibility by Rate Class

Customer Class	API-2010	
	$	%
R1	11,391,088	63.96
R2	4,254,691	23.89
Street Lighting	279,629	1.57
Seasonal	1,885,123	10.58
Total	17,810,531	100.00

TRANSFORMER OWNERSHIP ALLOWANCE

API has an approved Transformer Ownership Allowance, EB-2007-0744, of $0.60 per kW applicable to customers in the Residential – R2 class that own their own transformation. A forecast of volumes is provided in Exhibit 8, (Rate Design).

API's existing approved distribution rates, EB-2007-0744, including the Transformer Ownership Allowance, were not based on a cost allocation but rather on an extension of historic allocations. Funding of the Transformer Ownership Allowance has been omitted from the calculations in the 2010 Cost Allocation.

The rates and charges associated with the Residential – R2 class is subject to RRRP funding and rate design is limited by the Board's Decision and Order, EB-2007-0744.

API proposes in this Application to maintain the currently approved Transformer Ownership Allowance for the 2010 and 2011 Test Years.

RATE RECOVERY OVERVIEW

INTRODUCTION

As a result of regulations made under the *Ontario Energy Board Act* (the "OEB Act"), API must take a unique approach to revenue recovery. The regulations affect the recovery of revenue through the provision of a payment under the Rural and Remote Rate Protection regime ("RRRP"). The setting of rates is affected by the reclassification of some customers to the Residential rate class.

To explain API's approach to revenue recovery and rates, API describes below the regulatory regime established by the regulations.

REGULATORY REGIME

The regulations made under the *OEB Act* result in the reclassification of some of API's customers and provide a mechanism to establish an annual payment of funds to API under the RRRP regulation.

Reclassification

Ontario Regulation 445/07 made in respect of Section 78 of the *OEB Act* (the "Reclassification Regulation") provides as follows:

> "1. (1) For the purposes of fixing just and reasonable rates under section 78 of the Act, the Board shall ensure that a consumer who falls into one of the following categories shall be treated as residential-rate class consumer if the criteria in subsection (2) are satisfied:
>
> 1. A Consumer who is charged by the distributor as a general service, less than 50 kilowatt demand rate-class customer.
> 2. A consumer who is charged by the distributor for distribution of electricity as having a demand of greater than 50 kilowatt rate-class customer.
>
> (2) A consumer who falls into one of the categories set out in subsection (1) shall be treated as residential-rate class consumer, if,

> (a) the distributor that serves the consumer is licensed to serve in an area of not less than 10,000 square kilometres in size; and
>
> (b) the average customer density for the distributor is less than seven customers per kilometre of distribution line.
>
> (3) The rate classifications to ensure that consumers that fall into a category set out in subsection (1) are treated as residential-rate class consumers if the criteria in subsection (2) are satisfied take effect on the date of the distributor's next rate order made on or after August 15, 2007."

API satisfies the criteria in Section 1(2) above. As a result, with the exception of those customers falling into the Seasonal and Street Lighting rate classes, all of API's customers will fall within the Residential customer class. This reclassification was made effective as a result of the OEB's decision dated October 30, 2008 (EB-2007-0744).

Rural Rate Protection

For rate setting purposes, the Reclassification Regulation is linked with the Rural and Remote Electricity Rate Protection Regulation (O. Reg 442/01) as amended (the "RRRP Regulation").

Calculation of Available Rate Assistance

The amount of rural rate protection is prescribed in subsection 4(3.1) of the RRRP Regulation. Subsection 4(3.1) of the RRRP Regulation states:

> "4. (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)."

Simply put, under subsection 4(3.1) the amount by which forecasted revenue requirement exceeds the forecasted consumer revenue is the amount of rate assistance available to be paid to the distributor. The methodology to calculate forecasted consumer revenue is set out in subsection 4(3.2) of the RRRP Regulation. Subsection 4(3.2) provides:

> "4. (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)."

Under this provision, forecasted consumer revenue for a year is based upon the current rates adjusted for the average increase or decrease in rates approved by the Board for the same rate year. This average adjustment reflects the ratepayers contribution to recovery of any revenue deficiency.

In its decision dated October 30, 2008 (EB-2007-0744), the Board adopted the methodology for the rate adjustment as described in Board Staff Discussion Paper titled Methodology for Determining the Average Adjustment to the Rates of Great Lakes Power Limited (KT1.3) dated March 31, 2008. This discussion paper has been included in Exhibit 8, Tab 1, Appendix A.

The remainder of the revenue sufficient to permit the distributor to recover its revenue requirement is provided by the RRRP payment. No matter the level of revenue requirement established by the Board, if there is a revenue deficiency, rates must rise by the average adjustment to fully recover the established revenue requirement.

RRRP Payment

Paragraph 5 of Section 2 of the RRRP Regulation sets out the eligibility criteria applicable to API for rural rate protection. This paragraph provides that:

> "5. Consumers,
>
> (i) who are treated as residential-rate class consumers 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 kilometres in size, and
> C. the average customer density for the distributor is less than seven customers per kilometre of distribution line."

Based on this provision and paragraph 3 of subsection 4(4) of the RRRP Regulation, all of API's newly re-classified Residential customers are eligible for rural rate protection. This protection does not currently extend to Seasonal and Street Lighting customers. Paragraph 3 of subsection 4(4) of the RRRP Regulation states as follows:

> "4(4) 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."

Because not all of API's customers are eligible to receive rate protection through the RRRP payment, only a portion of the funds available for rate assistance determined according to subsection 4(3.1) listed above would be used for the RRRP payment.

As a result, the determination of rate assistance is a two step process:

1. the determination of funds available for rate assistance; and

2. the allocation of a part of those available funds to eligible customers as a RRRP payment.

The application of this two step process with respect to API is set out in the following sections.

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Methodology for Determining the Average Adjustment to the Rates of Great Lakes Power Limited

Board Staff Discussion Paper

EB-2007-0744

March 31, 2008

INTRODUCTION

Ontario Regulation 442/01 entitled “Rural or Remote Electricity Rate Protection”, (“RRRP”) made under the *Ontario Energy Board Act, 1998* (“the Act”) establishes the rules and eligibility criteria for the application of the RRRP process as it applies to the eligible electricity distributors and their eligible customers/rate classes. This has recently been amended by two Regulations, O. Reg. 335/07 and O. Reg. 446/07. O. Reg. 335/07 amended Section 4 dealing with the “Amount of rate protection: 2004 and 2005” and O. Reg. 446/07 amended Section 2 dealing with “Eligibility for rate protection”.

O. Reg. 335/07 added the following subsections to O. Reg. 442/01 that require the Board to determine a distributor’s (i.e. GLPL’s) forecasted consumer revenues:

> (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.
>
> (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.

Staff’s interpretation of sub-section 3.2 of Section 4 of O. Reg. 442/01 is that it is meant to adjust the revenues received from the rate classes and rates set out for those classes in the most recent rate order made by the Board. That adjustment mechanism has not yet been defined. However, Staff has developed two proposals shown below and seek input from parties as to what issues the Board should consider when reviewing these options.

The main assumptions Board staff used to develop the following options are:

- The data are readily available and in the public domain;
- The calculation is relatively simple and straight forward;

- The data set includes all the bills of each distributor (e.g. the 87 acquired utilities of Hydro One and the 11 Chatham-Kent rate classes).

- The use of the change in the "Delivery" component of bills only for a residential class customer at a consumption level of 1,000 kWh per month is a reasonable proxy for "the average, as calculated by the Board, of any adjustment to rates approved by the Board for other distributors for the same rate year".

OPTION ONE:

The determination of the adjustment factor is based on the year over year percentage change in the simple average of the "Delivery" component (as shown on the "Standard Bill" format) of the Residential 1,000 kWh/month bills for all the distributors (excluding GLPL) whose rates have changed in the period (excluding the three First Nations distributors and Hydro One Remote Communities because of their unique situations), rounded to one decimal point. This reflects the level of a bill issued on May 1, 2007 compared to a bill issued on May 1, 2006.

The Delivery component includes the Monthly Service Charge, the Volumetric Distribution component, and the charges associated with the cost of transmission.

Based on data presently available and excluding those distributors that did not have a rate change between May 1, 2006 and May 1, 2007, GLPL and the previously noted distributors, the simple average level of the Delivery component for the May 1, 2006 bill was $40.15. Similarly, the simple average level of the Delivery component for the May 1, 2007 bill was $41.01. The difference is an increase of $0.86 or 2.15%, rounded to 2.2%.

Details for this determination are found in Appendix A.

OPTION TWO:

Similar to Option One but the percentage change will be based on the weighted average (by residential customers) rather than the simple average. Therefore, for example, the impact of the change in the bills for the nearly 600,000 Toronto Hydro residential customers will be more important than the impact of the change in the bills for the nearly 600 Grand Valley Energy residential customers.

Based on data presently available and excluding those distributors that did not have a rate change between May 1, 2006 and May 1, 2007, GLPL and the previously noted distributors, the resulting percentage increase from May 1, 2006 to May 1, 2007 of the weighted calculation is 1.31%, rounded to 1.3%.

Details for this determination are found in Appendix B. It should be noted that the 2006 customer data comes from the Board's 2006 Yearbook. The breakdown of the number residential customers for those distributors that have multiple service areas, such as Hydro One or Chatham-Kent, is not available. As a result, the calculation took the simple average of the distributor's values and applied that to the number of customers.

QUESTIONS

1. Are the assumptions reasonable?

2. Is the proposed method to determine the average rate adjustment consistent with the requirements as outlined in Ontario Regulation 442/01, as amended by O. Reg. 335/07?

3. The proposed method uses the rates in effect on May 1, 2006 and on May 1, 2007 to calculate the bills. Some distributors had rate changes subsequent to May 1, 2007 during the calendar year of 2007. Should the calculation include rate adjustments made known after a specific date? If not, what should be the last date of inclusion?

Attachments:

- Appendix A – Option One Calculations
- Appendix B – Option Two Calculations

RATE DESIGN

API has used an EXCEL Spreadsheet to perform rate design of the fixed and variable components of the electricity distribution delivery charges. The live version of this spreadsheet, API_RateDesignModule_20100607Ad1, accompanies this application.

The basic components of the rate design are:

- The customer forecast, Exhibit 3, Tab 2, Schedule 1
- The weather normalized forecast, Exhibit 3, Tab 2, Schedule 1
- The 2007 Board Approved rates and volumes, Draft Rate Order, EB-2007-0744 and the Rate Order, EB-2007-0744, December 24, 2008
- The Cost Allocation Study, Exhibit 7, Tab 1, Schedule 2
- Simple average increase in Delivery Charge as provided by Board staff on June 7, 2010 using method Option One in Exhibit 8, Tab 1, Appendix A.

As described in Exhibit 8, Tab 1, Schedule 1, rate changes associated with the Residential R – 1 and Residential R – 2 classes are designed on the basis of the simple average increase in Delivery Charge per Ontario Regulation 442/01. API has used estimated increases of 5.5% for 2010 and 2.0% for 2011. These values were provided by Board staff on June 7, 2010.

The rate changes associated with the Seasonal and Street Lighting classes have been designed to fully recover the proportion of revenue requirement from rates that have been allocated to those classes by the Cost Allocation Model with a strategy to achieve Board guideline targets over a three year timeframe.

The seasonal deferral amount and the street light annual shortfall[1] that were described in the Board's Decision and Order have been eliminated in this rate design.

[1] Board's Decision and Order, EB-2007-0744, October 30, 2008, page 37

The results of the rate design are detailed in Table 1 below.

Exhibit 8, Tab 1, Schedule 2, Table 1

2007 Board Approved Tariff, EB-2007-0744				Proposed		
Delivery Charges				Delivery Charges		
Monthly Rates and Charges	**Metric**	**Effective September 2007**		**Proposed July 1, 2010**		**Proposed January 1, 2011**
Residential - R1						
Monthly Service Charge	$	20.41		21.53		21.96
Distribution Volumetric Rate	$/kWh	0.0287		0.0303		0.0309
Residential - R2						
Monthly Service Charge	$	596.12		628.91		641.48
Distribution Volumetric Rate	$/kW	2.4549		2.5899		2.6417
Seasonal						
Monthly Service Charge	$	24.00		24.00		24.00
Distribution Volumetric Rate	$/kWh	0.0700		0.0993		0.0852
Street Lighting						
Monthly Service Charge	$	-		0.98		1.08
Distribution Volumetric Rate	$/kWh	0.0496		0.1292		0.2208
Rural and Remote Rate Protection	$	8,861,800		10,186,621		11,596,870

The Rural and Remote Rate Protection ("RRRP") funding that is applicable to the Residential class (R1 and R2) pursuant to O. Reg. 442/01 is calculated as described in Exhibit 8, Tab 1, Schedule 1. The RRRP required in the Test Years is shown in Table 2.

Exhibit 8, Tab 1, Schedule 2, Table 2

2010 and 2011 Rural and Remote Rate Protection Funding Requirement	
2010	$10,186,621
2011	$11,596,870

Discussion of Methodology

The methodology used to determine distribution rates is discussed here by referencing the Tab names in the Excel Spreadsheet, API_RateDesignModule_20100607Ad1, accompanying this Application.

Tariff Sheet

This tab summarizes the delivery rates determined in the model.

Forecast Data

This is a summary of the weather normalized load forecast and the customer forecast for the Test Years.

2007 GLP DRO

This tab summarized the final determinations of the Board's Decision and Order, EB-2007-0744. The lower section of the table determines the class specific distribution rates that were necessary to recover, through fixed and variable rates, all of the revenue requirement including;

- Revenue from rates,
- RRRP revenue,
- Seasonal Deferral amount, and
- Revenue shortfall.

The fixed charge has been held constant so that the volumetric rate for all classes recovers the additional amounts described above.

Customer Forecast

This is the monthly forecast of customers per rate class and is the same as those described in Forecast Data tab.

2010 Dx Revenue Forecast

This tab calculated the 2010 revenue requirement by class based on the 2007 rates determined in tab "2007 GLP DRO" and the customers and volumes from tab "Forecast Data".

2011 Dx Revenue Forecast

This is the same exercise as tab "2010 Dx Revenue Forecast" and calculated the 2011 revenue from rates.

Cost Allocation Sheet O1

This is the output sheet from the Cost Allocation Study, Exhibit 7, Tab 1, Schedule 2.

2010 Cost Allocation Design

This tab proportions the revenue requirement determined in tab 2010 "Dx Revenue Forecast" to achieve the Board's targets related to cost allocation. In this tab Residential R -1, Residential R -2 and Street Lighting are all moved to their closest boundary of the Board's range using annual increments of one third of the difference between the actual revenue-to-cost ratio and the closest boundary. This would require three years to move all customer classes into the Board's range.

The Seasonal class is the beneficiary of the movement of the other classes.

2010 Allocated Revenues

Using the class allocated revenues from tab "2010 Cost Allocation Design", this tab calculates the class specific rates required to recover the revenue requirement from rates. The monthly service charges have been held constant in this tab.

2011 Cost Allocation Design

This tab serves the same function as tab "2010 Cost Allocation Design" for the 2011 Test Year. The cost allocation review performs the second one third increment to

Board's range. In 2011, the Seasonal class is less than one third increment from 100% recovery, therefore it is set to a cost-to-revenue ratio of 100% and the Residential R – 1 class becomes the beneficiary of the movement in the other classes.

2011 Allocated Revenues

This tab has the same functionality as tab "2010 Allocated Revenues" but for 2011 distribution rates.

2010 RRRP Determination

This tab takes the class revenue requirement for Residential R -1 and Residential R - 2 from tab "2010 Allocated Revenues" then the 2007 Board Approved distribution rates for each class is escalated by the simple average increase of 5.5%. The revenue to be recovered from rates is determined as the product of the 2010 forecasted volumes and the escalated rate components.

The difference between the revenue from rates and the total class revenue requirement is equal to the RRRP funding required.

2011 RRRP Determination

This tab serves the same function as tab "2010 RRRP Determination" and uses a simple average increase of 2.0%.

2010 Non-RRRP Rate Design

This tab takes the class revenue requirement for Seasonal and Street Lighting classes from tab "2010 Allocated Revenues" and determines the rates required to recover the class specific 2010 revenue requirement from rates. For the Seasonal class the fixed monthly charge has been held constant and the marginal revenue requirement is recovered from the variable rate component.

The Street Lighting class had no fixed component in the 2007 rates. In this rate design a fixed component has been introduced and set at the minimum level established in the Cost Allocation Study.

2011 Non-RRRP Rate Design

This tab provides the same functionality as tab “2010 Non-RRRP Rate Design” but for 2011.

A print version of the model is provided here beginning on the following page.

Algoma Power Inc.
Distribution Rate Design Module
2010 Electricity Distribution Rate Application
EB-2009-0278
June 1, 2010
Addendum No. 1 Filed June 7, 2010

2007 Board Approved Tariff, EB-2007-0744				Proposed		
Delivery Charges				Delivery Charges		
Monthly Rates and Charges	**Metric**	**Effective September 2007**		**Proposed July 1, 2010**		**Proposed January 1, 2011**
Residential - R1						
Monthly Service Charge	$	20.41		21.53		21.96
Distribution Volumetric Rate	$/kWh	0.0287		0.0303		0.0309
Residential - R2						
Monthly Service Charge	$	596.12		628.91		641.48
Distribution Volumetric Rate	$/kW	2.4549		2.5899		2.6417
Seasonal						
Monthly Service Charge	$	24.00		24.00		24.00
Distribution Volumetric Rate	$/kWh	0.0700		0.0993		0.0852
Street Lighting						
Monthly Service Charge	$	-		0.98		1.08
Distribution Volumetric Rate	$/kWh	0.0496		0.1292		0.2208
Rural and Remote Rate Protection	$	8,861,800		10,186,621		11,596,870

Algoma Load and Customer Forecast Information										
	2003	2004	2005	2006	2007 Application	2007	2008	2009	2010 Test Year	2011 Test Year
R1										
Number of Customers	7,837	7,763	7,758	7,740	7,740	7,815	7,923	7,997	8,024	8,049
Change in Customer Count		(74)	(5)	(18)		75	109	74	27	25
Kilowatt-hours	108,693,027	105,879,912	103,661,767	99,478,516	104,428,306	100,674,579	103,691,076	103,761,012		
Weather Normalized Kilowatt-hours								103,317,932	104,754,767	106,119,297
Average per Customer - kWh	13,869	13,639	13,362	12,853	13,492	12,883	13,087	12,975		
Normalized Average per Customer - kWh								12,920	13,055	13,184
Seasonal										
Number of Customers	3,577	3,646	3,652	3,707	3,707	3,718	3,688	3,643	3,654	3,665
Change in Customer Count		69	6	55		11	(30)	(45)	11	11
Kilowatt-hours	11,867,258	11,692,754	11,678,117	11,746,043	11,746,043	11,665,351	11,591,418	12,341,792		
Weather Normalized Kilowatt-hours								12,289,090	12,459,994	12,622,297
Average per Customer - kWh	3,318	3,207	3,198	3,169	3,169	3,138	3,143	3,388		
Normalized Average per Customer - kWh								3,373	3,410	3,444
Residential - R2										
Number of Customers	49	49	47	45	47	47	48	48	48	48
Kilowatt-hours		30,337,868	66,360,103	68,290,099	50,139,889	75,340,938	66,017,652	69,931,763		
Kilowatts		163,453	182,693	180,802	197,392	191,492	159,280	150,499		
Weather Normalized Kilowatt-hours								69,808,980	70,228,773	70,606,900
Weather Normalized Kilowatts								150,235	151,138	151,952
Average per Customer - kWh		619,140	1,411,917	1,517,558	1,066,806	1,602,999	1,375,368	1,456,912		
Average per Customer - kW		3,336	3,887	4,018	4,200	4,074	3,318	3,135		
Normalized Average per Customer - kWh								1,454,354	1,463,099	1,470,977
Normalized Average per Customer - kW								3,130	3,149	3,166
Street Light										
Number of Customers	104	103	100	99	99	32	32	32	32	32
Kilowatt-hours	935,668	1,002,422	1,046,222	1,056,913	1,010,306	816,298	791,996	791,996	791,996	791,996
Kilowatts							2,304	2,304	2,304	2,304
Totals										
Number of Customers	11,567	11,561	11,557	11,591	11,593	11,611	11,691	11,720	11,758	11,794
Kilowatt-hours		148,912,956	182,746,209	180,571,571	167,324,544	188,497,166	182,092,142	186,826,563		
Kilowatts		163,453	182,693	180,802	197,392	191,492	161,584	152,803		
Weather Normal Kilowatt-hours								186,207,998	188,235,530	190,140,490
Weather Normal Kilowatts								152,539	153,442	154,256

Table C10 - Revenue Recovery Summary
EB-2007-0744 Draft Rate Order

	2007 Revenue Requirement	Total Rvenue from Rates	RRRP	Approved Deferrals	Total Revenue	Annual Revenue Shortfall
Residential - R1	12,420,000	4,821,500	7,926,800		12,748,300	
Residential - R2	2,098,200	834,900	935,000		1,769,900	
Seasonal	2,710,100	1,880,500		829,600	2,710,100	
Street Lighting	53,800	44,200			44,200	9,500
Totals	17,282,100	7,581,100	8,861,800	829,600	17,272,500	9,500

Simulated Distribution Rates to Recover Total Revenue Requirement
Data From EB-2007-0744 Draft Rate Order

	Metric	Billing Determinant	No. of Customers	Revenue	Monthly Service Charge	Volumetric Distribution Charge	Fixed Revenue Amount	Variable Revenue Amount
Residential - R1	kWh	101,468,266	7,775	12,748,300	20.41	0.1069	1,904,253	10,844,047
Residential - R2	kW	191,492	51	1,769,900	596.12	7.3375	364,825	1,405,075
Seasonal	kWh	11,657,297	3,696	2,710,100	24.00	0.1412	1,064,448	1,645,652
Street Lighting	kWh	891,877	1,052	53,700	-	0.0602	-	53,700
Totals			12,574	17,282,000			3,333,526	13,948,474

Street Lighting based on number of connections

2010 Algoma Customer Count By Rate Class

	Actual		Forecast													Change
Rate Class	Dec-07	Dec-08	Dec-09	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	
Residential - R1	7,815	7,923	7,997	7,999	8,001	8,003	8,005	8,008	8,011	8,014	8,016	8,018	8,020	8,022	8,024	27
Residential - R2	47	48	48	48	48	48	48	48	48	48	48	48	48	48	48	
Seasonal	3,718	3,688	3,643	3,643	3,643	3,643	3,645	3,647	3,649	3,651	3,653	3,654	3,654	3,654	3,654	11
Street Lights	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	-
Total	11,611	11,691	11,720	11,722	11,724	11,726	11,730	11,735	11,740	11,745	11,749	11,752	11,754	11,756	11,758	38

2011 Algoma Customer Count By Rate Class

	Actual		Forecast													Change
Rate Class	Dec-08	Dec-09	Dec-10	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	
Residential - R1	7,923	7,997	8,024	8,026	8,028	8,030	8,032	8,035	8,038	8,041	8,043	8,045	8,047	8,049	8,049	25
Residential - R2	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	
Seasonal	3,688	3,643	3,654	3,654	3,654	3,654	3,655	3,657	3,659	3,661	3,663	3,665	3,665	3,665	3,665	11
Street Lights	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	-
Total	11,691	11,720	11,758	11,760	11,762	11,764	11,767	11,772	11,777	11,782	11,786	11,790	11,792	11,794	11,794	36

2010 Weather Normalized Forecasted Revenue Recovery Summary								
Customer Class	**Billing Metric**	**No. of Cust.**	**Charge Determinant**	**Simulated Rates**		**Revenue**		
				Fixed	*Volumetric*	*Fixed*	*Volumetric*	*Total*
Residential								
R1 Energy Rate	kWh	8,012	104,754,767	20.41	0.1069	1,962,238	11,195,280	13,157,517
R2 Demand Rate	kW	48	151,138	596.12	7.3375	343,365	1,108,977	1,452,342
Total Residential						*2,305,603*	*12,304,256*	14,609,859
Seasonal	kWh	3,649	12,459,994	24.00	0.1412	1,050,960	1,758,968	2,809,928
Street Lights (conn.)	kWh	1,052	791,996	-	0.0602	-	47,686	47,686
						3,356,563	14,110,911	17,467,474

2011 Weather Normalized Forecasted Revenue Recovery Summary								
Customer Class	**Billing Metric**	**No. of Cust.**	**Charge Determinant**	**Rates**		**Revenue**		
				Fixed	*Volumetric*	*Fixed*	*Volumetric*	*Total*
Residential								
R1 Energy Rate	kWh	8,039	106,119,297	20.41	0.1069	1,968,810	11,341,109	13,309,919
R2 Demand Rate	kW	48	151,952	596.12	7.3375	343,365	1,114,949	1,458,315
Total Residential						*2,312,175*	*12,456,058*	14,768,233
Seasonal	kWh	3,660	12,622,297	24.00	0.1412	1,054,008	1,781,880	2,835,888
Street Lights (conn.)	kWh	1,052	791,996	-	0.0602	-	47,686	47,686
						3,366,183	14,285,625	17,651,808

2006 Cost Allocation Information Filing

Algoma Power Inc.

EB-2010-0278

Tuesday, June 01, 2010

Sheet O1 Revenue to Cost Summary Worksheet - First Run

Rate Base Assets		Total	1 R1	2 R2	7 Street Light	12 Seasonal
crev	Distribution Revenue (sale)	$17,467,474	$13,157,517	$1,452,342	$47,686	$2,809,928
mi	Miscellaneous Revenue (mi)	$343,057	$217,490	$88,133	$5,003	$32,431
	Total Revenue	**$17,810,531**	**$13,375,007**	**$1,540,474**	**$52,689**	**$2,842,360**
	Expenses					
di	Distribution Costs (di)	$4,762,863	$2,866,301	$1,306,234	$87,720	$502,608
cu	Customer Related Costs (cu)	$1,693,808	$1,394,715	$91,659	$11,235	$196,199
ad	General and Administration (ad)	$2,652,964	$1,737,897	$590,030	$40,563	$284,474
dep	Depreciation and Amortization (dep)	$4,056,672	$2,563,128	$975,345	$70,644	$447,555
INPUT	PILs (INPUT)	$751,038	$456,888	$209,628	$11,219	$73,304
INT	Interest	$2,342,000	$1,424,736	$653,693	$34,985	$228,587
	Total Expenses	**$16,259,345**	**$10,443,665**	**$3,826,589**	**$256,366**	**$1,732,726**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$1,430,361	$870,148	$399,239	$21,367	$139,608
	Revenue Requirement (includes NI)	$17,689,706	$11,313,812	$4,225,828	$277,732	$1,872,334
		Revenue Requirement Input equals Output				
	Rate Base Calculation					
	Net Assets					
dp	Distribution Plant - Gross	$101,557,858	$61,697,989	$27,444,170	$1,706,422	$10,709,276
gp	General Plant - Gross	$10,530,382	$6,406,067	$2,939,214	$157,302	$1,027,799
accum dep	Accumulated Depreciation	($46,509,937)	($28,210,059)	($12,079,334)	($884,122)	($5,336,422)
co	Capital Contribution	$0	$0	$0	$0	$0
	Total Net Plant	**$65,578,302**	**$39,893,997**	**$18,304,050**	**$979,602**	**$6,400,653**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$17,166,389	$9,553,250	$6,404,606	$72,227	$1,136,306
	OM&A Expenses	$9,109,635	$5,998,913	$1,987,923	$139,518	$983,281
	Directly Allocated Expenses	$0	$0	$0	$0	$0
	Subtotal	***$26,276,024***	***$15,552,163***	***$8,392,529***	***$211,745***	***$2,119,587***
	Working Capital	**$3,941,404**	**$2,332,825**	**$1,258,879**	**$31,762**	**$317,938**
	Total Rate Base	**$69,519,706**	**$42,226,821**	**$19,562,929**	**$1,011,364**	**$6,718,591**
		Rate Base Input equals Output				
	Equity Component of Rate Base	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income on Allocated Assets	**$1,551,185**	**$2,931,343**	**($2,286,114)**	**($203,676)**	**$1,109,633**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$1,551,185**	**$2,931,343**	**($2,286,114)**	**($203,676)**	**$1,109,633**
	RATIOS ANALYSIS					
	REVENUE TO EXPENSES %	100.68%	118.22%	36.45%	18.97%	151.81%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$120,824	$2,061,195	($2,685,353)	($225,043)	$970,025
	RETURN ON EQUITY COMPONENT OF RATE BASE	0.00%	0.00%	0.00%	0.00%	0.00%

2010 Cost Allcoaction Results									
	Cost Allocation Revenue Requirement	Revenue Requirement Allocation Percentage	Cost Allocation Misc.	Cost Allocation Misc. Percentage	2010 Service Revenue Requirement	2010 Misc. Revenue	2010 Base Revenue Requirement		
Residential - R1	11,313,812	64.0%	217,490	63.4%	12,105,830	217,490	11,888,340		
Residential - R2	4,225,828	23.9%	88,133	25.7%	4,521,654	88,133	4,433,522		
Seasonal	1,872,334	10.6%	32,431	9.5%	2,003,406	32,431	1,970,974		
Street Lighting	277,732	1.6%	5,003	1.5%	297,175	5,003	292,172		
	17,689,706	100.0%	343,057	100.0%	18,928,065	343,057	18,585,008		

2010 Base Distribution Rate Cost Allcation Design									
	2010 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	One Third Increment
Residential - R1	11,888,340	64.0%	74.9%	13,921,390	2,033,050	117.1%	118.22%	85-115%	117.1%
Residential - R2	4,433,522	23.9%	12.2%	2,260,894	(2,172,627)	51.0%	36.45%	80-180%	51.0%
Seasonal	1,970,974	10.6%	12.3%	2,288,029	317,054	116.1%	151.81%	85-115%	Beneficary
Street Lighting	292,172	1.6%	0.6%	114,695	(177,477)	39.3%	18.97%	70-120%	39.3%
	18,585,008	100.0%	100.0%	18,585,008					

2010 Distribution Base Rate Determination											
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8012	104,754,767		14.1%	85.9%	20.41	0.1142	1,962,238	11,959,152	13,921,390
Residential - R2	kW	48		151,138	15.2%	84.8%	596.12	12.6873	343,365	1,917,529	2,260,894
Seasonal	kWh	3649	12,459,994		45.9%	54.1%	24.00	0.0993	1,050,960	1,237,069	2,288,029
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.1448	-	114,695	114,695
									3,356,563	**15,228,445**	**18,585,008**

2011 Cost Allcoaction 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	11,313,812	64.0%	217,490	63.4%	13,080,580	234,623	12,845,958		
Residential - R2	4,225,828	23.9%	88,133	25.7%	4,885,734	95,075	4,790,659		
Seasonal	1,872,334	10.6%	32,431	9.5%	2,164,718	34,986	2,129,732		
Street Lighting	277,732	1.6%	5,003	1.5%	321,103	5,397	315,706		
	17,689,706	100.0%	343,057	100.0%	20,452,136	370,082	20,082,054		
2011 Base Distribution Rate Cost Allcation Design									
	2011 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	Two Third Increment
Residential - R1	12,845,958	64.0%	72.8%	14,626,532	1,780,574	113.9%	118.22%	85-115%	Beneficary
Residential - R2	4,790,659	23.9%	15.6%	3,137,280	(1,653,379)	65.5%	36.45%	80-180%	65.5%
Seasonal	2,129,732	10.6%	10.6%	2,129,732	-	100.0%	151.81%	85-115%	100.0%
Street Lighting	315,706	1.6%	0.9%	188,510	(127,195)	59.7%	18.97%	70-120%	59.7%
	20,082,054	100.0%	100.0%	20,082,054					

2011 Distribution Base Rate Determination											
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.5%	86.5%	20.41	0.1193	1,968,810	12,657,722	14,626,532
Residential - R2	kW	48		151,952	10.9%	89.1%	596.12	18.3868	343,365	2,793,915	3,137,280
Seasonal	kWh	3660	12,622,297		49.5%	50.5%	24.00	0.0852	1,054,008	1,075,724	2,129,732
Street Lighting	kWh	1052	791,996		0.0%	100.0%	-	0.2380	-	188,510	188,510
									3,366,183	**16,715,871**	**20,082,054**

2010 Distribution Base Rate Determination											
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8012	104,754,767		14.1%	85.9%	20.41	0.1142	1,962,238	11,959,152	13,921,390
Residential - R2	kW	48		151,138	15.2%	84.8%	596.12	12.6873	343,365	1,917,529	2,260,894
									2,305,603	**13,876,682**	**16,182,284**
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 2010 using the Board Approved Methodology, EB-2007-0744											**5.50%**
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8012	104,754,767		39.5%	60.5%	21.53	0.0303	2,070,161	3,171,817	5,241,978
Residential - R2	kW	48		151,138	48.1%	51.9%	628.91	2.5899	362,250	391,435	753,685
									2,432,411	**3,563,252**	**5,995,664**
The Rural and Remote Rate Protection Amount Required for 2010											**$ 10,186,621**

2011 Distribution Base Rate Determination											
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8039	106,119,297		13.5%	86.5%	20.41	0.1193	1,968,810	12,657,722	14,626,532
Residential - R2	kW	48		151,952	10.9%	89.1%	596.12	18.3868	343,365	2,793,915	3,137,280
									2,312,175	**15,451,637**	**17,763,812**
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 2011using the Board Approved Methodology, EB-2007-0744											**2.00%**
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			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%	21.96	0.0309	2,118,636	3,277,396	5,396,032
Residential - R2	kW	48		151,952	47.9%	52.1%	641.48	2.6417	369,495	401,414	770,910
									2,488,131	**3,678,810**	**6,166,942**
The Rural and Remote Rate Protection Amount Required for 2011											**$ 11,596,870**

2010 Distribution Base Rate Determination											
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Seasonal	kWh	3649	12,459,994		45.9%	54.1%	24.00	0.0993	1,050,960	1,237,069	2,288,029
Street Lighting	kWh	1052	791,996		10.8%	89.2%	0.98	0.1292	12,372	102,323	114,695
									1,063,332	**1,339,392**	**2,402,724**

Seasonal

2010 Average Monthly Consumption per customer	284	kWh
Delivery Charges Based on Designed Rates	$ 52.21	
Delivery Charges Based on Current Rates	$ 43.89	
Percentage Change in the Delivery Component	19%	

Street Lighting

2010 Average Monthly Consumption per customer	192	kWh
Delivery Charges Based on Designed Rates	$ 25.79	
Delivery Charges Based on Current Rates	$ 9.52	
Percentage Change in the Delivery Component	171%	

2011 Distribution Base Rate Determination											
Customer Class	Metric	Average # of Customers	Billing Determinant		F/V Split		Distribution Rates		Revenues		
			kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Seasonal	kWh	3660	12,622,297		49.5%	50.5%	24.00	0.0852	1,054,008	1,075,724	2,129,732
Street Lighting	kWh	1052	791,996		7.2%	92.8%	1.08	0.2208	13,634	174,876	188,510
									1,067,642	**1,250,600**	**2,318,242**

Seasonal

2010 Average Monthly Consumption per customer	287	kWh
Delivery Charges Based on Designed Rates	$ 48.46	
Delivery Charges Based on 2010 Rates	$ 52.21	
Percentage Change in the Delivery Component	-7%	

Street Lighting

2010 Average Monthly Consumption per customer	192	kWh
Delivery Charges Based on Designed Rates	$ 43.47	
Delivery Charges Based on 2010 Rates	$ 25.79	
Percentage Change in the Delivery Component	69%	

SEASONAL CUSTOMER RATE MITIGATION PLAN

In the Board's Decision and Order, EB-2007-0744, on page 37 in its findings, the Board stated:

> *"In its next rate application the Applicant is required to present a planned approach for the management of the mitigation plan so as to ensure that balances are cleared with regularity, at levels and in a manner that does not result in undue hardship for these customers or any other class of customers."*

The Cost Allocation recognizes that the Seasonal class is over contributing to the revenue requirement. In the 2010 Test Year, the delivery component increases by a manageable amount which allows the recovery of the proposed class revenue requirement. In the 2011 Test Year, the delivery component will decrease to bring the Seasonal class into the Board's guidelines for revenue to cost, this decrease will be offset by the introduction of a rate rider to clear the existing deferral account balance over five years.

Seasonal Customer Rate Mitigation Plan

Proposed Rate Rider to Become Effective January 1, 2011

EB-2007-0744 Mitigated Amount of Revenue Requirement	$829,600
Accumulated Balance of Deferral Account as of December 31, 2009	$1,935,733
2010 Forecast of Energy Throughput in the Seasonal Class – kWh	12,622,297
Forecasted Term of the Deferral Account Recovery (Years)	5
Rate Rider to Clear the Deferral in One Year - $/kWh	0.0307

API proposes that in its next application it will update the deferral account balance to the implementation date as determined by the board and clear residual balances at that time.

FIXED AND VARIABLE PROPORTION

The fixed and variable proportions of the Residential – R1 and the Residential – R2 remain unchanged from the electricity distribution rates established in EB-2007-0744. In that Decision and Order it stated, beginning on page 29,

> *Section 4 (3.2) of that regulation requires forecasted customer revenues to be based on currently approved rates "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 year."*

In compliance with this Decision and Order, API has increased rates on the basis of the simple average of delivery charge rate impacts for rates of other distributors published on the Board's website as of May 7, 2010. This methodology does not contemplate a change to the fixed/variable proportions by design.

Rate design for the Seasonal class has held the fixed charge constant at the currently approved level of $24.00 per customer per month. This exceeds the upper threshold of the cost allocation model which has been determined to be $21.72. API has elected to maintain the current fixed monthly service charge because of the API mitigation plan to recover Seasonal deferral amounts. In EB-2007-0744, a deferral account was established to address issues related to the Seasonal class. API has a Seasonal Customer Rate Mitigation Plan, as contemplated in the Board's Decision and Order, EB-2007-0744, on page 37 which is discussed in Exhibit 8, Tab 1, Schedule 3.

As a result of maintaining the fixed charge constant from the Board Approved rate to the 2010 proposed rate and the 2011 proposed rate the fixed component is:

- Board Approved 59.1%
- 2010 Proposed 45.9%
- 2011 Proposed 49.5%

The determination of this rate is shown in Exhibit 8, Tab 1, Schedule 2, (Rate Design Discussion).

The current Board Approved rate for Street Lighting is 100% volumetric. The Cost Allocation Model determines that the minimum fixed cost is $0.98 per connection. API is implementing this minimum fixed cost as the monthly service charge per connection. This change will yield a 11% fixed component for the class revenue requirement.

RETAIL TRANSMISSION SERVICE RATES

API's entire electricity distribution system is connected to the IESO-controlled grid via the GLPT transmission system. Transmission Network Service Rates, Line Connection Service Rates and Transformation Connection Service Rates are levied to API by the IESO at the prevailing Uniform Transmission Rate ("UTR").

API's existing Retail Transmission Service Rates ("RTSR") are those first developed for market opening, May 1, 2002. API's predecessor did not file a 2006 EDR application and did not file applications related to the incentive rate mechanisms. Pursuant to an application filed August 31, 2007, EB-2007-0744, the Board approved electricity distribution rates in its Decision and Order dated December 24, 2008 which did not effect changes to the prevailing RTSR at API. Since May 1, 2002, RTSR have not been adjusted to compensate for ongoing variance trending with retail transmission service charge revenues or changes to the UTR.

API has undertaken a review of its RTSR in a manner consistent with the Board's Guideline: *Electricity Retail Service Rates, Guideline G-2008-0001, October 22, 2008* ("the Board's Guideline"). API has trended 2008 and 2009 historical data for the wholesale network and connection costs against the corresponding RTSR revenues. In addition, API has projected the 2010 Test Year costs based on UTR effective January 1, 2010 and RTSR revenues based on the current RTSR and examined the resulting variance projection. The 2010 Test Year RTSR is being proposed to minimize the forecasted variant between costs and revenues.

The operational realities of an electricity distributor with multiple IESO Delivery Points make it impossible to predict with certainty its wholesale network and connection costs. API has nine IESO delivery points and it will be necessary to properly maintain service to all these points on both a planned and unplanned basis, in order to transfer electrical load between delivery points. Depending on the timing and duration of these load transfers, the wholesale

network and connection costs will be impacted without a correlating impact to the RTSR revenues.

Table 1 below shows the relativity of the wholesale network and connection costs with the RTSR revenues for API over the period of 2008 and 2009.

Exhibit 8, Tab 3, Schedule 1, Table 1

Comparison of Wholesale Network and Connection Costs and Retail Transmission Service Rate Revenues						
	Network Service			Connection Service		
2008	**Costs**	**Revenues**	**Spread**	**Costs**	**Revenues**	**Spread**
January	90,266	110,076	19,811	81,402	96,499	15,097
February	80,744	88,441	7,697	73,178	77,067	3,889
March	104,174	120,268	16,094	102,659	105,371	2712
April	70,748	89,067	18,319	66,799	77,924	11,125
May	57,556	85,500	27,944	55,831	74,640	18,809
June	48,364	65,450	17,086	46,982	57,390	10,408
July	50,381	67,243	16,862	45,344	58,770	13,426
August	48,487	65,611	17,124	45,916	57,372	11,456
September	62,241	56,186	(6,055)	63,182	49,177	(14,006)
October	79,037	83,967	4,931	74,745	73,474	(1,272)
November	70,286	79,514	9,227	63,689	69,317	5,628
December	91,273	112,711	21,438	99,426	98,487	(940)
Total for 2008	**853,557**	**1,024,035**	**170,478**	**819,153**	**895,486**	**76,333**
2009						
January	103,443	121,251	17,809	82,381	105,962	23,580
February	96,863	90,502	(6,361)	76,768	78,802	2,034
March	95,655	117,028	21,373	79,337	102,331	22,995
April	86,141	95,149	9,008	78,871	83,194	4,322
May	58,352	78,012	19,660	54,586	68,503	13,917
June	76,172	68,042	(8,130)	70,528	59,586	(10,943)
July	59,339	75,700	16,361	47,738	65,770	18,032
August	62,297	68,059	5,762	51,871	59,150	7,279
September	77,233	66,182	(11,051)	68,606	57,393	(11,213)
October	90,533	75,222	(15,311)	78,906	67,266	(11,640)
November	80,010	78,529	(1,481)	61,723	68,680	6,958
December	97,885	87,366	(10,520)	76,196	77,541	1,345
Total for 2009	**983,924**	**1,021,042**	**37,118**	**827,511**	**894,178**	**66,667**

As evidenced in Table 1, the API revenues from RTSR exceed the costs associated with the wholesale network and connections charges. However, there is a significant decline in the amount of over-collection when the 2009 results are compared to the 2008 results. This stems from the fact UTR increases came effective in January 1, 2009. The UTR, in January 2009 increased as shown below:

Charge Type	Determinant	2008	2009	% Change
Network Service Rate	$/kW	2.31	2.57	11.26
Line Connection Service Rate	$/kW	0.59	0.70	18.64
Transformation Connection Rate	$/kW	1.61	1.62	0.62

Because API did not participate in any form of cost of service application or incentive rate mechanism adjustment, its RTSR were not adjusted accordingly. The result is the reduction in over collection shown in Table 1 above.

Effective January 1, 2010, new UTR has been approved by the Board, EB-2008-0272. These are shown below:

Charge Type	Determinant	2009	2010	% Change
Network Service Rate	$/kW	2.57	2.97	15.56
Line Connection Service Rate	$/kW	0.70	0.73	4.29
Transformation Connection Rate	$/kW	1.62	1.71	5.56

API has projected this UTR increase into the 2010 Test Year by escalating the 2009 wholesale network and connections charges by the Approved increases in the UTR, the results are shown in Table 2 below:

Exhibit 8, Tab 3, Schedule 1, Table 2

Comparison of Wholesale Network and Connection Costs and Retail Transmission Service Rate Revenues						
	Network Service			Connection Service		
Projection for 2010	**Costs**	**Revenues**	**Spread**	**Costs**	**Revenues**	**Spread**
January	119,543	105,962	(13,581)	86,642	105,962	19,319
February	101,873	90,502	(11,371)	76,768	78,802	2,034
March	95,655	117,028	21,373	79,337	102,331	22,995
April	86,141	95,149	9,008	78,871	83,194	4,322
May	58,352	78,012	19,660	54,586	68,503	13,917
June	76,172	68,042	(8,130)	70,528	59,586	(10,943)
July	59,339	75,700	16,361	47,738	65,770	18,032
August	62,297	68,059	5,762	51,871	59,150	7,279
September	77,233	66,182	(11,051)	68,606	57,393	(11,213)
October	90,533	75,222	(15,311)	78,906	67,266	(11,640)
November	80,010	78,529	(1,481)	61,723	68,680	6,958
December	97,885	87,366	(10,520)	76,196	77,541	1,345
Total for 2010	**1,005,034**	**1,005,753**	**718**	**831,772**	**894,178**	**62,406**

Projecting the 2010 Board Approved UTR upon the 2009 actual wholesale network and connections charges and comparing it to the 2009 revenues from RSTR indicates that the gap between the charges and revenue is closing due to attrition. Based on these projections the Retail Transmission – Network Service Rate is within reason. The Retail Transmission – Connection Service Rate is over-collecting by $62,406 annually or at a rate of 6.98% per year.

On the basis of the foregoing discussion and analysis, API proposes to leave its existing Retail Transmission – Network Service Rate unchanged and proposes to reduce its Retail Transmission – Connection Service Rate by 6.98% uniformly across all classes to compensate for the accrual of over-collection. This adjustment will align the forecasted wholesale network and connections costs more closely with the 2010 Test Year RSTR revenue.

Exhibit 8, Tab 3, Schedule 1, Table 3

Proposed Schedule of Retail Transmission Service Rates			
Residential – R1	Metric	Existing	2010 Proposed
Retail Transmission Rate - Network Service Rate	$/kWh	0.0057	0.0053
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050	0.0050
Residential – R2			
Regular			
Retail Transmission Rate - Network Service Rate	$/kW	2.1218	1.9737
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7882	1.7882
Interval Metered greater than 1,000 kW			
Retail Transmission Rate - Network Service Rate	$/kW	2.2508	2.0937
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.9763	1.9763
Seasonal			
Retail Transmission Rate - Network Service Rate	$/kWh	0.0057	0.0053
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050	0.0050
Street Lighting			
Retail Transmission Rate - Network Service Rate	$/kW	1.6002	1.4885
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3824	1.3824

These Retail Transmission Service Rates are included in API's proposed Tariff of Rates and Charges detailed in Exhibit 1, Tab 1, Schedule 2, Appendix A.

LOW VOLTAGE

API's entire electricity distribution system is directly connected to the IESO-controlled grid via the GLPT transmission system. Transmission Network Service Rates, Line Connection Service Rates and Transformation Connection Service Rates are levied to API by the IESO at the prevailing Uniform Transmission Rate ("UTR"). Accordingly, there are no Low Voltage charges applicable to API.

LOSS ADJUSTMENT FACTORS

The API distribution system is supplied and its entire energy requirement is delivered by the IESO controlled grid from the GLPT transmission system.

In its most recent electricity distribution rate application, EB-2007-0744, API's approved Tariff of Rates and Charges provided for a 1.1025 Total Loss Factor for secondary metered customers and a 1.0915 Total Loss Factor for primary metered customers.

As discussed elsewhere in this Application, API has undertaken capital works programs to replace deteriorated overhead conductor and to upgrade its distribution system through voltage conversions and substation rationalizations. Not only are these projects justified on their own merits based upon such criteria as safety, system integrity and reliability, but also they result in an enduring energy loss reduction. This further benefits customers as a result of lower energy costs.

The nature of these capital programs have smaller deteriorated steel conductors replaced with newer conductors with increased load carrying capabilities which mean fewer losses over the wires. The conversions from the 4.8 kV delta distribution system to 8.3 kV wye configured system has the inherent benefit of lower line currents reducing losses.

API has determined its loss adjustment factor in compliance with Section 2.9.4 Loss Adjustment Factors of the Filing Requirements. Appendix 2 – Q is provided on the following page and details the derivation of the proposed loss adjustment factor.

Appendix 2 – Q Loss Factors

	Losses in Algoma Power's System					
		2005	2006	2007	2008	2009
A_1	"Wholesale" kWh delivered to distributor (higher value)	202,948,230	198,908,810	205,899,550	198,145,080	203,888,072
A_2	"Wholesale" kWh delivered to distributor (lower value)	202,034,963	196,964,899	203,956,543	196,991,365	201,931,224
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)	-	-	-	-	-
C	Net "Wholesale" kWh delivered to distributor (A_2)-(B)	202,034,963	196,964,899	203,956,543	196,991,365	201,931,224
D	"Retail" kWh delivered by distributor	184,779,998	181,341,387	188,497,165	182,092,142	186,826,563
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)	-	-	-	-	-
F	Net "Retail" kWh delivered by distributor (D)-(E)	184,779,998	181,341,387	188,497,165	182,092,142	186,826,563
G	Loss Factor in distributor's system [(C)/(F)]	1.0934	1.0862	1.0820	1.0818	1.0808
	Losses Upstream of Distributor's System					
H	Supply Facility Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses					
I	Total Loss Factor [(G)x(H)]	1.0983	1.0910	1.0869	1.0867	1.0857

API is directly connected to the IESO controlled grid and the wholesale kWh delivered to API from the IESO controlled grid is provided on line A_1 for the five year period from 2005 to 2009. Line A_2 provides the metered value for each of the corresponding years.

API does not service a Wholesale Large Customer as defined by Line B and zeros have been entered for each of the years.

Line D shows the total billed energy sales for the period. API has does not service a Retail Large Customer as defined by Line E and zeros have been entered for each of the years.

Line G yields the calculated distribution system's loss factor. As evidenced by the results from the period 2005 through 2009, the distribution system loss factor is decreasing over time. This is a validation that the anticipated impacts of the conductor replacement program and the voltage conversion are being realized, Exhibit 2, Tab 4, Schedule 1.

On Line H, because API is directly connected to the IESO controlled grid it has used the default value for the Supply Facility Loss Factor of 1.0045 as stipulated in the Filing Requirements, Appendix 2 – Q, Section H.

Line I yields the Total System Loss Factor.

To realize the enduring benefits of the ongoing conductor replacement program and the voltage conversions, API is proposing to use the average of its most recent three years for its loss adjustment factor.

Exhibit 8 Tab 5 Schedule 1, Table 1

Determination of Loss Adjustment Factor				
	2007	2008	2009	Average
Supply Facility Loss Factor	1.0045	1.0045	1.0045	1.0045
Distribution System Loss Factor	1.0820	1.0818	1.0808	1.0815
Total Loss Factor	1.0869	1.0867	1.0857	1.0864

API recognizes that the loss factors determined here are greater than the 5% threshold discussed in the Board's filing guideline. API serves a very large geographic area of

approximately 14,200 square kilometers with 1845 kilometers of line servicing 11,720 customers. It is recognized that as such with its very low customer density its loss factor will exceed 5%.

RATE IMPACTS

API has used an EXCEL Spreadsheet to calculate rate impacts for each class with the ability to vary the consumptions and demand. There is a separate model for each Test Year. The 2010 Test Year proposed electricity distribution rates, effective July 1, 2010, are compared to existing Board Approved rates to determine the impacts. The proposed 2011 Test Year electricity distribution rates, effective January 1, 2011, are compared to the proposed 2010 rates to determine the rate impacts. These two Excel spreadsheets, *2010 API Rate Impact Sheet 20100607Ad1.xls* and 2011 *API Rate Impact Sheet 20100607Ad1.xls* accompany this Application.

The outputs of the models are in Appendix 2-R format and follow here.

Algoma Power Inc.
2010 Distribution Rate Impact Module
2010 Electricity Distribution Rate Application
EB-2009-0278
June 1, 2010
Amendment Filed June 7, 2010

Electricity Distribution Impacts
Rates Effective July 1, 2010

	Metric	2007 Approved	Proposed July 1, 2010
Monthly Rates and Charges			
Residential - R1			
Monthly Service Charge	$	20.41	21.53
Smart Meter Rate Adder	$	-	1.00
Monthly Service Charge Rate Adder # 1	$		
Monthly Service Charge Rate Adder # 2	$		
Distribution Volumetric Rate	$/kWh	0.0287	0.0303
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012			0.0054
Distribution Volumetric Rate Rate Adder # 2			
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kWh	(0.0041)	(0.0041)
Deferral Account Rate Rider # 2			
Retail Transmission Rate - Network Service Rate	$/kWh	0.0057	0.0053
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0010	0.0013
Special Purpose Charge	$/kWh	0.0003725	0.0003725
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25
Residential - R2			
Monthly Service Charge	$	596.12	628.91
Smart Meter Rate Adder	$	-	1.00
Monthly Service Charge Rate Adder # 1	$		
Monthly Service Charge Rate Adder # 2	$		
Distribution Volumetric Rate	$/kW	2.4549	2.5899
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012			0.0044
Distribution Volumetric Rate Rate Adder # 2			
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kW	(0.2025)	(0.2025)
Deferral Account Rate Rider # 2			
Retail Transmission Rate - Network Service Rate	$/kW	2.1218	1.9737
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7882	1.7882
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	$/kW	2.2508	2.0937
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	$/kW	1.9763	1.9763
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0010	0.0013
Special Purpose Charge	$/kWh	0.0003725	0.0003725
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25
Seasonal			
Monthly Service Charge	$	24.00	24.00
Smart Meter Rate Adder	$	-	1.00
Monthly Service Charge Rate Adder # 1	$		
Monthly Service Charge Rate Adder # 2	$		
Distribution Volumetric Rate	$/kWh	0.0700	0.0993
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012			0.0083
Distribution Volumetric Rate Rate Adder # 2			
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kWh	(0.0041)	(0.0041)
Deferral Account Rate Rider # 2			
Retail Transmission Rate - Network Service Rate	$/kWh	0.0057	0.0053
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0010	0.0013
Special Purpose Charge	$/kWh	0.0003725	0.0003725
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25
Street Lighting			
Monthly Service Charge	$	-	0.98
Smart Meter Rate Adder	$	-	-
Monthly Service Charge Rate Adder # 1	$		
Monthly Service Charge Rate Adder # 2	$		
Distribution Volumetric Rate	$/kWh	0.0496	0.1292
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012			0.0219
Distribution Volumetric Rate Rate Adder # 2			
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kWh	(0.0016)	(0.0016)
Deferral Account Rate Rider # 2			
Retail Transmission Rate - Network Service Rate	$/kW	1.6002	1.4885
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3824	1.3824
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0010	0.0013
Special Purpose Charge	$/kWh	0.0003725	0.0003725
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25
Other			
Debt Retirement Charge	$/kWh	0.0020	0.0020
Energy - First Tier	$/kWh	0.0650	0.0650
Energy - Second Tier	$/kWh	0.0750	0.0750
Loss Factor			
Total Loss Factor		1.1025	1.0864
GST / HST		5%	13%

Electricity Distribution Impacts
Rates Effective July 1, 2010

Residential - R1	Metric	2007 Approved	Proposed July 1, 2010
Monthly Service Charge	$	20.41	21.53
Smart Meter Rate Adder	$	-	1.00
Monthly Service Charge Rate Adder # 1	$	-	-
Monthly Service Charge Rate Adder # 2	$	-	-
Distribution Volumetric Rate	$/kWh	0.0287	0.0303
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012		-	0.0054
Distribution Volumetric Rate Rate Adder # 2		-	-
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kWh	(0.0041)	(0.0041)
Deferral Account Rate Rider # 2		-	-
Retail Transmission Rate - Network Service Rate	$/kWh	0.0057	0.0053
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0010	0.0013
Special Purpose Charge	$/kWh	0.0004	0.0004
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	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	35.28%
Energy, Second Tier (kWh)	132	0.0750	9.90	119	0.0750	8.93	-0.97	-9.76%	6.47%
Sub-Total: Energy			58.65			57.68	-0.97	-1.65%	41.75%
Monthly Service Charge	1	20.41	20.41	1	21.53	21.53	1.12	5.49%	15.58%
Smart Meter Rate Adder	1	0.00	0.00	1	1.00	1.00	1.00	100.00%	0.72%
Monthly Service Charge Rate Adder # 1	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Monthly Service Charge Rate Adder # 2	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	800	0.0287	22.96	800	0.0303	24.24	1.28	5.57%	17.54%
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	800	0.0000	0.00	800	0.0054	4.32	4.32	0.00%	3.13%
Distribution Volumetric Rate Rate Adder # 2	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
Deferral Account Rate Rider # 1- effective until December 31, 2010	800	-0.0041	-3.28	800	-0.0041	-3.28	0.00	0.00%	-2.37%
Deferral Account Rate Rider # 2	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
Total: Distribution			40.09			47.81	7.72	19.26%	34.60%
Retail Transmission Rate - Network Service Rate	882	0.0057	5.03	869	0.0053	4.61	-0.42	-8.38%	3.33%
Retail Transmission Rate - Line and Transformation Connection Service Rate	882	0.0050	4.41	869	0.0050	4.35	-0.06	-1.46%	3.15%
Total: Retail Transmission			9.44			8.95	-0.49	-5.14%	6.48%
Sub-Total: Delivery (Distribution and Retail Transmission)			49.53			56.76	7.23	14.61%	41.08%
Wholesale Market Service Rate	882	0.0052	4.59	869	0.0052	4.52	-0.07	-1.46%	3.27%
Rural Rate Protection Charge	882	0.0010	0.88	869	0.0013	1.13	0.25	28.10%	0.82%
Special Purpose Charge	882	0.0004	0.33	869	0.0004	0.32	0.00	-1.46%	0.23%
Standard Supply Service - Administarive Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.18%
Sub-Total: Regulatory			6.05			6.22	0.18	2.91%	4.50%
Debt Retirement Charge	800	0.0020	1.60	800	0.0020	1.60	0.00	0.00%	1.16%
Total Bill Before Taxes			115.82			122.27	6.44	5.56%	88.50%
GST / HST		5%	5.79		13%	15.89	10.10	174.47%	11.50%
Total Bill			**$ 121.62**			**$ 138.16**	**$ 16.55**	13.61%	100.00%

Electricity Distribution Impacts
Rates Effective July 1, 2010

Residential - R2	Metric	2007 Approved	Proposed July 1, 2010
Monthly Service Charge	$	596.12	628.91
Smart Meter Rate Adder	$	-	1.00
Monthly Service Charge Rate Adder # 1	$	-	-
Monthly Service Charge Rate Adder # 2	$	-	-
Distribution Volumetric Rate	$/kW	2.4549	2.5899
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012		-	0.0044
Distribution Volumetric Rate Rate Adder # 2		-	-
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kW	(0.2025)	(0.2025)
Deferral Account Rate Rider # 2		-	-
Retail Transmission Rate - Network Service Rate	$/kW	2.1218	1.9737
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7882	1.7882
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	$/kW	2.2508	2.0937
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	$/kW	1.9763	1.9763
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0010	0.0013
Special Purpose Charge	$/kWh	0.0004	0.0004
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	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	0.42%
Energy, Second Tier (kWh)	98475	0.0750	7385.63	97026	0.0750	7276.95	-108.68	-1.47%	62.73%
Sub-Total: Energy			7434.38			7325.70	-108.68	-1.46%	63.15%
Monthly Service Charge	1	596.12	596.12	1	628.91	628.91	32.79	5.50%	5.42%
Smart Meter Rate Adder	1	0.00	0.00	1	1.00	1.00	1.00	100.00%	0.01%
Monthly Service Charge Rate Adder # 1	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Monthly Service Charge Rate Adder # 2	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	225	2.4549	552.35	225	2.5899	582.73	30.38	5.50%	5.02%
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	225	0.0000	0.00	225	0.0044	0.99	0.99	0.00%	0.01%
Distribution Volumetric Rate Rate Adder # 2	225	0.0000	0.00	225	0.0000	0.00	0.00	0.00%	0.00%
Deferral Account Rate Rider # 1- effective until December 31, 2010	225	-0.2025	-45.56	225	-0.2025	-45.56	0.00	0.00%	-0.39%
Deferral Account Rate Rider # 2	225	0.0000	0.00	225	0.0000	0.00	0.00	0.00%	0.00%
Total: Distribution			1102.91			1168.07	65.16	5.91%	10.07%
Retail Transmission Rate - Network Service Rate	248	2.1218	526.34	244	1.9737	482.45	-43.89	-8.34%	4.16%
Retail Transmission Rate - Line and Transformation Connection Service Rate	248	1.7882	443.59	244	1.7882	437.11	-6.48	-1.46%	3.77%
Total: Retail Transmission			969.92			919.56	-50.37	-5.19%	7.93%
Sub-Total: Delivery (Distribution and Retail Transmission)			2072.83			2087.62	14.79	0.71%	18.00%
Wholesale Market Service Rate	99225	0.0052	515.97	97776	0.0052	508.44	-7.53	-1.46%	4.38%
Rural Rate Protection Charge	99225	0.0010	99.23	97776	0.0013	127.11	27.88	28.10%	1.10%
Special Purpose Charge	99225	0.0004	36.96	97776	0.0004	36.42	-0.54	-1.46%	0.31%
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			652.41			672.22	19.81	3.04%	5.79%
Debt Retirement Charge	90000	0.0020	180.00	90000	0.0020	180.00	0.00	0.00%	1.55%
Total Bill Before Taxes			10339.62			10265.54	-74.08	-0.72%	88.50%
GST / HST		5%	516.98		13%	1334.52	817.54	158.14%	11.50%
Total Bill			**$ 10,856.60**			**$ 11,600.06**	**$ 743.46**	6.85%	100.00%

Electricity Distribution Impacts
Rates Effective July 1, 2010

Residential Customers with an Interval Meter

Residential - R2	Metric	2007 Approved	Proposed July 1, 2010
Monthly Service Charge	$	596.12	628.91
Smart Meter Rate Adder	$	-	1.00
Monthly Service Charge Rate Adder # 1	$	-	-
Monthly Service Charge Rate Adder # 2	$	-	-
Distribution Volumetric Rate	$/kW	2.4549	2.5899
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012		-	0.0044
Distribution Volumetric Rate Rate Adder # 2		-	-
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kW	(0.2025)	(0.2025)
Deferral Account Rate Rider # 2		-	-
Retail Transmission Rate - Network Service Rate	$/kW	2.1218	1.9737
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7882	1.7882
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	$/kW	2.2508	2.0937
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	$/kW	1.9763	1.9763
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0010	0.0013
Special Purpose Charge	$/kWh	0.0004	0.0004
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	65,000	kWh	225 kW	Loss Factor 1.0864
RPP Tier One	750	kWh	Load Factor 39.6%	

Residential - R2	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Impacts $	Impacts %	Impacts % of Total Bill
Energy, First Tier (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	0.53%
Energy, Second Tier (kWh)	70913	0.0750	5318.44	69866	0.0750	5239.95	-78.49	-1.48%	57.48%
Sub-Total: Energy			5367.19			5288.70	-78.49	-1.46%	58.02%
Monthly Service Charge	1	596.12	596.12	1	628.91	628.91	32.79	5.50%	6.90%
Smart Meter Rate Adder	1	0.00	0.00	1	1.00	1.00	1.00	100.00%	0.01%
Monthly Service Charge Rate Adder # 1	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Monthly Service Charge Rate Adder # 2	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	225	2.4549	552.35	225	2.5899	582.73	30.38	5.50%	6.39%
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	225	0.0000	0.00	225	0.0044	0.99	0.99	0.00%	0.01%
Distribution Volumetric Rate Rate Adder # 2	225	0.0000	0.00	225	0.0000	0.00	0.00	0.00%	0.00%
Deferral Account Rate Rider # 1- effective until December 31, 2010	225	-0.2025	-45.56	225	-0.2025	-45.56	0.00	0.00%	-0.50%
Deferral Account Rate Rider # 2	225	0.0000	0.00	225	0.0000	0.00	0.00	0.00%	0.00%
Total: Distribution			1102.91			1168.07	65.16	5.91%	12.81%
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	248	2.2508	558.34	244	2.0937	511.78	-46.56	-8.34%	5.61%
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	248	1.9763	490.25	244	1.9763	483.09	-7.16	-1.46%	5.30%
Total: Retail Transmission			1048.58			994.87	-53.71	-5.12%	10.91%
Sub-Total: Delivery (Distribution and Retail Transmission)			2151.49			2162.94	11.44	0.53%	23.73%
Wholesale Market Service Rate	71663	0.0052	372.65	70616	0.0052	367.20	-5.44	-1.46%	4.03%
Rural Rate Protection Charge	71663	0.0010	71.66	70616	0.0013	91.80	20.14	28.10%	1.01%
Special Purpose Charge	71663	0.0004	26.69	70616	0.0004	26.30	-0.39	-1.46%	0.29%
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			471.25			485.56	14.31	3.04%	5.33%
Debt Retirement Charge	65000	0.0020	130.00	65000	0.0020	130.00	0.00	0.00%	1.43%
Total Bill Before Taxes			8119.93			8067.19	-52.74	-0.65%	88.50%
GST / HST		5%	406.00		13%	1048.74	642.74	158.31%	11.50%
Total Bill			**$ 8,525.93**			**$ 9,115.93**	**$ 590.00**	6.92%	100.00%

Electricity Distribution Impacts
Rates Effective July 1, 2010

Seasonal	Metric	2007 Approved	Proposed July 1, 2010
Monthly Service Charge	$	24.00	24.00
Smart Meter Rate Adder	$	-	1.00
Monthly Service Charge Rate Adder # 1	$	-	-
Monthly Service Charge Rate Adder # 2	$	-	-
Distribution Volumetric Rate	$/kWh	0.0700	0.0993
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	0	-	0.0083
Distribution Volumetric Rate Rate Adder # 2	0	-	-
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kWh	(0.0041)	(0.0041)
Deferral Account Rate Rider # 2	0	-	-
Retail Transmission Rate - Network Service Rate	$/kWh	0.0057	0.0053
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0010	0.0013
Special Purpose Charge	$/kWh	0.0004	0.0004
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	1,000 kWh	kW	
RPP Tier One	750 kWh	Load Factor	

Loss Factor	1.0864

Seasonal	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Impacts $	Impacts %	% of Total Bill
Energy, First Tier (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	19.31%
Energy, Second Tier (kWh)	353	0.0750	26.44	336	0.0750	25.23	-1.21	-4.57%	9.99%
Sub-Total: Energy			75.19			73.98	-1.21	-1.61%	29.31%
Monthly Service Charge	1	24	24	1	24.00	24.00	0.00	0.00%	9.51%
Smart Meter Rate Adder	1	0.00	0.00	1	1.00	1.00	1.00	100.00%	0.40%
Monthly Service Charge Rate Adder # 1	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Monthly Service Charge Rate Adder # 2	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	1000	0.0700	70.00	1000	0.0993	99.30	29.30	41.86%	39.34%
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	1000	0.0000	0.00	1000	0.0083	8.30	8.30	0.00%	3.29%
Distribution Volumetric Rate Rate Adder # 2	1000	0.0000	0.00	1000	0.0000	0.00	0.00	0.00%	0.00%
Deferral Account Rate Rider # 1- effective until December 31, 2010	1000	-0.0041	-4.10	1000	-0.0041	-4.10	0.00	0.00%	-1.62%
Deferral Account Rate Rider # 2	1000	0.0000	0.00	1000	0.0000	0.00	0.00	0.00%	0.00%
Total: Distribution			89.9			128.50	38.60	42.94%	50.91%
Retail Transmission Rate - Network Service Rate	1103	0.0057	6.28	1086	0.0053	5.76	-0.53	-8.38%	2.28%
Retail Transmission Rate - Line and Transformation Connection Service Rate	1103	0.0050	5.51	1086	0.0050	5.43	-0.08	-1.46%	2.15%
Total: Retail Transmission			11.80			11.19	-0.61	-5.14%	4.43%
Sub-Total: Delivery (Distribution and Retail Transmission)			101.70			139.69	37.99	37.36%	55.34%
Wholesale Market Service Rate	1103	0.0052	5.73	1086	0.0052	5.65	-0.08	-1.46%	2.24%
Rural Rate Protection Charge	1103	0.0010	1.10	1086	0.0013	1.41	0.31	28.10%	0.56%
Special Purpose Charge	1103	0.0004	0.41	1086	0.0004	0.40	-0.01	-1.46%	0.16%
Standard Supply Service - Administarive Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.10%
Sub-Total: Regulatory			7.50			7.72	0.22	2.94%	3.06%
Debt Retirement Charge	1000	0.0020	2.00	1000	0.0020	2.00	0.00	0.00%	0.79%
Total Bill Before Taxes			186.38			223.39	37.01	19.85%	88.50%
GST / HST		5%	9.32		13%	29.04	19.72	211.62%	11.50%
Total Bill			**$ 195.70**			**$ 252.43**	**$ 56.73**	28.99%	100.00%

Electricity Distribution Impacts
Rates Effective July 1, 2010

Street Lighting	Metric	2007 Approved	Proposed July 1, 2010
Monthly Service Charge	$	-	0.98
Smart Meter Rate Adder	$	-	-
Monthly Service Charge Rate Adder # 1	$	-	-
Monthly Service Charge Rate Adder # 2	$	-	-
Distribution Volumetric Rate	$/kWh	0.0496	0.1292
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	0	-	0.0219
Distribution Volumetric Rate Rate Adder # 2	0	-	-
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kWh	(0.0016)	(0.0016)
Deferral Account Rate Rider # 2	0	-	-
Retail Transmission Rate - Network Service Rate	$/kW	1.6002	1.4885
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3824	1.3824
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0010	0.0013
Special Purpose Charge	$/kWh	0.0004	0.0004
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

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

Loss Factor	1.0864

Street Lighting	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Impacts $	Impacts %	% of Total Bill
Energy, First Tier (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	0.64%
Energy, Second Tier (kWh)	26813	0.0750	2010.94	26410	0.0750	1980.75	-30.19	-1.50%	25.96%
Sub-Total: Energy			2059.69			2029.50	-30.19	-1.47%	26.60%
Monthly Service Charge	428	0	0	428	0.98	419.44	419.44	0.00%	5.50%
Smart Meter Rate Adder	428	0.00	0.00	428	0.00	0.00	0.00	0.00%	0.00%
Monthly Service Charge Rate Adder # 1	428	0.00	0.00	428	0.00	0.00	0.00	0.00%	0.00%
Monthly Service Charge Rate Adder # 2	428	0.00	0.00	428	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	25000	0.0496	1240.00	25000	0.1292	3230.00	1990.00	160.48%	42.33%
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	25000	0.0000	0.00	25000	0.0219	547.50	547.50	0.00%	7.17%
Distribution Volumetric Rate Rate Adder # 2	25000	0.0000	0.00	25000	0.0000	0.00	0.00	0.00%	0.00%
Deferral Account Rate Rider # 1- effective until December 31, 2010	25000	-0.0016	-40.00	25000	-0.0016	-40.00	0.00	0.00%	-0.52%
Deferral Account Rate Rider # 2	25000	0.0000	0.00	25000	0.0000	0.00	0.00	0.00%	0.00%
Total: Distribution			1200			4156.94	2956.94	246.41%	54.48%
Retail Transmission Rate - Network Service Rate	78.8	1.6002	126.07	77.6	1.4885	115.56	-10.51	-8.34%	1.51%
Retail Transmission Rate - Line and Transformation Connection Service Rate	78.8	1.3824	108.91	77.6	1.3824	107.32	-1.59	-1.46%	1.41%
Total: Retail Transmission			234.98			222.88	-12.10	-5.15%	2.92%
Sub-Total: Delivery (Distribution and Retail Transmission)			1434.98			4379.82	2944.84	205.22%	57.40%
Wholesale Market Service Rate	27563	0.0052	143.33	27160	0.0052	141.23	-2.09	-1.46%	1.85%
Rural Rate Protection Charge	27563	0.0010	27.56	27160	0.0013	35.31	7.75	28.10%	0.46%
Special Purpose Charge	27563	0.0004	10.27	27160	0.0004	10.12	-0.15	-1.46%	0.13%
Standard Supply Service - Administarive Charge (if applicable)	428	0.25	107.00	428	0.25	107.00	0.00	0.00%	1.40%
Sub-Total: Regulatory			288.15			293.66	5.50	1.91%	3.85%
Debt Retirement Charge	25000	0.0020	50.00	25000	0.0020	50.00	0.00	0.00%	0.66%
Total Bill Before Taxes			3832.83			6752.98	2920.15	76.19%	88.50%
GST / HST		5%	191.64		13%	877.89	686.25	358.09%	11.50%
Total Bill			**$ 4,024.47**			**$ 7,630.86**	**$ 3,606.40**	89.61%	100.00%

Algoma Power Inc.
2011 Distribution Rate Impact Module
2010 Electricity Distribution Rate Application
EB-2009-0278
June 1, 2010
Amendment Filed June 7, 2010

Electricity Distribution Impacts
Rates Effective January 1, 2011

Monthly Rates and Charges	Metric	Proposed July 1, 2010	Proposed January 1, 2011
Residential - R1			
Monthly Service Charge	$	21.53	21.96
Smart Meter Rate Adder	$	1.00	1.00
Monthly Service Charge Rate Adder # 1	$		
Monthly Service Charge Rate Adder # 2	$		
Distribution Volumetric Rate	$/kWh	0.0303	0.0309
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012		0.0054	0.0054
Distribution Volumetric Rate Rate Adder # 2			
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kWh	(0.0041)	
Deferral Account Rate Rider # 2			
Retail Transmission Rate - Network Service Rate	$/kWh	0.0053	0.0053
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0013	0.0013
Special Purpose Charge	$/kWh	0.0003725	0.0003725
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25
Residential - R2			
Monthly Service Charge	$	628.91	641.48
Smart Meter Rate Adder	$	1.00	1.00
Monthly Service Charge Rate Adder # 1	$		
Monthly Service Charge Rate Adder # 2	$		
Distribution Volumetric Rate	$/kW	2.5899	2.6417
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012		0.0044	0.0044
Distribution Volumetric Rate Rate Adder # 2			
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kW	(0.2025)	
Deferral Account Rate Rider # 2			
Retail Transmission Rate - Network Service Rate	$/kW	1.9737	1.9737
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7882	1.7882
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	$/kW	2.0937	2.0937
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	$/kW	1.9763	1.9763
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0013	0.0013
Special Purpose Charge	$/kWh	0.0003725	0.0003725
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25
Seasonal			
Monthly Service Charge	$	24.00	24.00
Smart Meter Rate Adder	$	1.00	1.00
Monthly Service Charge Rate Adder # 1	$		
Monthly Service Charge Rate Adder # 2	$		
Distribution Volumetric Rate	$/kWh	0.0891	0.0852
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012		0.0083	0.0083
Distribution Volumetric Rate Rate Adder # 2 - effective until December 31, 2015			0.0307
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kWh	(0.0041)	
Deferral Account Rate Rider # 2			
Retail Transmission Rate - Network Service Rate	$/kWh	0.0053	0.0053
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0013	0.0013
Special Purpose Charge	$/kWh	0.0003725	0.0003725
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25
Street Lighting			
Monthly Service Charge	$	0.98	1.08
Smart Meter Rate Adder	$	-	-
Monthly Service Charge Rate Adder # 1	$		
Monthly Service Charge Rate Adder # 2	$		
Distribution Volumetric Rate	$/kWh	0.1205	0.2208
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012		0.0219	0.0219
Distribution Volumetric Rate Rate Adder # 2			
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kWh	(0.0016)	
Deferral Account Rate Rider # 2			
Retail Transmission Rate - Network Service Rate	$/kW	1.4885	1.4885
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3824	1.3824
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0013	0.0013
Special Purpose Charge	$/kWh	0.0003725	0.0003725
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25
Other			
Debt Retirement Charge	$/kWh	0.0020	0.0020
Energy - First Tier	$/kWh	0.0650	0.0650
Energy - Second Tier	$/kWh	0.0750	0.0750
Loss Factor			
Total Loss Factor		1.0864	1.0864
GST / HST		13%	13%

Electricity Distribution Impacts
Rates Effective January 1, 2011

Residential - R1	Metric	Proposed July 1, 2010	Proposed January 1, 2011
Monthly Service Charge	$	21.53	21.96
Smart Meter Rate Adder	$	1.00	1.00
Monthly Service Charge Rate Adder # 1	$	-	-
Monthly Service Charge Rate Adder # 2	$	-	-
Distribution Volumetric Rate	$/kWh	0.0303	0.0309
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012		0.0054	0.0054
Distribution Volumetric Rate Rate Adder # 2		-	-
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kWh	(0.0041)	-
Deferral Account Rate Rider # 2		-	-
Retail Transmission Rate - Network Service Rate	$/kWh	0.0053	0.0053
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0013	0.0013
Special Purpose Charge	$/kWh	0.0004	0.0004
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	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	34.12%
Energy, Second Tier (kWh)	119	0.0750	8.93	119	0.0750	8.93	0.00	0.00%	6.25%
Sub-Total: Energy			57.68			57.68	0.00	0.00%	40.37%
Monthly Service Charge	1	21.53	21.53	1	21.96	21.96	0.43	2.00%	15.37%
Smart Meter Rate Adder	1	1.00	1.00	1	1.00	1.00	0.00	0.00%	0.70%
Monthly Service Charge Rate Adder # 1	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Monthly Service Charge Rate Adder # 2	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	800	0.0303	24.24	800	0.0309	24.72	0.48	1.98%	17.30%
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	800	0.0054	4.32	800	0.0054	4.32	0.00	0.00%	3.02%
Distribution Volumetric Rate Rate Adder # 2	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
Deferral Account Rate Rider # 1- effective until December 31, 2010	800	-0.0041	-3.28	800	0.0000	0.00	3.28	-100.00%	0.00%
Deferral Account Rate Rider # 2	800	0.0000	0.00	800	0.0000	0.00	0.00	0.00%	0.00%
Total: Distribution			47.81			52.00	4.19	8.76%	36.39%
Retail Transmission Rate - Network Service Rate	869	0.0053	4.61	869	0.0053	4.61	0.00	0.00%	3.22%
Retail Transmission Rate - Line and Transformation Connection Service Rate	869	0.0050	4.35	869	0.0050	4.35	0.00	0.00%	3.04%
Total: Retail Transmission			8.95			8.95	0.00	0.00%	6.26%
Sub-Total: Delivery (Distribution and Retail Transmission)			56.76			60.95	4.19	7.38%	42.65%
Wholesale Market Service Rate	869	0.0052	4.52	869	0.0052	4.52	0.00	0.00%	3.16%
Rural Rate Protection Charge	869	0.0013	1.13	869	0.0013	1.13	0.00	0.00%	0.79%
Special Purpose Charge	869	0.0004	0.32	869	0.0004	0.32	0.00	0.00%	0.23%
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			6.22			6.22	0.00	0.00%	4.35%
Debt Retirement Charge	800	0.0020	1.60	800	0.0020	1.60	0.00	0.00%	1.12%
Total Bill Before Taxes			122.27			126.46	4.19	3.43%	88.50%
GST / HST		13%	15.89		13%	16.44	0.54	3.43%	11.50%
Total Bill			**$ 138.16**			**$ 142.90**	**$ 4.73**	3.43%	100.00%

Electricity Distribution Impacts
Rates Effective January 1, 2011

Residential - R2	Metric	Proposed July 1, 2010	Proposed January 1, 2011
Monthly Service Charge	$	628.91	641.48
Smart Meter Rate Adder	$	1.00	1.00
Monthly Service Charge Rate Adder # 1	$	-	-
Monthly Service Charge Rate Adder # 2	$	-	-
Distribution Volumetric Rate	$/kW	2.5899	2.6417
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012		0.0044	0.0044
Distribution Volumetric Rate Rate Adder # 2		-	-
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kW	(0.2025)	-
Deferral Account Rate Rider # 2		-	-
Retail Transmission Rate - Network Service Rate	$/kW	1.9737	1.9737
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7882	1.7882
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	$/kW	2.0937	2.0937
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	$/kW	1.9763	1.9763
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0013	0.0013
Special Purpose Charge	$/kWh	0.0004	0.0004
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

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

Loss Factor	1.0864

Residential - R2	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Impacts $	Impacts %	% of Total Bill
Energy, First Tier (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	0.42%
Energy, Second Tier (kWh)	97026	0.0750	7276.95	97026	0.0750	7276.95	0.00	0.00%	62.31%
Sub-Total: Energy			7325.70			7325.70	0.00	0.00%	62.73%
Monthly Service Charge	1	628.91	628.91	1	641.48	641.48	12.57	2.00%	5.49%
Smart Meter Rate Adder	1	1.00	1.00	1	1.00	1.00	0.00	0.00%	0.01%
Monthly Service Charge Rate Adder # 1	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Monthly Service Charge Rate Adder # 2	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	225	2.5899	582.73	225	2.6417	594.38	11.66	2.00%	5.09%
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	225	0.0044	0.99	225	0.0044	0.99	0.00	0.00%	0.01%
Distribution Volumetric Rate Rate Adder # 2	225	0.0000	0.00	225	0.0000	0.00	0.00	0.00%	0.00%
Deferral Account Rate Rider # 1- effective until December 31, 2010	225	-0.2025	-45.56	225	0.0000	0.00	45.56	-100.00%	0.00%
Deferral Account Rate Rider # 2	225	0.0000	0.00	225	0.0000	0.00	0.00	0.00%	0.00%
Total: Distribution			1168.065			1237.85	69.79	5.97%	10.60%
Retail Transmission Rate - Network Service Rate	244	1.9737	482.45	244	1.9737	482.45	0.00	0.00%	4.13%
Retail Transmission Rate - Line and Transformation Connection Service Rate	244	1.7882	437.11	244	1.7882	437.11	0.00	0.00%	3.74%
Total: Retail Transmission			919.56			919.56	0.00	0.00%	7.87%
Sub-Total: Delivery (Distribution and Retail Transmission)			2087.62			2157.41	69.79	3.34%	18.47%
Wholesale Market Service Rate	97776	0.0052	508.44	97776	0.0052	508.44	0.00	0.00%	4.35%
Rural Rate Protection Charge	97776	0.0013	127.11	97776	0.0013	127.11	0.00	0.00%	1.09%
Special Purpose Charge	97776	0.0004	36.42	97776	0.0004	36.42	0.00	0.00%	0.31%
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			672.22			672.22	0.00	0.00%	5.76%
Debt Retirement Charge	90000	0.0020	180.00	90000	0.0020	180.00	0.00	0.00%	1.54%
Total Bill Before Taxes			10265.54			10335.33	69.79	0.68%	88.50%
GST / HST		13%	1334.52		13%	1343.59	9.07	0.68%	11.50%
Total Bill			**$ 11,600.06**			**$ 11,678.92**	**$ 78.86**	0.68%	100.00%

Electricity Distribution Impacts
Rates Effective January 1, 2011

Residential Customers with an Interval Meter

Residential - R2	Metric	Proposed July 1, 2010	Proposed January 1, 2011
Monthly Service Charge	$	628.91	641.48
Smart Meter Rate Adder	$	1.00	1.00
Monthly Service Charge Rate Adder # 1	$	-	-
Monthly Service Charge Rate Adder # 2	$	-	-
Distribution Volumetric Rate	$/kW	2.5899	2.6417
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012		0.0044	0.0044
Distribution Volumetric Rate Rate Adder # 2		-	-
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kW	(0.2025)	-
Deferral Account Rate Rider # 2		-	-
Retail Transmission Rate - Network Service Rate	$/kW	1.9737	1.9737
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7882	1.7882
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	$/kW	2.0937	2.0937
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	$/kW	1.9763	1.9763
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0013	0.0013
Special Purpose Charge	$/kWh	0.0004	0.0004
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	65,000	kWh	225 kW	Loss Factor 1.0864
RPP Tier One	750	kWh	Load Factor 39.6%	

Residential - R2	Volume	Rate	Charge	Volume	Rate	Charge	Impacts		
		$	$		$	$	$	%	% of Total Bill
Energy, First Tier (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	0.53%
Energy, Second Tier (kWh)	69866	0.0750	5239.95	69866	0.0750	5239.95	0.00	0.00%	56.99%
Sub-Total: Energy			5288.70			5288.70	0.00	0.00%	57.52%
Monthly Service Charge	1	628.91	628.91	1	641.48	641.48	12.57	2.00%	6.98%
Smart Meter Rate Adder	1	1.00	1.00	1	1.00	1.00	0.00	0.00%	0.01%
Monthly Service Charge Rate Adder # 1	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Monthly Service Charge Rate Adder # 2	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	225	2.5899	582.73	225	2.6417	594.38	11.66	2.00%	6.46%
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	225	0.0044	0.99	225	0.0044	0.99	0.00	0.00%	0.01%
Distribution Volumetric Rate Rate Adder # 2	225	0.0000	0.00	225	0.0000	0.00	0.00	0.00%	0.00%
Deferral Account Rate Rider # 1- effective until December 31, 2010	225	-0.2025	-45.56	225	0.0000	0.00	45.56	-100.00%	0.00%
Deferral Account Rate Rider # 2	225	0.0000	0.00	225	0.0000	0.00	0.00	0.00%	0.00%
Total: Distribution			1168.065			1237.85	69.79	5.97%	13.46%
Retail Transmission Rate - Network Service Rate - Interval Meter > 1,000 kW	244	2.0937	511.78	244	2.0937	511.78	0.00	0.00%	5.57%
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval > 1,000 kW	244	1.9763	483.09	244	1.9763	483.09	0.00	0.00%	5.25%
Total: Retail Transmission			994.87			994.87	0.00	0.00%	10.82%
Sub-Total: Delivery (Distribution and Retail Transmission)			2162.94			2232.72	69.79	3.23%	24.28%
Wholesale Market Service Rate	70616	0.0052	367.20	70616	0.0052	367.20	0.00	0.00%	3.99%
Rural Rate Protection Charge	70616	0.0013	91.80	70616	0.0013	91.80	0.00	0.00%	1.00%
Special Purpose Charge	70616	0.0004	26.30	70616	0.0004	26.30	0.00	0.00%	0.29%
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			485.56			485.56	0.00	0.00%	5.28%
Debt Retirement Charge	65000	0.0020	130.00	65000	0.0020	130.00	0.00	0.00%	1.41%
Total Bill Before Taxes			8067.19			8136.98	69.79	0.87%	88.50%
GST / HST		13%	1048.74		13%	1057.81	9.07	0.87%	11.50%
Total Bill			**$ 9,115.93**			**$ 9,194.79**	**$ 78.86**	0.87%	100.00%

Electricity Distribution Impacts
Rates Effective January 1, 2011

Seasonal	Metric	Proposed July 1, 2010	Proposed January 1, 2011
Monthly Service Charge	$	24.00	24.00
Smart Meter Rate Adder	$	1.00	1.00
Monthly Service Charge Rate Adder # 1	$	-	-
Monthly Service Charge Rate Adder # 2	$	-	-
Distribution Volumetric Rate	$/kWh	0.0891	0.0852
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	0	0.0083	0.0083
Distribution Volumetric Rate Rate Adder # 2 - effective until December 31, 2015	0	-	0.0307
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kWh	(0.0041)	-
Deferral Account Rate Rider # 2	0	-	-
Retail Transmission Rate - Network Service Rate	$/kWh	0.0053	0.0053
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050	0.0050
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0013	0.0013
Special Purpose Charge	$/kWh	0.0004	0.0004
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

Consumption	1,000 kWh	kW	
RPP Tier One	750 kWh	Load Factor	

Loss Factor	1.0864

Seasonal	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Impacts $	Impacts %	Impacts % of Total Bill
Energy, First Tier (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	17.67%
Energy, Second Tier (kWh)	336	0.0750	25.23	336	0.0750	25.23	0.00	0.00%	9.15%
Sub-Total: Energy			73.98			73.98	0.00	0.00%	26.82%
Monthly Service Charge	1	24	24	1	24.00	24.00	0.00	0.00%	8.70%
Smart Meter Rate Adder	1	1.00	1.00	1	1.00	1.00	0.00	0.00%	0.36%
Monthly Service Charge Rate Adder # 1	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Monthly Service Charge Rate Adder # 2	1	0.00	0.00	1	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	1000	0.0891	89.10	1000	0.0852	85.20	-3.90	-4.38%	30.89%
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	1000	0.0083	8.30	1000	0.0083	8.30	0.00	0.00%	3.01%
Distribution Volumetric Rate Rate Adder # 2 - effective until December 31, 2015	1000	0.0000	0.00	1000	0.0307	30.70	30.70	0.00%	11.13%
Deferral Account Rate Rider # 1- effective until December 31, 2010	1000	-0.0041	-4.10	1000	0.0000	0.00	4.10	-100.00%	0.00%
Deferral Account Rate Rider # 2	1000	0.0000	0.00	1000	0.0000	0.00	0.00	0.00%	0.00%
Total: Distribution			118.3			149.20	30.90	26.12%	54.09%
Retail Transmission Rate - Network Service Rate	1086	0.0053	5.76	1086	0.0053	5.76	0.00	0.00%	2.09%
Retail Transmission Rate - Line and Transformation Connection Service Rate	1086	0.0050	5.43	1086	0.0050	5.43	0.00	0.00%	1.97%
Total: Retail Transmission			11.19			11.19	0.00	0.00%	4.06%
Sub-Total: Delivery (Distribution and Retail Transmission)			129.49			160.39	30.90	23.86%	58.15%
Wholesale Market Service Rate	1086	0.0052	5.65	1086	0.0052	5.65	0.00	0.00%	2.05%
Rural Rate Protection Charge	1086	0.0013	1.41	1086	0.0013	1.41	0.00	0.00%	0.51%
Special Purpose Charge	1086	0.0004	0.40	1086	0.0004	0.40	0.00	0.00%	0.15%
Standard Supply Service - Administarive Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.09%
Sub-Total: Regulatory			7.72			7.72	0.00	0.00%	2.80%
Debt Retirement Charge	1000	0.0020	2.00	1000	0.0020	2.00	0.00	0.00%	0.73%
Total Bill Before Taxes			213.19			244.09	30.90	14.49%	88.50%
GST / HST		13%	27.71		13%	31.73	4.02	14.49%	11.50%
Total Bill			**$ 240.90**			**$ 275.82**	**$ 34.92**	14.49%	100.00%

Electricity Distribution Impacts
Rates Effective January 1, 2011

Street Lighting	Metric	Proposed July 1, 2010	Proposed January 1, 2011
Monthly Service Charge	$	0.98	1.08
Smart Meter Rate Adder	$	-	-
Monthly Service Charge Rate Adder # 1	$	-	-
Monthly Service Charge Rate Adder # 2	$	-	-
Distribution Volumetric Rate	$/kWh	0.1205	0.2208
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	0	0.0219	0.0219
Distribution Volumetric Rate Rate Adder # 2 - effective until December 31, 2015	0	-	-
Deferral Account Rate Rider # 1- effective until December 31, 2010	$/kWh	(0.0016)	-
Deferral Account Rate Rider # 2	0	-	-
Retail Transmission Rate - Network Service Rate	$/kW	1.4885	1.4885
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3824	1.3824
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0013	0.0013
Special Purpose Charge	$/kWh	0.0004	0.0004
Standard Supply Service - Administarive Charge (if applicable)	$	0.25	0.25

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

Loss Factor	1.0864

Street Lighting	Volume	Rate	Charge	Volume	Rate	Charge	Impacts		
		$	$		$	$	$	%	% of Total Bill
Energy, First Tier (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.00%	0.47%
Energy, Second Tier (kWh)	26410	0.0750	1980.75	26410	0.0750	1980.75	0.00	0.00%	19.21%
Sub-Total: Energy			2029.50			2029.50	0.00	0.00%	19.68%
Monthly Service Charge	428	0.98	419.44	428	1.08	462.24	42.80	10.20%	4.48%
Smart Meter Rate Adder	428	0.00	0.00	428	0.00	0.00	0.00	0.00%	0.00%
Monthly Service Charge Rate Adder # 1	428	0.00	0.00	428	0.00	0.00	0.00	0.00%	0.00%
Monthly Service Charge Rate Adder # 2	428	0.00	0.00	428	0.00	0.00	0.00	0.00%	0.00%
Distribution Volumetric Rate	25000	0.1205	3012.50	25000	0.2208	5520.00	2507.50	83.24%	53.53%
Distribution Volumetric Rate Rate Adder # 1- effective until December 31, 2012	25000	0.0219	547.50	25000	0.0219	547.50	0.00	0.00%	5.31%
Distribution Volumetric Rate Rate Adder # 2 - effective until December 31, 2015	25000	0.0000	0.00	25000	0.0000	0.00	0.00	0.00%	0.00%
Deferral Account Rate Rider # 1- effective until December 31, 2010	25000	-0.0016	-40.00	25000	0.0000	0.00	40.00	-100.00%	0.00%
Deferral Account Rate Rider # 2	25000	0.0000	0.00	25000	0.0000	0.00	0.00	0.00%	0.00%
Total: Distribution			3939.44			6529.74	2590.30	65.75%	63.32%
Retail Transmission Rate - Network Service Rate	77.6	1.4885	115.56	77.6	1.4885	115.56	0.00	0.00%	1.12%
Retail Transmission Rate - Line and Transformation Connection Service Rate	77.6	1.3824	107.32	77.6	1.3824	107.32	0.00	0.00%	1.04%
Total: Retail Transmission			222.88			222.88	0.00	0.00%	2.16%
Sub-Total: Delivery (Distribution and Retail Transmission)			4162.32			6752.62	2590.30	62.23%	65.48%
Wholesale Market Service Rate	27160	0.0052	141.23	27160	0.0052	141.23	0.00	0.00%	1.37%
Rural Rate Protection Charge	27160	0.0013	35.31	27160	0.0013	35.31	0.00	0.00%	0.34%
Special Purpose Charge	27160	0.0004	10.12	27160	0.0004	10.12	0.00	0.00%	0.10%
Standard Supply Service - Administarive Charge (if applicable)	428	0.25	107.00	428	0.25	107.00	0.00	0.00%	1.04%
Sub-Total: Regulatory			293.66			293.66	0.00	0.00%	2.85%
Debt Retirement Charge	25000	0.0020	50.00	25000	0.0020	50.00	0.00	0.00%	0.48%
Total Bill Before Taxes			6535.48			9125.78	2590.30	39.63%	88.50%
GST / HST		13%	849.61		13%	1186.35	336.74	39.63%	11.50%
Total Bill			**$ 7,385.09**			**$ 10,312.13**	**$ 2,927.04**	39.63%	100.00%

STREET LIGHT BILLING - DISCUSSION

Ontario Regulation 445/07, states:

> **RECLASSIFYING CERTAIN CLASSES OF CONSUMERS AS RESIDENTIAL-RATE CLASS CUSTOMERS: SECTION 78 OF THE ACT**
>
> **Treating certain consumers as residential-rate class customers**
>
> **1.** (1) For the purposes of fixing just and reasonable rates for a distributor under section 78 of the Act, the Board shall ensure that a consumer who falls into one of the following categories shall be treated as a residential-rate class customer if the criteria in subsection (2) are satisfied:
>
> 1. A consumer who is charged by the distributor as a general service, less than 50 kilowatt demand rate-class customer.
>
> 2. A consumer who is charged by the distributor for the distribution of electricity as having a demand of greater than 50 kilowatt rate-class customer.
>
> (2) A consumer who falls into one of the categories set out in subsection (1) shall be treated as a residential-rate class customer if,
>
> (a) the distributor that serves the consumer is licensed to serve in an area of not less than 10,000 square kilometres in size; and
>
> (b) the average customer density for the distributor is less than seven customers per kilometre of distribution line.
>
> (3) The rate classifications to ensure that consumers that fall into a category set out in subsection (1) are treated as residential-rate class customers if the criteria in subsection (2) are satisfied take effect on the date of the distributor's next rate order made on or after August 15, 2007.

And, Ontario Regulation 442/01, states:

> "residential premises" means a dwelling occupied as a residence continuously for at least eight months of the year…"

In the Decision and Order, EB-2007-0744, the Street Lighting customers were inadvertently not included within the RRRP. However, Ontario Regulation 445/07 does not imply that

Street Lighting customers should not be treated as a residential rate class for the intent of this Regulation.

The purpose of this discussion is to request that the Street Lighting classification be included in the RRRP funding by reclassifying these customers as Residential.

It is clear the Street Lighting in the Algoma Region is a matter of public necessity and public security. There are 32 Street Lighting customers in the API service territory with the Town of Wawa being the single largest customer with 428 street lighting connections. Eight of the Street Lighting customers are either First Nations or located within First Nations communities with a total of 128 street light connections. The remaining customers are associated with remote roadway lighting and remote communities scattered throughout the API service territory.

The Board's Decision and Order, EB-2007-0744, states on page 3;

> *"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."*

It is clear from the cost allocation methodology applied here, and is consistent with the Board's direction related to cost allocation, that conventional rate making cannot result in a rate that is reasonable from the ratepayer's point of view.

API requests that the Board recognize the Street Light classification as a Residential class in order to allow costs of the Class to be recovered through a suitably indexed formula of funding from rates in combination with RRRP funding.

DISCUSSION OF REGULATORY DEFERRAL AND VARIANCE ACCOUNTS

Overview

API is applying to recover its audited December 31, 2009 year end balances in its Regulatory Asset accounts, with the exception of the Smart Meters (OEB account 1556), Deferred Rate Impact Amounts (OEB account 1574) and Recovery of Regulatory Asset Balances (OEB account 1590).

A summary of the account balances for 2005, 2006, 2007, 2008 and 2009 is provided in the table below. Schedule 2 of the Exhibit provides details for each OEB account including opening and closing balances, principal amounts, and carrying charges for the period December 31, 2005 to December 31, 2009.

Summary of Regulated Deferral & Variance Accounts

Account Description	OEB Account	2005	2006	2007	2008	2009
RSVA - Wholesale Market Service Charge	1580	340,048	133,349	(131,856)	(423,766)	(447,296)
RSVA - Retail Transmission Network Charge	1584	25,812	76,242	84,122	(80,627)	(124,143)
RSVA - Retail Transmission Connection Charge	1586	(374,230)	(436,955)	(520,398)	(399,601)	(424,692)
RSVA - Power excluding Global Adjustment	1588	189,204	1,433,109	1,670,818	1,765,518	3,117,101
RSVA - Power Global Adjustment	1588	(694,543)	28,628	106,710	(30,785)	(66,815)
Other Regulatory Assets	1508	155,994	155,994	155,994		6,602
Misc. Deferred Debits (Section 71)	1525					411,630
Smart Meter OM&A Variance	1556				110,347	1,937,416
Qualifying Transition Costs	1570	1,153,699	1,252,491	1,302,249		
Deferred Rate Impact Amounts	1574	10,166,184	13,606,090	17,185,022	14,890,316	
Deferred Rate Impact Amounts - Seasonal deferral	1574				1,106,132	1,950,260
Recovery of Regulatory Asset Balances	1590	(1,024,149)	(2,154,196)	(3,296,836)	(899,952)	(771,737)
Total		9,938,019	14,094,752	16,555,825	16,037,582	5,588,326

Carrying Charges on Deferral and Variance Accounts

Account balances include carrying charges, as specified in the APH (July 2007), Article 220), which are calculated using the OEB-approved interest rates on the monthly opening balance less any accumulated interest in the account. API has not historically applied carrying charges to its RSVA accounts. The calculations of the carrying charges are included in Schedule 4 of this Exhibit.

Activity in RSVA Accounts from January 1, 2005 to December 31, 2009

The balances in the commodity accounts as at December 31, 2009 include principal and carrying charges accumulated in the accounts since January 1, 2005. The balances in the commodity accounts as at December 31, 2004 were approved for recovery in API's 2007 EDR Application and as such, the December 31, 2004 balances were transferred to USoA Account 1590 – Recovery of Regulatory Asset Balances – in accordance with the APH.

Activity in Non-RSVA Accounts from January 1, 2005 to December 31, 2007

The balances of these accounts as at December 31, 2007 include principal and carrying charges accumulated in these accounts since January 1, 2005. The balances, if any, in the deferral accounts at December 31, 2004 that were approved for recovery in API's 2007 EDR Application and as such the balances at December 31, 2004 were transferred to USoA account 1590 – Recovery of Regulatory Asset Balances – in accordance with the APH.

Activity in Account 1525 – Miscellaneous Deferred Debits

The activity in Account 1525, Miscellaneous Deferred Debits is discussed in detail in Tab 2, Schedule 2 of this Exhibit.

Activity in Account 1574 – Deferred Rate Impact Amounts

The activity in Account 1574, Deferred Rate Impact Amounts – Rate Mitigation, is discussed in detail in Exhibit 1, Tab 1, Schedule 17.

Disposition Proposed

API proposes the disposition of the deferral and variance accounts as listed in the Table below. The Table provides the principal balance as of December 31, 2009, interest/carrying charges to December 31, 2009 and forecasted interest to June 30, 2010. Interest to June 30, 2010 was calculated using the prescribed interest rate in effect for Q1 and Q2 2010.

Variance and Deferral Accounts for Disposition

Account Description	OEB Account	Principal Balance at December 31, 2009	Interest Balance at December 31, 2009	Interest to June 30, 2010	Total
RSVA - Wholesale Market Service Charge	1580	(429,311)	(17,985)	(1,181)	(448,477)
RSVA - Retail Transmission Network Charge	1584	(131,681)	7,538	(362)	(124,505)
RSVA - Retail Transmission Connection Charge	1586	(388,944)	(35,748)	(1,070)	(425,762)
RSVA - Power excluding Global Adjustment	1588	2,940,434	176,667	8,086	3,125,187
RSVA - Power Global Adjustment	1588	(20,821)	(45,994)	(57)	(66,872)
Other Regulatory Assets	1508	6,602	-	18	6,620
Misc. Deferred Debits (Section 71)	1525	410,695	935	1,129	412,759
Total		2,386,974	85,413	6,563	2,478,950

The total of deferral and variance accounts for disposition is a debit balance (under recovery) of $2,478,950.

API used the OEB's 2006 EDR Regulatory Asset model to calculate the allocation of the deferral and variance account balances and also calculate the variable rate rider to be applied to each customer class. Tab 2, Schedule 1 includes worksheets showing the calculation of the rate riders by customer class for disposition of the deferral and variance account balances.

Disposition of Account 1556 – Smart Meter Variance Account

Account 1556, Smart Meter Variance, is discussed in Exhibit 10.

Disposition of Account 1574 – Deferred Rate Impact – Seasonal Deferral Account

Account 1574, Deferred Rate Impact Amounts – Seasonal Deferral, is discussed in Exhibit 8, Tab 1, Schedule 3.

Disposition of Account 1590 – Recovery of Regulatory Asset Balances

Account 1590, Recovery of Regulatory Asset Balances, is not proposed for disposition at this time. API received approval from the OEB for the final recovery of regulatory assets accumulated to December 31, 2004 through a rate rider as part of its 2007 Board Approved Distribution rates. The recovery period was for two years beginning January 1, 2009. At the end of the two year recovery period, API will apply to the OEB to true up the balance in Account 1590 as per Phase 2 Decision for the Review and Recovery of Regulatory Assets.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Algoma Power Inc.	**LICENCE NUMBER**	ED-2009-0072
NAME OF CONTACT	Mark Faught	**DOCID NUMBER**	EB-2009-0278
E-mail Address	mfaught@glp.on.ca		
VERSION NUMBER	v3.0	**PHONE NUMBER**	705-941-5602
Date	1-Jun-10	**(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:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

			2005									
Account Description		**Account Number**	**Opening Principal Amounts as of Jan-1-05 1**	**Transactions (additions) during 2005, excluding interest and adjustments 6**	**Transactions (reductions) during 2005, excluding interest and adjustments 6**	**Adjustments during 2005 - instructed by Board 2**	**Adjustments during 2005 - other 3**	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**
RSVA - Wholesale Market Service Charge		1580	$ 186,623	$ 153,425				$ 340,048			$ -
RSVA - One-time Wholesale Market Service		1582						$ -			$ -
RSVA - Retail Transmission Network Charge		1584	$ (4,479)	$ 30,291				$ 25,812			$ -
RSVA - Retail Transmission Connection Charge		1586	$ (276,208)	$ (98,022)				$ (374,230)			$ -
RSVA - Power (excluding Global Adjustment)		1588	$ 175,161	$ 14,043				$ 189,204			$ -
RSVA - Power - Sub-Account - Global Adjustment 4		1588		$ (694,543)				$ (694,543)			$ -
	Sub-Totals		$ 81,097	$ (594,806)		$ -	$ -	$ (513,709)	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		1508	$ 55,582	$ 100,412				$ 155,994			$ -
Other Regulatory Assets - Sub-Account - Pension Contributions		1508						$ -			$ -
Other Regulatory Assets - Sub-Account - Other 7		1508						$ -			$ -
Other Regulatory Assets - Sub-Account - Other 7		1508						$ -			$ -
Other Regulatory Assets - Sub-Account - Other 7		1508						$ -			$ -
Retail Cost Variance Account - Retail		1518						$ -			$ -
Retail Cost Variance Account - STR		1548						$ -			$ -
Misc. Deferred Debits		1525						$ -			$ -
LV Variance Account		1550						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital		1555						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries		1555						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Met		1555						$ -			$ -
Smart Meter OM&A Variance		1556						$ -			$ -
Conservation and Demand Management Expenditures and Recoveries		1565						$ -			$ -
CDM Contra		1566						$ -			$ -
Qualifying Transition Costs 5		1570	$ 915,092	n/a	n/a			$ 915,092	$ 188,125	$ 50,482	$ 238,607
Pre-Market Opening Energy Variances Total 5		1571		n/a	n/a			$ -			$ -
Extra-Ordinary Event Costs		1572						$ -			$ -
Deferred Rate Impact Amounts		1574	$ 6,832,926	$ 3,333,258				$ 10,166,184			$ -
Other Deferred Credits		2425						$ -			$ -
	Sub-Totals		$ 7,803,600	$ 3,433,670	$ -	$ -	$ -	$ 11,237,270	$ 188,125	$ 50,482	$ 238,607
Deferred Payments in Lieu of Taxes		1562				**see PILs reconciliation requested**					
2006 PILs & Taxes Variance		1592				**see PILs reconciliation requested**					
	Sub-Totals					**see PILs reconciliation requested**					
	Total		$ 7,884,697	$ 2,838,864	$ -	$ -	$ -	$ 10,723,561	$ 188,125	$ 50,482	$ 238,607
The following is not included in the total claim but is included on a memo basis:											
Deferred PILs Contra Account 8		1563				**see PILs reconciliation requested**					
Deferred Rate Impact Amounts - Seasonal deferral		1574									
Recovery of Regulatory Asset Balances		1590	$ (32,674)	$ (991,475)				$ (1,024,149)			$ -

Q:\AP_2010_EDR\Financial Worksheets\DEFERRAL ACCOUNTS\Final\[AL_E9_T1_S2(Continuity_Schedule)20100525.XLS]Continuity Schedule

[1] As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis
[2] Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.
[3] Provide supporting statement indicating nature of this adjustments and periods they relate to
[4] Not included in sub-total
[9] Interest projected on December 31, 2008 closing principal balance.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Algoma Power Inc.
NAME OF CONTACT	Mark Faught
E-mail Address	mfaught@glp.on.ca
VERSION NUMBER	v3.0
Date	1-Jun-10

Account Description		Account Number	Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments 6	Transactions (reductions) during 2006, excluding interest and adjustments 6	Adjustments during 2006 - instructed by Board 2	Adjustments during 2006 - other 3	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec31-06	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Interest Amounts as of Dec-31-06
			2006										
RSVA - Wholesale Market Service Charge		1580	$ 340,048	$ (206,699)					$ 133,349	$ -			$ -
RSVA - One-time Wholesale Market Service		1582	$ -						$ -	$ -			$ -
RSVA - Retail Transmission Network Charge		1584	$ 25,812	$ 50,430					$ 76,242	$ -			$ -
RSVA - Retail Transmission Connection Charge		1586	$ (374,230)	$ (62,725)					$ (436,955)	$ -			$ -
RSVA - Power (excluding Global Adjustment)		1588	$ 189,204	$ 1,243,905					$ 1,433,109	$ -			$ -
RSVA - Power - Sub-Account - Global Adjustment 4		1588	$ (694,543)	$ 723,172					$ 28,628	$ -			$ -
	Sub-Totals		$ (513,709)	$ 1,748,083		$ -	$ -	$ -	$ 1,234,374	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		1508	$ 155,994						$ 155,994	$ -			$ -
Other Regulatory Assets - Sub-Account - Pension Contributions		1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Other 7		1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Other 7		1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Other 7		1508	$ -						$ -	$ -			$ -
Retail Cost Variance Account - Retail		1518	$ -						$ -	$ -			$ -
Retail Cost Variance Account - STR		1548	$ -						$ -	$ -			$ -
Misc. Deferred Debits		1525	$ -						$ -	$ -			$ -
LV Variance Account		1550	$ -						$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital		1555	$ -						$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries		1555	$ -						$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Met		1555	$ -						$ -	$ -			$ -
Smart Meter OM&A Variance		1556	$ -						$ -	$ -			$ -
Conservation and Demand Management Expenditures and Recoveries		1565	$ -						$ -	$ -			$ -
CDM Contra		1566	$ -						$ -	$ -			$ -
Qualifying Transition Costs 5		1570	$ 915,092	n/a	n/a				$ 915,092	$ 238,607	$ 98,792		$ 337,399
Pre-Market Opening Energy Variances Total 5		1571	$ -	n/a	n/a				$ -	$ -			$ -
Extra-Ordinary Event Costs		1572	$ -						$ -	$ -			$ -
Deferred Rate Impact Amounts		1574	$ 10,166,184	$ 3,439,906					$ 13,606,090	$ -			$ -
Other Deferred Credits		2425	$ -						$ -	$ -			$ -
	Sub-Totals		$ 11,237,270	$ 3,439,906	$ -	$ -	$ -	$ -	$ 14,677,176	$ 238,607	$ 98,792	$ -	$ 337,399
Deferred Payments in Lieu of Taxes		1562					see PILs reconciliation requested						
2006 PILs & Taxes Variance		1592					see PILs reconciliation requested						
	Sub-Totals						see PILs reconciliation requested						
	Total		$ 10,723,561	$ 5,187,988	$ -	$ -	$ -	$ -	$ 15,911,549	$ 238,607	$ 98,792	$ -	$ 337,399
The following is not included in the total claim but is included on a memo basis:													
Deferred PILs Contra Account 8		1563					see PILs reconciliation requested						
Deferred Rate Impact Amounts - Seasonal deferral		1574											
Recovery of Regulatory Asset Balances		1590	$ (1,024,149)	$ (1,130,047)					$ (2,154,196)	$ -			$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Algoma Power Inc.
NAME OF CONTACT	Mark Faught
E-mail Address	mfaught@glp.on.ca
VERSION NUMBER	v3.0
Date	1-Jun-10

Account Description		Account Number	Opening Principal Amounts as of Jan-1-07	Transactions (additions) during 2007, excluding interest and adjustments 6	Transactions (reductions) during 2007, excluding interest and adjustments 6	Adjustments during 2007 - instructed by Board 2	Adjustments during 2007 - other 3	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec31-07	Closing Interest Amounts as of Dec-31-07
			2007								
RSVA - Wholesale Market Service Charge		1580	$ 133,349	$ (265,204)				$ (131,856)	$ -		$ -
RSVA - One-time Wholesale Market Service		1582	$ -					$ -	$ -		$ -
RSVA - Retail Transmission Network Charge		1584	$ 76,242	$ 7,879				$ 84,122	$ -		$ -
RSVA - Retail Transmission Connection Charge		1586	$ (436,955)	$ (83,444)				$ (520,398)	$ -		$ -
RSVA - Power (excluding Global Adjustment)		1588	$ 1,433,109	$ 237,709				$ 1,670,818	$ -		$ -
RSVA - Power - Sub-Account - Global Adjustment 4		1588	$ 28,628	$ 78,082				$ 106,710	$ -		$ -
	Sub-Totals		$ 1,234,374	$ (24,977)		$ -	$ -	$ 1,209,396	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		1508	$ 155,994					$ 155,994	$ -		$ -
Other Regulatory Assets - Sub-Account - Pension Contributions		1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other 7		1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other 7		1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other 7		1508	$ -					$ -	$ -		$ -
Retail Cost Variance Account - Retail		1518	$ -					$ -	$ -		$ -
Retail Cost Variance Account - STR		1548	$ -					$ -	$ -		$ -
Misc. Deferred Debits		1525	$ -					$ -	$ -		$ -
LV Variance Account		1550	$ -					$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital		1555	$ -					$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries		1555	$ -					$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Met		1555	$ -					$ -	$ -		$ -
Smart Meter OM&A Variance		1556	$ -					$ -	$ -		$ -
Conservation and Demand Management Expenditures and Recoveries		1565	$ -					$ -	$ -		$ -
CDM Contra		1566	$ -					$ -	$ -		$ -
Qualifying Transition Costs 5		1570	$ 915,092	n/a	n/a			$ 915,092	$ 337,399	$ 49,758	$ 387,157
Pre-Market Opening Energy Variances Total 5		1571	$ -	n/a	n/a			$ -	$ -		$ -
Extra-Ordinary Event Costs		1572	$ -					$ -	$ -		$ -
Deferred Rate Impact Amounts		1574	$ 13,606,090	$ 2,333,433				$ 15,939,523	$ -	$ 1,245,499	$ 1,245,499
Other Deferred Credits		2425	$ -					$ -	$ -		$ -
	Sub-Totals		$ 14,677,176	$ 2,333,433	$ -	$ -	$ -	$ 17,010,609	$ 337,399	$ 1,295,257	$ 1,632,656
Deferred Payments in Lieu of Taxes		1562				see PILs reconciliation requested					
2006 PILs & Taxes Variance		1592				see PILs reconciliation requested					
	Sub-Totals					see PILs reconciliation requested					
	Total		$ 15,911,549	$ 2,308,456	$ -	$ -	$ -	$ 18,220,005	$ 337,399	$ 1,295,257	$ 1,632,656
The following is not included in the total claim but is included on a memo basis:											
Deferred PILs Contra Account 8		1563				see PILs reconciliation requested					
Deferred Rate Impact Amounts - Seasonal deferral		1574									$ -
Recovery of Regulatory Asset Balances		1590	$ (2,154,196)	$ (1,142,641)				$ (3,296,836)	$ -		$ -

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Algoma Power Inc.
NAME OF CONTACT	Mark Faught
E-mail Address	mfaught@glp.on.ca
VERSION NUMBER	v3.0
Date	1-Jun-10

Account Description		Account Number	2008 Opening Principal Amounts as of Jan-1-08	2008 Transactions (additions) during 2008, excluding interest and adjustments 6	2008 Transactions (reductions) during 2008, excluding interest and adjustments 6	2008 Adjustments during 2008 - instructed by Board 2	2008 Adjustments during 2008 - other 3	2008 Closing Principal Balance as of Dec-31-08	2008 Opening Interest Amounts as of Jan-1-08	2008 Adjustments during 2008 - instructed by Board 2	2008 Adjustments during 2008 - other 3	2008 Interest Jan-1 to Dec31-08	2008 Closing Interest Amounts as of Dec-31-08
RSVA - Wholesale Market Service Charge		1580	$ (131,856)	$ (105,287)		$ (186,623)		$ (423,766)	$ -	$ (54,581)	$ 54,581		$ -
RSVA - One-time Wholesale Market Service		1582	$ -					$ -	$ -				$ -
RSVA - Retail Transmission Network Charge		1584	$ 84,122	$ (169,228)		$ 4,479		$ (80,627)	$ -	$ (882)	$ 882		$ -
RSVA - Retail Transmission Connection Charge		1586	$ (520,398)	$ (95,411)		$ 276,208		$ (339,601)	$ -	$ 65,690	$ (65,690)		$ -
RSVA - Power (excluding Global Adjustment)		1588	$ 1,670,818	$ 269,861		$ (175,161)		$ 1,765,518	$ -	$ (31,701)	$ 31,701		$ -
RSVA - Power - Sub-Account - Global Adjustment 4		1588	$ 106,710	$ (137,496)				$ (30,785)	$ -				$ -
	Sub-Totals		$ 1,209,396	$ (237,561)		$ (81,097)	$ -	$ 890,738	$ -	$ (21,474)	$ 21,474	$ -	$ -
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		1508	$ 155,994			$ (184,182)	$ 28,188	$ -	$ -	$ (23,427)	$ 23,427		$ -
Other Regulatory Assets - Sub-Account - Pension Contributions		1508	$ -					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other 7		1508	$ -					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other 7		1508	$ -					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other 7		1508	$ -					$ -	$ -				$ -
Retail Cost Variance Account - Retail		1518	$ -					$ -	$ -				$ -
Retail Cost Variance Account - STR		1548	$ -					$ -	$ -				$ -
Misc. Deferred Debits		1525	$ -					$ -	$ -				$ -
LV Variance Account		1550	$ -					$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital		1555	$ -					$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries		1555	$ -					$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Met		1555	$ -					$ -	$ -				$ -
Smart Meter OM&A Variance		1556	$ -	$ 110,347				$ 110,347	$ -				$ -
Conservation and Demand Management Expenditures and Recoveries		1565	$ -					$ -	$ -				$ -
CDM Contra		1566	$ -					$ -	$ -				$ -
Qualifying Transition Costs 5		1570	$ 915,092	n/a	n/a	$ (915,092)		$ -	$ 387,157	$ (331,901)	$ (55,256)	$ -	$ 0
Pre-Market Opening Energy Variances Total 5		1571	$ -	n/a	n/a			$ -	$ -				$ -
Extra-Ordinary Event Costs		1572	$ -					$ -	$ -				$ -
Deferred Rate Impact Amounts		1574	$ 15,939,523			$ (283,341)	$ (1,503,633)	$ 14,152,549	$ 1,245,499	$ (12,440)		$ (495,292)	$ 737,767
Other Deferred Credits		2425	$ -					$ -	$ -				$ -
	Sub-Totals		$ 17,010,609	$ 110,347	$ -	$ (1,382,615)	$ (1,475,445)	$ 14,262,896	$ 1,632,656	$ (367,768)	$ (31,829)	$ (495,292)	$ 737,767
Deferred Payments in Lieu of Taxes		1562					see PILs reconciliation requested						
2006 PILs & Taxes Variance		1592					see PILs reconciliation requested						
	Sub-Totals						see PILs reconciliation requested						
	Total		$ 18,220,005	$ (127,214)	$ -	$ (1,463,712)	$ (1,475,445)	$ 15,153,634	$ 1,632,656	$ (389,242)	$ (10,355)	$ (495,292)	$ 737,767
The following is not included in the total claim but is included on a memo basis:													
Deferred PILs Contra Account 8		1563					see PILs reconciliation requested						
Deferred Rate Impact Amounts - Seasonal deferral		1574	$ -				$ 1,106,132	$ 1,106,132	$ -				$ -
Recovery of Regulatory Asset Balances		1590	$ (3,296,836)	$ 672,682		$ 1,463,712	$ 128,163	$ (1,032,279)	$ -	$ 335,504	$ (128,163)	$ (75,014)	$ 132,327

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Algoma Power Inc.
NAME OF CONTACT	Mark Faught
E-mail Address	mfaught@glp.on.ca
VERSION NUMBER	v3.0
Date	1-Jun-10

Account Description	Account Number	2009 Opening Principal Amounts as of Jan-1-09	2009 Transactions (additions) during 2009, excluding interest and adjustments 6	2009 Transactions (reductions) during 2009, excluding interest and adjustments 6	2009 Adjustments during 2009 - other 3	2009 Closing Principal Balance as of Dec-31-09	2009 Opening Interest Amounts as of Jan-1-09	2009 Adjustments during 2009 - other 3	2009 Interest Jan-1 to Dec31-09	2009 Closing Interest Amounts as of Dec-31-09	Projected Interest on Dec 31 -09 balance from Jan 1, 2010 to Jun 30, 2010 9	Total Claim
RSVA - Wholesale Market Service Charge	1580	$ (423,766)	$ (5,545)			$ (429,311)	$ -	$ (13,042)	$ (4,943)	$ (17,985)	$ (1,181)	$ (448,477)
RSVA - One-time Wholesale Market Service	1582	$ -				$ -	$ -	$ -		$ -		$ -
RSVA - Retail Transmission Network Charge	1584	$ (80,627)	$ (51,054)			$ (131,681)	$ -	$ 8,786	$ (1,248)	$ 7,538	$ (362)	$ (124,505)
RSVA - Retail Transmission Connection Charge	1586	$ (339,601)	$ (49,342)			$ (388,944)	$ -	$ (31,630)	$ (4,118)	$ (35,748)	$ (1,070)	$ (425,762)
RSVA - Power (excluding Global Adjustment)	1588	$ 1,765,518	$ 1,174,915			$ 2,940,434	$ -	$ 155,647	$ 21,020	$ 176,667	$ 8,086	$ 3,125,187
RSVA - Power - Sub-Account - Global Adjustment 4	1588	$ (30,785)	$ 9,965			$ (20,821)	$ -	$ (46,943)	$ 949	$ (45,994)	$ (57)	$ (66,872)
Sub-Totals		$ 890,738	$ 1,078,939		$ -	$ 1,969,677	$ -	$ 72,818	$ 11,660	$ 84,478	$ 5,416	$ 2,059,571
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -	$ 6,602		$ -	$ 6,602	$ -	$ -		$ -	$ 18	$ 6,620
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Other 7	1508	$ -				$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Other 7	1508	$ -				$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Other 7	1508	$ -				$ -	$ -			$ -		$ -
Retail Cost Variance Account - Retail	1518	$ -				$ -	$ -			$ -		$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -			$ -		$ -
Misc. Deferred Debits	1525	$ -	$ 410,695			$ 410,695	$ -		$ 935	$ 935	$ 1,129	$ 412,759
LV Variance Account	1550	$ -				$ -	$ -			$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -				$ -	$ -			$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -				$ -	$ -			$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Met	1555	$ -				$ -	$ -			$ -		$ -
Smart Meter OM&A Variance	1556	$ 110,347	$ 1,824,836			$ 1,935,184	$ -		$ 2,232	$ 2,232	$ 5,322	$ 1,942,738
Conservation and Demand Management Expenditures and Recoveries	1565	$ -				$ -	$ -			$ -		$ -
CDM Contra	1566	$ -				$ -	$ -			$ -		$ -
Qualifying Transition Costs 5	1570	$ -	n/a	n/a		$ -	$ 0	$ -	$ -	$ 0		$ 0
Pre-Market Opening Energy Variances Total 5	1571	$ -	n/a	n/a		$ -	$ -			$ -		$ -
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -			$ -		$ -
Deferred Rate Impact Amounts	1574	$ 14,152,549			$ (14,152,549)	$ -	$ 737,767		$ (737,767)	$ 0	$ -	$ 0
Other Deferred Credits	2425	$ -				$ -	$ -			$ -		$ -
Sub-Totals		$ 17,010,609	$ 2,242,133	$ -	$ (14,152,549)	$ 2,352,480	$ 737,767	$ -	$ (734,600)	$ 3,167	$ 6,469	$ 2,362,117
Deferred Payments in Lieu of Taxes	1562				see PILs reconciliation requested							
2006 PILs & Taxes Variance	1592				see PILs reconciliation requested							
Sub-Totals					see PILs reconciliation requested							$ -
Total		$ 18,220,005	$ 3,321,072	$ -	$ (14,152,549)	$ 4,322,157	$ 737,767	$ 72,818	$ (722,940)	$ 87,645	$ 11,885	$ 4,421,687
The following is not included in the total claim but is included on a memo basis:												
Deferred PILs Contra Account 8	1563				see PILs reconciliation requested							
Deferred Rate Impact Amounts - Seasonal deferral	1574	$ 1,106,132	$ 829,601		$ -	$ 1,935,733	$ -		$ 14,527	$ 14,527	$ 5,323	$ 1,955,583
Recovery of Regulatory Asset Balances	1590	$ (1,032,279)	$ 138,528		$ -	$ (893,751)	$ 132,327	$ -	$ (10,313)	$ 122,014	$ (2,094)	$ (773,831)

RECONCILIATION TO RRR

OEB ACCT	Description	2005			2006			2007			2008			2009				
		RRR	Continuity Schedule	Difference	RRR	Continuity Schedule	Difference	RRR	Continuity Schedule	Difference	RRR	Continuity Schedule	Difference	RRR	Continuity Schedule	Difference	Interest Difference	Difference
1508	Other Regulatory Assets	155,994	155,994	(0)	155,994	155,994	(0)	155,994	155,994	(0)	-	-	-	6,602	6,602	0		0
1525	Miscellaneous Deferred Debits	-		-	-		-	-		-	-	-	-	410,695	411,630	(935)	935	(0)
1556	Smart Meter Variance Account - Sub-account OM	-		-	-		-	-		-	110,347	110,347	0	1,935,184	1,937,416	(2,232)	2,232	(0)
1574	Deferred Rate Impact Amounts	10,166,184	10,166,184	(0)	13,606,089	13,606,090	(1)	17,185,021	17,185,022	(1)	15,996,448	15,996,448	0	1,935,733	1,950,260	(14,527)	14,527	0
1580	RSVAWMS	340,048	340,048	(0)	133,348	133,349	(1)	(131,856)	(131,856)	(0)	(423,767)	(423,766)	(1)	(429,312)	(447,296)	17,984	(17,985)	(1)
1584	RSVANW	25,812	25,812	0	76,242	76,242	0	84,122	84,122	(0)	(80,627)	(80,627)	0	(131,681)	(124,143)	(7,538)	7,538	0
1586	RSVACN	(374,230)	(374,230)	(0)	(436,955)	(436,955)	0	(520,398)	(520,398)	(0)	(339,602)	(339,602)	0	(388,944)	(424,692)	35,748	(35,748)	0
1588	RSVAPOWER	(505,340)	(505,339)	(1)	1,461,737	1,461,737	0	1,777,528	1,777,528	0	1,734,733	1,734,733	(0)	2,919,612	3,050,286	(130,674)	130,673	(1)
1590	1590-Recovery of regulatory asset balances	(1,024,149)	(1,024,149)	0	(2,154,196)	(2,154,196)	0	(3,296,836)	(3,296,836)	(0)	(899,952)	(899,952)	0	(761,424)	(771,737)	10,313	(10,313)	0

INTEREST CALCULATION

Account 1580

	Opening Balance	Additions during Quarter	Ending Balance	Interest Rate	Interest	
Q1 2005	-	14,941	14,941	7.25%	271	
Q2 2005	14,941	4,582	19,523	7.25%	271	
Q3 2005	19,523	138,825	158,348	7.25%	354	
Q4 2005	158,348	(4,924)	153,424	7.25%	2,870	3,766
Q1 2006	153,424	(94,645)	58,779	7.25%	2,781	
Q2 2006	58,779	27,591	86,370	4.14%	608	
Q3 2006	86,370	(45,938)	40,432	4.59%	991	
Q4 2006	40,432	(93,708)	(53,276)	4.59%	464	4,844
Q1 2007	(53,276)	(62,102)	(115,378)	4.59%	(611)	
Q2 2007	(115,378)	(90,784)	(206,162)	4.59%	(1,324)	
Q3 2007	(206,162)	(20,962)	(227,124)	4.59%	(2,366)	
Q4 2007	(227,124)	(91,356)	(318,480)	5.14%	(2,919)	(7,220)
Q1 2008	(318,480)	(56,507)	(374,987)	5.14%	(4,092)	
Q2 2008	(374,987)	(28,606)	(403,593)	4.08%	(3,825)	
Q3 2008	(403,593)	29,326	(374,267)	3.35%	(3,380)	
Q4 2008	(374,267)	(49,500)	(423,767)	3.35%	(3,134)	(14,432)
Adjustment in 2009 for rate application					**(13,042)**	**(13,042)**
Q1 2009	(423,767)	(34,704)	(458,471)	2.45%	(2,596)	
Q2 2009	(458,471)	5,197	(453,274)	1.00%	(1,146)	
Q3 2009	(453,274)	32,840	(420,434)	0.55%	(623)	
Q4 2009	(420,434)	(8,878)	(429,312)	0.55%	(578)	(4,943)
Interest for 2009					**(4,943)**	**(4,943)**
Q1 2010	(429,312)	-	(429,312)	0.55%	(590)	
Q2 2010	(429,312)	-	(429,312)	0.55%	(590)	(1,181)
Interest to June 30, 2010 on Dec 31, 2009 balance					**(1,181)**	**(1,181)**

Account 1584

	Opening Balance	Additions during Quarter	Ending Balance	Interest Rate	Interest	
Q1 2005	-	1,131	1,131	7.25%	20	
Q2 2005	1,131	10,201	11,332	7.25%	20	
Q3 2005	11,332	38,424	49,756	7.25%	205	
Q4 2005	49,756	(19,465)	30,291	7.25%	902	1,148
Q1 2006	30,291	11,903	42,194	7.25%	549	
Q2 2006	42,194	28,950	71,144	4.14%	437	
Q3 2006	71,144	29,793	100,937	4.59%	816	
Q4 2006	100,937	(20,216)	80,721	4.59%	1,158	2,960
Q1 2007	80,721	7,890	88,611	4.59%	926	
Q2 2007	88,611	(12,602)	76,009	4.59%	1,017	
Q3 2007	76,009	16,282	92,291	4.59%	872	
Q4 2007	92,291	(3,691)	88,600	5.14%	1,186	4,001
Q1 2008	88,600	(62,261)	26,339	5.14%	1,139	
Q2 2008	26,339	(50,545)	(24,206)	4.08%	269	
Q3 2008	(24,206)	(38,900)	(63,106)	3.35%	(203)	
Q4 2008	(63,106)	(17,521)	(80,627)	3.35%	(529)	676
Adjustment in 2009 for rate application					**8,786**	**8,786**
Q1 2009	(80,627)	(37,372)	(117,999)	2.45%	(494)	
Q2 2009	(117,999)	(43,460)	(161,459)	1.00%	(295)	
Q3 2009	(161,459)	(10,712)	(172,171)	0.55%	(222)	
Q4 2009	(172,171)	40,490	(131,681)	0.55%	(237)	(1,248)
Interest for 2009					**(1,248)**	**(1,248)**
Q1 2010	(131,681)	-	(131,681)	0.55%	(181)	
Q2 2010	(131,681)	-	(131,681)	0.55%	(181)	(362)
Interest to June 30, 2010 on Dec 31, 2009 balance					**(362)**	**(362)**

Account 1586

	Opening Balance	Additions during Quarter	Ending Balance	Interest Rate	Interest	
Q1 2005	-	(45,191)	(45,191)	7.25%	(819)	
Q2 2005	(45,191)	(27,330)	(72,521)	7.25%	(819)	
Q3 2005	(72,521)	15,317	(57,204)	7.25%	(1,314)	
Q4 2005	(57,204)	(40,818)	(98,022)	7.25%	(1,037)	(3,989)
Q1 2006	(98,022)	(39,454)	(137,476)	7.25%	(1,777)	
Q2 2006	(137,476)	5,636	(131,840)	4.14%	(1,423)	
Q3 2006	(131,840)	10,355	(121,485)	4.59%	(1,513)	
Q4 2006	(121,485)	(39,261)	(160,746)	4.59%	(1,394)	(6,106)
Q1 2007	(160,746)	(44,699)	(205,445)	4.59%	(1,845)	
Q2 2007	(205,445)	(28,012)	(233,457)	4.59%	(2,357)	
Q3 2007	(233,457)	(5,049)	(238,506)	4.59%	(2,679)	
Q4 2007	(238,506)	(5,683)	(244,189)	5.14%	(3,065)	(9,946)
Q1 2008	(244,189)	(49,639)	(293,828)	5.14%	(3,138)	
Q2 2008	(293,828)	(19,363)	(313,191)	4.08%	(2,997)	
Q3 2008	(313,191)	(24,733)	(337,924)	3.35%	(2,623)	
Q4 2008	(337,924)	(1,678)	(339,602)	3.35%	(2,830)	(11,588)
Adjustment in 2009 for rate application					**(31,630)**	**(31,630)**
Q1 2009	(339,602)	(28,656)	(368,258)	2.45%	(2,080)	
Q2 2009	(368,258)	(32,681)	(400,939)	1.00%	(921)	
Q3 2009	(400,939)	(11,031)	(411,970)	0.55%	(551)	
Q4 2009	(411,970)	23,026	(388,944)	0.55%	(566)	(4,118)
Interest for 2009					**(4,118)**	**(4,118)**
Q1 2010	(388,944)	-	(388,944)	0.55%	(535)	
Q2 2010	(388,944)	-	(388,944)	0.55%	(535)	(1,070)
Interest to June 30, 2010 on Dec 31, 2009 balance					**(1,070)**	**(1,070)**

Account 1588 P

	Opening Balance	Additions during Quarter	Ending Balance	Interest Rate	Interest	
Q1 2005	-	193,504	193,504	7.25%	3,507	
Q2 2005	193,504	(70,515)	122,989	7.25%	3,507	
Q3 2005	122,989	(209,931)	(86,942)	7.25%	2,229	
Q4 2005	(86,942)	100,985	14,043	7.25%	(1,576)	7,668
Q1 2006	14,043	287,550	301,593	7.25%	255	
Q2 2006	301,593	509,245	810,838	4.14%	3,121	
Q3 2006	810,838	371,382	1,182,220	4.59%	9,304	
Q4 2006	1,182,220	75,729	1,257,949	4.59%	13,566	26,246
Q1 2007	1,257,949	(96,645)	1,161,304	4.59%	14,435	
Q2 2007	1,161,304	19,271	1,180,575	4.59%	13,326	
Q3 2007	1,180,575	248,515	1,429,090	4.59%	13,547	
Q4 2007	1,429,090	66,569	1,495,659	5.14%	18,364	59,672
Q1 2008	1,495,659	46,255	1,541,914	5.14%	19,219	
Q2 2008	1,541,914	(23,095)	1,518,819	4.08%	15,728	
Q3 2008	1,518,819	199,840	1,718,659	3.35%	12,720	
Q4 2008	1,718,659	46,859	1,765,518	3.35%	14,394	62,061
Adjustment in 2009 for rate application					**155,647**	**155,647**
Q1 2009	1,765,518	4,872	1,770,390	2.45%	10,814	
Q2 2009	1,770,390	83,301	1,853,691	1.00%	4,426	
Q3 2009	1,853,691	496,704	2,350,395	0.55%	2,549	
Q4 2009	2,350,395	590,038	2,940,433	0.55%	3,232	21,020
Interest for 2009					**21,020**	**21,020**
Q1 2010	2,940,433	-	2,940,433	0.55%	4,043	
Q2 2010	2,940,433	-	2,940,433	0.55%	4,043	8,086
Interest to June 30, 2010 on Dec 31, 2009 balance					**8,086**	**8,086**

Account 1588 GA

	Opening Balance	Additions during Quarter	Ending Balance	Interest Rate	Interest	
Q1 2005	-	-	-	7.25%	-	
Q2 2005	-	(694,543)	(694,543)	7.25%	-	
Q3 2005	(694,543)	-	(694,543)	7.25%	(12,589)	
Q4 2005	(694,543)	-	(694,543)	7.25%	(12,589)	(25,177)
Q1 2006	(694,543)	(143,529)	(838,072)	7.25%	(12,589)	
Q2 2006	(838,072)	860,821	22,749	4.14%	(8,674)	
Q3 2006	22,749	(65,899)	(43,150)	4.59%	261	
Q4 2006	(43,150)	71,778	28,628	4.59%	(495)	(21,497)
Q1 2007	28,628	(230,159)	(201,531)	4.59%	329	
Q2 2007	(201,531)	166,163	(35,368)	4.59%	(2,313)	
Q3 2007	(35,368)	(47,650)	(83,018)	4.59%	(406)	
Q4 2007	(83,018)	189,728	106,710	5.14%	(1,067)	(3,457)
Q1 2008	106,710	(104,782)	1,928	5.14%	1,371	
Q2 2008	1,928	206,351	208,279	4.08%	20	
Q3 2008	208,279	(202,049)	6,230	3.35%	1,744	
Q4 2008	6,230	(37,016)	(30,786)	3.35%	52	3,187
Adjustment in 2009 for rate application					**(46,943)**	**(46,943)**
Q1 2009	(30,786)	107,110	76,324	2.45%	(189)	
Q2 2009	76,324	163,611	239,935	1.00%	191	
Q3 2009	239,935	208,807	448,742	0.55%	330	
Q4 2009	448,742	(469,563)	(20,821)	0.55%	617	949
Interest for 2009					**949**	**949**
Q1 2010	(20,821)	-	(20,821)	0.55%	(29)	
Q2 2010	(20,821)	-	(20,821)	0.55%	(29)	(57)
Interest to June 30, 2010 on Dec 31, 2009 balance					**(57)**	**(57)**

Account 1525

	Opening Balance	Additions during Quarter	Ending Balance	Interest Rate	Interest	
Q1 2009	-	-	-	2.45%	-	
Q2 2009	-	292,919	292,919	1.00%	-	
Q3 2009	292,919	94,473	387,392	0.55%	403	
Q4 2009	387,392	23,303	410,695	0.55%	533	935
Interest for 2009					**935**	**935**
Q1 2010	410,695	-	410,695	0.55%	565	
Q2 2010	410,695	-	410,695	0.55%	565	1,129
Interest to June 30, 2010 on Dec 31, 2009 balance					**1,129**	**1,129**

Account 1508

	Opening Balance	Additions during Quarter	Ending Balance	Interest Rate	Interest	
Q1 2009	-	-	-	2.45%	-	
Q2 2009	-	-	-	1.00%	-	
Q3 2009	-	-	-	0.55%	-	
Q4 2009	-	6,602	6,602	0.55%	-	-
Interest for 2009					**-**	**-**
Q1 2010	6,602	-	6,602	0.55%	9	
Q2 2010	6,602	-	6,602	0.55%	9	18
Interest to June 30, 2010 on Dec 31, 2009 balance					**18**	**18**

Account 1556

	Opening Balance	Additions during Quarter	Ending Balance	Interest Rate	Interest	
Q1 2008	-	-	-	5.14%	-	
Q2 2008	-	-	-	4.08%	-	
Q3 2008	-	-	-	3.35%	-	
Q4 2008	-	110,347	110,347	3.35%	-	-
Adjustment in 2009 for rate application					**-**	**-**
Q1 2009	110,347	27,525	137,872	2.45%	676	
Q2 2009	137,872	271,796	409,668	1.00%	345	
Q3 2009	409,668	61,851	471,519	0.55%	563	
Q4 2009	471,519	1,463,665	1,935,184	0.55%	648	2,232
Interest for 2009					**2,232**	**2,232**
Q1 2010	1,935,184	-	1,935,184	0.55%	2,661	
Q2 2010	1,935,184	-	1,935,184	0.55%	2,661	5,322
Interest to June 30, 2010 on Dec 31, 2009 balance					**5,322**	**5,322**

Account 1574

	Opening Balance	Additions during Quarter	Ending Balance	Interest Rate	Interest	
Q1 2008	-	-	-	5.14%	-	
Q2 2008	-	-	-	4.08%	-	
Q3 2008	-	-	-	3.35%	-	
Q4 2008	-	1,106,133	1,106,133	3.35%	-	-
Adjustment in 2009 for rate application					**-**	**-**
Q1 2009	1,106,133	207,400	1,313,533	2.45%	6,775	
Q2 2009	1,313,533	207,400	1,520,933	1.00%	3,284	
Q3 2009	1,520,933	207,400	1,728,333	0.55%	2,091	
Q4 2009	1,728,333	207,400	1,935,733	0.55%	2,376	14,527
Interest for 2009					**14,527**	**14,527**
Q1 2010	1,935,733	-	1,935,733	0.55%	2,662	
Q2 2010	1,935,733	-	1,935,733	0.55%	2,662	5,323
Interest to June 30, 2010 on Dec 31, 2009 balance					**5,323**	**5,323**

Account 1590

	Opening Balance	Additions during Quarter	Ending Balance	Interest Rate	Interest	
Q1 2008	-	-	-	5.14%	-	
Q2 2008	-	-	-	4.08%	-	
Q3 2008	-	-	-	3.35%	-	
Q4 2008	-	(899,952)	(899,952)	3.35%	-	-
Adjustment in 2009 for rate application					**-**	**-**
Q1 2009	(899,952)	(27,861)	(927,813)	2.45%	(5,512)	
Q2 2009	(927,813)	(13,489)	(941,302)	1.00%	(2,320)	
Q3 2009	(941,302)	78,374	(862,928)	0.55%	(1,294)	
Q4 2009	(862,928)	101,504	(761,424)	0.55%	(1,187)	(10,313)
Interest for 2009					**(10,313)**	**(10,313)**
Q1 2010	(761,424)	-	(761,424)	0.55%	(1,047)	
Q2 2010	(761,424)	-	(761,424)	0.55%	(1,047)	(2,094)
Interest to June 30, 2010 on Dec 31, 2009 balance					**(2,094)**	**(2,094)**

REGULATORY ASSET ACCOUNTS REQUESTED

This exhibit requests approval to establish new deferral and variance accounts for Algoma Power Inc as follows:

- Pension expense variance account
- IFRS deferral account

API further requests an accounting order to establish a deferral account to record the revenue requirement deficiencies incurred from July 1, 2010 until API proposed rates for 2010 are implemented.

Pension Expense Variance Account

API proposes to establish a variance account to track the differences between the actual pension expense costs booked using the actuarial assessments provided by Mercer, and the estimated assessment pension costs used in this filing.

IFRS Deferral Account

API seeks the approval of an IFRS deferral account to capture the aggregate impact on the 2011 revenue requirement resulting from any changes to the existing IFRS standards and changes in the interpretation and implementation of such standards.

RRRP 2002 – 2007 FUNDING VARIANCE

API had been funded through a previous RRRP regime from 2002 – September 2007. The current RRRP regime was implemented in February 2009. There was a variance of approximately $400k that related to the 2002-2007 funding which has been recorded as a receivable on the balance sheet of API and should be relieved through an additional payment from the RRRP funding pool administered by Hydro One. API is seeking recovery through discussions with Hydro One and OEB compliance and is hopeful that the matter will be resolved This variance has accumulated in the normal course and has been properly credited to customer accounts in accordance with applicable. Should this issue not be resolved, API will submit additional evidence in this proceeding and seek direction from the Board.

SHEET 1 - December 31, 2009 Regulatory Assets

NAME OF UTILITY	Algoma Power Inc.	**LICENCE NUMBER**	ED-2009-0072
NAME OF CONTACT	Mark Faught	**DOCID NUMBER**	EB-2009-0278
E-mail Address	mfaught@glp.on.ca		
VERSION NUMBER	v2.0	**PHONE NUMBER**	705-941-5602
Date	1-Jun-10	**(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:
(These amounts should correspond to your December 31, 2004 Regulatory Asset filings with the OEB.)

Account Description	Account Number	Principal Amounts as of Dec-31 2009	Interest to Dec31-09	Interest Jan1-10 to June30-10					Total Claim
RSVA - Wholesale Market Service Charge	1580	$ (429,311)	$ (17,985)	$ (1,181)					$ (448,477)
RSVA - One-time Wholesale Market Service	1582	$ -							$ -
RSVA - Retail Transmission Network Charge	1584	$ (131,681)	$ 7,538	$ (362)					$ (124,505)
RSVA - Retail Transmission Connection Charge	1586	$ (388,944)	$ (35,748)	$ (1,070)					$ (425,762)
RSVA - Power excluding Global Adjustment	1588	$ 2,940,434	$ 176,667	$ 8,086					$ 3,125,187
RSVA - Power Global Adjustment	1588	$ (20,821)	$ (45,994)	$ (57)					$ (66,872)
Sub-Totals		$ 1,969,677	$ 84,478	$ 5,416	$ -	$ -	$ -	$ -	$ 2,059,571
Other Regulatory Assets	1508	$ 6,602	$ -	$ 18					$ 6,620
Retail Cost Variance Account - Retail	1518								$ -
Retail Cost Variance Account - STR	1548								$ -
Misc. Deferred Debits (Section 71)	1525	$ 410,695	$ 935	$ 1,129					$ 412,759
Pre-Market Opening Energy Variances Total	1571								$ -
Extra-Ordinary Event Losses	1572								$ -
Deferred Rate Impact Amounts	1574	$ -	$ -	$ -	$ -				$ -
Other Deferred Credits	2425								$ -
Sub-Totals		$ 417,297	$ 935	$ 1,147	$ -	$ -	$ -		$ 419,379
Qualifying Transition Costs	1570	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Totals per column		$ 2,386,974	$ 85,413	$ 6,563	$ -	$ -	$ -	$ -	$ 2,478,950

Enter the appropriate 2004 data in the cells below.
Once the data in the yellow fields on Sheet 1 has been entered, the relevant allocations will appear on Sheet 2.
Go to Sheets 3, 4 and 5 and enter the appropriate data in the yellow cells.

2009 Data By Class	kW	kWhs	Cust. Num.'s	Dx Revenue	Cust. Num.'s
RESIDENTIAL - R1		103,761,012	7,997	$ 5,054,329	7,997
SEASONAL		12,341,792	3,643	$ 1,862,280	3,643
RESIDENTIAL - R2	0	69,931,763	48	$ 891,879	48
GENERAL SERVICE >50 KW TIME OF USE	0	0	0	$ -	0
INTERMEDIATE USE	0	0	0	$ -	0
LARGE USE	0	0	1		1
SMALL SCATTERED LOADS	0	0	0	$ -	0
SENTINEL LIGHTS	0	0	0	$ -	0
STREET LIGHTING		791,996	1,052	$ 39,204	1,052
Totals	-	186,826,563	12,741	$ 7,847,692	12,741

Allocators	kW	kWhs	Cust. Num.'s	Dx Revenue	Cust. #'s w/ Rebate Cheques	kWhs for Non TOU Customers
RESIDENTIAL - R1		55.5%	62.8%	64.4%	62.8%	55.78%
SEASONAL		6.6%	28.6%	23.7%	28.6%	6.63%
RESIDENTIAL - R2		37.4%	0.4%	11.4%	0.4%	37.59%
GENERAL SERVICE >50 KW TIME OF USE		0.0%	0.0%	0.0%	0.0%	
INTERMEDIATE USE		0.0%	0.0%	0.0%	0.0%	
LARGE USE		0.0%	0.0%	0.0%	0.0%	
SMALL SCATTERED LOADS		0.0%	0.0%	0.0%	0.0%	0.00%
SENTINEL LIGHTS		0.0%	0.0%	0.0%	0.0%	
STREET LIGHTING		0.4%	8.3%	0.5%	8.3%	
Totals	0%	100%	100%	100%	100%	100%

Sheet 2 - Rate Riders Calculation

NAME OF UTILITY	Algoma Power Inc.	**LICENCE NUMBER**	ED-2009-0072
NAME OF CONTACT	Mark Faught	**DOCID NUMBER**	EB-2009-0278
E-mail Address	mfaught@glp.on.ca		
VERSION NUMBER	v2.0	**PHONE NUMBER**	705-941-5602
Date	1-Jun-10	**(extension)**	

Regulatory Asset Accounts:	**Decision Ref.#**	**Amount**	**ALLOCATOR**	**Residential -R1**	**Seasonal**	**Residential -R2**	**GS > 50 TOU**	**Intermediate Use**	**Large Use**	**Small Scattered Load**	**Sentinel Lighting**	**Street Lighting**	**Total**
WMSC - Account 1580	2.0.35	$ (448,477)	kWh	$ (249,078)	$ (29,626)	$ (167,871)	$ -	$ -	$ -	$ -	$ -	$ (1,901)	$ (448,477)
One-Time WMSC - Account 1582	2.0.35	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Network - Account 1584	2.0.35	$ (124,505)	kWh	$ (69,149)	$ (8,225)	$ (46,604)	$ -	$ -	$ -	$ -	$ -	$ (528)	$ (124,505)
Connection - Account 1586	2.0.35	$ (425,762)	kWh	$ (236,462)	$ (28,126)	$ (159,368)	$ -	$ -	$ -	$ -	$ -	$ (1,805)	$ (425,762)
Power - Account 1588 excluding GA	2.0.35	$ 3,125,187	kWh	$ 1,735,687	$ 206,450	$ 1,169,800	$ -	$ -	$ -	$ -	$ -	$ 13,248	$ 3,125,187
Power - Account 1588 GA	2.0.35	$ (66,872)	kWh	$ (37,140)	$ (4,418)	$ (25,031)	$ -	$ -	$ -	$ -	$ -	$ (283)	$ (66,872)
Subtotal - RSVA		$ 2,059,571		$ 1,143,858	$ 136,056	$ 770,926	$ -	$ -	$ -	$ -	$ -	$ 8,731	$ 2,059,571
Other Regulatory Assets - Account 1508		$ 6,620	# of Customers	$ 4,155	$ 1,893	$ 25	$ -	$ -	$ -	$ -	$ -	$ 547	$ 6,619
Retail Cost Variance Account - Acct 1518		$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retail Cost Variance Account (STR) Acct 1548		$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Misc debits - Acct 1525 (Section 71)	5.0.19	$ 412,759	# of Customers	$ 259,072	$ 118,019	$ 1,555	$ -	$ -	$ -	$ -	$ -	$ 34,081	$ 412,726
Hydro One's Environmental Costs - Acct 1525	5.0.25	$ -	Dx Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pre Market Opening Energy - Acct 1571	3.0.27	$ -	kWh for Non TOU Cust.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extraordinary Event Losses - Acct 1572		$ -											$ -
Deferred Rate Impact Amounts - Acct 1574		$ -	Dx Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Deferred Credits - Acct 2425		$ -											$ -
Transition Costs - Acct 1570	7.0.67		# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Non RSVA		$ 419,379		$ 263,227	$ 119,912	$ 1,580	$ -	$ -	$ -	$ -	$ -	$ 34,627	$ 419,346
Total to be Recovered		$ 2,478,950		$ 1,407,085	$ 255,967	$ 772,506	$ -	$ -	$ -	$ -	$ -	$ 43,358	$ 2,478,917
Balance to be collected or refunded (# years below)		$ 2,478,950		$ 1,407,085	$ 255,967	$ 772,506	$ -	$ -	$ -	$ -	$ -	$ 43,358	$ 2,478,917
Balance to be collected or refunded per year		$ 991,580		$ 562,834	$ 102,387	$ 309,002	$ -	$ -	$ -	$ -	$ -	$ 17,343	$ 991,567

Class	# years	**Residential -R1**	**Seasonal**	**Residential -R2**	**GS > 50 TOU**	**Intermediate Use**	**Large Use**	**Small Scattered Load**	**Sentinel Lighting**	**Street Lighting**
Regulatory Asset Rate Riders	2.5	$ 0.0054	$ 0.0083	$ 0.0044						$ 0.0219
Billing Determinants		kWh	kWh	kW	kW	kW	kW	kWh	kW	kWh

ACCOUNT 1525 - MISCELLANEOUS DEFERRED DEBITS (MORE PROPERLY REFERRED TO ACCOUNT 1572 - EXTRAORDINARY EVENT COSTS)

The purpose of this section is to discuss certain costs in Account 1525 that are more properly referred to as Account 1572 – Extraordinary Event Costs.

API is an electricity distribution company that is solely in the business of owning and operating its electricity distribution system in accordance with Section 71 of the Ontario Energy Board Act (the "OEB Act"). API is the successor of Great Lakes Power Distribution Inc. ("GLPD"), which was the distribution business acquired by FortisOntario. GLPD was the successor of GLPL's distribution business that, had been part of Great Lakes Power Limited ("GLPL"), along with GLPL's transmission and generation businesses, but functioned as a division. Under Section 5(4) of Ontario Regulation 161/99, GLPL was exempt from Section 71 of the OEB Act until December 31, 2008 and, as a result, was permitted to carry on the activities of transmission and distribution, together with generation, within the same corporation until such date.

In anticipation of the expiry of the Section 71 exemption, a reorganization began in which the distribution assets of GLPL were transferred to GLPD in July 2009. This was approved by a Decision and order of the Board issued on May 5, 2009 (ED-2009-0072), which granted an electricity distribution licence to GLPD, and cancelled GLPL's electricity distribution licence (ED-2008-0342), subject to the condition that the commercial transaction for the transfer of assets closed on or before December 31, 2009. The transfer of the assets closed on July 1, 2009. Full compliance with Section 71 occurred on this date as the distribution business was transferred to GLPD and the transmission and distribution activity was carried on in two stand alone entities – GLPT and GLPD, respectively.

As part of acquiring the distribution assets from GLPL, GLPD incurred costs in the amount of $410,695, which was recorded as an extraordinary event cost. The projected balance as of June 30, 2010 in Account 1525 is $412,759 which includes $2,064 of carrying charges, as calculated in the table below.

Calculation of Extraordinary Event Costs

Year	Opening Balance	Carrying Charges	Carrying Charge Balance	Accruals	Accrual Balance	Closing Balance
2009	-	935	935	410,695	410,695	411,630
2010	411,630	1,129	2,064	-	410,695	412,759
Balance to June 30, 2010			2,064		410,695	412,759

API proposes to recover this balance from ratepayers in accordance with the methodology outlined in Exhibit 9.

The costs in question arose because of the unique circumstance of Section 71 and the expiration of the legislative exemption to GLPL. Unlike nearly all utilities in Ontario, GLPL was corporately organized prior to the existence of Section 71 of the OEB Act. As a result, Section 71 was not an issue of compliance for most utilities since they could organize with the regulation in mind. For GLPL and any successor to it, Section 71 presented a compliance issue. The Section 71 exemption regulation granted time to prepare for compliance, but nevertheless, compliance could not be avoided in the long term. As a result, the unwinding of a long-standing corporation was both a unique and extraordinary event not contemplated in the ordinary course of utility business at the time GLPL was created. In the event of a non-compliance, the ability to operate the distribution business would have been affected and there would have been a possibility of legal consequences against the business. In particular, under the OEB Act, the Board has the power to suspend or revoke a licence and to issue administrative penalties. Moreover, where convicted of an offence, such as for contravening a provision of the OEB Act or a regulation made under the OEB Act, there is a possibility of substantial fines being issued.

The costs incurred are material as they represent more than 0.5% of API's distribution revenue requirement.

The circumstance giving rise to the costs was not within management's control as it arose from a statutory requirement that was implemented notwithstanding that the integration structure of GLPL was known and long standing.

The costs have been prudently incurred. The transaction in question was complicated and time consuming since it involved:

- Extensive land transfers and land registrations;
- Renegotiation of material contracts;
- Statutory filings;
- New pension plans, pension asset transfers and regulatory approvals;
- Tax considerations; and
- Application to the Board seeking multiple forms of relief.

Should the criteria of causation, materiality, inability of management control, and prudence apply to the disbursal of this account, API submits that it has satisfied those criteria.

Therefore, API proposes to recover the projected June 30, 2010 balance for this account of $412,759 from ratepayers, in accordance with the methodology outlined in Exhibit 9.

SMART METER OVERVIEW

In 2007, API began working with a group of neighbouring utilities in northeastern Ontario in response to the provincial Smart Meter mandate. In addition to API, this "District 9" group includes Chapleau PUC, Espanola Regional Hydro Distribution, Hearst Power Distribution, North Bay Hydro Distribution, Northern Ontario Wires and PUC Distribution (Sault Ste. Marie). This group has combined efforts in relation to planning, consulting and procurement in order to reduce the overall cost and resource requirements of each LDC's Smart Meter deployment. In accordance with Ontario Regulation 427/06, the group of LDC's 'piggybacked' on the London Hydro Smart Meter RFP process in order to select an AMI vendor in accordance with Smart Metering procurement regulations. As a result of this process, the Sensus FlexNet AMI was selected as the preferred vendor and this system will be deployed at API. Infrastructure deployment commenced in 2009 and will continue into 2010, with mass meter exchanges beginning in the spring of 2010.

Due to the expansive, low-density nature of API's service territory, the capital costs related to the Smart Metering initiative are expected to be well above those of the average LDC on a cost per meter basis. API expects the total capital costs for its AMI deployment to be approximately $5M (over $400 per meter). The higher capital costs are related to the requirement for installation of a significant amount of communications infrastructure to read all meters in its service territory. Sensus propagation studies indicate that the communications network will require eight Sensus Tower Gateway Base-stations, supplemented by an expected 46 repeaters to provide the radio frequency coverage in remote or low-density areas (see attached locational maps). This infrastructure requirement will also result in API's ongoing Smart Metering O&M costs being higher than average on a per meter basis. API's preliminary estimate is that its total unsubsidized monthly cost per meter will be in the range of $8 per meter per month (capital, cost of funds, inflation and O&M over the life of the asset). In accordance with the Government's Smart Metering initiative, API plans to have its communication infrastructure and all of its <50 kW meters installed by December 31st, 2010. API plans

to be integrated with the IESO's MDM/R in 2012, following its transition to the SAP Customer Information System in 2011, as described in Exhibit 2, Tab 4, Schedule 5, Appendix A.

Algoma Power Inc.
Smart Meter Capital Spending by year 2008-2011

	2007 Actual	2008 Actual	2009 Actual	2010 Forecast	2011 Forecast
Capital	$31,427	$78,920	$1,597,025	$2,830,012	-
O&M	-	-	-	$287,402	$384,577
Replace/Repair Customer-Owned Equipment	-	-	$123,690	$124,632	-

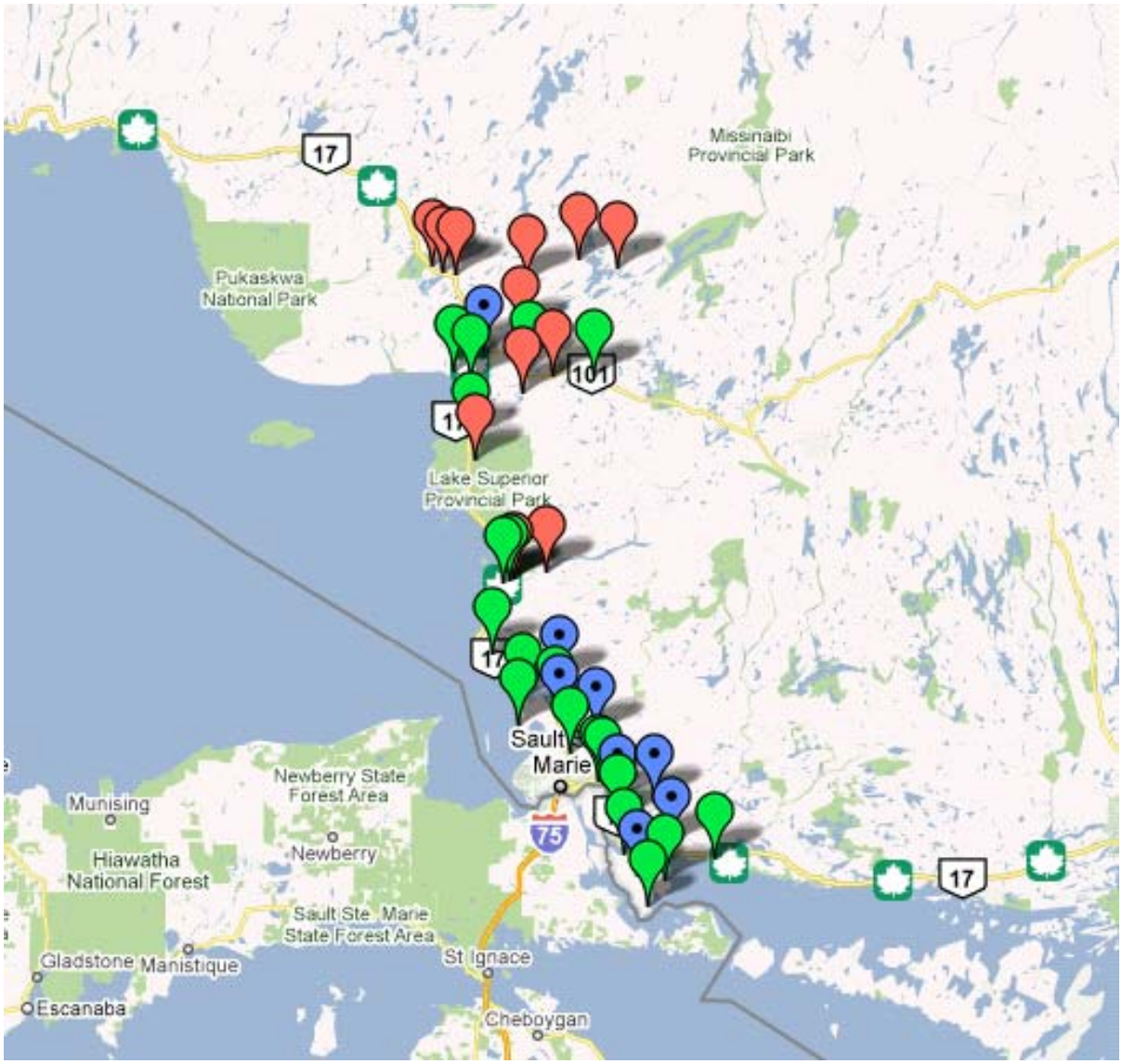
According to the Board's Smart Meter Funding and Cost Recovery Guideline (G-2008-0002), an application may be made to the Board for recovery of smart meter costs when a distributor achieves at least 50% penetration of smart meters within its service area. API expects to achieve 50% penetration during the course of this proceeding, in or around July of 2010. When it does, API will file audited smart meter cost information and will update its application accordingly to recover smart meter costs.

Funding Effective July 1, 2010

API does not currently have a Smart Meter Funding Adder being charged to metered customers in its service territory. API, in this Application, is proposing a common Smart Meter Funding Adder of $1.00 per metered customer effective July 1, 2010.

The meters purchased and being installed are compliant with the minimum functionality adopted in O. Reg. 425/06. API is not incurring SME costs associated with functions for which the IESO has exclusive authority in O. Reg. 393/07.

Exhibit 10, Tab 1, Schedule 1, Table 1



LEGEND	
Blue Markers	TGB (Tower)
Green Markers	FNP (Repeater to Tower)
Red Markers	FRP (Stand-alone Repeater)