niagara peninsula energy

Our energy works for you.

Head Office:
7447 Pin Oak Drive
Box 120
Niagara Falls, Ontario
L2E 6S9

T: 905-356-2681
Toll Free: 1-877-270-3938
F: 905-356-0118
E: info@npei.ca
www.npei.ca

November 26, 2010

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

Attention: Ms. Kirsten Walli, Board Secretary

2011 Electricity Distribution Rates, EB-2010-0138

Dear Ms. Walli:

Please find enclosed two hard copies of Niagara Peninsula Energy Inc.'s 2011 Electricity Distribution Rates Application.

A complete copy of the Application has been filed electronically with the Board today.

If further information is required, please contact Suzanne Wilson, Vice-President Finance, at 905-353-6004 or Suzanne.Wilson@npei.ca.

Yours truly,

Brian Wilkie
President & CEO

NIAGARA PENINSULA ENERGY INC.

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES

EFFECTIVE MAY 1, 2011

Table of Contents

EXHIBIT 1 – ADMINISTRATION DOCUMENTS

APPLICATION

IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an application by Niagara Peninsula Energy Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2011.

Title of Proceeding:	An application by Niagara Peninsula Energy for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2011.
Applicant's Name:	Niagara Peninsula Energy Inc.
Applicant's Address for Service:	7447 Pin Oak Drive, Niagara Falls, Ontario L2E 6S9
	Attention: Mr. Brian Wilkie, President and CEO Telephone: (905) 356-2681 ext. 6000 Fax: (905) 356-0118 E-mail: Bian.Wilkie@npei.ca

APPLICATION:

1) Introduction

a) Niagara Peninsula Energy Inc. (NPEI) is a corporation incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the City of Niagara Falls. NPEI carries on the business of distributing electricity within the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham.

b) NPEI hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the *Ontario Energy Board Act, 1998 (the "OEB Act")* for approval of its proposed distribution rates and other charges, effective May 1, 2011.
A list of requested approvals is set out in Exhibit 1.

c) NPEI followed Chapter 2 of the OEB's Filing Requirements for Transmission and Distribution Applications dated June 28, 2010 (the "Filing Requirements") in order to prepare this application.

2) Proposed Distribution Rates and Other Charges

a) The Schedule of Rates and Charges proposed in this Application are identified in Exhibit 1, Table 1-6 and 1-6.1 included in this application and Exhibit 8, and the material being filed in support of this Application sets out NPEI's approach to its distribution rates and charges.

3) Proposed Effective Date of Rate Order

a) NPEI requests that the OEB make its Rate Order effective May 1, 2011 in accordance with the Filing Requirements.

4) The Proposed Distribution Rates and Other Charges are Just and Reasonable

a) NPEI submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

(i) the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles;

(ii) the proposed adjusted rates are necessary to meet NPEI's Market Based Rate of Return ("MBRR") and Payments in Lieu of Taxes ("PILs") requirements;

(iii) there are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by the Applicant or the implementation of any other mitigation measures other than those described in Exhibit 8

(iv) the other service charges proposed by NPEI are now harmonized and the same as those previously approved by the OEB; and

(v) such other grounds as may be set out in the material accompanying this Application Summary.

5) Relief Sought

NPEI applies for an Order or Orders approving the proposed distribution rates and other charges set out in Exhibit 1, Table 1-6 and 1-6.1 to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2011, or as soon as possible thereafter; and

6) Form of Hearing Requested

NPEI requests that this Application be disposed of by way of a written hearing.

DATED at: Niagara Falls, Ontario. This 30th day of November, 2010.

All of which is respectfully submitted,

Original Signed By

Brian Wilkie
President and CEO
Niagara Peninsula Energy Inc.

Contact Information

Niagara Peninsula Energy Inc.

Niagara Peninsula Energy Inc.
7447 Pin Oak Drive
Box 120
Niagara Falls, Ontario
L2E 6S9
Telephone: (905) 356-2681
Fax: (905) 356-0118

President and Chief Executive Officer
Mr. Brian Wilkie
Telephone: (905) 353-6000
Email: Brian.Wilkie@npei.ca

Vice President Finance
Mrs. Suzanne Wilson
Telephone: (905) 353-6004
Email: Suzanne.Wilson@npei.ca

Vice President Operations
Mr. Dan Sebert
Telephone: (905) 353-6017
Email: Dan.Sebert@npei.ca

Vice President Engineering
Mr. Tom Sielicki
Telephone: (905) 353-6016
Email: Tom.Sielicki@npei.ca

Manager of Engineering
Mr. Kevin Carver
Telephone: (905) 353-6015
Email: Kevin.Carver@npei.ca

Regulatory and Financial Analyst
Mr. Paul Blythin
Telephone: (905) 356-2681 ext. 6064
Email: Paul.blythin@npei.ca

EXECUTIVE SUMMARY
2011
DISTRIBUTION
RATE APPLICATION

Executive Summary

Exhibit 1 – Application

Niagara Peninsula Energy Inc. is submitting this Application for revised distribution rates effective May 1, 2011 in accordance with the 2011 Rate Filing Guidelines for Cost of Service rate applications issued June 28, 2010.

The proposed distribution rates are required to:

1) Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system.

2) Continue with training programs for line staff needed to meet future staffing requirements and prepare for succession planning.

3) Manage staffing levels and skills to ensure regulatory compliance, promote conservation programs, implement changes resulting from the adoption of International Financial Reporting Standards and ensure NPEI can continue to move forward with changes stemming from the Green Energy and Green Economy Act.

4) Maintain or improve the level of service expected by our customers.

5) To provide a reasonable rate of return to the Shareholder.

6) Harmonize distribution rate classes, distribution rates, loss factors, low voltage rates, Retail Transmission Service Rates (Network and Connection) and other Specific Service Charges as agreed to in the merger agreement approved by the OEB on December 27, 2007

7) Harmonize the Conditions of Services between the former Niagara Falls Hydro LDC and the former Peninsula West Utilities Ltd LDC.

<u>NPEI's Mission Statement is:</u>

To deliver safe, efficient and reliable electricity through dedicated employees in an environmentally sustainable and technologically focused manner. To provide excellence in customer service and respond to the needs of our communities.

<u>NPEI's Vision Statement is:</u>

Deliver environmentally responsible and sustainable energy for the future of our communities.

<u>NPEI's Values are:</u>

To conduct ourselves with commitment to the values of: Integrity, fairness, responsibility, respect and transparency.

<u>NPEI's priorities are to:</u>

Invest heavily in our staff and rely on them to help us accomplish our goals by keeping staff informed; understand their expectations and their importance to the organization providing them with the tools, equipment and training.

Stay current with industry, sector and regulatory changes.

Investigate roles and opportunities that NPEI can pursue through conservation and demand management initiatives.

Keep with the vision to pursue health and safety as NPEI's top priority.

The Schedule of Proposed Rates and Charges are set out in Exhibit 1, Table 1-6 and Table 1-6.1.

The information presented in this Application is NPEI's forecasted results for its 2011 Test Year.

NPEI is also presenting the historical information for the OEB-approved data for 2006, Actual data for fiscal years 2006 through 2009, and forecast results for the 2010 Bridge Year. Data for the OEB-approved 2006 and actual data for 2006 and 2007 were compiled separately for Niagara Falls Hydro Inc. and Peninsula West Utilities Limited and then combined to create continuity flow and comparative information.

The financial information supporting the Test Year for this Application will be NPEI's fiscal year ending December 31, 2011 (the "2011 Test Year"). However, this information will be used to set rates for the period May 1, 2011 to April 30, 2012.

NPEI's forecast has been prepared over many months, beginning in the third quarter of 2009. Due to the merger of two utilities several schedules, exhibits and tables were required to be prepared first for the two former utilities for 2006 and 2007 data years and then shown as a combined company for 2006 and 2007.
It has been approved by NPEI's Senior Management.

Background

Niagara Peninsula Energy Inc. (NPEI) is a medium sized LDC in the Province of Ontario and is responsible for providing all regulated electricity distribution services to over 52,000 residential and business customers in the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham.

NPEI was created in 2008 as a result of the amalgamation of Niagara Falls Hydro Inc. and Peninsula West Utilities Limited. Niagara Falls Hydro and Peninsula West Utilities were amalgamated creating a service territory that even today is still one of the largest in the province at 827 sq. km. NPEI notes that of its 827 sq km. service territory, approximately 92% of the area is rural and 8% is urban. A larger rural component adds costs above an urban area due to the distance to travel the service area to respond to outages, to travel to construction sites, to perform inspections and to perform maintenance. In addition it takes a greater amount of investment to service customers in the rural areas as the density is much lower than in an urban area. In NPEI's cost allocation model (Exhibit 7) the density based on road kilometers is 27 customers/km, which is closer to the rural area defined in this model (<30 customers/km), than the urban area (>60 customers/km).

Home to two prominent casinos and many hotels and tourism based businesses; NPEI is focused on providing excellent customer service and provides educational information through various sources to its customers.

NPEI also operates and makes decisions based from a sound business perspective. It has a progressive Board of Directors that provides oversight in not only providing what is best for NPEI's customers, it also ensures that it is done using sound business analysis and practices. NPEI is always striving to contain its costs where possible and it is aware that all costs are ultimately borne by its customers.

NPEI, similar to many LDC's, is facing an aging workforce and looming retirements. NPEI experienced the beginning of the wave of retirements recently. NPEI works diligently to maintain its level of staff members and with upcoming retirements NPEI is prudently preparing for the future by hiring apprentices and trainees. Apprenticeship training periods are four to five years, thus, planning is imperative to have trainees part way through their apprenticeship in advance of a Journeyperson retiring.

NPEI's capital and operating programs have a history of adapting based on asset inspection findings and in keeping with industry best practices NPEI maintains excellent inspection and maintenance practices. A third party, Kinetrics, was engaged to perform an asset condition study and prepare an Asset Management Plan for NPEI. Once this report is complete, NPEI will submit it as an appendix to Exhibit 2.

NPEI stays current with all Regulatory Proceedings, including OEB, OPA, IESO, ESA and MEI. It ensures that its practices and reporting are in compliance with the regulatory rules and participates in many proceedings, working groups, and assists the Board in testing some of its rate models.

NPEI constructed its own transformer station commencing in 2003 and opening in 2004 due to the increase in load from the construction of the second casino and several hotels.

NPEI has a competent and results oriented senior management.

In 2004, NPEI converted from a legacy accounting and financial information system to Great Plains which is a product of Microsoft. In 2006, NPEI began the conversion of the legacy billing system and become the beta site for the implementation of a new Harris billing system. On January 1st, 2008, NPEI's former Niagara Falls Hydro customers were live on the Harris billing system and in October 2009 the former Peninsula West Utility customers were converted onto the Harris billing system. Also, NPEI has implemented an extensive geographical information system (GIS) over the past seven years to track plant and equipment assets in the field, as well as provide a new tool for planning and design purposes. NPEI is currently in the process of implementing a workforce management information (WMI) system. The WMI system will provide outage management information as well as dispatched work management functionality which will effectively replace the current paper based work ticket system. The work dispatched will be communicated using a wireless technology from the control room directly to mobile laptops installed in the trucks. In 2010 and 2011 NPEI will be converting its fixed asset information into a fixed asset module that will prepare NPEI for the transition to IFRS in 2011.

The former Peninsula West Utility office employees rented office space in Beamsville and their line and stores employees worked in an extremely old building in the Town of Lincoln which PWU owned at the time. The Town of Lincoln building was excluded from the merger and transferred to the PWU holding company. In 2008, NPEI constructed a new service centre in the Township of West Lincoln. In the fall of 2009 all former PWU employees were moved to either the new service centre located in Smithville or the administration building located in Niagara Falls.

The amalgamation resulted in many voltage levels and NPEI has worked diligently to reduce this to the two most common distribution voltages used in the province, 13.8kV and 27.6 kV. NPEI has increased their rate of conversion to higher distribution voltage levels in the past few years, in order to provide more reliable service to their customers in a more cost efficient manner.

NPEI has harmonized its Conditions of Services between the two predecessor utilities and will be submitting it with the 2011 COS rate application.

Canadian Generally Accepted Accounting Principles (CGAAP)

This application has been filed in accordance with Canadian Generally Accepted Accounting Principles (CGAAP) as allowed for in the Board's July 28, 2009 EB-2008-0408 *Report of the Board: Transition to International Financial Reporting Standards*. The Filing Requirements for Rate Applications Section states, "The Board will require electricity distributors filing for 2011 rates to provide the required years, the 2010 bridge year and the 2011 forecasts in CGAAP based format. An electricity distributor may choose to present modified IFRS based forecasts for 2010 and 2011, if the distributor prefers to have rates set on the basis of modified IFRS." NPEI has chosen to provide the required years, the 2010 bridge year and the 2011 forecast in CGAAP based format. The CGAAP based format extends itself to all costs in this application, including Rate Base, Depreciation and OM&A Costs and is prepared under the same CGAAP basis that NPEI's audited financial statements are prepared under. NPEI submits that the application of the format is not severable, an example of which is that capitalization of direct and indirect costs (overheads) cannot be on a CGAAP basis, while depreciation rates are subject to the new IFRS componentization rules. NPEI notes that the Board's letter of April 30, 2010 "Depreciation Study for Electricity Distributors (EB-2010-0178) – Transition to International Financial Reporting Standards ("IFRS") clearly defines the depreciation study, and any changes as a result of the application of the study, under the realm of IFRS.

NPEI is not submitting an updated depreciation study and thus, has adhered to the depreciation rates contained in the 2006 EDR Handbook, Appendix B.

Harmonized Sales Tax (HST)

NPEI has adjusted its 2010 Rate Base and OM&A Bridge Year Costs for the impacts of the Harmonized Sales Tax (HST) which is effective July 1, 2010. NPEI used the actual costs at June 30, 2010 and projected the remaining six months excluding PST that would have previously been capitalized or expensed. NPEI is required to record the incremental input tax credit (ITC) it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST into the deferral account 1592 (PILS and Tax Variances, Sub-account HST/OVAT Input Tax Credits (ITC's) as a result of the April 8, 2010 Board Decisions EB-2009-0205 and EB-2009-0206 on its May 1, 2010 distribution rate application. 50% of the confirmed balances in this account will be returned to the ratepayers in the future.

NPEI has reviewed each line item in its 2011 Rate Base and OM&A Test Year Costs and adjusted for impacts of the HST. These impacts include removal of any Provincial Sales Tax (PST) that had been included in the cost where the PST portion of the HST is recoverable by NPEI as an input tax credit. NPEI notes that as a company with sales in excess of $10,000,000, it is subject to input tax credit (ITC) restrictions. These restrictions include:

- Non-recovery of the PST portion of the HST on energy costs for its own consumption
- Non-recovery of the PST portion of HST on telecommunication costs, excluding 1-800 numbers and internet charges
- Non-recovery of the PST portion of HST on certain costs for road vehicles weighing less than 3,000 kilograms
- Non-recovery of the PST portion of HST on meals and entertainment costs

NPEI notes that expenses, where the previously paid PST is now fully recoverable through HST, will reduce its costs.

However, with the ITC restrictions above, some expenses that previously were not subject to PST are now subject to HST, and the PST portion of the HST is not recoverable. The net effect of this restriction is that it adds costs to our business.

In addition, some expenses previously did not attract PST (i.e. audit fees), thus, the charging of HST is simply a pass-through, and, there is no impact to the costs, which is no different than when the only Goods & Services Tax (GST) was charged.

Exhibit 2 – Capital Expenditures & Rate Base

NPEI is an infrastructure-based business with its distribution system assets the key element in the delivery of electricity to its existing and new customers. NPEI's distribution system include three (3) Transformer Stations that step down the voltage from 115kV to 13.8kV for distribution in the City of Niagara Falls and three (3) Transformer Stations that step down the voltage from 115kV/230kV to 27.6kV in the former Peninsula West service territory. NPEI constructed, owns, and maintains one of these six Transformer Stations since 2004. This new transformer station was approved to be a deemed distribution asset in the 2006 EDR rate application. The transformer station was built over a two year period from 2003 to 2004 and as a result, half of the addition costs were included in the rate base for the 2006 EDR rate application. The remaining portion is included in the 2011 Cost of Service rate application. All of the transformer stations are operated by Hydro One.

NPEI's distribution assets range in age from new to over 70 years old. A third party, Kinetrics, was engaged to perform an asset condition study and prepare an Asset Management Plan for NPEI. Once this report is complete, NPEI will submit it as an appendix to Exhibit 2.

NPEI commenced deployment of smart meters in December 2009. As at June 30, 2010, NPEI obtained an audit report on financial information related to smart meters. NPEI had 74% of its total deployment installed at June 30, 2010 and has included $4,175,010 in its rate base for 2010.

NPEI historically calculated accumulated depreciation and depreciation expense using a full year's depreciation in the year of purchase. In 2010, NPEI has changed the calculation of accumulated depreciation and depreciation expense using the half year rule. This change was done to minimize the timing differences between amortization and CCA calculated for tax purposes.

Exhibit 3 – Load Forecast & Operating Revenue

NPEI has a long and proud history of serving its customers in the City of Niagara Falls (since 1915), the former Niagara Falls Hydro Inc. and in the Town of Lincoln, Township of West Lincoln and the Town of Pelham, former Peninsula West Utilities Limited (since 2000).

NPEI's service area has been an area of steady growth at approximately 1.3% per year.

The load forecast was prepared using historical data as well as several variables. The load forecast model and Operating Revenue calculations are included in Exhibit 3.

Exhibit 4 – Operating Costs

NPEI has three factors of note that increase its costs compared to many other distributors. NPEI's service territory is one of the largest in the province and approximately 92% is rural. A large service territory with such a large rural component, results in additional costs in labour and trucking for NPEI to reach customers to respond to service calls, to inspect and maintain its plant. In addition NPEI has sections of its service territory that have very few customers per kilometer, increasing the cost to construct and maintain on a per customer basis. Another factor that would reflect in increased cost per customer in comparison to other distributors is NPEI's ownership and maintenance of one Transformer Station (TS). All costs to own and maintain the TS' are included in distribution expenses, while those distributors that do not own their own TS' do not incur these expenses; the customer is charged via the Retail Transmission Network Connection Charge, rather than the distribution charge. And finally, NPEI does not include an administration component as part of overhead calculations.

Based on the OEB's 2009 Yearbook of Electricity Distributors, as updated with 2009 Data issued on August 25, 2010, NPEI's OM&A costs per customer was $256.67. In 2008, NPEI's cost per customer was $254.55. The increase from 2008 to 2009 was 0.8%. Per the OEB's yearbook in 2008 the average of all LDC's OM&A cost per customer was $258.00 and in 2009 the average of all LDC's OM&A per customer was $267.00. In both years NPEI's OM&A cost per customer was below the average. The OEB's Comparison of Ontario Electricity Distributors Costs (EB-2006-0268), as updated with 2007 Data issued on December 4, 2009 was not used as it does not incorporate the merged company of Niagara Peninsula Energy Inc. which was incorporated on January 1, 2008.
As the distribution system expands and ages, however, it is reasonable to expect that additional costs will be incurred to maintain the additional assets. Likewise, additional investments in new distribution system infrastructure and facilities increases amortization expense, for example, the addition of the Kalar Road Transformer Station in 2004 and the new service centre located in the Township of West Lincoln in 2009 and smart meters implemented in 2010.

The 2011 OM&A Expenditures have been adjusted by the impact of the introduction of the

Harmonized Sales Tax (HST) as discussed above, and, as such, no further adjustments are necessary. The 2010 OM&A Expenditures have also been adjusted as discussed above in Application (Exhibit 1)”.

The rate base expenditures and amortization have been prepared in the CGAAP format, as discussed above in Application (Exhibit 1)”.

As detailed, in the evidence of the application, NPEI strives to maintain the appropriate employee complement; however, as demonstrated in the sections of the application, the effect of an aging workforce, long training or apprenticeship periods and the increased regulatory environment has culminated with increases in staff in 2010. Apprenticeships for Power line Workers occur over a four to five year period, and training periods for Engineering Technologist/Technician occur over a five year period.

NPEI is experiencing what others in the industry are experiencing, an aging workforce and a high volume of retirements in the foreseeable future. In addition, increased requirements for regulatory requirements (MDM/R, expense in Smart Meter Deferral Account 1556), and Programming and Reporting needs, have increased NPEI’s staffing compliment.

Service Quality Indicators

NPEI tracks and files its Service Quality Indicators with the Board through its RRR reporting. The results are reviewed by Senior Management to ensure that NPEI is maintaining the high level of service that its customers expect. When deficiencies are identified, NPEI’s Senior Management team investigates to correct any issues that may exist.

The NPEI’s Service Quality Indicators have been targeted to maintain its performance at levels equal to or above the OEB’s standards in 2010 and 2011. In August of 2009, the SAIFI for the Pen west service territory was 3.8 which was due to a severe storm.

NPEI tracks service reliability statistics SAIDI (System Average Interruption Duration Index) and SAFI (System Average Frequency Index) including and excluding Hydro One related incidents (loss of supply).

NPEI is committed to the reliability of the distribution system and continues to make capital investments in infrastructure in order to maintain or improve its reliability statistics.

NPEI's Service Quality Indicators are presented in Table 1-1 and Table 1-2.

Table 1-1 Service Reliability Indices

Niagara Peninsula Energy Inc.

	2009			2008		
	SAIDI	**SAIFI**	**CAIDI**	**SAIDI**	**SAIFI**	**CAIDI**
Niagara Falls Territory	1.37	0.82	1.68	1.42	0.97	1.46
Peninsula West Territory	5.41	1.75	3.09	1.99	1.04	1.92
NPEI Combined	2.67	1.12	2.39	1.60	0.99	1.61

Table 1-2 Three Year Comparison Service Quality Indicators

Table 1-2
Niagara Peninsula Energy Inc.
Service Quality Indicators
Three Year Comparison

Indicator	SQI Standard	2007	2008	2009
Appointments Met - at the appointed time	90% of the time	100.0%	100.0%	100.0%
Appointments Scheduled - within 5 working days (new 2009)	90% of the time	n/a	n/a	100.0%
Rescheduling a missed appointment - contact before missed and rescheduling within 1 day (new 2009)	90% of the time	n/a	n/a n/a	
Telephone Accessibility - answered in person within 30 seconds.	65% of the time	99.0%	99.1%	61.0%
Telephone Call Abandon Rate - calls abandoned before they are answered (new 2009)	10% or less	n/a	n/a	3.6%
Underground Cable Locates - within 5 working days	90% of the time	92.1%	98.7%	98.9%
Connection of New Low Voltage Services - within 5 working days	90% of the time	91.3%	89.4%	87.9%
Connection of New High Voltage Services - within 10 working days	90% of the time	100.0%	100.0%	90.0%
Emergency Response - Urban within 90 minutes	80% of the time	100.0%	87.0%	100.0%
Emergency Response - Rural within 120 minutes	80% of the time	100.0%	-	92.9%
Written Responses to Inquiries - within 10 working days	80% of the time	100.0%	100.0%	99.8%

Exhibit 5 – Cost of Capital & Capital Structure

NPEI completed its transition to a capital structure of 60% debt and 40% equity through its 2010 electricity distribution rate application (EB-2009-0206 and EB-2009-0205) as outlined in the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006 (the “Cost of Capital Report”). NPEI plans to maintain its current capital structure with no changes in 2011.

NPEI has assumed a return on equity of 9.85% consistent with the Cost of Capital Parameter Updates for 2010 Cost of Service Applications issued by the OEB on March 8, 2010.

NPEI understands the OEB will be finalizing the return on equity for 2011 rates based on January 2011 market interest rate information.

NPEI continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. Expenditures are also being made to meet regulations set out by both the OEB and IESO including load transfers and primary metering points.

Exhibit 6 – Calculation of Revenue Requirement

NPEI's requested service revenue requirement for 2011 in the amount of $32,421,330 includes the recovery of its costs to provide distribution services and its' permitted Return on Equity ("ROE") as shown on Table 6-5 and on the enclosed Revenue Requirement Work Form in Table 1-4. When forecasted energy and demand levels for 2011 are considered, NPEI estimates that its present rates will produce a deficiency in Gross Distribution Revenue of $3,378,275 for the 2011 Test Year as shown in Table 1-3. Should this revenue deficiency continue NPEI will not be able to sustain the current capital investment, staffing requirements and maintenance required to ensure a safe and reliable distribution system. Note the Revenue Requirement Work Form in Table 1-4 does not consider the two tiers for Energy and as a result differ from the Bill Impacts included in Exhibit 8.

The revenue deficiency is primarily the result of:

Additions to capital assets in all years exceeded depreciation levels resulting in an increased rate base on which the rate of return is calculated. In particular, in 2009, NPEI put in service its new service centre in the Township of West Lincoln and in 2010 NPEI implemented its smart meters.

Increases in OM&A expenses (discussed in Exhibit 4) primarily due to:

- Increases in direct and indirect labour costs

  Economic wage increases have increased salaries and wages paid each year. Effective April 1 of each year, economic increases negotiated through collective agreements were 3.0%, 3.0% and 3.0% for 2008, 2009 and 2010 respectively. NPEI has a 3% cost of living increase estimated in its incremental payroll for 2011.

- Inflation

- Increase in planned maintenance programs

- Increasing Regulatory Expenses

  NPEI's regulatory expenses have been steadily increasing year to year (discussed in Exhibit 4) and it further expects to incur each year over the next four years $77,500 in additional expenses due to the 2011 rate application.

Table 1-3 Revenue Deficiency Determination

Niagara Peninsula Energy
Revenue Deficiency Determination

Description	2010 Bridge Actual	2011 Test Existing Rates	2011 Test - Required Revenue
Revenue			
Revenue Deficiency	0	0	**3,378,275**
Distribution Revenue	25,989,747	26,857,308	26,857,308
Other Operating Revenue (Net)	1,999,852	2,185,747	2,185,747
Total Revenue	**27,989,599**	**29,043,055**	**32,421,330**
Costs and Expenses			
Administrative & General, Billing & Collecting	7,766,452	8,153,328	8,153,328
Operation & Maintenance	5,935,146	6,142,107	6,142,107
Depreciation & Amortization	7,000,940	7,143,688	7,143,688
Property Taxes	232,000	222,474	222,474
Capital Taxes	83,846	0	0
Deemed Interest	4,100,818	4,340,146	4,340,146
Total Costs and Expenses	**25,119,202**	**26,001,743**	**26,001,743**
Less OCT Included Above	(83,846)	0	0
Total Costs and Expenses Net of OCT	**25,035,356**	**26,001,743**	**26,001,743**
Utility Income Before Income Taxes	**2,954,243**	**3,041,312**	**6,419,587**
Income Taxes:			
Corporate Income Taxes	893,733	798,315	1,725,276
Total Income Taxes	**893,733**	**798,315**	**1,725,276**
Utility Net Income	**2,060,510**	**2,242,997**	**4,694,311**
Capital Tax Expense Calculation:			
Total Rate Base	114,503,962	119,144,943	119,144,943
Exemption	15,000,000	0	0
Deemed Taxable Capital	**99,503,962**	**119,144,943**	**119,144,943**
Ontario Capital Tax	83,846	0	0
Income Tax Expense Calculation:			
Accounting Income	2,954,243	3,041,312	6,419,587
Tax Adjustments to Accounting Income	93,207	(131,884)	(131,884)
Taxable Income	**3,047,450**	**2,909,428**	**6,287,703**
Income Tax Expense	893,733	798,315	1,725,276
Tax Rate Refecting Tax Credits	29.33%	27.44%	27.44%
Actual Return on Rate Base:			
Rate Base	114,503,962	119,144,943	119,144,943
Interest Expense	4,100,818	4,340,146	4,340,146
Net Income	2,060,510	2,242,997	4,694,311
Total Actual Return on Rate Base	**6,161,327**	**6,583,143**	**9,034,456**
Actual Return on Rate Base	5.38%	5.53%	7.58%
Required Return on Rate Base:			
Rate Base	114,503,962	119,144,943	119,144,943
Return Rates:			
Return on Debt (Weighted)	5.97%	6.07%	6.07%
Return on Equity	9.00%	9.85%	9.85%
Deemed Interest Expense	4,100,818	4,340,146	4,340,146
Return On Equity	4,122,143	4,694,311	4,694,311
Total Return	**8,222,960**	**9,034,456**	**9,034,456**
Expected Return on Rate Base	7.18%	7.58%	7.58%
Revenue Deficiency After Tax	**2,061,633**	**2,451,313**	**0**
Revenue Deficiency Before Tax	**2,917,154**	**3,378,275**	**0**

Table 1-4 Revenue Requirement Work Form

REVENUE REQUIREMENT WORK FORM

Name of LDC:	Niagara Peninsula Energy Inc.	(1)
File Number:	EB-2010-0138	
Rate Year:	2011	**Version:** 2.11

Table of Content

Notes:
(1) Pale green cells represent inputs
(2) Pale yellow cells represent drop=down lists
(3) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(4) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Niagara Peninsula Energy Inc.
File Number: EB-2010-0138
Rate Year: 2011

Data Input (1)

		Initial Application			(7)	Per Board Decision	
1	**Rate Base**						
	Gross Fixed Assets (average)	$205,000,203		$ 205,000,203		$205,000,203	
	Accumulated Depreciation (average)	($103,031,549)	(5)	-$ 103,031,549		($103,031,549)	
	Allowance for Working Capital:						
	Controllable Expenses	$14,517,909		$ 14,517,909		$14,517,909	
	Cost of Power	$99,990,688		$ 99,990,688		$99,990,688	
	Working Capital Rate (%)	15.00%		15.00%		15.00%	
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$26,857,308					
	Distribution Revenue at Proposed Rates	$30,235,583					
	Other Revenue:						
	Specific Service Charges	$956,878					
	Late Payment Charges	$518,557					
	Other Distribution Revenue	$558,164					
	Other Income and Deductions	$152,148					
	Operating Expenses:						
	OM+A Expenses	$14,295,435		$ 14,295,435		$14,295,435	
	Depreciation/Amortization	$7,143,688		$ 7,143,688		$7,143,688	
	Property taxes	$222,474		$ 222,474		$222,474	
	Capital taxes	$0					
	Other expenses						
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($131,884)	(3)				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$1,237,886					
	Income taxes (grossed up)	$1,725,276					
	Capital Taxes	$ -	(6)		(6)		(6)
	Federal tax (%)	16.50%					
	Provincial tax (%)	11.75%					
	Income Tax Credits	($51,000)					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(2)		(2)		(2)
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)						
		100.0%					
	Cost of Capital						
	Long-term debt Cost Rate (%)	6.36%					
	Short-term debt Cost Rate (%)	2.07%					
	Common Equity Cost Rate (%)	9.85%					
	Prefered Shares Cost Rate (%)						

Notes:

(Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the data. Notes should be put on the applicable pages to explain numbers shown.

(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.
(6) Not applicable as of July 1, 2010

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Niagara Peninsula Energy Inc.
File Number: EB-2010-0138
Rate Year: 2011

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$205,000,203	$ -	$205,000,203	$ -	$205,000,203
2	Accumulated Depreciation (average)	(3)	($103,031,549)	$ -	($103,031,549)	$ -	($103,031,549)
3	Net Fixed Assets (average)	(3)	$101,968,654	$ -	$101,968,654	$ -	$101,968,654
4	Allowance for Working Capital	(1)	$17,176,290	$ -	$17,176,290	$ -	$17,176,290
5	**Total Rate Base**		$119,144,943	$ -	$119,144,943	$ -	$119,144,943

	(1) Allowance for Working Capital - Derivation						
6	Controllable Expenses		$14,517,909	$ -	$14,517,909	$ -	$14,517,909
7	Cost of Power		$99,990,688	$ -	$99,990,688	$ -	$99,990,688
8	Working Capital Base		$114,508,597	$ -	$114,508,597	$ -	$114,508,597
9	Working Capital Rate %	(2)	15.00%	0.00%	15.00%	0.00%	15.00%
10	Working Capital Allowance		$17,176,290	$ -	$17,176,290	$ -	$17,176,290

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

Version: 2.11

Name of LDC: Niagara Peninsula Energy Inc.
File Number: EB-2010-0138
Rate Year: 2011

Line No.	Particulars		Initial Application	Utility income			Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$30,235,583	($30,235,583)	$ -	$ -	$ -
2	Other Revenue	(1)	$2,185,747	($2,185,747)	$ -	$ -	$ -
3	Total Operating Revenues		$32,421,330	($32,421,330)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$14,295,435	$ -	$14,295,435	$ -	$14,295,435
5	Depreciation/Amortization		$7,143,688	$ -	$7,143,688	$ -	$7,143,688
6	Property taxes		$222,474	$ -	$222,474	$ -	$222,474
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$21,661,597	$ -	$21,661,597	$ -	$21,661,597
10	Deemed Interest Expense		$4,340,146	($4,340,146)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$26,001,743	($4,340,146)	$21,661,597	$ -	$21,661,597
12	**Utility income before income taxes**		$6,419,587	($28,081,184)	($21,661,597)	$ -	($21,661,597)
13	Income taxes (grossed-up)		$1,725,276	$ -	$1,725,276	$ -	$1,725,276
14	**Utility net income**		$4,694,311	($28,081,184)	($23,386,874)	$ -	($23,386,874)

Notes

(1)

Other Revenues / Revenue Offsets					
Specific Service Charges	$956,878		$ -		$ -
Late Payment Charges	$518,557		$ -		$ -
Other Distribution Revenue	$558,164		$ -		$ -
Other Income and Deductions	$152,148		$ -		$ -
Total Revenue Offsets	$2,185,747	$ -	$ -	$ -	$ -

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Niagara Peninsula Energy Inc.
File Number: EB-2010-0138
Rate Year: 2011

Taxes/PILs

Line No.	Particulars	Application				Per Board Decision	
	Determination of Taxable Income						
1	Utility net income before taxes	$4,694,311		$ -		$ -	
2	Adjustments required to arrive at taxable utility income	($131,884)		$ -		($131,884)	
3	Taxable income	$4,562,427		$ -		($131,884)	
	Calculation of Utility income Taxes						
4	Income taxes	$1,237,886		$1,237,886		$1,237,886	
5	Capital taxes	$ -	(1)	$ -	(1)	$ -	(1)
6	Total taxes	$1,237,886		$1,237,886		$1,237,886	
7	Gross-up of Income Taxes	$487,391		$487,391		$487,391	
8	Grossed-up Income Taxes	$1,725,276		$1,725,276		$1,725,276	
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$1,725,276		$1,725,276		$1,725,276	
10	Other tax Credits	($51,000)		($51,000)		($51,000)	
	Tax Rates						
11	Federal tax (%)	16.50%		16.50%		16.50%	
12	Provincial tax (%)	11.75%		11.75%		11.75%	
13	Total tax rate (%)	28.25%		28.25%		28.25%	

Notes
1 **(1)** Capital Taxes not applicable after July 1, 2010 (i.e. for 2011 and later test years)

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Niagara Peninsula Energy Inc.
File Number: EB-2010-0138
Rate Year: 2011

Capitalization/Cost of Capital

Initial Application

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$66,721,168	6.36%	$4,241,494
2	Short-term Debt	4.00%	$4,765,798	2.07%	$98,652
3	**Total Debt**	60.00%	$71,486,966	6.07%	$4,340,146
	Equity				
4	Common Equity	40.00%	$47,657,977	9.85%	$4,694,311
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$47,657,977	9.85%	$4,694,311
7	**Total**	100.00%	$119,144,943	7.58%	$9,034,456

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$119,144,943	0.00%	$ -

Per Board Decision

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
8	Long-term Debt	0.00%	$ -	6.36%	$ -
9	Short-term Debt	0.00%	$ -	2.07%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	9.85%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$119,144,943	0.00%	$ -

Notes

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

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Niagara Peninsula Energy Inc.
File Number: EB-2010-0138
Rate Year: 2011

Revenue Sufficiency/Deficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$3,378,275		($5,318,717)		$21,661,597
2	Distribution Revenue	$26,857,308	$26,857,308	$26,857,308	$35,554,301	$ -	($21,661,597)
3	Other Operating Revenue Offsets - net	$2,185,747	$2,185,747	$ -	$ -	$ -	$ -
4	**Total Revenue**	$29,043,055	$32,421,330	$26,857,308	$30,235,583	$ -	$ -
5	Operating Expenses	$21,661,597	$21,661,597	$21,661,597	$21,661,597	$21,661,597	$21,661,597
6	Deemed Interest Expense	$4,340,146	$4,340,146	$ -	$ -	$ -	$ -
	Total Cost and Expenses	$26,001,743	$26,001,743	$21,661,597	$21,661,597	$21,661,597	$21,661,597
7	**Utility Income Before Income Taxes**	$3,041,312	$6,419,587	$5,195,711	$8,573,986	($21,661,597)	($21,661,597)
8	Tax Adjustments to Accounting Income per 2009 PILs	($131,884)	($131,884)	($131,884)	($131,884)	$ -	$ -
9	**Taxable Income**	$2,909,429	$6,287,703	$5,063,827	$8,442,102	($21,661,597)	($21,661,597)
10	Income Tax Rate	28.25%	28.25%	28.25%	28.25%	28.25%	28.25%
11	**Income Tax on Taxable Income**	$821,914	$1,776,276	$1,430,531	$2,384,894	($6,119,401)	($6,119,401)
12	**Income Tax Credits**	($51,000)	($51,000)	($51,000)	($51,000)	$ -	$ -
13	**Utility Net Income**	$2,270,399	$4,694,311	$3,816,180	($23,386,874)	($15,542,196)	($23,386,874)
14	**Utility Rate Base**	$119,144,943	$119,144,943	$119,144,943	$119,144,943	$119,144,943	$119,144,943
	Deemed Equity Portion of Rate Base	$47,657,977	$47,657,977	$ -	$ -	$ -	$ -
15	Income/Equity Rate Base (%)	4.76%	9.85%	0.00%	0.00%	0.00%	0.00%
16	Target Return - Equity on Rate Base	9.85%	9.85%	0.00%	0.00%	0.00%	0.00%
17	Sufficiency/Deficiency in Return on Equity	-5.09%	0.00%	0.00%	0.00%	0.00%	0.00%
18	Indicated Rate of Return	5.55%	7.58%	3.20%	0.00%	-13.04%	0.00%
19	Requested Rate of Return on Rate Base	7.58%	7.58%	0.00%	0.00%	0.00%	0.00%
20	Sufficiency/Deficiency in Rate of Return	-2.03%	0.00%	3.20%	0.00%	-13.04%	0.00%
21	Target Return on Equity	$4,694,311	$4,694,311	$ -	$ -	$ -	$ -
22	Revenue Deficiency/(Sufficiency)	$2,423,912	$ -	($3,816,180)	$ -	$15,542,196	$ -
23	**Gross Revenue Deficiency/(Sufficiency)**	$3,378,275 **(1)**		($5,318,717) **(1)**		$21,661,597 **(1)**	

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

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Niagara Peninsula Energy Inc.
File Number: EB-2010-0138
Rate Year: 2011

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$14,295,435		$14,295,435		$14,295,435	
2	Amortization/Depreciation	$7,143,688		$7,143,688		$7,143,688	
3	Property Taxes	$222,474		$222,474		$222,474	
4	Capital Taxes	$ -		$ -		$ -	
5	Income Taxes (Grossed up)	$1,725,276		$1,725,276		$1,725,276	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$4,340,146		$ -		$ -	
	Return on Deemed Equity	$4,694,311		$ -		$ -	
8	Distribution Revenue Requirement before Revenues	$32,421,330		$23,386,874		$23,386,874	
9	Distribution revenue	$30,235,583		$ -		$ -	
10	Other revenue	$2,185,747		$ -		$ -	
11	**Total revenue**	$32,421,330		$ -		$ -	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	($23,386,874)	(1)	($23,386,874)	(1)

Notes
(1) Line 11 - Line 8

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Niagara Peninsula Energy Inc.
File Number: EB-2010-0138
Rate Year: 2011

Residential

Consumption 800 kWh

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
1	Monthly Service Charge	monthly	$ 15.9600	1	$ 15.96	$ 16.5500	1	$ 16.55	$ 0.59	3.70%
2	Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate	per kWh	$ 0.0136	800	$ 10.88	$ 0.0167	800	$ 13.36	$ 2.48	22.79%
6	Low Voltage Rate Adder	per kWh		800	$ -	$ 0.0003	800	$ 0.24	$ 0.24	
7	Volumetric Rate Adder(s)	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
8	Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
9	Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider			800	$ -		800	$ -	$ -	
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0028	800	-$ 2.24	-$ 0.0028	800	-$ 2.24	$ -	0.00%
12	Deferrral & Variance Acct (kWh) May 2011-April 2012	per kWh	$ -	800	$ -	$ 0.0001	800	$ 0.08	$ 0.08	
13	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	per kWh	$ 0.0011	800	$ 0.88	$ 0.0011	800	$ 0.88	$ -	0.00%
14	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	per kWh	$ -	800	$ -	$ 0.0016	800	$ 1.28	$ 1.28	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 26.48**			**$ 31.15**	**$ 4.67**	**17.64%**
17	RTSR - Network	per kWh	$ 0.0053	845.76	$ 4.48	$ 0.0057	844.7922	$ 4.79	$ 0.30	6.80%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0046	845.76	$ 3.89	$ 0.0045	844.7922	$ 3.77	-$ 0.12	-3.03%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 34.85**			**$ 39.71**	**$ 4.86**	**13.94%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	845.76	$ 4.40	$ 0.0052	844.7922	$ 4.39	-$ 0.01	-0.11%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	845.76	$ 1.10	$ 0.0013	844.7922	$ 1.10	-$ 0.00	-0.11%
22	Special Purpose Charge	per kWh	$ 0.0003725	845.76	$ 0.32	$ -	844.7922	$ -	-$ 0.32	-100.00%
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	845.76	$ 5.92	$ 0.0070	844.7922	$ 5.91	-$ 0.01	-0.11%
25	Energy	per kWh	$ 0.0650	845.76	$ 54.97	$ 0.0650	844.7922	$ 54.91	-$ 0.06	-0.11%
26	Energy		$ 0.0750	32.8	$ 2.46	$ 0.0750	32.8	$ 2.46	$ -	0.00%
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 104.27**			**$ 108.74**	**$ 4.47**	**4.28%**
29	HST		13%		$ 13.56	13%		$ 14.14	$ 0.58	4.28%
30	**Total Bill (including Sub-total B)**				**$ 117.83**			**$ 122.87**	**$ 5.04**	**4.28%**
31	**Loss Factor (%)**	**Note 1**	5.72%			5.60%				

Residential – Niagara Falls customer, Note the Revenue Work Form model does not calculate the two tiers for Energy and differs from the Bill Impacts in Exhibit 8

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Niagara Peninsula Energy Inc.
File Number: EB-2010-0138
Rate Year: 2011

General Service < 50 kW

Consumption: 2000 kWh

#		Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge	monthly	$ 47.2700	1	$ 47.27	$ 38.4500	1	$ 38.45	-$ 8.82	-18.66%
2	Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate	per kWh	$ 0.0100	2000	$ 20.00	$ 0.0141	2000	$ 28.20	$ 8.20	41.00%
6	Low Voltage Rate Adder	per kWh	$ -	2000	$ -	$ 0.0003	2000	$ 0.60	$ 0.60	
7	Volumetric Rate Adder(s)	per kWh	$ -	2000	$ -	$ -	2000	$ -	$ -	
8	Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
9	Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
10	LRAM & SSM Rider			2000	$ -		2000	$ -	$ -	
11	Deferral/Variance Account Disposition Rate Rider	monthly	-$ 0.0027	2000	-$ 5.40	-$ 0.0027	2000	-$ 5.40	$ -	0.00%
12	Deferrral & Variance Acct (kWh) May 2011-April 2012	per kWh	$ -	2000	$ -	-$ 0.0013	2000	-$ 2.60	-$ 2.60	
13	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	per kWh	$ 0.0011	2000	$ 2.20	$ 0.0011	2000	$ 2.20	$ -	0.00%
14	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	per kWh	$ -	2000	$ -	$ 0.0019	2000	$ 3.80	$ 3.80	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 65.07**			**$ 66.25**	**$ 1.18**	**1.81%**
17	RTSR - Network	per kWh	$ 0.0046	2114.4	$ 9.73	$ 0.0051	2111.981	$ 10.84	$ 1.11	11.44%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0045	2114.4	$ 9.51	$ 0.0039	2111.981	$ 8.25	-$ 1.26	-13.26%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 84.31**			**$ 85.34**	**$ 1.03**	**1.22%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2114.4	$ 10.99	$ 0.0052	2111.981	$ 10.98	-$ 0.01	-0.11%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2114.4	$ 2.75	$ 0.0013	2111.981	$ 2.75	-$ 0.00	-0.11%
22	Special Purpose Charge	per kWh	$ 0.0003725	2114.4	$ 0.79	$ -	2111.981	$ -	-$ 0.79	-100.00%
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2114.4	$ 14.80	$ 0.0070	2111.981	$ 14.78	-$ 0.02	-0.11%
25	Energy	per kWh	$ 0.0650	2114.4	$ 137.44	$ 0.0650	2111.981	$ 137.28	-$ 0.16	-0.11%
26	Energy		$ 0.0750	201.87	$ 15.14	$ 0.0750	201.87	$ 15.14	$ -	0.00%
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 266.47**			**$ 266.52**	**$ 0.05**	**0.02%**
29	HST		13%		$ 34.64	13%		$ 34.65	$ 0.01	0.02%
30	**Total Bill (including Sub-total B)**				**$ 301.11**			**$ 301.17**	**$ 0.06**	**0.02%**
31	**Loss Factor**	**Note 1**	5.72%			5.60%				

GS < 50 – Niagara Falls Customer

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Niagara Peninsula Energy -Peninsula West
File Number:
Rate Year: 2011

Residential

Consumption 800 kWh

#		Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge	monthly	$ 10.0400	1	$ 10.04	$ 16.5500	1	$ 16.55	$ 6.51	64.84%
2	Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate	per kWh	$ 0.0180	800	$ 14.40	$ 0.0167	800	$ 13.36	-$ 1.04	-7.22%
6	Low Voltage Rate Adder	per kWh	$ 0.0023	800	$ 1.84	$ 0.0003	800	$ 0.24	-$ 1.60	-86.96%
7	Volumetric Rate Adder(s)	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
8	Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
9	Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider			800	$ -		800	$ -	$ -	
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0064	800	-$ 5.12	-$ 0.0064	800	-$ 5.12	$ -	0.00%
12	Deferrral & Variance Acct (kWh) May 2011-April 2012		$ -	800	$ -	$ 0.0001	800	$ 0.08	$ 0.08	
13	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.		$ 0.0007	800	$ 0.56	$ 0.0007	800	$ 0.56	$ -	0.00%
14	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.		$ -	800	$ -	$ 0.0016	800	$ 1.28	$ 1.28	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 22.72**			**$ 27.95**	**$ 5.23**	**23.02%**
17	RTSR - Network	per kWh	$ 0.0052	848.08	$ 4.41	$ 0.0057	844.7922	$ 4.79	$ 0.38	8.56%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0051	848.08	$ 4.33	$ 0.0045	844.7922	$ 3.77	-$ 0.55	-12.77%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 31.46**			**$ 36.51**	**$ 5.05**	**16.07%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	848.08	$ 4.41	$ 0.0052	844.7922	$ 4.39	-$ 0.02	-0.39%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	848.08	$ 1.10	$ 0.0013	844.7922	$ 1.10	-$ 0.00	-0.39%
22	Special Purpose Charge	per kWh	$ 0.0003725	848.08	$ 0.32	$ -	844.7922	$ -	-$ 0.32	-100.00%
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	848.08	$ 5.94	$ 0.0070	844.7922	$ 5.91	-$ 0.02	-0.39%
25	Energy	per kWh	$ 0.0650	848.08	$ 55.13	$ 0.0650	844.7922	$ 54.91	-$ 0.21	-0.39%
26	Energy	per kWh	$ 0.0750	33.07	$ 2.48	$ 0.0750	33.07	$ 2.48	$ -	0.00%
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 101.08**			**$ 105.56**	**$ 4.48**	**4.43%**
29	HST		13%		$ 13.14	13%		$ 13.72	$ 0.58	4.43%
30	**Total Bill (including Sub-total B)**				**$ 114.22**			**$ 119.28**	**$ 5.06**	**4.43%**
31	**Loss Factor (%)**	**Note 1**	6.01%			5.60%				

Residential Urban – Peninsula West customer

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Niagara Peninsula Energy -Peninsula West
File Number:
Rate Year: 2011

Residential

Consumption 800 kWh

			Current Board-Approved			Proposed			Impact	
		Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
1	Monthly Service Charge	monthly	$ 10.6500	1	$ 10.65	$ 16.5500	1	$ 16.55	$ 5.90	55.40%
2	Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate	per kWh	$ 0.0134	800	$ 10.72	$ 0.0167	800	$ 13.36	$ 2.64	24.63%
6	Low Voltage Rate Adder	per kWh	$ 0.0022	800	$ 1.76	$ 0.0003	800	$ 0.24	-$ 1.52	-86.36%
7	Volumetric Rate Adder(s)	per kWh	$ -	800	$ -	$ -	800	$ -	$ -	
8	Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
9	Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider			800	$ -		800	$ -	$ -	
11	Deferral/Variance Account Disposition Rate Rider	monthly	-$ 0.0064	800	-$ 5.12	-$ 0.0064	800	-$ 5.12	$ -	0.00%
12	Deferrral & Variance Acct (kWh) May 2011-April 2012		$ -	800	$ -	$ 0.0001	800	$ 0.08	$ 0.08	
13	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.		$ 0.0007	800	$ 0.56	$ 0.0007	800	$ 0.56	$ -	0.00%
14	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.		$ -	800	$ -	$ 0.0016	800	$ 1.28	$ 1.28	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 19.57**			**$ 27.95**	**$ 8.38**	**42.82%**
17	RTSR - Network	per kWh	$ 0.0052	848.08	$ 4.41	$ 0.0057	844.7922	$ 4.79	$ 0.38	8.56%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0051	848.08	$ 4.33	$ 0.0045	844.7922	$ 3.77	-$ 0.55	-12.77%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 28.31**			**$ 36.51**	**$ 8.20**	**28.99%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	848.08	$ 4.41	$ 0.0052	844.7922	$ 4.39	-$ 0.02	-0.39%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	848.08	$ 1.10	$ 0.0013	844.7922	$ 1.10	-$ 0.00	-0.39%
22	Special Purpose Charge	per kWh	$ 0.0003725	848.08	$ 0.32	$ -	844.7922	$ -	-$ 0.32	-100.00%
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	848.08	$ 5.94	$ 0.0070	844.7922	$ 5.91	-$ 0.02	-0.39%
25	Energy	per kWh	$ 0.0650	848.08	$ 55.13	$ 0.0650	844.7922	$ 54.91	-$ 0.21	-0.39%
26	Energy	per kWh	$ 0.0750	33.07	$ 2.48	$ 0.0750	33.07	$ 2.48	$ -	0.00%
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 97.93**			**$ 105.56**	**$ 7.63**	**7.79%**
29	HST		13%		$ 12.73	13%		$ 13.72	$ 0.99	7.79%
30	**Total Bill (including Sub-total B)**				**$ 110.66**			**$ 119.28**	**$ 8.62**	**7.79%**
31	**Loss Factor (%)**	**Note 1**	6.01%			5.60%				

Residential Suburban – Peninsula West customer

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Niagara Peninsula Energy -Peninsula West
File Number:
Rate Year: 2011

General Service < 50 kW

Consumption 2000 kWh

			Current Board-Approved			Proposed			Impact	
		Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
1	Monthly Service Charge	monthly	$ 10.3500	1	$ 10.35	$ 38.4500	1	$ 38.45	$ 28.10	271.50%
2	Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.0000	1	$ 1.00	$ -	0.00%
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate	per kWh	$ 0.0176	2000	$ 35.20	$ 0.0141	2000	$ 28.20	-$ 7.00	-19.89%
6	Low Voltage Rate Adder	per kWh	$ 0.0018	2000	$ 3.60	$ 0.0003	2000	$ 0.60	-$ 3.00	-83.33%
7	Volumetric Rate Adder(s)	per kWh	$ -	2000	$ -	$ -	2000	$ -	$ -	
8	Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
9	Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
10	LRAM & SSM Rider			2000	$ -		2000	$ -	$ -	
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0065	2000	-$ 13.00	-$ 0.0065	2000	-$ 13.00	$ -	0.00%
12	Deferrral & Variance Acct (kWh) May 2011-April 2012		$ -	2000	$ -	-$ 0.0013	2000	-$ 2.60	-$ 2.60	
13	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.		$ 0.0007	2000	$ 1.40	$ 0.0007	2000	$ 1.40	$ -	0.00%
14	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.		$ -	2000	$ -	$ 0.0019	2000	$ 3.80	$ 3.80	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 38.55**			**$ 57.85**	**$ 19.30**	**50.06%**
17	RTSR - Network	per kWh	$ 0.0047	2120.2	$ 9.96	$ 0.0051	2111.981	$ 10.84	$ 0.87	8.77%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0045	2120.2	$ 9.54	$ 0.0039	2111.981	$ 8.25	-$ 1.29	-13.50%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 58.06**			**$ 76.94**	**$ 18.89**	**32.53%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2120.2	$ 11.03	$ 0.0052	2111.981	$ 10.98	-$ 0.04	-0.39%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2120.2	$ 2.76	$ 0.0013	2111.981	$ 2.75	-$ 0.01	-0.39%
22	Special Purpose Charge	per kWh	$ 0.0003725	2120.2	$ 0.79	$ -	2111.981	$ -	-$ 0.79	-100.00%
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2120.2	$ 14.84	$ 0.0070	2111.981	$ 14.78	-$ 0.06	-0.39%
25	Energy	per kWh	$ 0.0650	2120.2	$ 137.81	$ 0.0650	2111.981	$ 137.28	-$ 0.53	-0.39%
26	Energy	per kWh	$ 0.0750	202.8	$ 15.21	$ 0.0750	201.6	$ 15.12	-$ 0.09	-0.59%
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 240.74**			**$ 258.10**	**$ 17.36**	**7.21%**
29	HST		13%		$ 31.30	13%		$ 33.55	$ 2.26	7.21%
30	**Total Bill (including Sub-total B)**				**$ 272.04**			**$ 291.66**	**$ 19.62**	**7.21%**
31	**Loss Factor**	**Note 1**	6.01%			5.60%				

GS < 50 Customer – Peninsula West customer

Exhibit 7 – Cost Allocation

NPEI notes that for its Residential, General Service <50 kW, and General Service >50 kW rate classes, the current revenue to cost ratio of each rate class is within the applicable threshold defined by the OEB in the November 28, 2007, Report on Application of Cost Allocation for Electricity Distributors. The Street Lighting and Sentinel rate classes will be within the Board's applicable threshold within a three year period.

The former Peninsula West Utilities Limited submitted a Cost of Service filing in 2007. However the former Niagara Falls Hydro did not due to the timing of the merger. The cost allocation model submitted with this 2011 rate application better reflects the costs and activities of the new merged company.

Exhibit 8 – Rate Design

In preparing this application, NPEI has considered the impact on its customers, with a goal of minimizing those impacts. Customer impacts including percentage average Total Bill Impact are set out in Appendix 8A. Embedded in this monthly bill impact is the effect of revised distribution rates (monthly service charge and volumetric rate), Smart Meter Funding Adder at its existing level, revised Loss Factors, Deferral and Variance Account Rate Rider to dispose of the balances at December 31, 2008 and a Deferral and Variance Account Rate Rider to dispose of the balances at December 31, 2009 in the Deferral and Variance accounts requested in this Application over a one period. Updated retail transmission network and connection rates have also been included as well as the Low Voltage rate rider. NPEI has harmonized the monthly service charge and distribution volumetric charge for all rate classes and in doing so has eliminated the Residential Urban and Residential Suburban rate classes from the former Peninsula West Utilities and replaced these two classes with one Residential rate class.

The proposed Total Bill Impact for a Niagara Falls Residential customer excluding HST is $4.46 per month or 4.28% per month. Using the average monthly consumption of 800 kWh per month a residential customer's monthly bill would be $108.72 or $1,304.64 annually excluding HST. The annual increase totals $53.52. The current rates in 2010 are based on 2004 values adjusted each year using the IRM model. The annual increase of $53.52 is a cumulative result of not having rate rebasing increases from 2005 to 2010, or six years. The cumulative increase would have been $8.92 per year from 2005 to 2010 or $0.74 per month for the last 72 months.

The proposed Total Bill Impact for a Peninsula West Residential Urban customer excluding HST is $4.45 per month or 4.41% per month. Using the average monthly consumption of 800 kWh per month a residential customer's monthly bill would be $105.52 or $1,266.24 annually excluding HST. The annual increase totals $53.40. The current rates in 2010 are based on 2004 values adjusted each year using the IRM model. The annual increase of $53.40 is a cumulative result of not having rate rebasing increases from 2005 to 2010, or six years. The cumulative increase would have been $8.90 per year from 2005 to 2010 or $0.74 per month for the last 72 months.

The proposed Total Bill Impact for a Peninsula West Residential Suburban customer excluding HST is $7.60 per month or 7.78% per month. Using the average monthly consumption of 800 kWh per month a residential customer's monthly bill would be $105.52 or $1,266.24 annually excluding HST. The annual increase totals $91.20. The current rates in 2010 are based on 2004 values adjusted each year using the IRM model. The annual increase of $91.20 is a cumulative result of not having rate rebasing increases from 2005 to 2010, or six years. The cumulative increase would have been $15.20 per year from 2005 to 2010 or $1.27 per month for the last 72 months.

The difference between the residential bill impacts is due to the impact of harmonizing the residential rate subclasses to one residential rate class and also due to the Deferral & Variance Rate Rider that is in effect from May 2010 to April 2012 over two years, is different between a Niagara Falls customer and a Peninsula West customer because these accounts had different premerger values.

Table 1-5 Monthly Bill Impact – Percent & Dollar

Monthly Bill Impacts Former Niagara Falls Hydro Customers Summary			
		Monthly Bill Impact	
Rate Class	Typical Monthly Usage	$	%
Residential	800 kWh/month		
Comparison to 2010		$ 5.04	4.27%
GS<50 kw	2,000 kWh/month		
Comparison to 2010		$0.03	0.01%
GS>50 kW	65,000 kWh/month 180 kW/month		
Comparison to 2010		$ 142.93	1.96%
Sentinel	44 kWh/month 0.12 kW/month		
Comparison to 2010		$ 7.96	123.59%
Streetlighting	50 kWh/month 0.13 kW/month		
Comparison to 2010		$ 0.76	13.36%
USL	250 kWh/month		
Comparison to 2010		$ (2.88)	-5.18%

Monthly Bill Impacts Former Peninsula West Utilities Customers Summary			
		Monthly Bill Impact	
Rate Class	Typical Monthly Usage	$	%
Residential - Urban	800 kWh/month		
Comparison to 2010		$ 5.03	4.40%
Residential - Suburban	800 kWh/month		
Comparison to 2010		$ 8.59	7.76%
GS<50 kW	2,000 kWh/month		
Comparison to 2010		$19.63	7.22%
GS>50 kW	55,000 kWh/month 175 kW/month		
Comparison to 2010		$ (414.75)	-6.14%
Sentinel	44 kWh/month 0.12 kW/month		
Comparison to 2010		$ 8.36	141.63%
Streetlighting	52 kWh/month 0.14 kW/month		
Comparison to 2010		$ 0.47	7.92%
USL	250 kWh/month		
Comparison to 2010		$ 15.20	41.69%

Exhibit 9 – Deferral and Variance Accounts

NPEI is holding a payable position in various Deferral and Variance accounts and a receivable position in the RSVA power Global Adjustment account as at December 31, 2009.

NPEI is requesting the disposition of the amounts specified in Exhibit 9 over a one year period, via an additional rate rider, allocated to the harmonized rate classes.

NPEI is also requesting the continuation of the standard Smart Meter Funding Adder of $1.00 per metered customer per month that was approved by the Board through the 2010 electricity distribution rate application process.

As part of this application, NPEI will not be seeking recovery of a one-time expense which is expected to be paid on June 30, 2011. If this payment is made, it will serve to resolve longstanding litigation against all former municipal electric utilities ("MEUs") in the Province in relation to late payment penalty ("LPP") charges collected pursuant to, first, Ontario Hydro rate schedules and, after industry restructuring, Ontario Energy Board rate orders (the "LPP Class Action"). The LDC's propose that, following expiry of applicable appeal and opt out periods (the "Date of Final Determination"), the Board hold a generic hearing to determine if the costs incurred in this litigation and settlement are recoverable from customers and, if so, the form and timing of recovery from customers. Complete details are provided in Exhibit 9.

ORGANIZATION STRUCTURE

Utility Organization Structure

Corporate Structure

NPEI is 74.5% owned by Niagara Falls Hydro Holding Corporation and 25.5% owned by Peninsula West Power Inc. Niagara Falls Hydro Holding Corporation is wholly owned by the City of Niagara Falls. Peninsula West Power Inc. is owned 59% by the Town of Lincoln, 24% by the Township of West Lincoln and 17% by the Town of Pelham. A chart illustrating NPEI's corporate family is provided at Chart 1-1.

There are nine members of the Niagara Falls Hydro Holding Corporation's Board of Directors. Two of these Directors are also members of the Niagara Peninsula Energy Inc.'s Board of Directors. There are six members of the Peninsula West Power Inc.'s Board of Directors and the President of Peninsula West Power Inc. is also a Board of Director for Niagara Peninsula Energy Inc. Niagara Falls Hydro Holding Corporation and Peninsula West Power Inc. each hold 50% of the total representation of the Board of Directors of NPEI.

Niagara Falls Hydro Holding Corporation owns 100% of Niagara Falls Hydro Services Inc. Niagara Falls Hydro Services Inc. carries on non-distribution activities such as billing and collecting of water on behalf of the City of Niagara Falls and meter verifications on behalf of neighboring utilities. These activities are in compliance with the Affiliate Relationship Code.

Peninsula West Power Inc. owns 100% of Peninsula West Services Inc. Peninsula West Services Inc. carries on non-distribution activities such as water heater rentals, sentinel light rentals and streetlight maintenance on behalf of the former Peninsula West Utility customers. These activities only take place in the Town of Lincoln, the Township of West Lincoln and the Town of Pelham. These activities are in compliance with the Affiliate Relationship Code.

Peninsula West Power Inc. also owns 50% of Niagara West Transformation Corporation. The other 50% is owned by Grimsby Power's holding corporation.

Chart 1-1 – Ownership Structure

CORPORATE ENTITIES RELATIONSHIP CHART

Niagara Peninsula Energy Inc. Corporate Structure

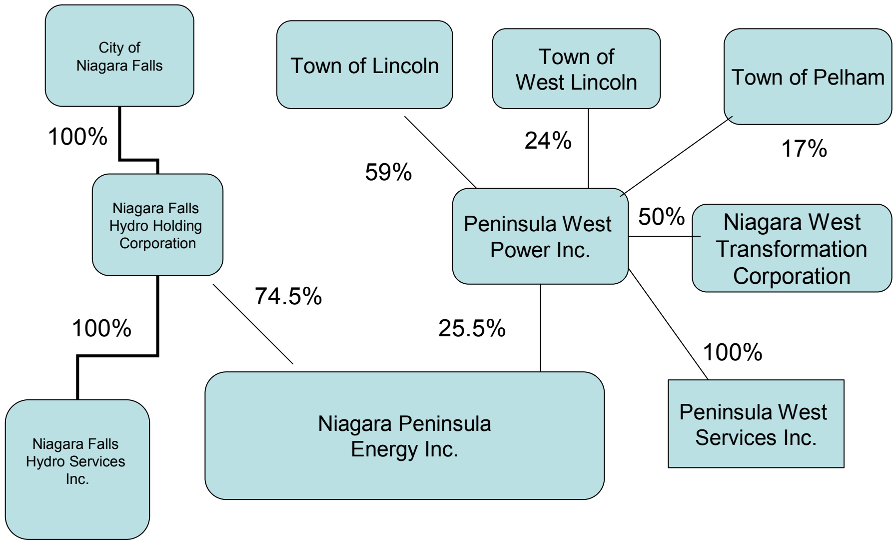
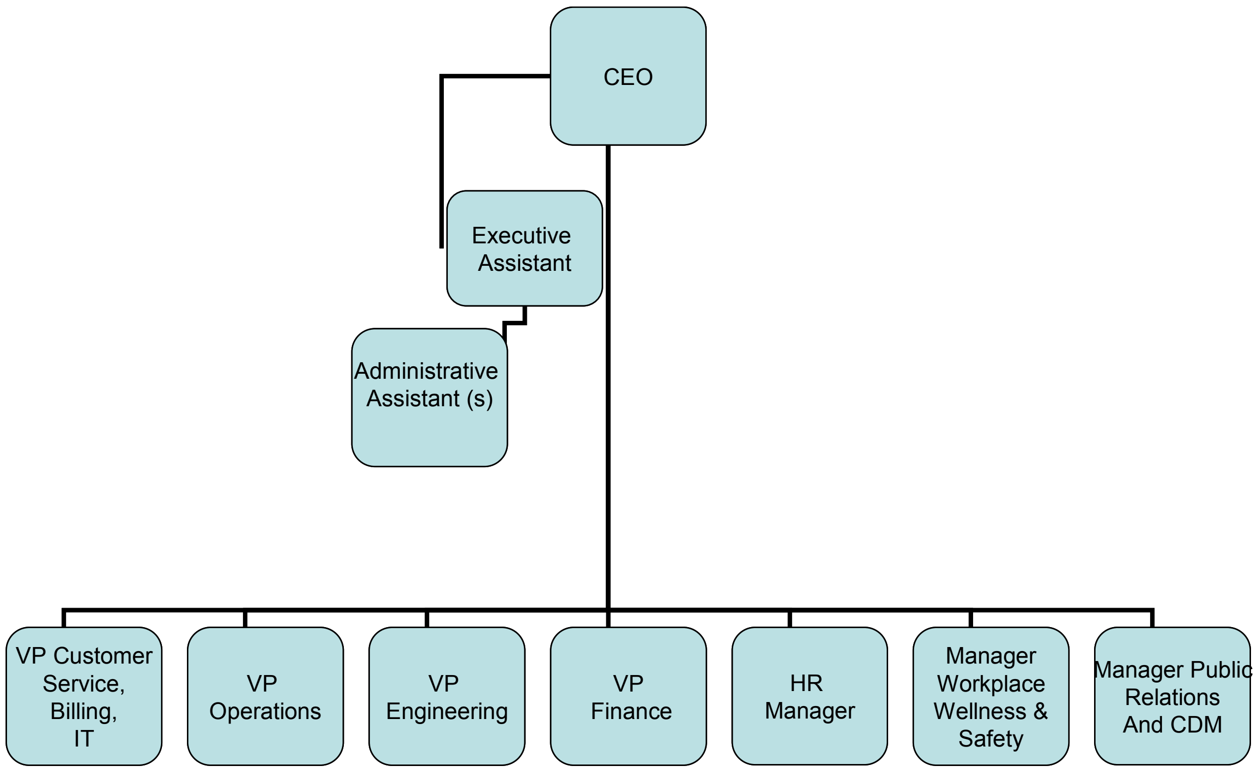
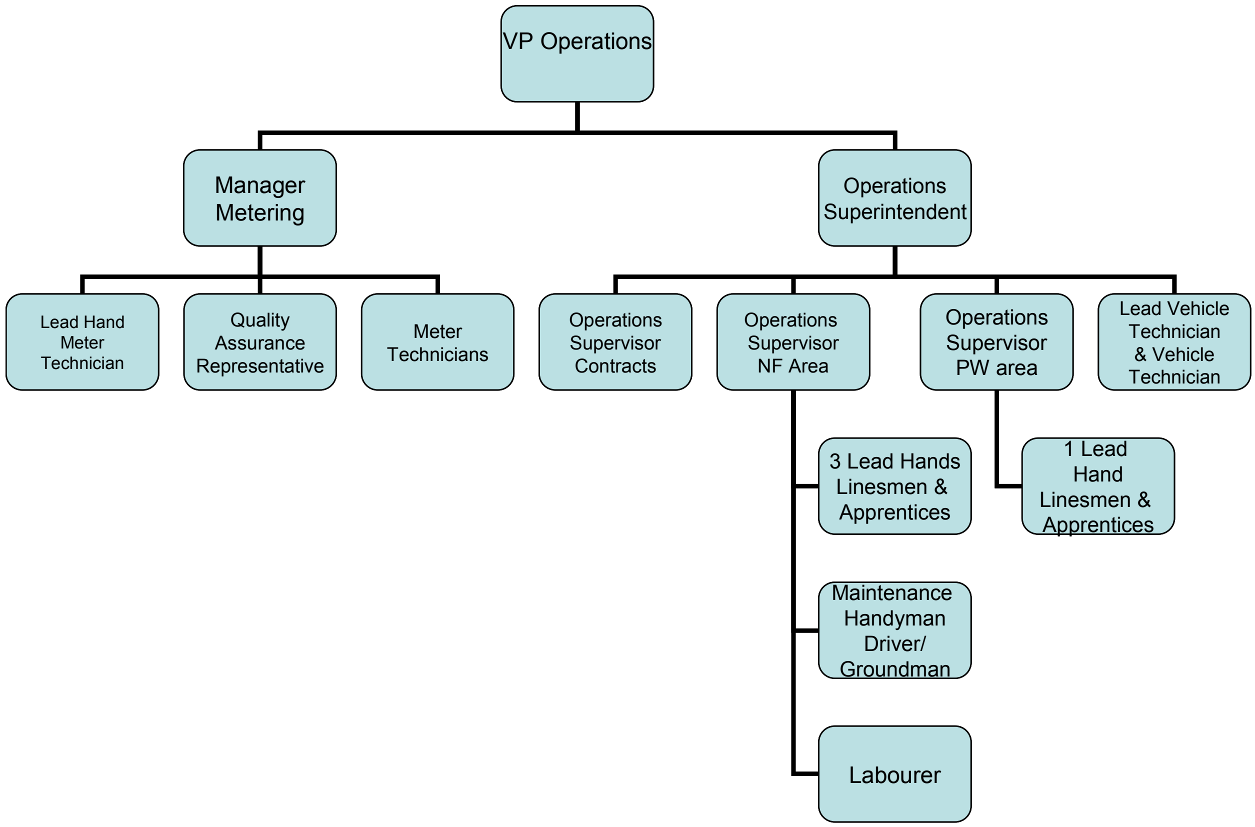


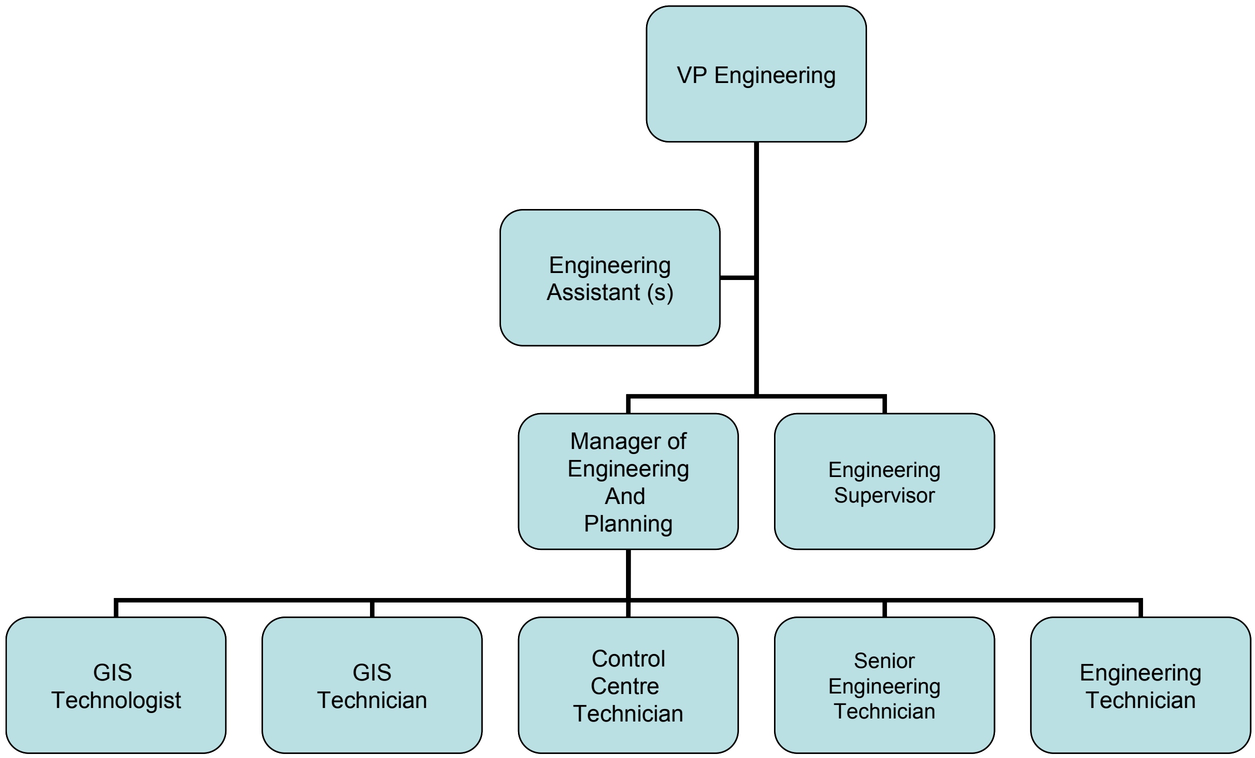
Chart 1-2 Organizational Structure

ORGANIZATIONAL CHART

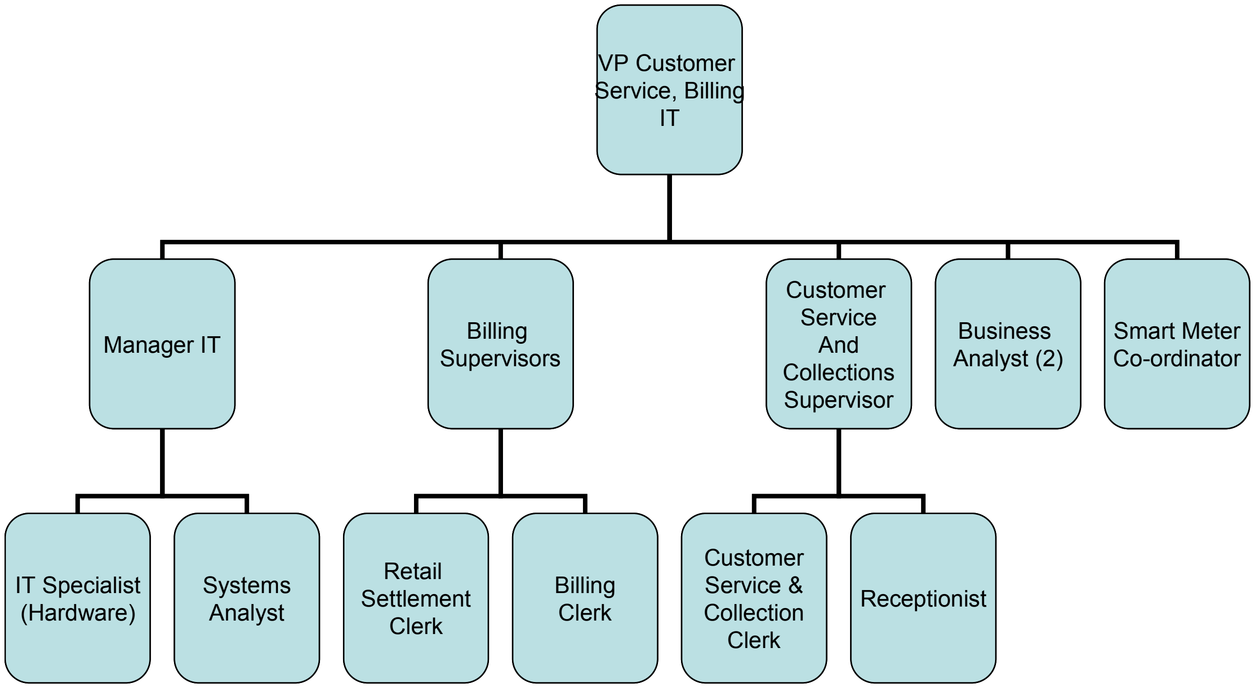
Administration Department

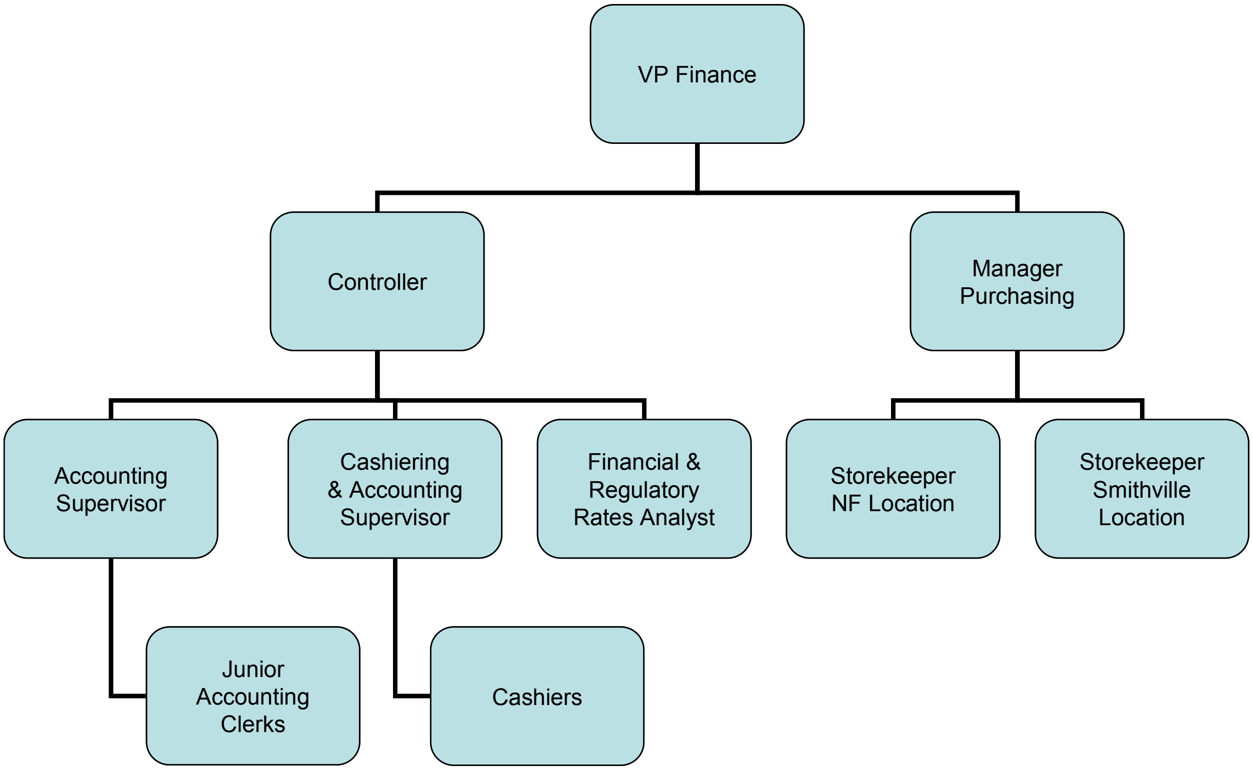



VP Operations
Manager Metering
Operations Superintendent
Lead Hand Meter Technician
Quality Assurance Representative
Meter Technicians
Operations Supervisor Contracts
Operations Supervisor NF Area
Operations Supervisor PW area
Lead Vehicle Technician & Vehicle Technician
3 Lead Hands Linesmen & Apprentices
1 Lead Hand Linesmen & Apprentices
Maintenance Handyman Driver/ Groundman
Labourer


VP Engineering
Engineering Assistant (s)
Manager of Engineering And Planning
Engineering Supervisor
GIS Technologist
GIS Technician
Control Centre Technician
Senior Engineering Technician
Engineering Technician

1


VP Customer Service, Billing IT
Manager IT
Billing Supervisors
Customer Service And Collections Supervisor
Business Analyst (2)
Smart Meter Co-ordinator
IT Specialist (Hardware)
Systems Analyst
Retail Settlement Clerk
Billing Clerk
Customer Service & Collection Clerk
Receptionist


VP Finance
Controller
Manager Purchasing
Accounting Supervisor
Cashiering & Accounting Supervisor
Financial & Regulatory Rates Analyst
Storekeeper NF Location
Storekeeper Smithville Location
Junior Accounting Clerks
Cashiers

Planned Changes in Corporate and Operational Structure

No changes to NPEI's corporate and/or operational structures are planned at the present time.

List of Witnesses and Curriculum Vitae

While NPEI requests that this Application be disposed of by way of a written hearing, should a technical conference or an oral hearing be necessary NPEI will provide the following witnesses:

<u>Brian Wilkie</u>

Brian Wilkie has been the President and CEO since 1997. Mr. Wilkie previously was the Treasurer for Niagara Falls Hydro Inc. for 12 years. Mr. Wilkie holds a Certified General Accountants Designation since 1988. Mr. Wilkie has over 25 years in the electrical utility industry.

<u>Suzanne Wilson</u>

Suzanne is the Vice-President of Finance and has been with the Corporation since 2002. Suzanne is a Chartered Accountant since 1991 and has over 20 years of experience in the public and private sectors.

<u>Dan Sebert</u>

Dan Sebert is the Vice-President of Operations and has been with the Corporation since 1987. Dan is a Certified Engineering Technologist, since 1994.

<u>Tom Sielicki</u>

Tom Sielicki is the Vice-President of Engineering and has been with the Corporation since 1985. Tom is a Certified Engineering Technologist, since 1994.

<u>Kevin Carver</u>

Kevin Carver is the Manager of Engineering and has been with the Corporation since 2004. Kevin is a Professional Engineer since 2008.

Paul Blythin

Paul is the Regulatory and Financial Rate Analyst. Paul joined Niagara Peninsula Energy in 2009. He worked previously at another utility in the rates department. Paul became a Certified General Accountant in 2007. Paul has fourteen years of experience in the public and private sectors.

DISTRIBUTION SERVICE AREA

&

DISTRIBUTION SYSTEM

Distribution Service Territory & Distribution System

Description of Distributor: Niagara Peninsula Energy Inc.

COMMUNITY SERVED:	City of Niagara Falls, Town of Lincoln Township of West Lincoln Town of Pelham
TOTAL SERVICE AREA:	827 sq km
URBAN SERVICE AREA:	68 sq km
RURAL SERVICE AREA:	759 sq km
DISTRIBUTION TYPE:	Electricity distribution
SERVICE AREA POPULATION:	136,285
MUNICIPAL POPULATION:	137,189

A map of the NPEI's Distribution Service Territory accompanies this Schedule as Map 1-1.

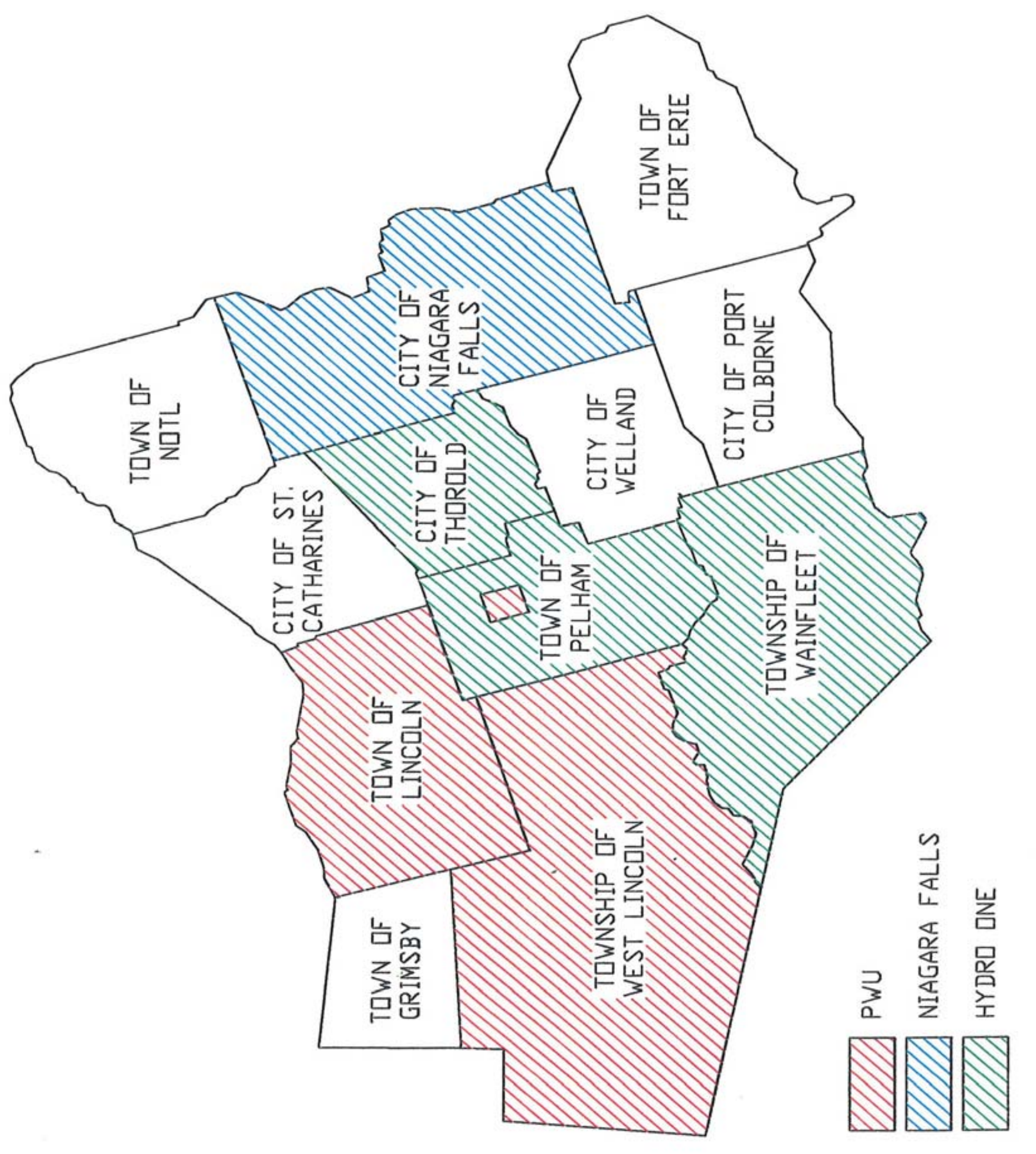
A schematic diagram of NPEI's distribution system is attached in Maps 1-2, 1-3, 1-4 and Map 1-5.

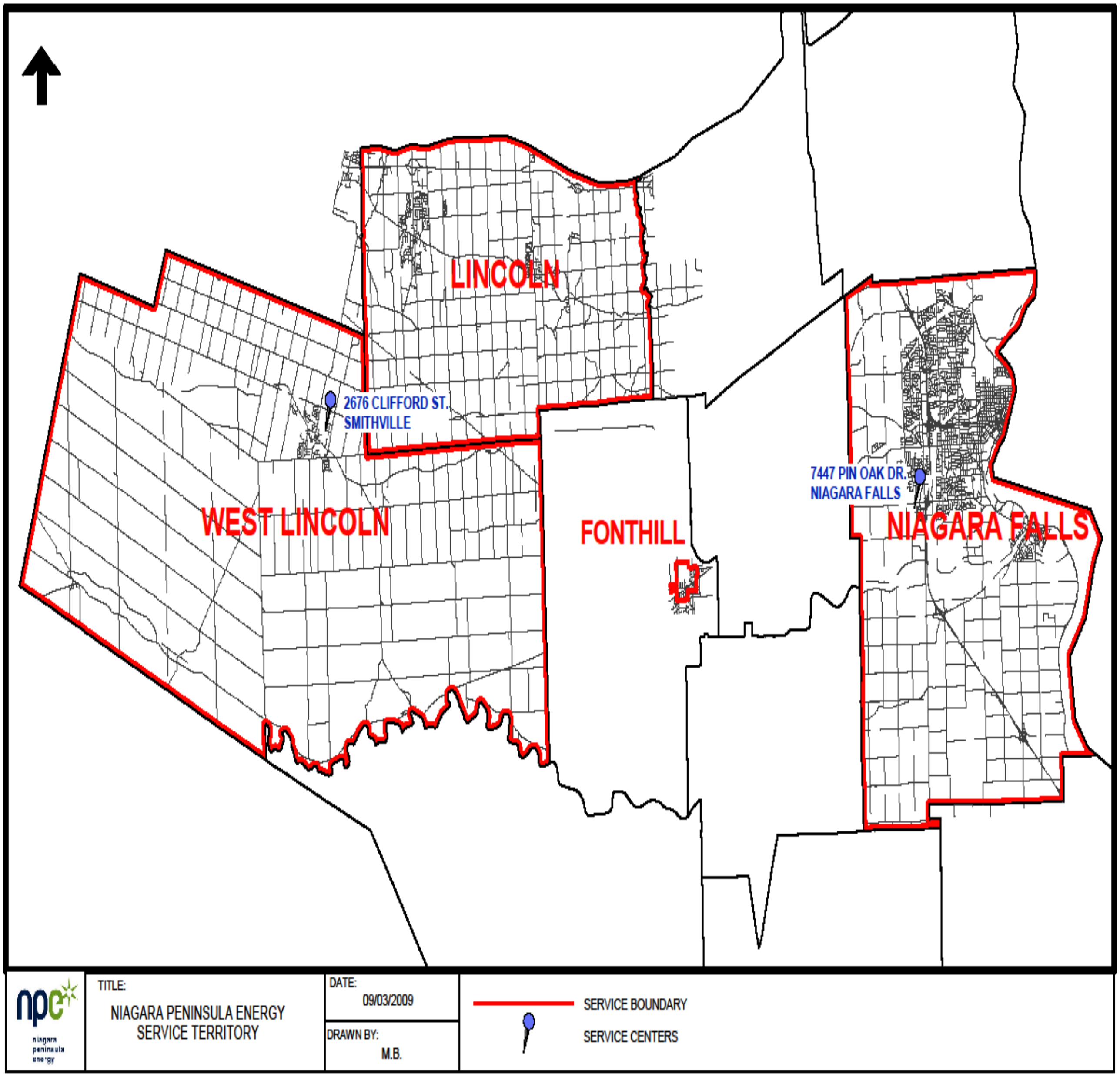
Map 1-1 – Map of NPEI's Distribution Territory

MAP OF DISTRIBUTION SERVICE TERRITORY

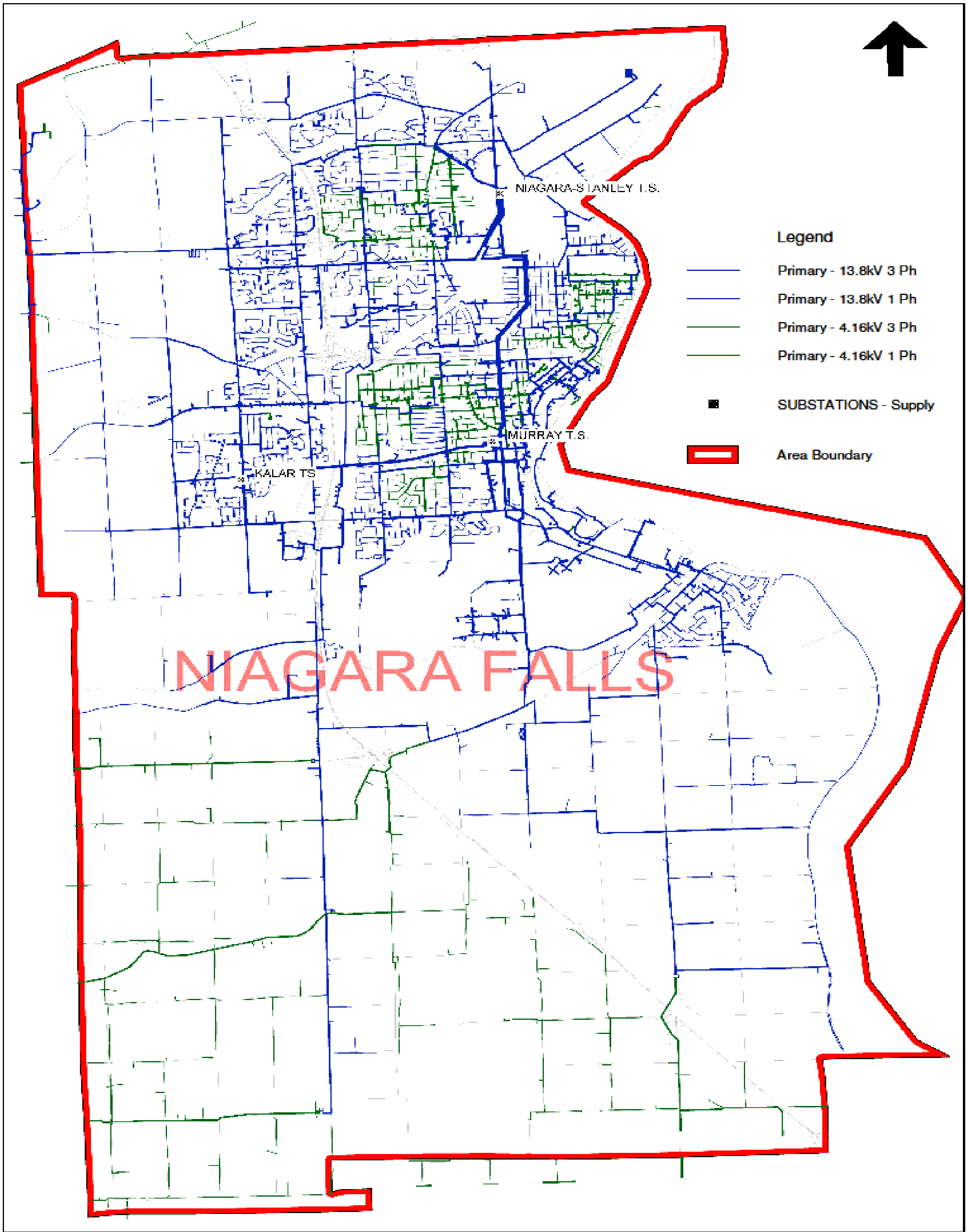
MAP OF DISTRIBUTION SERVICE TERRITORY

The outlined area represents the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham.



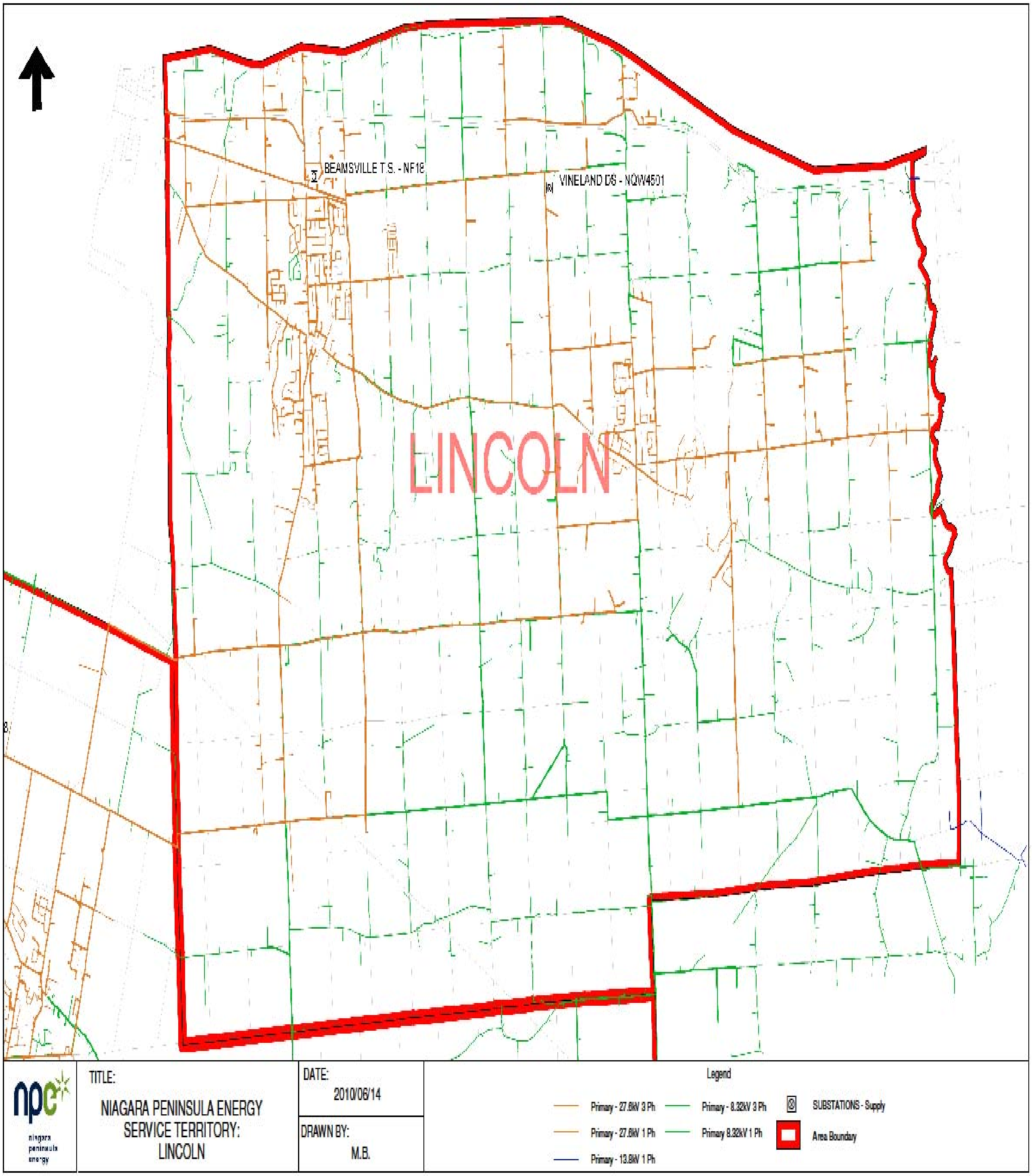

LINCOLN
2676 CLIFFORD ST.
SMITHVILLE
WEST LINCOLN
FONTHILL
7447 PIN OAK DR.
NIAGARA FALLS
NIAGARA FALLS
TITLE:
NIAGARA PENINSULA ENERGY
SERVICE TERRITORY
DATE:
09/03/2009
DRAWN BY:
M.B.
SERVICE BOUNDARY
SERVICE CENTERS

Map 1-2 – NPEI's Distribution System – Niagara Falls
MAP OF DISTRIBUTION SYSTEM

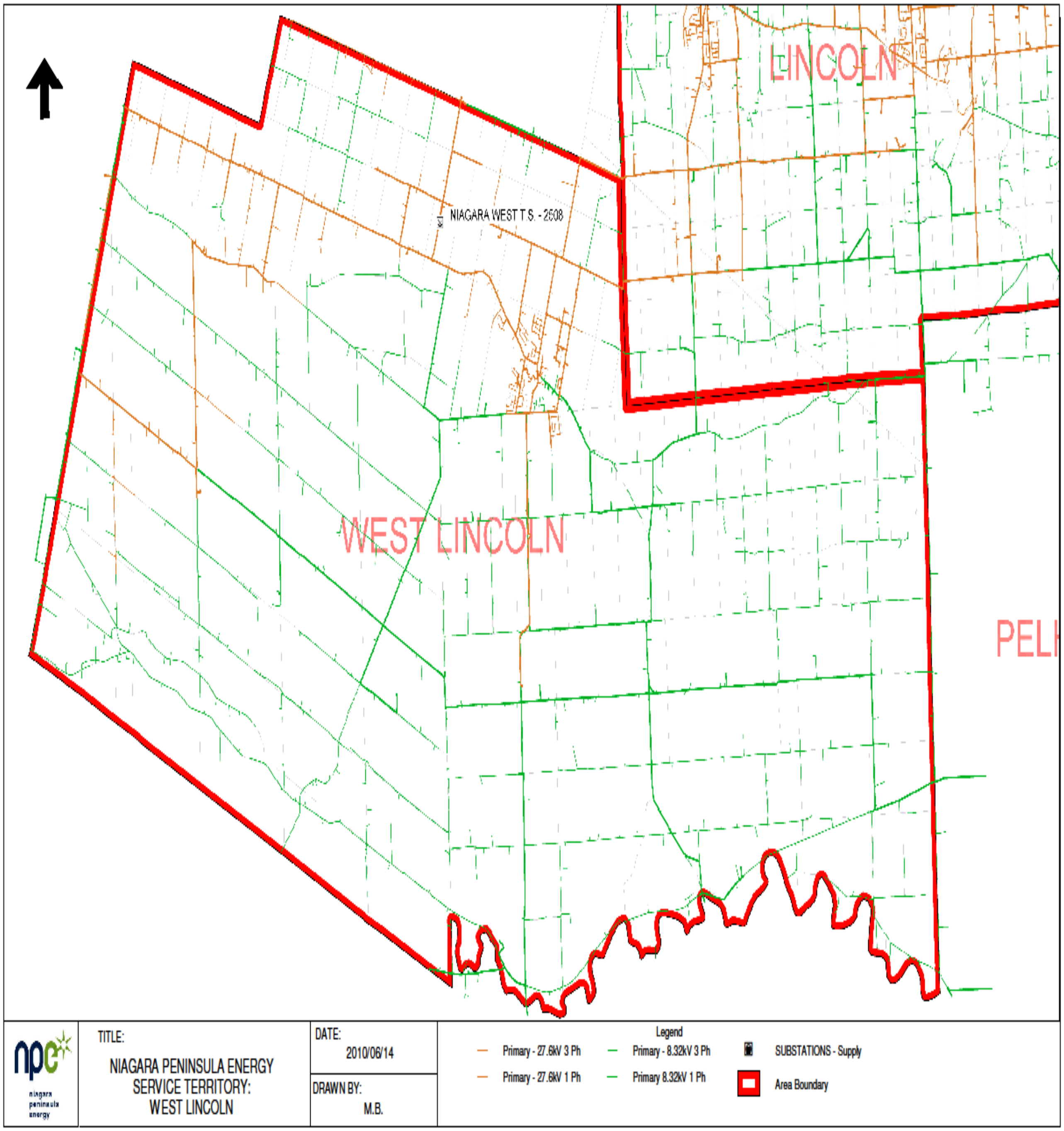


npe niagara peninsula energy	TITLE: NIAGARA PENINSULA ENERGY SERVICE TERRITORY: NIAGARA FALLS	DATE: 2010/06/14 DRAWN BY: M.B.	0 1 2 Kilometers

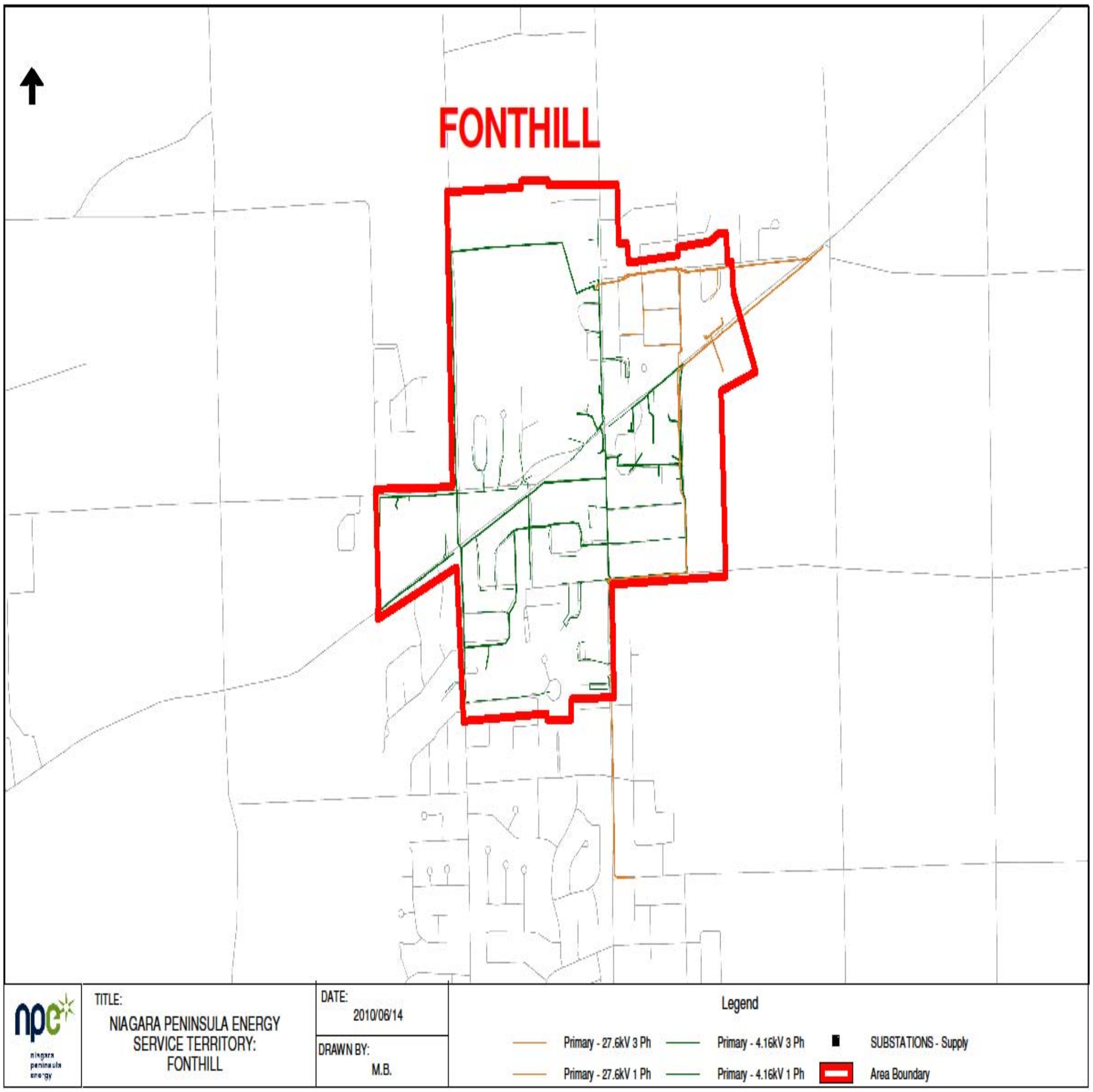
Map 1-3 – NPEI's Distribution System - Lincoln



Map 1-4 – NPEI's Distribution System – West Lincoln



Map 1-5 – NPEI's Distribution System - Fonthill



NPEI's Distribution System Description

NPEI owns and operates the electricity distribution system in its licensed service area in the City of Niagara Falls, the Town of Lincoln, the Townships of West Lincoln and the Town of Pelham, serving approximately 52,000 Residential, General Service, Street Light, Sentinel and Unmetered Scattered Load customers.

NPEI's distribution assets include one (1) Transformer Station (TS) that steps voltage down from 115kV to 13.8kV for distribution in the City of Niagara Falls. NPEI constructed, owns, and has maintained its TS since 2004. This new TS was approved to be a deemed distribution asset in the 2006 EDR rate application. The TS was built over a two year period from 2003 to 2004 and as a result, half of the addition costs were included in the rate base for the 2006 EDR rate application. The remaining portion is included in the 2011 Cost of Service rate application.

In addition, NPEI receives power from two (2) Hydro One 115/13.8kV TS's, one (1) Hydro One 115/27.6kV TS, one (1) Hydro One 115/27.6kV Distribution Station (DS), one (1) Hydro One 27.6/8.32kV DS, three (3) Hydro One 27.6kV feeders, and (1) 230kV/27.6kV TS owned by Niagara West Transformer Corporation.

NPEI also owns and operates ten (10) 13.8kV/4.16kV Municipal Stations (MS's), four (4) 27.6kV/8.32kV DS's, and two (2) 27.6kV/4.16kV DS's.

Electricity is then distributed through NPEI's service area of 827 square kilometers through over 482 kilometers of underground cable and 1059 kilometers of overhead conductor. Voltage is stepped down from the primary feeders through approximately 7513 LDC owned distribution transformers. NPEI monitors its distribution system through a supervisory control system at its main office. Hydro One operates the Supervisory Control and Data Acquisition ("SCADA") system twenty-four hours a day, seven days a week.

NPEI owns and maintains approximately 52,000 meters installed on its customers' premises for the purpose of measuring consumption of electricity for billing purposes. Meters vary in type by customer and include meters capable of measuring kWh consumption, kW and kVA demand as well as hourly interval data. NPEI is currently completing the installation of Smart Meters as part of the Province of Ontario's smart meter initiative. On June 25, 2008, Ontario Regulation 235/08 was filed by the Ontario Provincial Government giving NPEI authorization to proceed with its first phase of Smart Meter installation. A total of $4,175,010 of NPEI's Smart Meter capital incurred as at June 30, 2010 is included in its 2011 rate base and revenue requirement. The smart meter costs incurred after June 30, 2010 have been included as part of its Deferral account 1555. Upon completion of its Smart Meter installs, NPEI expects to bring a Smart Meter cost recovery application before the Board.

In managing its distribution system assets, NPEI's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, public and worker safety, and customer service requirements. This Application incorporates NPEI's 2011 Capital and OM&A Expense Budgets in determining the revenue requirement to bring these plans to fruition. Further information will be provided later in this Application. NPEI considers performance related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, and system configuration, to determine investment needs of the system.

List of Neighboring Utilities

NPEI is bounded by: Canadian Niagara Power
Welland Hydro
Niagara-on-the Lake Hydro
Hydro One
Horizon Utilities
Haldimand County Hydro
Grimsby Power

Explanation of Host and Embedded Utilities

There are no embedded utilities within NPEI's distribution service territory nor is NPEI a host utility to other distributors.

APPLICATION

Application

Summary

APPLICATION

IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an application by Niagara Peninsula Energy Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2011.

Title of Proceeding:	An application by Niagara Peninsula Energy for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2011.
Applicant's Name:	Niagara Peninsula Energy Inc.
Applicant's Address for Service:	7447 Pin Oak Drive, Niagara Falls, Ontario L2E 6S9 Attention: Mr. Brian Wilkie, President and CEO Telephone: (905) 356-2681 ext. 6000 Fax: (905) 356-0118 E-mail: Bian.Wilkie@npei.ca

APPLICATION:

1) Introduction

a) Niagara Peninsula Energy Inc. (NPEI) is a corporation incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the City of Niagara Falls. NPEI carries on the business of distributing electricity within the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham.

b) NPEI hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the *Ontario Energy Board Act, 1998 (the "OEB Act")* for approval of its proposed distribution rates and other charges, effective May 1, 2011.

A list of requested approvals is set out in Exhibit 1.

c) NPEI followed Chapter 2 of the OEB's Filing Requirements for Transmission and Distribution Applications dated June 28, 2010 (the "Filing Requirements") in order to prepare this application.

2) Proposed Distribution Rates and Other Charges

b) The Schedule of Rates and Charges proposed in this Application are identified in Table 1-6 and Table 1-6.1 in this application and Exhibit 8, and the material being filed in support of this Application sets out NPEI's approach to its distribution rates and charges.

3) Proposed Effective Date of Rate Order

a) NPEI requests that the OEB make its Rate Order effective May 1, 2011 in accordance with the Filing Requirements.

4) The Proposed Distribution Rates and Other Charges are Just and Reasonable

a) NPEI submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

(iv) the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles;

(v) the proposed adjusted rates are necessary to meet NPEI's Market Based Rate of Return ("MBRR") and Payments in Lieu of Taxes ("PILs") requirements;

(vi) there are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by the Applicant or the implementation of any other mitigation measures other than those described in Exhibit 8

(iv) the other service charges proposed by NPEI are now harmonized and the same as those previously approved by the OEB; and

(v) such other grounds as may be set out in the material accompanying this Application Summary.

5) Relief Sought

NPEI applies for an Order or Orders approving the proposed distribution rates and other charges set out in Exhibit 1, Table 1-6 and Table 1-6.1 included in this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2011, or as soon as possible thereafter; and

6) Form of Hearing Requested

NPEI requests that this Application be disposed of by way of a written hearing.

DATED at: Niagara Falls, Ontario. This 30th day of November, 2010.

All of which is respectfully submitted,

Original Signed By

Brian Wilkie
President and CEO
Niagara Peninsula Energy Inc.

Table 1-6 - Schedule of Proposed Rates and Charges – Niagara Falls

Table 1-6
Niagara Peninsula Energy Inc. - Niagara Falls
Proposed schedule of rates and charges
Effective May 1, 2011

Residential

Service Charge	per month	16.55
Service Charge Smart Meters	per month	1.00
Distribution Volumetric Rate	$/kWh	0.0167
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kWh	0.0011
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kWh	(0.0028)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0016
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0001
Low Voltage Rider	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	per month	38.45
Service Charge Smart Meters	per month	1.00
Distribution Volumetric Rate	$/kWh	0.0141
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kWh	0.0011
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kWh	(0.0027)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0019
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.0013)
Low Voltage Rider	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	per month	222.81
Service Charge Smart Meters	per month	1.00
Distribution Volumetric Rate	$/kW	4.0311
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kW	0.4244
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kW	(1.1600)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.6442
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.6119)
Low Voltage Rider	$/kWh	0.1042
Retail Transmission Rate – Network Service Rate	$/kW	2.1173
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5483
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

SCHEDULE OF PROPOSED RATES AND CHARGES FOR NIAGARA FALLS-continued

Unmetered Scattered Load

Service Charge (per connection)	$	19.87
Distribution Volumetric Rate	$/kWh	0.0139
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kWh	0.0011
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kWh	(0.0027)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0016
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.0005)
Low Voltage Rider	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	per month	7.19
Distribution Volumetric Rate	$/kW	8.9771
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kW	0.3939
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kW	(1.2973)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.9780
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	2.1482
Low Voltage Rider	$/kWh	0.0871
Retail Transmission Rate – Network Service Rate	$/kW	1.5676
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2938
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 (per connection)	per month	0.80
Distribution Volumetric Rate	$/kW	3.1398
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kW	0.0000
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kW	(0.5038)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.6613
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.6329)
Low Voltage Rider	$/kWh	0.0801
Retail Transmission Rate – Network Service Rate	$/kW	1.6006
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1895
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

microFIT GENERATOR SERVICE CLASSIFICATION

Service Charge (per connection) delivery component - effective September 21, 2009	$	5.25

SCHEDULE OF PROPOSED RATES AND CHARGES FOR NIAGARA FALLS-continued

Specific Service Charges

Customer Administration

Returned cheque charge (plus bank charges)	$	20.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00

Other

Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
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	$	1,000.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35

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

LOSS FACTORS

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0560
Total Loss Factor - Secondary Metered Customer > 5,000 kW	
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0454
Total Loss Factor - Primary Metered Customer > 5,000 kW	

Table 1-6.1 - Schedule of Proposed Rates and Charges – Peninsula West

Table 1-6.1
Niagara Peninsula Energy Inc. - Peninsula West
Proposed schedule of rates and charges
Effective May 1, 2011

Residential

Service Charge	per month	16.55
Service Charge Smart Meters	per month	1.00
Distribution Volumetric Rate	$/kWh	0.0167
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kWh	0.0007
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kWh	(0.0064)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0016
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0001
Low Voltage Rider	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	per month	38.45
Service Charge Smart Meters	per month	1.00
Distribution Volumetric Rate	$/kWh	0.0141
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kWh	0.0007
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kWh	(0.0065)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0019
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.0013)
Low Voltage Rider	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	per month	222.81
Service Charge Smart Meters	per month	1.00
Distribution Volumetric Rate	$/kW	4.0311
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kW	0.3116
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kW	(1.9651)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.6442
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.6119)
Low Voltage Rider	$/kWh	0.1042
Retail Transmission Rate – Network Service Rate	$/kW	2.1173
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5483
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

SCHEDULE OF PROPOSED RATES AND CHARGES FOR FORMER PENINSULA WEST UTILITIY CUSTOMER-continued

Unmetered Scattered Load

Service Charge (per connection)	per month	19.87
Distribution Volumetric Rate	$/kWh	0.0139
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kWh	0.0010
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kWh	(0.0064)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0016
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.0005)
Low Voltage Rider	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	per month	7.19
Distribution Volumetric Rate	$/kW	8.9771
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kW	0.2799
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kW	(2.2732)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.9780
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	2.1482
Low Voltage Rider	$/kWh	0.0871
Retail Transmission Rate – Network Service Rate	$/kW	1.5676
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2938
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 (per connection)	per month	0.80
Distribution Volumetric Rate	$/kW	3.1398
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kW	0.0000
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kW	(2.1909)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.6613
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.6329)
Low Voltage Rider	$/kWh	0.0801
Retail Transmission Rate – Network Service Rate	$/kW	1.6006
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1895
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

microFIT GENERATOR SERVICE CLASSIFICATION

Service Charge (per connection) delivery component - effective September 21, 2009	$	5.25

SCHEDULE OF PROPOSED RATES AND CHARGES FOR FORMER PENINSULA WEST UTILITIY CUSTOMER-continued

Specific Service Charges

Customer Administration		
Returned cheque charge (plus bank charges)	$	20.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Other		
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
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	$	1,000.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35

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

LOSS FACTORS

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0560
Total Loss Factor - Secondary Metered Customer > 5,000 kW	
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0454
Total Loss Factor - Primary Metered Customer > 5,000 kW	

Specific Approvals Requested

In this proceeding, NPEI is requesting the following approvals:

Approval to charge rates effective May 1, 2011 to recover a revenue requirement of $32,421,330 which includes a revenue deficiency of $3,378,275 as set out in Table 1-3 and Table 1-4. The schedule of proposed rates is set out in Table 1-6 and 1-6.1;

Approval of the harmonization of NPEI's distribution rate classes and distribution rates across two geographical areas served by NPEI. The amalgamation of Niagara Falls Hydro Inc. and Peninsula West Utilities Limited, EB-2007-0749 was approved by the OEB on December 27, 2007.

In the merger application NPEI had indicated that it would file with the OEB an application to harmonize the rates of the two entities in a cost of service rate filing within five years of the closing of the transaction;

Approval to maintain NPEI's deemed capital structure, consisting of a deemed common equity component of 40% and a deemed debt component of 60%, as set out in Exhibit 5, consistent with the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, dated December 11, 2009 (EB-2009-0084). The approved 2010 Distribution Rates for each of NPEI's service territories (EB-2009-0205) and EB-2009-0206) are based on a 60/40 debt to equity deemed capital structure.

Approval of the proposed loss factor as set out in Exhibit 8.

Approval of revised low voltage rates to be included in the standard distribution rates as proposed and described in Exhibit 8.

Approval to continue to charge the Standard Supply Administrative, Wholesale Market and Rural Rate Protection Charges approved in the OEB Decisions and Orders in the matter of NPEI's 2010 Distribution Rates (EB-2009-0205 and EB-2009-0206) subject to any modifications as a result of future OEB decisions;

Approval to harmonize the Retail Transmission Service Rates (Network and Connection) of NPEI's two service territories (former Niagara Falls Hydro Inc. and former Peninsula West Utilities Limited), including, if necessary, modifications as a result of an OEB decision on Hydro One Networks' 2011 Uniform Transmission Rate Application (EB-2010-0002) effective January 1, 2011;

Approval to harmonize and continue the Specific Service Charges and Transformer Allowances approved in the OEB Decisions and Orders in the matter of NPEI's 2010 Distribution Rates (EB-2009-0205 and EB-2009-0206);

Approval to dispose of the following Deferral and Variance Account Balances as at December 31, 2009, with projected interest to April 30, 2011, over a one-year period using the method of recovery described in Exhibit 9.

Group 1
1580 Wholesale Market Service Charges Variance
1584 Transmission Network Variance
1586 Transmission Connection Variance
1588 Power Variance
1588 Global Adjustment Variance

Group 2
1508 Other Regulatory Assets-HONI Incremental Capital Charge
1518 Retail Cost Variance Account
1548 Retail Cost Variance Account (STR)

1550 Low Voltage Variance

1582 One-Time Charges Variance

Approval to continue the Smart Meter Adder at $1.00 per month per metered customer.

Draft Issues List

NPEI would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2011 Test Year may constitute issues in this Application:

The amount of NPEI's proposed revenue requirement;

The reasonableness of the proposed harmonized electricity distribution rate classes and distribution rates;

The reasonableness of the 2011 Capital and OM&A Budgets;

The reasonableness of the 2011 Load Forecast;

The appropriateness of NPEI's proposed cost allocation-related adjustments to class-specific revenue requirements, reflected in the proposed distribution rates; and

The appropriateness of NPEI's harmonization of Low Voltage charges.

Procedural Orders and Motions/Notices

On December 27, 2007, the Board approved an application (EB-2-007-0749) by Niagara Falls Hydro Inc. and Peninsula West Utilities Limited seeking an order for leave to amalgamate and the issuance of a new electricity distribution license to the amalgamated corporation, Niagara Peninsula Energy Inc. At the time of amalgamation, NPEI contemplated rebasing and harmonizing rates in either 2009 or 2010. Subsequently, NPEI requested that its Cost of Service application be postponed until 2011. On March 5, 2009 the Board issued a letter to all licensed distributors which included lists of distributors that were expected to file a Cost of Service application in 2010 and 2011. NPEI was included in Appendix B of that document, “Selection of Electricity Distributors for Rate Rebasing in 2011.

Accounting Orders Requested

NPEI is not requesting Accounting Orders in this proceeding.

Materiality Thresholds

NPEI has determined its materiality thresholds in accordance with the Filing Requirements which states the threshold is to be based on 0.5% of the Distribution Revenue Requirement. The materiality threshold utilized for NPEI's OM&A variances is $75,000 and Capital Asset variances is $150,000 these variances are presented below in Table 1-7.

Table 1-7 Materiality

Table 1-7
Niagara Peninsula Energy Inc.
Materiality Threshold

Service Revenue Requirement (from Revenue Deficiency Calculation)	32,421,330
Less Revenue Offsets	(2,185,747)
Base Revenue Requirement	**30,235,583**
Allocated to:	
Low Voltage Wheeling Costs	-
Directly Assigned CDM	-
Other	30,235,583
Total	**30,235,583**
Variance Calculation 0.5% of Distribution Revenue Requirement	**151,178**

FINANCIAL INFORMATION

Financial Information

Compliance with Uniform System of Accounts:

NPEI has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application.

Status of Board Directives from Previous Board Decisions

At this time there are no Board Directives from previous Board decisions.

Budget Directives and Guidelines

NPEI compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budget forecast. This budget information is compiled for both the 2010 Bridge Year and the 2011 Test Year.

Revenue Forecast

NPEI's energy sales and revenue forecast model was updated to reflect more recent information. This model was then used to prepare the revenues sales and throughput volume and revenue forecast at existing rates for fiscal 2010 and 2011. The forecast is weather normalized as outlined in Exhibit 3, and considers such factors as new customer additions, customer class changes, and load profiles for all classes of customers.

Operating Maintenance and Administration (“OM&A”) Expense Forecast

The OM&A expenses for the 2010 Bridge Year and the 2011 Test Year have been based on an in-depth review of operating priorities and requirements and is strongly influenced by prior year experience. Each item is reviewed account by account for each of the forecast years with indirect costs allocated to direct costs for budget presentation.

Capital Budget

The capital budget forecast 2010 and 2011 is influenced, among other factors, by NPEI’s capacity to finance capital projects and availability of resources. Indirect costs are allocated to direct costs in the capital budget. NPEI is subject to coordinate works with the Region of Niagara, the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham projects in order to achieve economies of scope. All proposed capital projects are assessed within the framework of its capital budget priority and are outlined in Exhibit 2, (Capital Expenditures by Project).

IFRS

NPEI has complied with the Board Report on the International Financial Reporting Standards (IFRS), EB-208-0408 and has prepared this application under Generally Accepted Accounting Principles (GAAP), it has not prepared this application under IFRS.

As stated in the Report “The Board will require electricity distributors filing for 2011 rates to provide the required years, the 2010 bridge year and the 2011 forecasts in CGAAP based format. An electricity distributor may choose to present modified IFRS based forecasts for 2010 and 2011, if the distributor prefers to have rates set on the basis if modified IFRS.” NPEI has chosen to provide the required years, the 2010 bridge year and the 2011 forecast in CGAAP based format.

Changes in Methodology

NPEI is not requesting any changes in methodology in the current proceeding.

Changes to Accounting Policies since last rebasing year

2005

There were no changes to accounting policy in 2005.

2006

There were no changes to accounting policy in 2006.

2007

Financial Instruments

Effective January 1, 2007, the Corporation adopted the new accounting standards comprising the following section of the Canadian Institute of Chartered Accountants (CICA) Handbook: 3855 - Financial Instruments – Recognition and Measurement; 3861 – Financial Instruments – Disclosure and Presentation. There was no adjustment necessary to opening retained earnings as a result of the change for the former Niagara Falls Hydro Inc but there was an adjustment to the former Peninsula West Utilities opening retained earnings as noted below.

Financial Assets and liabilities

Under the new standards, all financial instruments are classified into one of the following categories – held-for-trading, available for sale, held-to-maturity, other liabilities or loans and receivables. All financial instruments are carried on the balance sheet at fair value except for loans and receivables, held-to-maturity investments and other liabilities, which are measured at amortized cost.

The Corporation has classified its financial instruments as follows:

Cash and cash equivalents	Held for trading
Accounts receivable	Loans and receivables
Unbilled energy receivable	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Interest rate swap	Held for trading

Customer deposits	Other liabilities
Long-term liabilities	Other liabilities

In 2006, the former Peninsula West Utilities Ltd, designated its interest rate hedge agreement as hedges of the underlying debt. As a result of the implementation of the new CICA handbook sections, the interest rate swap was no longer designated as a hedge for accounting purposes. The interest rate swap was recorded at fair value based on quoted market prices with changes in fair value recorded in interest expense. The change in accounting policy was treated prospectively as required under the standard. The effect on PWU's opening shareholder equity in 2007 at January 1, was ($102,011).

2008

Future Income Taxes

Effective January 1, 2008, the Company adopted the amended sections of CICA Handbook, Section 3465, "Income taxes" in order to account for future payments in lieu of income taxes. The change was accounted for as an adjustment to opening retained earnings in the amount of $2,935,226 without the restatement of prior year's figures in accordance with the transitional provisions set out in this handbook section.

2009

There were no changes to accounting policy in 2009.

2010

NPEI is changing the depreciation accounting policy to calculate depreciation using the half year rule. This change in depreciation accounting will reduce the timing differences between accounting depreciation and the calculation of Capital Cost Allowance (CCA) that is used for tax purposes. This change is not retroactive and there is no entry to opening retained earnings.

Reconciliation of Audited and Regulatory Financial Statements

For 2006 and 2007 the Trial Balance for the former Peninsula West Utilities and the former Niagara Falls Hydro utilities were combined in the Revenue Requirement model to provide continuity for the purposes of comparison for this rate application. The combined audited net incomes of PWU and NFH from the external financial statements in 2006 and 2007 equal the Income Statement for each of these years in the Revenue Requirement Model.

In 2008, the merger was approved and for the external financial statements NFH was deemed to be the purchaser of PWU. As a result a fair market valuation of the PWU assets was completed and audited. The 2008 financial statements have the actual results of NPEI for 2008 compared to the actual 2007 results of just NFH.

The purchase equation of the merger resulted in a Fair Market Value bump to the former PWU assets. For 2008 and 2009 the fair market value bump on the assets was disclosed separately on the RRR Trial Balance in Account 2065 Other Electric Plant Adjustment and Account 2160 Accumulated Amortization of Other Electric Plant so as not to include these amounts in Rate Base. For 2008 these amounts are $45,735,559 and $25,239,221 respectively. For 2009 these amounts are $45,735,559 and $26,348,210. For the 2010 Bridge Year and 2011 Test year these amounts remain constant on the Trial Balance and are excluded from the calculation of Rate Base.

The Fixed Asset Continuity Schedules in the Revenue Requirement Model exclude the fair market value bump that resulted from the merger. For 2009, total Fixed Assets per the external audited financial statements had a net book value of $114,309,200 and per the Revenue Requirement model, Fixed Asset continuity schedule a net book value of $94,970,591. The following table reconciles the Net Book Value from Note 3 of the financial statements to the FA Continuity schedule of the Revenue Requirement Model for 2009.

Reconcile FA continuity
to Financial statements for 2009

	COST	Ending 2009 Per continuity schedule		FMV bump	Allocate Contribution and grants	Other reallocation	Balance with FMV Bump	Accum Deprec on purchase equation	Per Note to F/S
1805	Land	507,274							
1806	Land Rights	1,598,170							
1905	Land	508,970							
1906	Land Rights	0	2,614,413	342,080			2,956,493	49,814	3,006,307
1908	Buildings and Fixtures	12,391,184							
1808	Buildings and Fixtures	111,638							
1810	Leasehold Improvements	0							
1910	Leasehold Improvements	120,252	12,623,074				12,623,074	0	12,623,074
1815	Transformer Station Equipment -	6,558,514	6,558,514			(10,062)	6,548,452	(1,498,450)	5,050,002
1820	Distribution Station Equipment -	4,507,465	4,507,465	2,438,685		10,062	6,956,212	(407,760)	6,548,452
1825	Storage Battery Equipment	0							
1830	Poles, Towers and Fixtures	28,665,012							
1835	Overhead Conductors and Devices	31,395,023				0			
1855	Services	3,459,629	63,519,663	23,101,111	(6,592,423)	(450,367)	79,577,985	(16,045,645)	63,532,340
1840	Underground Conduit	10,367,640							
1845	Underground Conductors and Devices	54,396,854	64,764,495	16,116,341	(8,842,459)	430,166	72,468,543	(4,599,456)	67,869,087
1850	Line Transformers	31,103,686	31,103,686	3,309,178	(811,126)		33,601,738	(1,385,027)	32,216,711
2005	Property under Capital Lease	143,036							
1860	Meters	6,677,338	6,820,374	1,038,327	(74,641)		7,784,060	(420,546)	7,363,514
1865	Other Installations on Customer's Premises	440							
1915	Office Furniture and Equipment	1,107,299							
1920	Computer Equipment - Hardware	2,624,840							
1925	Computer Software	1,920,006							
1930	Transportation Equipment	5,484,897							
1935	Stores Equipment	200,261							
1940	Tools, Shop and Garage Equipment	1,566,110							
1945	Measurement and Testing Equipment	183,146							
1950	Power Operated Equipment	0							
1955	Communication Equipment	158,934							
1960	Miscellaneous Equipment	67,903							
1970	Load Management Controls - Customer Premises	0							
1975	Load Management Controls - Utility Premises	0							
1980	System Supervisory Equipment	128,961	13,442,796	(610,164)		162,477	12,995,109	330,986	13,326,095
1985	Sentinel Lighting Rentals	0							
1990	Other Tangible Property	0							
1995	Contributions and Grants	(16,320,649)	(16,320,649)		16,320,649		0		
		189,633,833	189,633,833	45,735,557	(1)	142,277	235,511,666	(23,976,084)	211,535,582

1

	ACCUMULATED DEPRECIATION	Ending 2009 Per continuity schedule		FMV bump	Allocate Contribution and grants	Other reallocation	Balance with FMV Bump	Difference = Accum Deprec on purchase equation	Per Note to F/S
1805	Land	0							
1806	Land Rights	633,336							
1905	Land	0							
1906	Land Rights	0	633,336	(31,234)		0	602,102	49,814	651,916
1908	Buildings and Fixtures	1,817,234							
1808	Buildings and Fixtures	91,870							
1810	Leasehold Improvements	0							
1910	Leasehold Improvements	120,252	2,029,356			0	2,029,356	(0)	2,029,356
1815	Transformer Station Equipment -	757,613	757,613				757,613	(0)	757,613
1820	Distribution Station Equipment -	2,809,726	2,809,726	2,157,813			4,967,538	(1,906,210)	3,061,328
1825	Storage Battery Equipment	0							
1830	Poles, Towers and Fixtures	14,461,696							
1835	Overhead Conductors and Devices	15,490,537							
1855	Services	626,179	30,578,412	16,777,288	(1,653,957)	(3,311)	45,698,432	(16,045,646)	29,652,786
1840	Underground Conduit	3,142,094							
1845	Underground Conductors and Devices	28,314,738	31,456,832	5,852,718	(1,716,595)		35,592,955	(4,599,456)	30,993,499
1850	Line Transformers	15,981,171	15,981,171	1,594,745			17,575,916	(1,385,027)	16,190,889
2005	Property under Capital Lease	0							
1860	Meters	3,921,874	3,921,874	490,028			4,411,903	(420,547)	3,991,356
1865	Other Installations on Customer's Premises	0							
1915	Office Furniture and Equipment	628,664							
1920	Computer Equipment - Hardware	1,953,498							
1925	Computer Software	1,735,390							
1930	Transportation Equipment	3,706,634							
1935	Stores Equipment	182,660							
1940	Tools, Shop and Garage Equipment	1,257,226							
1945	Measurement and Testing Equipment	133,421							
1950	Power Operated Equipment	0							
1955	Communication Equipment	92,379							
1960	Miscellaneous Equipment	46,643							
1970	Load Management Controls - Customer Premises	0							
1975	Load Management Controls - Utility Premises	0							
1980	System Supervisory Equipment	128,961	9,865,476	(493,150)		194,327	9,566,653	330,986	9,897,639
1985	Sentinel Lighting Rentals	0							
1990	Other Tangible Property	0							
1995	Contributions and Grants	(3,370,553)	(3,370,553)		3,370,553		0	0	0
		94,663,242	94,663,242	26,348,209	0	191,016	121,202,467	(23,976,085)	97,226,382
	2100-19 Deferred Costs					(48,739)			
	Net Book Value	94,970,591					114,309,198		

For both 2008 and 2009 the Net Income of $2,592,941 and $2,672,624 respectively per the external financial statements equals the Net Income per the Revenue Requirement model. The depreciation expense on the fair market value adjustment of fixed assets is presented separately on the external financial statements and was disclosed separately on the Trial Balance in account 5715. For 2010 and 2011 this depreciation expense has been excluded for the purposes of Revenue Requirement. There are also zero tax implications as these amounts are not included in any UCC balances for 2008 or 2009.

In conclusion the Rate Base and Revenue Requirement in this rate application exclude the fair market value bump on fixed assets that resulted from the merger.

As a result of differences between deemed and actual interest expense, carrying charges on deferral and variance accounts and future income tax expense the net income per the 2011 Pro Forma Income Statement is higher that the deemed utility income per the Revenue Deficiency calculation. Table 1-10 provides a reconciliation for 2011 Pro Forma Income Statement and the Revenue Deficiency Statement.

Table 1-10 Reconciliation between Pro Forma and Rev Deficiency Statements

Reconciliation between Pro Forma Statements and Rev Deficiency		
Deemed Net Income		**4,694,311**
Plus		
Deemed Interest Expense	4,340,146	
Actual Interest Expense	(2,558,733)	
Provision for Future Income Taxes	600,000	2,381,413
Net Income per Pro Forma I/S		**7,120,919**

Pro Forma Financial Statements

The NPEI Pro Forma Statements for the 2010 Bridge Year and the 2011 Test Year are presented in Table 1-8 and Table 1-9 respectively.

Table 1-8 2010 Pro Forma Balance Sheet

Niagara Peninsula Energy Inc.

Niagara Peninsula Energy
, License Number ED-2007-0749, File Number EB-2010-0138

Niagara Peninsula Energy
2010 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	9,241,792
1010-Cash Advances and Working Funds	3,300
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	0
1100-Customer Accounts Receivable	9,877,624
1102-Accounts Receivable - Services	0
1104-Accounts Receivable - Recoverable Work	975,000
1105-Accounts Receivable - Merchandise, Jobbing, etc.	0
1110-Other Accounts Receivable	335,000
1120-Accrued Utility Revenues	12,829,399
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(550,000)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	0
1170-Notes Receivable	0
1180-Prepayments	535,000
1190-Miscellaneous Current and Accrued Assets	0
1200-Accounts Receivable from Associated Companies	30,000
1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total	**33,277,115**

Account Description	Total
1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	1,230,249
1340-Merchandise	0
1350-Other Material and Supplies	0
1100-Inventory Total	**1,230,249**

Account Description	Total
1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	0
1408-Long Term Receivable - Street Lighting Transfer	0
1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
1460-Other Non-Current Assets	1,926
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**1,926**

Table 1-8

Niagara Peninsula Energy Inc.
2010 Pro Forma Balance Sheet

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	458,743
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	521,189
1525-Miscellaneous Deferred Debits	0
1530-Deferred Losses from Disposition of Utility Plant	0
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	397,358
1550-LV Charges - Variance	(831,000)
1555-Smart Meters Recovery	(19,795)
1556-Smart Meters OM & A	286,919
1562-Deferred PILs	(4,769,322)
1563-Deferred PILs - Contra	3,972,809
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0
1580-RSVA - Wholesale Market Services	(1,419,362)
1582-RSVA - One-Time	7,293
1584-RSVA - Network Charges	1,705,373
1586-RSVA - Connection Charges	(1,086,880)
1588-RSVA - Commodity (Power)	(1,989,711)
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1595-Recovery of Deferral and Variance accounts	(5,292,893)
1200-Other Assets and Deferred Charges Total	**(8,059,279)**

1450-Distribution Plant	
1805-Land	507,274
1806-Land Rights	1,598,170
1808-Buildings and Fixtures	111,638
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	6,558,514
1820-Distribution Station Equipment - Normally Primary below 50 kV	4,692,651
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	31,525,625
1835-Overhead Conductors and Devices	32,626,350
1840-Underground Conduit	11,542,680
1845-Underground Conductors and Devices	56,120,648
1850-Line Transformers	32,487,696
1855-Services	3,946,552
1860-Meters	7,883,872
1865-Other Installations on Customer's Premises	440
1450-Distribution Plant Total	**189,602,109**

Table 1-8
Niagara Peninsula Energy Inc.
2010 Pro Forma Balance Sheet

1500-General Plant	
1905-Land	508,970
1906-Land Rights	0
1908-Buildings and Fixtures	12,579,740
1910-Leasehold Improvements	120,252
1915-Office Furniture and Equipment	1,177,863
1920-Computer Equipment - Hardware	2,898,340
1925-Computer Software	2,198,960
1930-Transportation Equipment	6,309,047
1935-Stores Equipment	219,161
1940-Tools, Shop and Garage Equipment	1,660,452
1945-Measurement and Testing Equipment	187,835
1950-Power Operated Equipment	0
1955-Communication Equipment	161,777
1960-Miscellaneous Equipment	72,952
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	128,961
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	(17,520,649)
1500-General Plant Total	**10,703,661**

1550-Other Capital Assets	
2005-Property Under Capital Leases	143,036
2010-Electric Plant Purchased or Sold	0
2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	0
2060-Electric Plant Acquisition Adjustment	142,277
2065-Other Electric Plant Adjustment	45,735,559
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**46,020,872**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(99,459,705)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	(48,739)
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	(142,277)
2160-Accumulated Amortization of Other Utility Plant	(26,348,210)
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(125,998,931)**

Total Assets	**146,777,723**

Table 1-8
Niagara Peninsula Energy Inc.
2010 Pro Forma Balance Sheet

1650-Current Liabilities	
2205-Accounts Payable	14,754,761
2208-Customer Credit Balances	0
2210-Current Portion of Customer Deposits	925,000
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	375,000
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	5,404,000
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	850,000
2252-Transmission Charges Payable	0
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	0
2260-Current Portion of Long Term Debt	2,023,330
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	0
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	(995,761)
2292-Payroll Deductions / Expenses Payable	0
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	0
2296-Future Income Taxes - Current	(2,931,369)
1650-Current Liabilities Total	**20,404,961**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	3,654,000
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	199,000
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	37,334
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	1,147,666
2340-Collateral Funds Liability	0
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	0
2405-Other Regulatory Liabilities	0
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	116,350
2435-Accrued Rate-Payer Benefit	0
1700-Non-Current Liabilities Total	**5,154,350**

Table 1-8
Niagara Peninsula Energy Inc.
2010 Pro Forma Balance Sheet

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	0
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	22,000,000
2525-Term Bank Loans - Long Term Portion	13,840,415
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	3,605,090
1800-Long-Term Debt Total	**39,445,505**

1850-Shareholders' Equity	
3005-Common Shares Issued	31,245,882
3008-Preference Shares Issued	0
3010-Contributed Surplus	18,753,902
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	21,433,182
3045-Unappropriated Retained Earnings	0
3046-Balance Transferred From Income	4,134,636
3047-Appropriations of Retained Earnings - Current Period	6,705,305
3048-Dividends Payable-Preference Shares	0
3049-Dividends Payable-Common Shares	(500,000)
3055-Adjustment to Retained Earnings	0
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**81,772,907**

Total Liabilities & Shareholder's Equity	**146,777,723**

Balance Sheet Total	(0)

Table 1-8 2010 Pro Forma Income Statement

Niagara Peninsula Energy
, License Number ED-2007-0749, File Number EB-2010-0138

Niagara Peninsula Energy
2010 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(28,900,233)
4010-Commercial Energy Sales	(7,917,372)
4015-Industrial Energy Sales	0
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(482,084)
4030-Sentinel Energy Sales	(19,077)
4035-General Energy Sales	(38,500,877)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	0
4055-Energy Sales for Resale	0
4060-Interdepartmental Energy Sales	0
4062-WMS	(8,031,734)
4064-Billed WMS-One Time	0
4066-NS	(6,598,076)
4068-CS	(5,522,464)
4075-LV Charges	(339,100)
3000-Sales of Electricity Total	**(96,311,017)**
3050-Revenues From Services - Distribution	
4080-Distribution Services Revenue	(25,906,029)
4082-RS Rev	(80,748)
4084-Serv Tx Requests	(2,970)
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distribution Total	**(25,989,747)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	0
4215-Other Utility Operating Income	(348,352)
4220-Other Electric Revenues	0
4225-Late Payment Charges	(518,557)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(884,942)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(1,751,852)**

Table 1-8
Niagara Peninsula Energy Inc.
2010 Pro Forma Income Statement

3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	0
4330-Costs and Expenses of Merchandising, Jobbing, Etc	0
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	0
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	(116,200)
4380-Expenses of Non-Utility Operations	0
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	(39,937)
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**(156,137)**
3200-Investment Income	
4405-Interest and Dividend Income	(91,863)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(91,863)**
3350-Power Supply Expenses	
4705-Power Purchased	75,819,643
4708-WMS	8,031,734
4710-Cost of Power Adjustments	0
4712-0	0
4714-NW	6,598,076
4715-System Control and Load Dispatching	0
4716-NCN	5,522,464
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	0
4750-LV Charges	339,100
3350-Power Supply Expenses Total	**96,311,017**

Table 1-8
Niagara Peninsula Energy Inc.
2010 Pro Forma Income Statement

3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	629,835
5010-Load Dispatching	42,867
5012-Station Buildings and Fixtures Expense	122,347
5014-Transformer Station Equipment - Operation Labour and Expenses	10,889
5015-Transformer Station - Operation Supplies and Expenses	53,279
5016-Distribution Station Equipment - Operation Labour	0
5017-Distribution Station Equipment - Operation Supplies and Expenses	0
5020-Overhead Distribution Poles, Towers and Fixtures-Operation Labour and Expenses	193,626
5025-Overhead Distribution Lines and Feeders - Operation Labour and Expenses	19,954
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	0
5040-Underground Distribution Conduit - Operation Labour and Expenses	71,410
5045-Underground Distribution Conductors and Devices - Operation Labour and Expenses	193,121
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	521,545
5070-Customer Premises - Operation Labour and Expenses	94,272
5075-Customer Premises - Materials and Expenses	0
5085-Misc. Distribution and Engineering Labour and Expenses	1,439,073
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**3,392,217**
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	448,874
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Maintenance Dist Stn Equip	4,871
5120-Maintenance of Poles, Towers and Fixtures	149,838
5125-Maintenance of Overhead Conductors and Devices	914,451
5130-Maintenance of Overhead Services	148,397
5135-Overhead Distribution Lines and Feeders - Right of Way	347,058
5145-Maintenance of Underground Conduit	43,016
5150-Maintenance of Underground Conductors and Devices	248,613
5155-Maintenance of Underground Services	89,602
5160-Maintenance of Line Transformers	133,749
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	14,459
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**2,542,929**

Table 1-8
Niagara Peninsula Energy Inc.
2010 Pro Forma Income Statement

3650-Billing and Collecting	
5305-Supervision labour and expenses	336,369
5310-Meter Reading labour and expense	461,855
5315-Customer Billing labour and expenses	1,928,990
5320-Collecting labour and expenses	475,013
5325-Collecting - Cash Over and Short	0
5330-Collection Charges	0
5335-Bad Debt Expense	425,100
5340-Miscellaneous Customer Accounts Expenses	256,895
3650-Billing and Collecting Total	**3,884,221**
3700-Community Relations	
5405-Supervision labour and expenses	0
5410-Community Relations - Sundry	79,548
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**79,548**
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	311,388
5610-Management Salaries and Expenses	1,743,297
5615-General Administrative Salaries and Expenses	400,853
5620-Office Supplies and Expenses	132,496
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	39,600
5635-Property Insurance	206,367
5640-Injuries and Damages	0
5645-Employee Pensions and Benefits	0
5650-Franchise Requirements	0
5655-Regulatory Expenses	190,000
5660-General Advertising Expenses	0
5665-Miscellaneous Expenses and Capital tax	185,605
5670-Rent	0
5675-Maintenance of General Plant	593,077
5680-Electrical Safety Authority Fees	0
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**3,802,684**

Table 1-8
Niagara Peninsula Energy Inc.
2010 Pro Forma Income Statement

3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	7,000,940
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**7,000,940**
3900-Interest Expense	
6005-Interest on Long Term Debt	2,226,625
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	261,369
6035-Other Interest Expense	138,697
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**2,626,691**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	232,000
3950-Taxes Other Than Income Taxes Total	**232,000**
4000-Income Taxes	
6110-Income Taxes	893,733
6115-Provision for Future Income Taxes	(600,000)
4000-Income Taxes Total	**293,733**
4100-Extraordinary & Other Items	
6205-Donations	0
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**0**
Net Income - (Gain)/Loss	**(4,134,636)**

Table 1-9 2011 PRO FORMA FINANCIAL STATEMENTS

Table 1-9 2011 Pro Forma Balance Sheet

Niagara Peninsula Energy
, License Number ED-2007-0749, File Number EB-2010-0138

Niagara Peninsula Energy
2011 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	11,541,203
1010-Cash Advances and Working Funds	3,300
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	0
1100-Customer Accounts Receivable	10,371,505
1102-Accounts Receivable - Services	0
1104-Accounts Receivable - Recoverable Work	994,500
1105-Accounts Receivable - Merchandise, Jobbing, etc.	0
1110-Other Accounts Receivable	341,700
1120-Accrued Utility Revenues	13,470,869
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(561,000)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	0
1170-Notes Receivable	0
1180-Prepayments	535,400
1190-Miscellaneous Current and Accrued Assets	0
1200-Accounts Receivable from Associated Companies	30,000
1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total	**36,727,477**

Account Description	Total
1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	1,254,854
1340-Merchandise	0
1350-Other Material and Supplies	0
1100-Inventory Total	**1,254,854**

Account Description	Total
1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	0
1408-Long Term Receivable - Street Lighting Transfer	0
1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
1460-Other Non-Current Assets	1,926
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**1,926**

Table 1-9
Niagara Peninsula Energy Inc.
2011 Pro Forma Balance Sheet

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	104,370
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	578,465
1525-Miscellaneous Deferred Debits	0
1530-Deferred Losses from Disposition of Utility Plant	0
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	451,538
1550-LV Charges - Variance	(1,203,000)
1555-Smart Meters Recovery	(619,795)
1556-Smart Meters OM & A	336,919
1562-Deferred PILs	(4,793,322)
1563-Deferred PILs - Contra	3,972,809
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0
1580-RSVA - Wholesale Market Services	(2,079,362)
1582-RSVA - One-Time	7,293
1584-RSVA - Network Charges	805,373
1586-RSVA - Connection Charges	(2,226,880)
1588-RSVA - Commodity (Power)	(2,299,874)
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1595-Recovery of Deferral and Variance accounts	(1,284,893)
1200-Other Assets and Deferred Charges Total	**(8,250,359)**

1450-Distribution Plant	
1805-Land	507,274
1806-Land Rights	1,598,170
1808-Buildings and Fixtures	111,638
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	6,558,514
1820-Distribution Station Equipment - Normally Primary below 50 kV	5,155,614
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	34,008,462
1835-Overhead Conductors and Devices	33,598,526
1840-Underground Conduit	12,911,969
1845-Underground Conductors and Devices	57,693,245
1850-Line Transformers	33,772,589
1855-Services	4,446,487
1860-Meters	8,069,057
1865-Other Installations on Customer's Premises	440
1450-Distribution Plant Total	**198,431,985**

Table 1-9
Niagara Peninsula Energy Inc.
2011 Pro forma Balance Sheet

1500-General Plant	
1905-Land	508,970
1906-Land Rights	0
1908-Buildings and Fixtures	12,579,740
1910-Leasehold Improvements	120,252
1915-Office Furniture and Equipment	1,270,456
1920-Computer Equipment - Hardware	3,190,238
1925-Computer Software	2,381,831
1930-Transportation Equipment	6,772,010
1935-Stores Equipment	219,161
1940-Tools, Shop and Garage Equipment	1,753,044
1945-Measurement and Testing Equipment	187,835
1950-Power Operated Equipment	0
1955-Communication Equipment	161,777
1960-Miscellaneous Equipment	72,952
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	128,961
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	(18,370,649)
1500-General Plant Total	**10,976,578**

1550-Other Capital Assets	
2005-Property Under Capital Leases	143,036
2010-Electric Plant Purchased or Sold	0
2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	0
2060-Electric Plant Acquisition Adjustment	142,277
2065-Other Electric Plant Adjustment	45,735,559
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**46,020,872**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(106,603,393)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	(48,739)
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	(142,277)
2160-Accumulated Amortization of Other Utility Plant	(26,348,210)
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(133,142,619)**

Total Assets	**152,020,715**

Table 1-9
Niagara Peninsula Energy Inc.
2011 Pro Forma Balance Sheet

1650-Current Liabilities	
2205-Accounts Payable	15,926,711
2208-Customer Credit Balances	0
2210-Current Portion of Customer Deposits	740,000
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	386,250
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	5,565,520
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	867,000
2252-Transmission Charges Payable	0
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	0
2260-Current Portion of Long Term Debt	2,135,996
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	0
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	(995,761)
2292-Payroll Deductions / Expenses Payable	0
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	0
2296-Future Income Taxes - Current	(3,531,369)
1650-Current Liabilities Total	**21,094,347**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	3,695,000
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	202,980
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	37,334
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	1,171,366
2340-Collateral Funds Liability	0
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	0
2405-Other Regulatory Liabilities	0
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	116,350
2435-Accrued Rate-Payer Benefit	0
1700-Non-Current Liabilities Total	**5,223,030**

Table 1-9
Niagara Peninsula Energy Inc.
2011 Pro Forma Balance Sheet

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	0
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	22,000,000
2525-Term Bank Loans - Long Term Portion	11,704,422
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	3,605,090
1800-Long-Term Debt Total	**37,309,512**

1850-Shareholders' Equity	
3005-Common Shares Issued	31,245,882
3008-Preference Shares Issued	0
3010-Contributed Surplus	18,753,902
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	25,067,818
3045-Unappropriated Retained Earnings	0
3046-Balance Transferred From Income	7,120,919
3047-Appropriations of Retained Earnings - Current Period	6,705,305
3048-Dividends Payable-Preference Shares	0
3049-Dividends Payable-Common Shares	(500,000)
3055-Adjustment to Retained Earnings	0
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**88,393,825**

Total Liabilities & Shareholder's Equity	**152,020,715**

Balance Sheet Total	(0)

Table 1-9 2011 Pro Forma Income Statement

Niagara Peninsula Energy Inc.

Niagara Peninsula Energy
, License Number ED-2007-0749, File Number EB-2010-0138

Niagara Peninsula Energy
2011 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(30,036,366)
4010-Commercial Energy Sales	(8,089,693)
4015-Industrial Energy Sales	0
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(488,646)
4030-Sentinel Energy Sales	(19,034)
4035-General Energy Sales	(40,074,746)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	0
4055-Energy Sales for Resale	0
4060-Interdepartmental Energy Sales	0
4062-WMS	(8,337,946)
4064-Billed WMS-One Time	0
4066-NS	(6,850,285)
4068-CS	(5,733,459)
4075-LV Charges	(360,512)
3000-Sales of Electricity Total	**(99,990,688)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(30,361,677)
4082-RS Rev	(80,748)
4084-Serv Tx Requests	(2,970)
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(30,445,395)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	0
4215-Other Utility Operating Income	(348,352)
4220-Other Electric Revenues	0
4225-Late Payment Charges	(518,557)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(956,878)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(1,823,787)**

Table 1-9
Niagara Peninsula Energy Inc.
2011 Pro Forma Income Statement

3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	0
4330-Costs and Expenses of Merchandising, Jobbing, Etc	0
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	0
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	(65,480)
4380-Expenses of Non-Utility Operations	0
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	(40,000)
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**(105,480)**
3200-Investment Income	
4405-Interest and Dividend Income	(91,863)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(91,863)**
3350-Power Supply Expenses	
4705-Power Purchased	78,708,485
4708-WMS	8,337,946
4710-Cost of Power Adjustments	0
4712-0	0
4714-NW	6,850,285
4715-System Control and Load Dispatching	0
4716-NCN	5,733,459
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	0
4750-LV Charges	360,512
3350-Power Supply Expenses Total	**99,990,688**

Table 1-9
Niagara Peninsula Energy Inc.
2011 Pro Forma Income Statement

3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	648,571
5010-Load Dispatching	43,800
5012-Station Buildings and Fixtures Expense	119,771
5014-Transformer Station Equipment - Operation Labour and Expenses	11,507
5015-Transformer Station - Operation Supplies and Expenses	54,733
5016-Distribution Station Equipment - Operation Labour	0
5017-Distribution Station Equipment - Operation Supplies and Expenses	0
5020-Overhead Distribution Poles, Towers and Fixtures-Operation Labour and	197,358
5025-Overhead Distribution Lines and Feeders - Operation Labour and Expen	20,421
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	0
5040-Underground Distribution Conduit - Operation Labour and Expenses	72,606
5045-Underground Distribution Conductors and Devices - Operation Labour a	194,991
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	489,927
5070-Customer Premises - Operation Labour and Expenses	96,423
5075-Customer Premises - Materials and Expenses	0
5085-Misc. Distribution and Engineering Labour and Expenses	1,623,583
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**3,573,690**

3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	462,681
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Maintenance Dist Stn Equip	4,767
5120-Maintenance of Poles, Towers and Fixtures	151,573
5125-Maintenance of Overhead Conductors and Devices	917,736
5130-Maintenance of Overhead Services	150,393
5135-Overhead Distribution Lines and Feeders - Right of Way	352,301
5145-Maintenance of Underground Conduit	42,841
5150-Maintenance of Underground Conductors and Devices	249,450
5155-Maintenance of Underground Services	91,252
5160-Maintenance of Line Transformers	132,000
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	13,426
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**2,568,416**

Table 1-9
Niagara Peninsula Energy Inc.
2011 Pro Forma Income Statement

3650-Billing and Collecting	
5305-Supervision labour and expenses	490,012
5310-Meter Reading labour and expense	473,321
5315-Customer Billing labour and expenses	2,080,927
5320-Collecting labour and expenses	483,163
5325-Collecting - Cash Over and Short	0
5330-Collection Charges	0
5335-Bad Debt Expense	410,000
5340-Miscellaneous Customer Accounts Expenses	258,306
3650-Billing and Collecting Total	**4,195,729**
3700-Community Relations	
5405-Supervision labour and expenses	0
5410-Community Relations - Sundry	81,464
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**81,464**
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	323,267
5610-Management Salaries and Expenses	1,818,577
5615-General Administrative Salaries and Expenses	421,595
5620-Office Supplies and Expenses	126,460
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	39,900
5635-Property Insurance	209,777
5640-Injuries and Damages	0
5645-Employee Pensions and Benefits	0
5650-Franchise Requirements	0
5655-Regulatory Expenses	268,429
5660-General Advertising Expenses	0
5665-Miscellaneous Expenses and Capital tax	103,810
5670-Rent	0
5675-Maintenance of General Plant	564,320
5680-Electrical Safety Authority Fees	0
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**3,876,135**

Table 1-9
Niagara Peninsula Energy Inc.
2011 Pro Forma Income Statement

3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	7,143,688
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**7,143,688**
3900-Interest Expense	
6005-Interest on Long Term Debt	2,136,564
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	261,369
6035-Other Interest Expense	160,800
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**2,558,733**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	222,474
3950-Taxes Other Than Income Taxes Total	**222,474**
4000-Income Taxes	
6110-Income Taxes	1,725,276
6115-Provision for Future Income Taxes	(600,000)
4000-Income Taxes Total	**1,125,276**
4100-Extraordinary & Other Items	
6205-Donations	0
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**0**
Net Income - (Gain)/Loss	**(7,120,919)**

Audited Financial Statements

Niagara Falls Hydro Inc. Audited Financial Statements 2006 and 2007 – Appendix A

Peninsula West Utilities Limited Audited Financial Statements 2006 and 2007 – Appendix B

Niagara Peninsula Energy Inc.'s Audited Financial Statements 2008 and 2009 – Appendix C

Appendix A – Audited F/S for Niagara Falls Hydro 2006 and 2007

Signed

crawford smith & swallow

NIAGARA FALLS HYDRO INC.

Financial Statements

December 31, 2007

Crawford, Smith and Swallow
Chartered Accountants LLP

4741 Queen Street
Niagara Falls, Ontario
L2E 2M2
Telephone (905) 356-4200
Telecopier (905) 356-3410

Offices in:
Niagara Falls, Ontario
St. Catharines, Ontario
Fort Erie, Ontario
Niagara-on-the-Lake, Ontario
Port Colborne, Ontario

crawford smith & swallow

AUDITORS' REPORT

To the Board Members and Shareholder of Niagara Falls Hydro Inc.

We have audited the balance sheet of Niagara Falls Hydro Inc. as at December 31, 2007 and the statements of operations, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the company'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 company as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Crawford, Smith and Swallow

Niagara Falls, Ontario
March 12, 2008

CRAWFORD, SMITH AND SWALLOW
CHARTERED ACCOUNTANTS LLP

LICENSED PUBLIC ACCOUNTANTS

NIAGARA FALLS HYDRO INC.

BALANCE SHEET

December 31, 2007

Assets - note 6	2007 $	2006 $
Fixed Assets - note 4	62,250,095	60,620,017
Current Assets - note 5	28,895,380	28,979,110
Regulatory Assets - note 14	0	620,523
	91,145,475	**90,219,650**

Liabilities and Shareholder's Equity

Long-Term Debt - note 6	30,628,864	31,366,482
Current Liabilities - note 7	16,197,508	17,439,137
Regulatory Liabilities - note 14	432,478	0
Other Liabilities - notes 8 and 15	4,549,144	4,410,847
Contingent Liabilities - note 12		
Shareholder's Equity		
Share capital - note 9	18,899,784	18,899,784
Paid-up capital	6,705,305	6,705,305
Retained Earnings	13,732,392	11,398,095
	39,337,481	37,003,184
	91,145,475	**90,219,650**

Signed on behalf of the Board:

_________________ Director

_________________ Director

See accompanying notes

NIAGARA FALLS HYDRO INC.

STATEMENT OF RETAINED EARNINGS
for the year ended December 31, 2007

	2007 $	2006 $
Retained Earnings, Beginning of Year	11,398,095	10,029,207
Net Income for the Year	2,334,297	1,368,888
Retained Earnings, End of Year	13,732,392	11,398,095

See accompanying notes

NIAGARA FALLS HYDRO INC.

STATEMENT OF OPERATIONS
for the year ended December 31, 2007

	2007 $	2006 $
Service Revenue		
Standard supply charge	52,359,124	49,788,760
Wholesale, network and connection charges	14,225,425	13,856,983
Service charge	9,262,222	8,483,542
Distribution volumetric charge	8,283,268	7,712,480
Standard supply service administration charge	83,799	84,767
Retailer revenue	65,900	57,919
Other income	(28,412)	(14,543)
	84,251,326	79,969,908
Cost of Power		
Power Purchased	66,584,549	63,645,743
Gross Profit	17,666,777	16,324,165
Other Revenue	1,970,997	1,721,740
	19,637,774	18,045,905
Expenses		
Operation and maintenance		
Distribution	3,892,921	3,383,943
Utilization	157,311	171,073
Administration and general	4,522,016	4,411,501
Billing and collecting	2,591,422	2,506,306
Depreciation	4,254,829	4,354,697
	15,418,499	14,827,520
Net Income before Payments in Lieu of Income Taxes	4,219,275	3,218,385
Payments in Lieu of Income Taxes	1,884,978	1,849,497
Net Income for the Year	2,334,297	1,368,888

See accompanying notes

NIAGARA FALLS HYDRO INC.

STATEMENT OF CASH FLOWS
for the year ended December 31, 2007

	2007 $	2006 $
Cash Provided By:		
Operations		
Net Income for the year	2,334,297	1,368,888
Items not involving cash		
Depreciation	4,254,829	4,354,697
Employee future benefits	13,162	6,425
	6,602,288	5,730,010
Changes in non-cash working capital components - note 10(a)	(1,345,988)	(1,540,582)
	5,256,300	4,189,428
Investments		
Additions to property and equipment - net	(5,884,908)	(4,672,285)
Regulatory costs - note 14	1,053,001	3,019,631
	(4,831,907)	(1,652,654)
Financing		
Long-term deposits	219,604	13,473
Long-term bank loan	(691,732)	(648,700)
Employees' accumulated vested sick leave	12,511	3,028
	(459,617)	(632,199)
Increase in Cash Position	(35,224)	1,904,575
Cash Position, Beginning of Year	11,830,483	9,925,908
Cash Position, End of Year	11,795,259	11,830,483
Cash Position		
Cash	11,655,279	11,696,355
Restricted cash	139,980	134,128
	11,795,259	11,830,483

See accompanying notes

NIAGARA FALLS HYDRO INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2007

Incorporation

On April 1, 2000, Niagara Falls Hydro Inc. was incorporated under the Business Corporations Act (Ontario) along with its affiliate companies, Niagara Falls Hydro Holding Corporation and Niagara Falls Hydro Services Inc. The incorporation was pursuant to the provisions of the Energy Competition Act, 1998.

1. Significant accounting policies

These financial statements of Niagara Falls Hydro Inc. have been prepared in accordance with Canadian generally accepted accounting principles, including accounting principles prescribed in the accounting procedures handbook for electric distribution utilities by the Ontario Energy Board. The company is a wholly-owned subsidiary of Niagara Falls Hydro Holding Corporation.

Revenue recognition

Service revenue from the sale of electrical energy includes an accrual for power supplied but not billed to customers from the date the meters were last read to the year end.

Fixed assets and depreciation

Fixed assets are stated at acquisition cost. Much of the distribution system is constructed by the company and is capitalized based on actual costs. Depreciation is determined on a straight-line basis with reference to estimated useful lives of the assets in accordance with the Ontario Energy Board policy. Depreciation periods for the fixed assets range from 4 years to 60 years.

Inventory

Inventory is valued at the lower of moving average cost and replacement cost. Inventory is comprised of material and supplies used to maintain and upgrade the electrical distribution system.

Ontario Municipal Employees Retirement System

The company makes contributions to the Ontario Municipal Employees Retirement System (OMERS), which is a multi-employer plan, on behalf of 75 members of its staff. The plan is a defined benefit plan which specifies the amount for the retirement benefit to be received by the employees based on the length of service and rates of pay.

The amount contributed to OMERS for the year ending December 31, 2007 was $372,276 (2006 - $349,259) for current service.

Long-term deposits

Deposits are considered long-term liabilities. Any deposits expected to be refunded in the next year in excess of deposits expected to be received have been shown as current liabilities.

Employee's accumulated vested sick benefits

Under the sick leave plan unused vested sick leave can accumulate and employees of the company as at April 1, 1987 can request at any time and will receive payment if funds are available as determined by the company. Full provisions for the liability, to the

NIAGARA FALLS HYDRO INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2007

1. Significant Accounting Policies - continued

Employee's accumulated vested sick benefits - continued

extent that cash payments to employees might be required, have been made in these financial statements.

Employees of the Corporation hired after March 31, 1987 can accumulate unused sick leave but it does not become vested at any time.

Paid-up capital

Paid-up capital reflects the balance of capital contributions received by the former Niagara Falls Hydro Electric Commission prior to January 1, 2001.

Employee future benefits

The company pays certain medical, dental and life insurance benefits on behalf of its retired employees. The company recognizes these post-retirement costs in the period in which the employees rendered the services. See note 15.

Actuarial gains/(losses)

Actuarial gains/(losses) are amortized over the expected average remaining service life of the active employees.

Regulation

The following are regulatory accounting principles which differ from Canadian GAAP for organizations operating in an unregulated environment:

Regulatory Assets and Liabilities

The company has certain costs and variance balances which have been deferred as regulatory assets or liabilities until the time of recovery of these costs from electricity distribution ratepayers. The recovery of these costs will be subject to review and approval of the OEB. See note 14.

Payments in lieu of income taxes and capital taxes

Under the Electricity Act, 1998, the company is required to make payments in lieu of corporate taxes to Ontario Electricity Financial Corporation (OEFC), commencing October 1, 2001. These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

The company provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected they will be included in the rates approved by the Ontario Energy Board and recovered from the customers of the Niagara Falls Hydro Inc.

NIAGARA FALLS HYDRO INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2007

1. Significant Accounting Policies - continued

Financial Instruments

As at January 1, 2007, the company adopted the CICA handbook section 3855 and has elected the following balance sheet classifications with respect to its financial assets and financial liabilities in accordance with this new section:

Cash is classified as "assets held-for-trading" and is measured at fair value.

Accounts receivable are classified as "loans and receivables" and are measured at amortized cost, which upon initial recognition, is considered equivalent to fair value.

Accounts payable, long-term deposits, and long-term debt are classified as "other financial liabilities" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.

2. Change in Accounting Policy

Effective January 1, 2007, the company adopted the CICA handbook sections 3855 - "Financial Instruments - Recognition and Measurement" and 3861 - "Financial Instruments - Disclosure and Presentation". There was no adjustment necessary to opening retained earnings as a result of the change.

3. Due from (to) Affiliated Companies

	2007 $	2006 $
Niagara Falls Hydro Holding Corporation	10,263	180,257
Niagara Falls Hydro Services Inc.	(3,669,574)	(5,946,924)
	(3,659,311)	**(5,766,667)**

Advances to and from affiliated companies are non-interest bearing and payable on demand.

4. Fixed Assets

	Cost $	Accumulated Depreciation $	2007 $	2006 $
Land and land rights	505,088		505,088	505,089
Buildings	5,970,485	1,598,607	4,371,878	4,087,595
Distribution stations	3,367,157	1,928,033	1,439,124	1,527,833
Transmission station	6,548,452	467,282	6,081,170	6,230,953
Distribution lines				
-overhead	27,474,171	11,409,258	16,064,913	14,538,779
-underground	43,313,401	22,012,238	21,301,163	21,514,154
Distribution transformers	19,971,528	10,789,231	9,182,297	8,811,827
Distribution meters	4,754,032	3,021,858	1,732,174	1,688,486
Trucks and equipment	8,427,694	6,855,406	1,572,288	1,715,301
	120,332,008	**58,081,913**	**62,250,095**	**60,620,017**

NIAGARA FALLS HYDRO INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2007

5. Current Assets

	2007 $	2006 $
Cash	11,655,279	11,696,355
Restricted cash	139,980	134,128
Accounts receivable - billed	6,212,115	6,767,000
Unbilled revenue	8,740,207	8,428,024
Deferred PILS revenue	0	0
Due from affiliated companies - note 3	10,263	180,257
Inventories	1,473,144	1,575,635
Prepaid expenses	418,862	197,711
Payments in lieu of corporate income taxes refundable	245,530	0
	28,895,380	**28,979,110**

6. Long-Term Debt

	2007 $	2006 $
Long-term note payable to the City of Niagara Falls pursuant to the transfer by-law - 7 1/4 % interest payable, effective May 1, 2002 on the implementation of the rate increases as required by the Ontario Energy Board and the Energy Competition Act. There is no immediate intent to redeem the long-term note	22,000,000	22,000,000
Long-term note payable to the Niagara Falls Hydro Holding Corporation, pursant to the transfer by-law - 7 1/4 % interest payable, effective May 1, 2002 on the implementation of the rate increases as required by the Ontario Energy Board and the Energy Competition Act. There is no immediate intent to redeem the long-term note.	3,605,090	3,605,090
Long-term bank loan payable to Scotiabank for the construction of the transmission station. Loan amortization period is for ten years commencing June 1, 2004 at a fixed interest rate of 6.44%.	5,761,392	6,453,124
	31,366,482	32,058,214
Current portion due within one year	(737,618)	(691,732)
	30,628,864	**31,366,482**

The bank loan payable is secured by a general security agreement covering all assets of the company, present and future, as well as appropriate insurance coverage, loss if any, payable to the creditor.

NIAGARA FALLS HYDRO INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2007

6. Long-Term Debt - continued

The principal payments of long-term debt are due as follows:

	$
2008	737,618
2009	786,548
2010	838,724
2011	894,361
2012	953,689

7. Current Liabilities

	2007 $	2006 $
Accounts payable	11,084,316	9,171,975
Payments in lieu of corporate income taxes payable	0	1,029,486
Due to affiliated companies - note 3	3,669,574	5,946,924
Current portion of long-term debt	737,618	691,732
Current portion of other liabilities	706,000	599,020
	16,197,508	**17,439,137**

8. Other Liabilities

	2007 $	2006 $
Long-term deposits	858,999	746,375
Employees' accumulated vested sick leave	165,622	153,111
Employee future benefits - note 15	3,524,523	3,511,361
	4,549,144	**4,410,847**

9. Share Capital

Authorized
Unlimited number of common shares

	2007 $	2006 $
Issued 1,000 common shares	**18,899,784**	**18,899,784**

NIAGARA FALLS HYDRO INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2007

10. Statement of Cash Flows

(a) Changes in non-cash working capital components include:

	2007	2006
	$	$
Accounts receivable - billed	554,885	(1,981,516)
Unbilled revenue	(312,183)	771,486
Inventories	102,491	(185,033)
Prepaid expenses	(221,151)	48,260
Payments in lieu of corporate income taxes	(1,275,016)	1,471,027
Accounts payable	1,912,342	(4,211,749)
Due to affiliated companies	(2,107,356)	2,546,943
	(1,345,988)	**(1,540,582)**

(b) Interest received and paid and payments in lieu of income taxes paid

	2007	2006
	$	$
Interest received	575,715	356,777
Interest paid	2,299,891	2,329,318
Payments in lieu of income taxes paid	3,159,994	579,262

11. Related Party Transactions

In the ordinary course of business, the company enters into transactions with related parties including the City of Niagara Falls and its boards and agencies. The company derives revenues from the sale of electricity and recovers costs of supplying electrical equipment and distribution system from these related parties. Revenue and expenses from related parties include service revenue and municipal taxes and these transactions take place at fair market value. Account balances resulting from these transactions which are included in the balance sheet are settled in accordance with normal trade terms.

12. Contingent Liabilities

Letter of Credit
The company has arranged for a standby letter of credit of $ 10,000,000 of which $ 4,316,687 ($4,748,480 - 2006) has been drawn down in favour of the Independent Electricity Market Operator. This is to provide a prudential letter of credit in support of the purchase of electrical power.

NIAGARA FALLS HYDRO INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2007

12. Contingent Liabilities - continued

Class Action Claim

Consumers' Gas Decision
On April 22, 2004, the Supreme Court of Canada ruled that The Consumers' Gas Company (currently Enbridge Gas Distribution Inc.) was required to repay a portion of certain late charges it collected from its customers that were in excess of the interest stipulated in section 347 of the Criminal code. The former Toronto Hydro-Electric Commission is not a party to the Consumers' Gas class action, however this action is relevant to the class action described below as the parties to the former Toronto Hydro-Electric Commission class action were awaiting the outcome of the Consumers' Gas Decision.

A class action claiming $ 500 million in restitution payments plus interest was served on the former Toronto Hydro-Electric Commission on November 18, 1998. The action was initiated against the former Toronto Hydro-Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities in Ontario which have charged late payment charges on overdue utility bills at any time after April 1, 1981.

The claim is based on the premise that late payment penalties result in the municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under section 347(1)(b) of the Criminal Code.

As a result of the Consumers' Gas decision, it is expected that the class action will now proceed.

The Electricity Distributors Association is undertaking the defense of this class action. At this time, it is not possible to quantify the effect, if any, on the financial statements of the Company.

On August 24, 2007, an employee was injured in an accident. This incident remains an open file with the Ministry of Labour, with the possibility of that proceeding alleging a violation of safety standards may be taken by the Ministry of Labour. If this is done Niagara Falls Hydro Inc. and its merged successor, Niagara Peninsula Energy Inc. could be fined. However, at this point in time, it is not possible to quantify the effect, if any, this incident will have on the financial statements of Niagara Falls Hydro Inc.

13. General Liability Insurance

The company is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) which is a pooling of general liability insurance risks. Members of MEARIE would be assessed, on a pro-rata basis, based on the total of their respective deposit premiums should losses be experienced by MEARIE, in excess of reserves and supplementary insurance, for the years in which the company or the former Niagara Falls Hydro Electric Commission was a member.
To December 31, 2007, the company has not been made aware of any additional assessments.
Participation in MEARIE covers a three year underwriting period which expires January 1, 2009. Notice to withdraw from MEARIE must be given six months prior to the commencement of the next three year underwriting term.

NIAGARA FALLS HYDRO INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2007

14. Regulatory Assets/Liabilities

The Ontario Energy Board (the "OEB") has, in accordance with the Electricity Distribution Handbook, approved recovery of regulatory assets of $1,184,616 (2006 - $ 1,073,574). These amounts are for the recovery of approved regulatory assets recorded in fiscal years prior to January 1, 2004. Under this regulation revenue is $ 1,184,616 higher (2006 - $ 1,073,574) than in the absence of rate regulation.

In accordance with the OEB's criteria, the company recorded carrying charges on the recovered amounts of ($ 197,145), (2006 - ($ 150,587)). Under this regulation a carrying charge expense of $ 197,145 in 2007, (carrying charge expense of $ 150,587 - 2006) was recorded. In the absence of rate regulations, Canadian generally accepted accounting principles would require the company to reverse the carrying charges related to the regulatory assets.

Retail settlement variances, retail cost variances, deferred payment in lieu of income taxes, other regulatory assets, conservation and demand management and smart meter recovery variance track the differences between certain costs incurred and the amounts recovered through the utility's rate orders. Under these regulations, expenditures are allowed to be deferred which would be expensed under Canadian generally accepted accounting principles for unregulated businesses.

Due to this regulation the company was allowed to defer these costs as regulatory assets which would have been expenesed under Canadian GAAP for unregulated businesses. As at December 31, 2007 the company has accumulated $ (432,478) ($620,523 - 2006) in regulatory liabilities on the balance sheet as other liabilities.

	2007 $	2006 $
Deferred payments in lieu of income taxes	(568,643)	(392,317)
Pre market settlement variances	0	755,751
Retail settlement variances	(378,170)	11,011
Retail cost variances	905,657	795,424
Other regulatory assets	57,361	185,790
Conservation and demand management	(275,275)	(679,313)
Smart meter recovery variances	(173,408)	(55,823)
	(432,478)	**620,523**

NIAGARA FALLS HYDRO INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2007

15. Employee Future Benefits

Defined Benefit Plan Information

	2007 $	2006 $
Employee benefit plan assets	0	0
Employee benefit plan liabilities	2,533,703	2,436,517
Employee benefit plan deficit	2,533,703	2,436,517
Unamortized actuarial gain	990,820	1,074,844
Accrued benefit obligation, end of year	**3,524,523**	**3,511,361**

	2007 $	2006 $
Accrued benefit obligation, beginning of year	3,511,361	3,504,936
Benefit Income/(Expense) for the year	121,527	112,935
Contributions/Benefit payments by the Employer	(108,365)	(106,510)
Accrued benefit obligation, end of year	**3,524,523**	**3,511,361**

The main actuarial assumptions employed for the valuation are as follows:

GENERAL INFLATION - Future general inflation levels, as measured by changes in the Consumer Price Index (CPI), were assumed at 2.1% in 2007 and thereafter.

INTEREST (DISCOUNT) RATE - The obligation as at December 31, 2007, the present value of future liabilities and the expense for the year ended December 31, 2007, were determined using a discount rate of 5.0%. This corresponds to the assumed CPI rate plus an assumed real rate of return of 2.1%.

SALARY LEVELS - Future general salary and wage levels were assumed to increase at 3.3% per annum.

MEDICAL COSTS - Medical costs were assumed to increase at the CPI rate plus a further increase of 5.9% in 2008 graded down to 4.9% in 2010 and thereafter.

DENTAL COSTS - Dental costs were assumed to increase at the CPI rate plus a further increase of 2.9% in 2008 to 2010 and thereafter.

NIAGARA FALLS HYDRO INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2007

16. Financial Instruments

Fair Value of Financial Instruments

The fair value of cash, receivables, accounts payable and accrued liabilities corresponds to their carrying value due to their short-term maturity.

Long-term debt and due from (to) affiliated companies are at a stated value. It is not practicable within the constraints of timeliness or cost to determine the fair value of these financial liabilities with sufficient reliability.

Credit Risk

The company, in the normal course of business, monitors the financial condition of its customers and reviews the credit history of new customers. The company is currently holding customer deposits on hand in the amount of $1,425,019 of which $719,019 is long-term and $ 706,000 is current (2006 - $1,211,266, long-term $ 612,246 and $ 599,020 current) which are reflected on the balance sheet. Allowances are also maintained for potential credit losses. Management believes that it has adequately provided for any exposure to normal customer credit risk.

Operating Line of Credit

As at December 31, 2007, the company had a line of credit of $ 3,000,000 (2006 - $ 3,000,000) of which NIL has been drawn down. The line of credit is a revolving operating line that bears interest at the prime rate. The line of credit is secured by the same security described in note 6.

17. Future Income Taxes

Future income taxes relating to this regulated business have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2007, future income tax assets of $ 2,935,226 ($3,032,405 - 2006), based on substantively enacted income tax rates, have not been recorded. The company was not subject to payments in lieu of corporate income taxes prior to October 1, 2001.

Temporary differences and carry forwards which give rise to future income tax assets and liabilities are as follows:

	2007	2006
	$	$
Excess of undepreciated capital cost over net book value of capital assets	1,768,234	1,988,234
Employee future benefits	1,022,112	1,268,304
Regulatory assets	144,880	(224,133)
	2,935,226	**3,032,405**

NIAGARA FALLS HYDRO INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2007

17. Future Income Taxes - continued

An independent valuation was completed effective October 1, 2001 in order to determine the fair market value of the company for the purpose of calculating payments in lieu of corporate income taxes under s. 93 of the Electricity Act. The valuation resulted in a fair market value of approximately $ 51,873,000 of tangible capital assets, an increase of approximately $ 5,070,000 over net book value as at October 1, 2001. The valuation was performed for the purposes of calculating payments in lieu of corporate income taxes only and has not been reflected as an adjustment to net book value for accounting purposes.

18. Income Taxes

The reconciliation of the company's effective income tax rate for payments in lieu of corporate income taxes is as follows:

	2007 %	2006 %
Combined basic federal and provincial statutory tax rate	36.12	36.12
Regulatory assets added for income tax purposes	2.54	18.53
Amortization in excess of capital cost allowance	5.84	8.87
Adjustment to 2003 tax provision	0	(5.90)
Other	0.18	(0.16)
Effective Tax Rate	**44.68**	**57.46**

19. Subsequent Events

On January 1, 2008, Niagara Falls Hydro Inc. amalgamated with Peninsula West Utilities Limited to become Niagara Peninsula Energy Inc. Niagara Falls Hydro Inc.'s parent company Niagara Falls Hydro Holding Corporation received 74.5% of the issued and outstanding common shares of the new company.

Appendix B – Audited F/S Peninsula West Utilities 2006 and 2007

Financial Statements of

PENINSULA WEST UTILITIES LIMITED

Year ended December 31, 2007

KPMG

KPMG LLP
Chartered Accountants
One St. Paul Street Suite 901
PO Box 1294 Stn Main
St. Catharines ON L2R 7A7

Telephone (905) 685-4811
Fax (905) 682-2008
Internet www.kpmg.ca

AUDITORS' REPORT

To the Shareholder of Peninsula West Utilities Limited

We have audited the balance sheet of Peninsula West Utilities Limited as at December 31, 2007 and the statements of earnings and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company'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 Company as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

St. Catharines, Canada
March 28, 2008

PENINSULA WEST UTILITIES LIMITED

Financial Statements

Year ended December 31, 2007

Financial Statements

PENINSULA WEST UTILITIES LIMITED

Balance Sheet

December 31, 2007, with comparative figures for 2006

	2007	2006
Assets		
Current assets:		
Cash	$ 2,079,330	$ 1,610,106
Accounts receivable	3,219,218	3,822,585
Unbilled revenue	4,227,172	3,966,192
Inventory	262,254	293,463
Prepaid expenses	83,070	141,888
	9,871,044	9,834,234
Investment (note 3)	-	1,200,000
Property and equipment (note 4)	21,580,284	19,889,481
Other assets:		
Regulatory assets (note 6)	-	1,069,907
Deferred charges	-	16,400
	-	1,086,307
Future payment in lieu of taxes	2,911,000	1,539,000
	$ 34,362,328	$ 33,549,022

		2007		2006
Liabilities and Shareholder's Equity				
Current liabilities:				
Accounts payable and accrued liabilities	$	6,872,759	$	7,401,181
Current portion of customer deposits		30,586		130,201
Current portion of capital lease (note 7)		21,641		21,641
Current portion of long-term liabilities (note 8)		9,500,000		9,523,618
		16,424,986		17,076,641
Long-term liabilities:				
Capital lease (note 7)		43,886		61,207
Customer deposits		382,971		296,247
Regulatory liabilities (note 6)		4,085,951		-
		4,512,808		357,454
Shareholder's equity:				
Capital stock :				
Unlimited number of common shares				
Issued:				
100 common shares		12,346,098		12,346,098
Retained earnings		1,078,436		3,768,829
		13,424,534		16,114,927
Contingent liabilities (note 11)				
Subsequent events (note 12)				
	$	34,362,328	$	33,549,022

See accompanying notes to financial statements.

On behalf of the Board:

____________________________ Director

____________________________ Director

PENINSULA WEST UTILITIES LIMITED

Statement of Earnings and Retained Earnings

Year ended December 31, 2007, with comparative figures for 2006

	2007	2006
Service revenue	$ 34,512,962	$ 35,025,202
Cost of power	26,400,573	27,066,024
Gross Margin	8,112,389	7,959,178
Other revenue	530,428	539,085
	8,642,817	8,498,263
Expenses:		
Operation maintenance	2,035,302	2,125,256
Administration	2,499,554	2,479,753
Depreciation	2,641,905 ✓	2,312,328
Interest on term loan	521,522 ✓	550,141
	7,698,283	7,467,478
Earnings before the undernoted	944,534	1,030,785
Earnings before payment in lieu of taxes	944,534	1,030,785
Payment in lieu of taxes:		
Current	2,304,916	738,484
Future reduction	(1,372,000)	(437,000)
	932,916	301,484
Net earnings	11,618	729,301
Retained earnings, beginning of year, as previously reported	3,768,829	3,039,528
Unrecognized loss on interest rate swap at beginning of year (note 2)	(102,011)	-
As restated	3,666,818	3,039,528
Dividends on common shares	(2,600,000)	-
Retained earnings, end of year	$ 1,078,436	$ 3,768,829

See accompanying notes to financial statements.

PENINSULA WEST UTILITIES LIMITED

Statement of Cash Flows

Year ended December 31, 2007, with comparative figures for 2006

	2007	2006
Cash provided by (used in):		
Operations:		
Net earnings	$ 11,618	$ 729,301
Items not involving cash:		
Depreciation	2,641,905	2,312,328
Loss on disposal of capital assets	1,321	-
Future payment in lieu of taxes	(1,372,000)	(437,000)
Change in fair value of interest rate swap	(26,724)	-
Change in non-cash operating working capital (note 9)	44,775	(1,078,308)
Change in customer deposits	(12,891)	(2,956)
	1,288,004	1,523,365
Financing:		
Repayment of long-term debt	(23,618)	(22,229)
Repayment of capital lease	(17,321)	(16,363)
Cash dividends on common shares	(1,400,000)	-
	(1,440,939)	(38,592)
Investments:		
Reduction in regulatory assets/liabilities	5,155,858	763,124
Addition to capital assets	(4,533,699)	(3,618,321)
	622,159	(2,855,197)
Increase (decrease) in cash	469,224	(1,370,424)
Cash, beginning of year	1,610,106	2,980,530
Cash, end of year	$ 2,079,330	$ 1,610,106

See accompanying notes to financial statements.

PENINSULA WEST UTILITIES LIMITED

Notes to Financial Statements

Year ended December 31, 2007

On October 25, 2000, Peninsula West Utilities Limited (the "Company") was incorporated under the Business Corporations Act with net assets contributed from the predecessor hydro-electric commissions. The Corporation is a regulated distribution company and provides electricity distribution and related services to its commercial and residential customers.

1. Significant accounting policies:

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Significant accounting policies are as follows:

(a) Service revenue:

Service revenue is recorded as revenue in the period to which it relates. Revenue is accrued from the last meter reading date to the end of the year.

(b) Inventory:

Inventory is valued at the lower of weighted average cost and net realizable value.

(c) Property and equipment:

Property and equipment are stated at cost. Depreciation is provided over the estimated life of the assets on a straight-line basis as follows:

Asset	Rate
Easements	25 - 40 years
Plant	10 - 25 years
Equipment	5 - 10 years
Leasehold improvements	Over the lease term

(d) Capital contributions:

Capital contributions received after January 1, 2000 are deferred and amortized on the same basis as the related asset.

(e) Investments:

Investments are recorded at cost.

PENINSULA WEST UTILITIES LIMITED

Notes to Financial Statements

Year ended December 31, 2007

---

1. Significant accounting policies (continued):

(f) Payment in lieu of taxes ("PILs"):

The Company is currently exempt from taxes under the Income Tax Act (Canada) ("ITA") and the Ontario Corporations Tax Act ("OCTA"). Pursuant to the Electricity Act, 1998 (Ontario) ("EA"), the Company is required to compute taxes under the ITA and OCTA and remit such amounts thereunder computed to the Ministry of Finance (Ontario).

The Company provides for PILs using the asset and liability method. Under this method, future tax assets and liabilities are recognized, to the extent such are determined likely to be realized, for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date of enactment or substantive enactment. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the Ontario Energy Board ("OEB") and recovered from the customers of the Company at that time.

PILs recoverable from loss carryforwards are recorded in future payments in lieu of taxes on the balance sheet at the current enacted statutory tax rates expected to apply when recovery of the loss carryforwards are expected to be recovered.

(g) Measurement uncertainty:

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures related thereto. Due to the inherent uncertainty in making estimates, actual results could differ from these estimates recorded in preparing these financial statements including changes as a result of future regulatory decisions.

Accounts receivable, unbilled revenue and regulatory assets/liabilities are stated after evaluation of amounts expected to be collected and an appropriate allowance for doubtful accounts. Inventory is recorded net of provisions for obsolescence. Amounts recorded for depreciation and amortization of equipment are based on estimates of useful service life.

PENINSULA WEST UTILITIES LIMITED

Notes to Financial Statements

Year ended December 31, 2007

2. Change in accounting policy:

Effective January 1, 2007, the Company adopted the new Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3855 "Financial Instruments - recognition and Measurement". Under the new standard, all financial instruments are initially recorded on the balance sheet at fair value. They are subsequently valued at fair value or amortized cost depending on the classification selected for the financial instrument. Financial assets are classified as either "held-for-trading", "held-to-maturity", "available-for-sale", or "loans and receivables" and financial liabilities are classified as either "held-for trading" or "other liabilities". Financial assets and liabilities classified as held-for-trading are measured at fair value with the change in fair value recorded in the statement of earnings and deficit. Financial assets classified as held-to-maturity or loans and receivables and financial liabilities classified as other liabilities are subsequently measured at amortized costs using the effective interest method. Available-for-sale financial assets that have a quoted price in an active market are measured at fair value with the change in fair value recorded in shareholders' equity. Such gains or losses are reclassified to the statement of earnings and deficit when the related financial asset is disposed of or when the decline in value is considered to be other-than-temporary.

The Company has classified it's financial instruments as follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivable
Unbilled revenue	Loans and receivable
Accounts payable and accrued liabilities	Other liabilities
Interest rate swap	Held-for-trading
Customer deposits	Other liabilities
Long-term liabilities	Other liabilities

In the prior year, the Company designated its interest rate hedge agreement as hedges of the underlying debt. As a result of the implementation of the new CICA handbook sections, the interest rate swap has no longer been designated as a hedge for accounting purposes. The interest rate swap is recorded at fair value based on quoted market prices with changes in fair value recorded in interest expense.

The change in accounting policy is treated prospectively as required under the standard. The effect on the opening shareholder's equity at January 1, 2007 is $(102,011).

3. Investment:

The Company transferred its' investment of 120 non-voting Class A special shares in Niagara West Transformation Corporation to the Company's parent. The Company issued a dividend in kind to its' parent in the amount of $1,200,000.

PENINSULA WEST UTILITIES LIMITED

Notes to Financial Statements

Year ended December 31, 2007

4. Property and equipment:

			2007	2006
	Cost	Accumulated amortization	Net book value	Net book value
Easements	$ 1,829,820	$ 519,636	$ 1,310,184	$ 1,395,701
Plant	48,640,451	23,712,963	24,927,488	22,040,802
Equipment	2,932,314	2,004,271	928,043	1,301,305
Leasehold improvements	120,252	120,252	-	885
Capital contributions	(6,703,820)	(1,118,389)	(5,585,431)	(4,849,212)
	$ 46,819,017	$ 25,238,733	$ 21,580,284	$ 19,889,481

5. Rate regulation:

The Company is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the Ontario Energy Board Act (1998). The OEB has the power and responsibility to approve or fix rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to electricity distributors which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment.

In January 2000, the OEB established that distribution rates would be subject to Performance Based Regulation ("PBR"), a method of regulation whereby distribution rates are reduced annually to reflect productivity improvements required of the Company. Under this rate methodology, rates also include regulated amounts for return on Company equity and debt, which were initially determined by the OEB to be 9% and 7.25%, respectively. While the initial PBR regulatory framework provided for those regulatory rates of return, subsequent regulation and Provincial Government initiatives prevented distribution companies from fully achieving the theoretical rate of return on equity.

In 2005, the Company filed rate applications to adjust its distribution charges to provide for the full theoretical regulatory rate of return of 9.88% and continued recovery of its regulatory assets. As mandated by the OEB, the rate increase is subject to a financial commitment by the Company to invest $404,538 in conservation and demand management activities over the period July 1, 2005 to April 30, 2008. Spending on this program is expected to be completed by April 30, 2008.

In 2006, the OEB approved the Company's 2006 distribution rates providing for a revised rate of return of 9.0% effective May 1, 2006.

PENINSULA WEST UTILITIES LIMITED

Notes to Financial Statements

Year ended December 31, 2007

6. Regulatory assets (liabilities):

	2007	2006
Regulatory assets (liabilities):		
Settlement variances	$ (4,773,861)	$ (1,474,245)
Smart meters	42,667	61,476
Regulatory asset recovery amount	645,243	2,482,676
	$ (4,085,951)	$ 1,069,907

Net regulatory assets (liabilities) represent variance between costs incurred by the Company and amounts billed to the consumer at OEB approved rates less recoveries. These amounts have been accumulated pursuant to the Electricity Act and deferred in anticipation of their future disposition in electricity distribution rates. Management assesses the future uncertainty with respect to the final regulatory disposition of those amounts, and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decision adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Regulatory assets (liabilities) earn (incur) interest at the rates ranging from 4.59% to 5.14% simple interest per annum.

Settlement variances - represent amounts that have accumulated since Market Opening and comprise:

(a) variances between amounts charged by the Independent Electricity System Operator ("IESO") for the operation of the wholesale electricity market and grid, various wholesale market settlement charges and transmission charges, and the amounts billed to customers by the Company based on the OEB approved wholesale market service rate; and

(b) variances between the amounts charged by the IESO for energy community costs and the amounts billed to customers by the Company based on OEB approved rates.

The Company filed for recovery of these costs as of December 31, 2004. The application was approved by the OEB effective May 1, 2006. As prescribed by the OEB, the balances being recovered have been moved to regulatory asset recovery amount.

PENINSULA WEST UTILITIES LIMITED

Notes to Financial Statements

Year ended December 31, 2007

---

6. Regulatory assets (liabilities) (continued):

Smart meters - the Province of Ontario has committed to have "Smart Meter" electricity meters installed in 800,000 homes and small businesses by the end of 2007 and throughout Ontario by the end of 2010. Smart meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals. Bill 21, Energy Conservation and Responsibility Act, provides the legislative framework and regulations to support this initiative.

Included in distribution rates, effective May 1, 2006, is a charge for smart meters of $0.26 per metered customer per month. Consistent with the OEB's direction and pending further guidance, all smart meters related expenditures and recoveries are currently being deferred in regulatory accounts.

Regulatory assets recovery amount - represents costs incurred by the Company which have been approved for recovery through rates in excess of amounts recovered from customers.

Restructuring of the electricity industry in Ontario - The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect the distribution rates that the Company may charge and the costs that the Company may recover, including the balance of its regulatory assets.

In the absence of rate regulation, generally accepted accounting principles would require the Company to record the costs and recoveries described above in the operating results of the year in which they are incurred and reported earnings before income taxes would be $5,155,858 (2006 - $(763,124)) lower (higher) than reported.

7. Capital lease:

	2007	2006
2007	$ -	$ 21,641
2008	21,641	21,641
2009	46,560	46,560
	68,201	89,842
Less amount representing interest at 5.75%	2,674	6,994
	65,527	82,848
Current portion of obligations under capital lease	21,641	21,641
	$ 43,886	$ 61,207

PENINSULA WEST UTILITIES LIMITED

Notes to Financial Statements

Year ended December 31, 2007

8. Long-term debt:

		2007		2006
Debentures outstanding to Town of Lincoln	$	-	$	23,618
Term loan		9,500,000		9,500,000
		9,500,000		9,523,618
Less principal included in current liabilities		9,500,000		9,523,618
	$	-	$	-

The term loan is a variable rate committed term loan issued as bankers acceptances bearing interest at the BA rate and is due in July 19, 2009. It is management's intention to renew this term loan when it comes due.

The term loan is secured by a general security agreement over all of the assets of the Company and an assignment of fire insurance.

The Company has entered into a swap transaction with the Company's banker the effect of which is to fix the interest rate on $8,000,000 of the term loan at 4.63% until July 20, 2009.

The fair value of the interest rate swap agreement is based on amounts quoted by the Company's bank to realize favourable contracts or settle unfavourable contracts, taking into account interest rates at December 31, 2007. At December 31, 2007, the interest rate swap agreement was in a net unfavourable position of $75,287 (2006 - $102,011 unrecorded net unfavourable position), which has been classified as held-for-trading under the new financial instrument standards. This unfavourable amount has been included in accounts payable and accrued liabilities. The current year impact of the change in fair value of the interest rate swap included in the Statement of Earnings is a reduction of interest expense by $26,724.

PENINSULA WEST UTILITIES LIMITED

Notes to Financial Statements

Year ended December 31, 2007

9. Change in non-cash operating working capital:

	2007	2006
Cash provided by (used in):		
Accounts receivable	$ 819,437	$ (1,455,002)
Unbilled revenue	(260,980)	(57,880)
Inventory	31,209	147,907
Prepaid expenses	58,818	(55,524)
Accounts payable and accrued liabilities	(603,709)	342,191
	44,775	(1,078,308)

Supplementary cash flow information:

	2007	2006
Cash paid during the year for interest	546,169	538,216
Cash paid during the year for payment in lieu of taxes	1,025,200	1,391,336
Cash received during the year from interest	185,191	82,894
Cash received during the year from payments in lieu of taxes	44,284	-

Included in accounts receivable are amounts due from related parties for the sale of capital assets in the amount of $199,670, and the sale of the long-term receivable from Enerconnect in the amount of $16,400.

10. Pension agreements:

The Company contributes to the Ontario Municipal Employees Retirement Fund ("OMERS") which is a multi-employer plan on behalf of thirty members of its staff. The plan is a defined benefit plan which specifies the amount of retirement benefit to be received by an employee based on the length of service and rate of pay.

Contributions by the Company were at a rate of 6.5% for employee earnings below the year's maximum pensionable earnings and 9.6% thereafter.

The amount contributed for 2007 is $128,540 (2006 - $108,271) and is included as an expenditure in the Statement of Earnings.

PENINSULA WEST UTILITIES LIMITED

Notes to Financial Statements

Year ended December 31, 2007

11. Contingent liabilities:

(a) The Town of Lincoln and the former Lincoln Hydro-Electric Commission conducted tests and have determined that there is excessive leachate in the soil at the Quarry Road property which was sold to Lincoln Hydro-Electric Commission by the Town in 1991 and subsequently transferred to Peninsula West Utilities Limited in 2000. The Town of Lincoln has agreed to pay for the clean-up and site restoration costs, currently estimated at $350,000.

(b) A class action lawsuit claiming $500 million in restitutionary payments plus interest was served on Toronto Hydro on November 18, 1998. The action was initiated against Toronto Hydro Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities in Ontario. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which has been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.

In 2007, Enbridge filed an application to the Ontario Energy Board to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008, the OEB approved the recovery of the said amounts from ratepayers over a five year period.

(c) The Company has issued an $1,405,280 irrevocable letter of credit in favour of the Independent Electricity Market Operator ("IMO") as security for the Company's purchase of electricity through the IMO. At year-end, no amounts were drawn on this letter of credit.

12. Subsequent events:

The Ontario Energy Board has approved the merger of Peninsula West Utilities Limited and Niagara Falls Hydro Inc. This merger is in effect as of January 1, 2008 to form Niagara Peninsula Energy Inc ("NEPI").

All assets and liabilities of Peninsula West Utilities Limited will be transferred to Niagara Peninsula Energy Inc, effective January 1, 2008 and Peninsula West Utilities Limited will cease to exist at that date. Operations will continue as Niagara Peninsula Energy Inc. The first year end of NEPI will end on December 31, 2008.

PENINSULA WEST UTILITIES LIMITED

Notes to Financial Statements

Year ended December 31, 2007

13. General liability insurance:

The Company is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE") which is a pooling of general liability insurance risks. Members of MEARIE would be assessed on a pro-rata basis should losses be experienced by MEARIE, for the years in which the Compilation was a member.

To December 31, 2007, the Company has not been made aware of any additional assessments.

Participation in MEARIE expires January 1, 2009. Notice to withdraw from MEARIE must be given six months prior to the commencement of the next underwriting term.

14. Transactions with related parties:

Related parties are the Company's parent Peninsula West Power Inc. and a subsidiary of the parent, Peninsula West Services Ltd.

The Company paid a management fee of $41,004 (2006 - $45,747) to its parent. The Company paid transformer charges to NWTC in the amount of $217,967 (2006 - $186,607). The Company received management fees of $28,732 (2006 - $26,753). These transactions are in the normal course of operations and are measured at the exchange amount.

Included in accounts receivable are $244,802 (2006 - $40,924) owing from related parties. Included in accounts payable are $nil (2006 - $48,679) owing to related parties and included in unbilled revenue is $28,998 (2006 - $nil). These balances are non-interest bearing with no fixed terms of repayment.

In the current year, the Company paid a cash dividend to its' parent in the amount of $1,400,000. The Company also paid a dividend in-kind to transfer the 120 non-voting Class A Special shares in Niagara West Transformation Corporation in the amount of $1,200,000.

The Company has sold capital assets to its' parent in the amount of $199,670, which is equal to the net book value of the capital assets. The Company also sold its' long-term receivable from Enerconnect for the amount of $16,400.

15. Financial instruments:

The carrying values of cash, accounts receivable, unbilled revenue, accounts payable and accrued liabilities approximate fair values because of the short maturity of these instruments.

Financial assets held by the Company, such as accounts receivable and unbilled revenue, expose it to credit risk. The Company earns its revenue from a broad base of customers located in the Towns of Lincoln and Pelham and Township of West Lincoln. No single customer would account for revenue in excess of 3% of the respective reported balances.

The carrying value of the term loan approximates fair value as the loan bears interest at current rates.

16. Dividend:

The Corporation paid a dividend of $1,400,000 to its parent company; Peninsula West Power Inc. ("the parent") during the year. The payment of this dividend is the subject of an arbitration proceeding regarding the legality of the payment. As a result, the dividend may have to be repaid to the Corporation by its parent company. This repayment will be recorded in the period in which the decision is rendered.

Appendix C – Audited Financial Statements NPEI 2008 and 2009

NIAGARA PENINSULA ENERGY INC.

Financial Statements

December 31, 2009

Crawford, Smith and Swallow
Chartered Accountants LLP

4741 Queen Street
Niagara Falls, Ontario
L2E 2M2
Telephone (905) 356-4200
Telecopier (905) 356-3410

Offices in:
Niagara Falls, Ontario
St. Catharines, Ontario
Fort Erie, Ontario
Niagara-on-the-Lake, Ontario
Port Colborne, Ontario

crawford smith & swallow

AUDITORS' REPORT

To the Board Members and Shareholders of Niagara Peninsula Energy Inc.

We have audited the balance sheet of Niagara Peninsula Energy Inc. as at December 31, 2009 and the statements of operations, retained earnings, contributed surplus and cash flows for the year then ended. These financial statements are the responsibility of the company'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 company 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.

Crawford, Smith and Swallow

Niagara Falls, Ontario
March 22, 2010

CRAWFORD, SMITH AND SWALLOW
CHARTERED ACCOUNTANTS LLP

LICENSED PUBLIC ACCOUNTANTS

NIAGARA PENINSULA ENERGY INC.

BALANCE SHEET
December 31, 2009

	2009 $	2008 $
Assets - note 4		
Current assets:		
Cash	9,585,855	12,569,585
Restricted cash	176,934	175,794
Accounts receivable	9,556,798	9,592,036
Unbilled revenue	14,329,399	12,740,521
Due from affiliated companies - note 2	30,068	43,647
Payments in lieu of corporate income taxes refundable	0	313,711
Inventory	1,281,510	1,550,367
Prepaid expenses	534,605	423,994
	35,495,169	37,409,655
Fixed assets - note 3	114,309,200	110,570,101
Future payment in lieu of taxes	2,331,369	1,295,826
	152,135,738	**149,275,582**
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	14,930,359	16,027,939
Due to affiliated companies - note 2	6,604,304	6,931,923
Payments in lieu of corporate income taxes payable	420,248	0
Current portion of customer deposits	920,998	871,903
Current portion of capital lease	0	47,177
Current portion of long-term liabilities - note 4	1,576,810	10,286,548
	24,452,719	34,165,490
Long-term liabilities:		
Long-term debt - note 4	37,468,835	29,842,316
Customer deposits	1,135,265	1,085,030
Employees' accumulated vested sick leave	198,757	185,679
Employee future benefits - note 11	3,612,877	3,571,160
Regulatory liabilities - note 10	7,629,013	4,960,259
	50,044,747	39,644,444
Shareholders' Equity		
Share capital - note 5	31,245,882	31,245,882
Contributed surplus	25,459,207	25,459,207
Retained earnings	20,933,183	18,760,559
	77,638,272	75,465,648
Contingent Liabilities - note 8		
	152,135,738	**149,275,582**

Signed on behalf of the Board:

____________________ Director   ____________________ Director

See accompanying notes

NIAGARA PENINSULA ENERGY INC.

STATEMENT OF RETAINED EARNINGS
for the year ended December 31, 2009

	2009 $	2008 $
Retained Earnings, Beginning of Year	18,760,559	16,667,618
Net Income for the Year	2,672,624	2,592,941
Dividends on Common Shares	(500,000)	(500,000)
Retained Earnings, End of Year	**20,933,183**	**18,760,559**

STATEMENT OF CONTRIBUTED SURPLUS
for the year ended December 31, 2009

	2009 $	2008 $
Contributed Surplus, Beginning of Year	25,459,207	6,705,305
Excess of Fair Value of Common Shares issued over Stated Capital	0	18,753,902
Contributed Surplus, End of Year	**25,459,207**	**25,459,207**

See accompanying notes

NIAGARA PENINSULA ENERGY INC.

STATEMENT OF OPERATIONS

for the year ended December 31, 2009

	2009	2008
	$	$
Service Revenue		
Standard supply charge	75,334,062	74,560,425
Wholesale, network and connection charges	20,350,350	20,971,923
Service charge	11,294,933	11,307,189
Distribution volumetric charge	14,222,434	14,226,692
Standard supply service administration charge	114,808	136,567
Retailer revenue	82,120	86,368
Other income	0	(25,272)
	121,398,707	121,263,892
Cost of Power		
Power Purchased	95,684,412	95,532,348
Gross Profit	25,714,295	25,731,544
Other Revenue	2,300,074	1,960,024
	28,014,369	27,691,568
Expenses		
Operation and maintenance		
Distribution	5,485,777	5,397,897
Utilization	121,308	158,862
Administration and general	6,684,443	6,391,380
Billing and collecting	3,822,567	3,944,953
Depreciation	6,642,439	6,571,651
Depreciation expense on fair market value adjustment of fixed assets	1,111,638	1,161,103
	23,868,172	23,625,846
Net Income before Payments in Lieu of Income Taxes	4,146,197	4,065,722
Payments in Lieu of Income Taxes		
Current	2,509,116	2,090,933
Future reduction	(1,035,543)	(618,152)
	1,473,573	1,472,781
Net Income for the Year	2,672,624	2,592,941

See accompanying notes

NIAGARA PENINSULA ENERGY INC.

STATEMENT OF CASH FLOWS

for the year ended December 31, 2009

	2009 $	2008 $
Cash Provided (Used) By:		
Operations		
Net Income for the year	2,672,624	2,592,941
Items not involving cash		
Depreciation	6,642,439	6,571,651
Depreciation expense on fair market value adjustment of fixed assets	1,111,638	1,161,103
Change in fair value of interest rate swap	0	116,361
Future payment in lieu of taxes	(1,035,543)	(618,152)
Employee future benefits	41,717	46,637
	9,432,875	9,870,541
Changes in non-cash working capital components - note 6(a)	(2,073,055)	2,628,341
	7,359,820	12,498,882
Investments		
Acquisition of Peninsula West Utilities Ltd cash	0	2,079,330
Additions to fixed assets	(11,493,176)	(12,861,125)
Regulatory costs - note 10	2,668,754	490,569
	(8,824,422)	(10,291,226)
Financing		
Long-term deposits increase/(decrease)	99,330	(21,623)
Long-term bank loan payments	(1,083,219)	(737,618)
Repayment of capital lease	(47,177)	(18,352)
Employees' accumulated vested sick leave	13,078	20,057
Cash dividends on common shares	(500,000)	(500,000)
	(1,517,988)	(1,257,536)
Increase/(Decrease) in Cash Position	(2,982,590)	950,120
Cash Position, Beginning of Year	12,745,379	11,795,259
Cash Position, End of Year	9,762,789	12,745,379
Cash Position		
Cash	9,585,855	12,569,585
Restricted cash	176,934	175,794
	9,762,789	12,745,379

See accompanying notes

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

Incorporation

The Company was incorporated under the Business Corporations Act (Ontario) on April 1, 2000 pursuant to the provisions of the Energy Competition Act, 1998.

1. Significant accounting policies

These financial statements of Niagara Peninsula Energy Inc. have been prepared in accordance with Canadian generally accepted accounting principles, including accounting principles prescribed in the accounting procedures handbook for electric distribution utilities by the Ontario Energy Board.

Regulation

The Ontario Energy Board Act (Ontario), 1998 ("OEBA") conferred on the Ontario Energy Board ("OEB") increased powers and responsibilities to regulate the electricity industry in Ontario. These powers and responsibilities include approving or fixing rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to electricity distributors which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate-setting purposes.

Rate Setting

The distribution rates of the Corporation are based on a revenue requirement that provides a regulated Maximum Allowable Return on Equity ("MARE") on the amount of shareholders' equity supporting the business of electricity distribution.

On April 12, 2006, the OEB approved distribution rates for the Corporation, effective May 1, 2006. Such distribution rates provided for a revised MARE of 9.0% on the amount of shareholders' equity supporting the business of electricity distribution as at December 31, 2004. In prior years, such MARE was 9.88%.

On April 12, 2007, the OEB approved distribution rates for the Corporation, effective May 1, 2007. Such distribution rates were effectively adjusted upwards by 1.90% representing the Gross Domestic Product Inflationary Price Index net of an industry productivity expectation of 1%; for a net increase of 0.90%.

On April 18, 2008, the OEB approved distribution rates for the Corporation, effective May 1, 2008. Such distribution rates were effectively adjusted upwards by 2.10% representing the Gross Domestic Product Inflationary Price Index net of an industry productivity expectation of 1%; for a net increase of 1.10%. Rate riders associated with the recovery of regulatory assets ceased on May 1, 2008. Any final balance in the regulatory recovery account will be disposed of in a future rate application proceeding.

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

1. Significant Accounting Policies - continued

Rate Setting - continued

On March 13, 2009, the OEB approved distribution rates for the Corporation, effective May 1, 2009. Such distribution rates were effectively adjusted upwards by 2.3% representing the Gross Domestic Product Inflationary Price Index net of an industry productivity expectation of 1%; for a net increase of 1.3%. Also, the OEB approved the standard smart meter rate adder of $1.00 per metered customer per month.

Regulatory Accounting

In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Corporation's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The Corporation's regulatory liabilities represent costs with respect to non-distribution market related charges and variances in recoveries that are expected to be settled in future periods. Specific regulatory assets and liabilities are disclosed in note 10.

NPEI submitted a rate application to the OEB in October 2009 for the disposition of the retail settlement variance account (RSVA) balances as at December 31, 2008. The RSVA account balances amount to a net regulatory liability of $7.8 million dollars. NPEI has requested that these balances be disposed of over a two year period.

Revenue recognition

Electricity distribution service charges are charges to customers for use of the Corporation's electricity distribution system. These charges are recorded when the related services are performed. Service revenue from the sale of electrical energy includes an accrual for power supplied but not billed to customers from the date the meters were last read to the year end.

Fixed assets and depreciation

Fixed assets are stated at acquisition cost. Much of the distribution system is constructed by the company and is capitalized based on actual costs. Depreciation is determined on a straight-line basis with reference to estimated useful lives of the assets in accordance with the Ontario Energy Board policy.

Asset	Amortization Period
Easements	25 - 40 years
Buildings	25 years
Electricity distribution infrastructure	25 years
Equipment	4 - 10 years

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

1. Significant Accounting Policies - continued

Inventory

Inventory is valued at the lower of moving average cost and replacement cost. Inventory is comprised mainly of construction and maintenance materials required for the electricity distribution infrastructure.

Ontario Municipal Employees Retirement System

The corporation makes contributions to the Ontario Municipal Employees Retirement System (OMERS), which is a multi-employer plan, on behalf of 118 members of its staff. The plan is a defined benefit plan which specifies the amount for the retirement benefit to be received by the employees based on the length of service and rates of pay. The Corporation records the required contributions as an expense in the period they accrue.

The amount contributed to OMERS for the year ending December 31, 2009 was $573,090 (2008 - $548,845) for current service.

Long-term deposits

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Customer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. Customer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risk, as determined by the Corporation. Customer deposits anticipated to be refunded by the Corporation within one year of the Corporation's year end have been shown as current liabilities on the balance sheet.

Employee's accumulated vested sick benefits

Under the sick leave plan unused vested sick leave can accumulate and employees of the company as at April 1, 1987 can request at any time and will receive payment if funds are available as determined by the company. Full provisions for the liability, to the extent that cash payments to employees might be required, have been made in these financial statements.
Employees of the Corporation hired after March 31, 1987 can accumulate unused sick leave but it does not become vested at any time.

Employee future benefits

The company pays certain medical, dental and life insurance benefits on behalf of its retired employees. The Corporation recognizes these post-retirement costs in the period in which the employees rendered the services. In 2008, the Corporation engaged an independent company to perform an actuarial valuation of the post-retirement non-pension benefits and determine the accounting results for those benefits for the fiscal period ending December 31, 2009. The actuarial valuation included the former Pen West employees and their past service for benefit eligibility purposes and thus for valuation purposes this results in a past service liability. For additional details related to post-retirement non-pension benefits see note 11.

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

1. Significant Accounting Policies - continued

Actuarial gains/(losses)
Actuarial gains/(losses) are amortized over the expected average remaining service life of the active employees.

Past service costs
Past service costs are amortized over the expected average remaining service life of active empoyees.

Payments in lieu of income taxes and capital taxes ("PILS")
The Company is currently exempt from taxes under the Income Tax Act (Canada) ("ITA") and the Ontario Corporations Tax Act ("OCTA"). Pursuant to the Electricity Act, 1998 (Ontario) ("EA"), the Company is required to compute taxes under the ITA and OCTA and remit such amounts there under computed to the Ministry of Finance (Ontario).

The company provides for PILS using the asset and liability method. Under this method, future PILS assets and liabilities are recognized, to the extent such are determined likely to be realized, for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future PILS assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future PILS assets and liabilities of a change in tax rates is recognized in income in the period that includes the date of enactment or substantive enactment. When unrecorded future PILS become payable, it is expected that they will be included in the rates approved by the Ontario Energy Board ("OEB") and recovered from the customers of the Company at that time.

PILS recoverable from loss carry forwards are recorded in future payments in lieu of taxes on the balance sheet at the current enacted statutory tax rates expected to apply when recovery of the loss carry forwards are expected to be recovered.

Financial instruments
The CICA Handbook section 3855, provides accounting guidelines for the recognition and measurement of financial assets and financial liabilities and related disclosures.

Under these standards, all financial assets are classified as held-for-trading, held-to-maturity, loans and receivables or available-for-sale and all financial liabilities must be classified as held-for-trading or other financial liabilities.

All financial instruments are carried on the balance sheet at fair value except for loans and receivables, held-to-maturity investments and other liabilities, which are measured at amortized cost.

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

1. Significant Accounting Policies - continued

Financial instruments - continued

The Corporation has classified its financial instruments as follows:

Cash and restricted cash	Held-for-trading
Accounts receivable	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Customer deposits	Other liabilities
Long-term liabilities	Other liabilities

Measurement uncertainty

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures related thereto. Due to the inherent uncertainty in making estimates, actual results could differ from these estimates recorded in preparing these financial statements including changes as a result of future regulatory decisions.

Accounts receivable, unbilled revenue and regulatory assets/liabilities are stated after evaluation of amounts expected to be collected and an appropriate allowance for doubtful accounts. Inventory is recorded net of provisions for obsolescence. Amounts recorded for depreciation and amortization of equipment are based on estimates of useful service life.

2. Due from (to) Affiliated Companies

	2009 $	2008 $
Niagara Falls Hydro Holding Corporation	28,468	23,190
Niagara Falls Hydro Services Inc.	(6,584,368)	(6,912,217)
Peninsula West Services Ltd.	(19,936)	(19,706)
Peninsula West Power Inc.	1,600	20,457
	(6,574,236)	**(6,888,276)**

Advances to and from affiliated companies are non-interest bearing and payable on demand.

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

3. Fixed Assets

	Cost $	Accumulated Depreciation $	2009 $	2008 $
Land and land rights	3,006,307	651,916	2,354,391	2,141,027
Buildings	12,623,074	2,029,356	10,593,718	8,339,548
Distribution stations	5,050,002	3,061,328	1,988,674	1,922,848
Transmission station	6,548,452	757,613	5,790,839	5,935,817
Distribution lines				
-overhead	63,532,340	29,652,786	33,879,554	32,160,051
-underground	67,869,087	30,993,499	36,875,588	37,570,567
Distribution transformers	32,216,711	16,190,889	16,025,822	16,040,281
Distribution meters	7,363,514	3,991,356	3,372,158	3,566,945
Trucks and equipment	13,326,095	9,897,639	3,428,456	2,893,017
	211,535,582	**97,226,382**	**114,309,200**	**110,570,101**

4. Long-Term Debt

	2009 $	2008 $
Long-term note payable to the City of Niagara Falls pursuant to the transfer by-law - 7 1/4 % interest payable. 20 year note due April 2020. There is no immediate intent to redeem the long-term note	22,000,000	22,000,000
Long-term note payable to the Niagara Falls Hydro Holding Corporation, pursuant to the transfer by-law - 7 1/4 % interest payable, 20 year note due April 2020 There is no immediate intent to redeem the long-term note.	3,605,090	3,605,090
Long-term bank loan payable to Scotia Bank for the construction of the transmission station. Loan amortization period is for ten years commencing June 1, 2004 at a fixed interest rate of 6.44%.	4,237,226	5,023,774

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

4. Long-Term Debt - continued

	2009 $	2008 $
Term loan payable to TD Bank at a fixed rate of 4.58%, due July 2019.	8,703,329	9,500,000
Revolving term loan payable to Scotia Bank for the installation of smart meters. Maximum loan amount is $10,000,000 at prime plus 0.35% for one year commencing September 2009. In September 2010, the revolving term loan will be repaid and converted to a non-revolving term loan. This loan will be for 5 years due September 2015. On November 19, 2009, the corporation secured a $4,500,000 non-revolving term loan to commence in September 2010 at a fixed rate of 4.97%.	500,000	0
	39,045,645	40,128,864
Current portion due within one year	(1,576,810)	(10,286,548)
	37,468,835	**29,842,316**

The principal payments of long-term debt are due as follows:

	$
2010	1,576,810
2011	1,666,973
2012	1,761,519
2013	1,863,484
2014	1,419,628

During the year, the Corporation incurred $2,414,975 (2008 - $2,802,473) of interest on long-term debt.

The Corporation's objectives when managing capital are to safeguard the Company's ability to continue as a going concern so that it can continue to provide returns for shareholders and benefits for other stakeholders. The Corporation provides an adequate return to shareholders by applying to the OEB for electricity distribution rates commensurately with the level of risk. On December 20, 2006, the OEB issued its final report on the cost of capital, this report outlines the OEB's policies and rationale for setting the debt to equity split for the purposes of rate-making. Currently, the Corporation is deemed to have a 50:50 debt to equity split, however over the next several years, the Corporation will migrate to the OEB's 60:40 deemed debt:equity split for rate making purposes. The Corporation manages the capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying assets as well as maintaining compliance with the OEB regulations.

4. Long-Term Debt - continued

The Corporation is indebted to two Canadian banks; Scotia Bank and the Toronto-Dominion Bank. Below outlines the debt covenants held by each bank:

Scotia Bank
The bank loans payable to Scotia Bank have the following general security; General Security Agreement ranking 1st over the Bank's share of the Borrower's present and future personal property as defined under the Inter-Creditor Agreement, with appropriate insurance coverage, loss if any, payable to the Bank. The Inter-Creditor Agreement is between Scotia Bank and The Toronto-Dominion Bank.

The conditions related to the Scotia Bank debt are as follows: The ratio of Total Debt (including contingent liabilities) to Capitalization is not to exceed 0.70:1. Capitalization is defined as total debt and total equity plus contingent liabilities. The ratio of EBITDA to interest expense plus the current portion of long-term debt and capital leases, calculated on a rolling 12 month basis, is to be maintained at all times at 1.50:1 or better. EBITDA is defined as net income before extraordinary and other non-recurring items plus interest, income tax, depreciation and amortization expenses during the period.

The Corporation's Total Debt to Capitalization ratio was 0.53:1 at December 31, 2009.
The Corporation's ratio of EBITDA to interest expense plus the current portion of long-term debt and capital leases is 3.79:1. Both covenants were met in 2009.

Toronto-Dominion bank
The conditions related to the Toronto-Dominion Bank debt are as follows: firstly, the loan is secured by a general security agreement pursuant to the Inter-creditor agreement between TD bank and Scotiabank and secondly to maintain a minimum debt service coverage ratio of 1.25:1. Debt service coverage is defined as: EBITDA divided by the sum of the total cash interest expense plus mandatory principal payments. The Corporation must also maintain a maximum debt to capitalization ratio of 0.60:1. Debt is defined as all third party interest bearing debt and non-interest debt, including guarantees, not subordinated to these credit facilities. Capitalization is defined as the sum of total debt, guarantees, shareholders' equity, contributed capital, and preference share capital net of any goodwill and other intangible assets such as deferred transition costs.

EBITDA is defined as earnings before interest, income taxes, depreciation, and amortization.

Both debt covenants are to be calculated on a combined basis with the borrower and its pro rata share of Niagara West Transformation Corporation. The Corporation guarantees 50% of the total debt held between Niagara West Transformation Corporation and The Toronto-Dominion Bank. The term of the guarantee expires in 2012.
The Corporation's Debt service coverage actual for 2009 was 2.08:1.
The Corporation's debt to capitalization ratio was 0.36:1 for 2009.
The Corporation met both bank covenants for the Toronto-Dominion Bank debt.

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

5. Share Capital

Authorized
Unlimited number of common shares

	2009	2008
	$	$
Issued		
1,000 common shares	**31,245,882**	**31,245,882**

6. Statement of Cash Flows

(a) Changes in non-cash working capital components include:

	2009	2008
	$	$
Accounts receivable - billed	35,238	(415,131)
Unbilled revenue	(1,588,878)	226,858
Inventory	268,857	185,031
Prepaid expenses	(110,611)	77,938
Payments in lieu of corporate income taxes	733,959	(1,576,181)
Accounts payable	(1,097,580)	(527,871)
Due to affiliated companies	(314,040)	4,657,697
	(2,073,055)	**2,628,341**

(b) Interest received and paid and payments in lieu of income taxes paid

	2009	2008
	$	$
Interest received	279,756	466,655
Interest paid	3,019,825	2,752,846
Payments in lieu of income taxes paid	1,775,157	3,667,114

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

7. Related Party Transactions

Related parties are the Company's parent Niagara Falls Hydro Holding Corporation and a subsidiary of the parent, Niagara Falls Hydro Services Inc. Peninsula West Power Inc. and Peninsula West Services Limited are also related parties to the Company.
The City of Niagara Falls is the sole shareholder of Niagara Falls Hydro Holding Corporation.
The Township of Lincoln, the Township of West Lincoln and the Town of Pelham are all shareholders of Peninsula West Power Inc. and Peninsula West Power Inc. is a fifty percent shareholder in Niagara West Transformer Corporation. In the ordinary course of business, the company enters into transactions with related parties including the City of Niagara Falls, the Township of Lincoln, the Township of West Lincoln and the Town of Pelham and its boards and agencies. The company derives revenues from the sale of electricity and recovers costs of supplying electrical equipment and distribution system from these related parties. Revenue and expenses from related parties include service revenue, municipal taxes and development charges and these transactions take place at the exchange amount. Account balances resulting from these transactions, which are included in the balance sheet, are settled in accordance with normal trade terms.

8. Contingent Liabilities

Letter of Credit

The company has arranged for a standby letter of credit of $ 10,000,000 of which $9,609,365 ($9,609,365 - 2008) has been drawn down. The Independent Electricity Market Operator is the beneficiary for $9,348,865. This is to provide a prudential letter of credit in support of the purchase of electrical power. An additional $260,500 was drawn down in favour of the Township of West Lincoln, this is in support of the development fees required for the construction of the new service centre located in the Township of West Lincoln.

Class Action Claim

Consumers' Gas Decision
On April 22, 2004, the Supreme Court of Canada ruled that The Consumers' Gas Company (currently Enbridge Gas Distribution Inc.) was required to repay a portion of certain late charges it collected from its customers that were in excess of the interest stipulated in section 347 of the Criminal code. The former Toronto Hydro-Electric Commission is not a party to the Consumers' Gas class action, however this action is relevant to the class action described below as the parties to the former Toronto Hydro-Electric Commission class action were awaiting the outcome of the Consumers' Gas Decision.

At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge. In 2007, Enbridge filed an application to the Ontario Energy Board to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008, the OEB approved the recovery of the said amounts from ratepayers over a five year period.

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

8. Contingent Liabilities - continued

A class action claiming $ 500 million in restitution payments plus interest was served on the former Toronto Hydro-Electric Commission on November 18, 1998. The action was initiated against the former Toronto Hydro-Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities in Ontario which have charged late payment charges on overdue utility bills at any time after April 1, 1981.

The claim is based on the premise that late payment penalties result in the municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under section 347(1)(b) of the Criminal Code.

The Electricity Distributors Association is undertaking the defense of this class action. At this time, it is not possible to quantify the effect, if any, on the financial statements of the Corporation.

Guarantee

The Corporation guarantees 50% of the debt of Niagara West Transformation Corporation. The Corporation's 50% guarantee amounts to $ 3,250,000.

9. General Liability Insurance

The company is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) which is a pooling of general liability insurance risks. Members of MEARIE would be assessed, on a pro-rata basis, based on the total of their respective deposit premiums should losses be experienced by MEARIE, in excess of reserves and supplementary insurance, for the years in which the Corporation was a member.
To December 31, 2009, the company has not been made aware of any additional assessments.

Participation in MEARIE covers a three year underwriting period which expires January 1, 2012. Notice to withdraw from MEARIE must be given six months prior to the commencement of the next three year underwriting term.

10. Regulatory Assets/Liabilities

The Ontario Energy Board (the "OEB") has, in accordance with the Electricity Distribution Handbook, approved recovery of regulatory assets of $0 (2008 - $ 1,566,541).
These amounts are for the recovery of approved regulatory assets recorded in fiscal years prior to January 1, 2004.

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

10. Regulatory Assets/Liabilities - continued

In accordance with the OEB's criteria, the company recorded net carrying charges on the recovered amounts of ($ 199,194), (2008 - ($ 211,487)). Under this regulation a net carrying charge expense of $ 199,194 in 2009, (net carrying charge expense of $ 211,487 - 2008) was recorded. In the absence of rate regulations, Canadian generally accepted accounting principles would require the company to reverse the carrying charges related to the regulatory assets.

Net regulatory assets/liabilities represent variance between costs incurred by the Corporation and amounts billed to the customer at OEB approved rates less recoveries. These amounts have been accumulated pursuant to the Electricity Act and deferred in anticipation of their future disposition in electricity distribution rates. Management assesses the future uncertainty with respect to the final regulatory disposition of those amounts, and the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decision adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Settlement variances - represent amounts that have accumulated since Market Opening and comprise:

(a) variances between amounts charged by the Independent Electricity System Operator ("IESO") for the operation of the wholesale electricity market and grid, various wholesale market settlement charges and transmission charges, and the amounts billed to customers by the Corporation based on the OEB approved wholesale market service rates; and
(b) variances between the amounts charged by the IESO for energy community costs and the amounts billed to customers by the Corporation based on OEB approved rates.

Smart meters - the Province of Ontario has committed to have "Smart Meter" electricity meters installed throughout Ontario by the end of 2010. Smart meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals. Bill 21, Energy Conservation and Responsibility Act, provides the legislation framework and regulations to support this initiative.

Included in distribution rates, effective May 1, 2009, is a charge for smart meters of $1.00 for Niagara Falls area customers and $1.00 for Peninsula West area customers per metered customers per month. Consistent with the OEB's direction and pending further guidance, all smart meters related expenditures and recoveries are currently being deferred in regulatory accounts.

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

10. Regulatory Assets/Liabilities - continued

Regulatory assets recovery amount - represent costs incurred by the Corporation which have been approved for recovery through rates in excess of amounts recovered from customers. Any balance remaining will be disposed of in future rate proceedings.

In the absence of rate regulation, Canadian generally accepted accounting principles would require the Corporation to record the costs and recoveries described above in the operating results of the year in which they are incurred and reported earnings before income taxes would be $4,117,709 higher (2008 - $4,527,781) than in the absence of regulation. Also, in the absence of rate regulation, the smart meters would be capitalized to fixed assets. As a result, the fixed assets would be $1,448,955 higher than in the absence of regulation.

As at December 31, 2009, the company has accumulated ($ 7,629,013) ($ 4,960,259 - 2008) in regulatory liabilities on the balance sheet as other liabilities.

	2009 $	2008 $
Deferred payments in lieu of income taxes	(774,473)	(740,945)
Retail settlement variances	(8,654,227)	(4,522,170)
Retail cost variances	807,095	710,678
Other regulatory assets	4,448	0
Smart meter recovery variances	1,100,588	(299,221)
Regulatory asset recovery amount	(112,444)	(108,601)
	(7,629,013)	**(4,960,259)**

11. Employee Future Benefits

Defined Benefit Plan Information

	2009 $	2008 $
Employee benefit plan assets	0	0
Employee benefit plan liabilities	2,781,134	2,683,024
Employee benefit plan deficit	2,781,134	2,683,024
Unamortized actuarial gain	1,032,243	1,108,686
Unamortized Past Service Cost	(200,500)	(220,550)
Accrued benefit obligation, end of year	**3,612,877**	**3,571,160**

	2009 $	2008 $
Accrued benefit obligation, beginning of year	3,571,160	3,524,523
Benefit (Income)/Expense for the year	180,563	169,670
Contributions/Benefit payments by the Employer	(138,846)	(123,033)
Accrued benefit obligation, end of year	**3,612,877**	**3,571,160**

An actuarial valuation was performed effective January 1, 2008, the valuation included the former Peninsula West employees. The next actuarial valuation for funding purposes will be January 1, 2011.

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

---

11. Employee Future Benefits - continued

The main actuarial assumptions employed for the valuation are as follows:

GENERAL INFLATION - Future general inflation levels, as measured by changes in the Consumer Price Index (CPI), were assumed at 2.3% in 2008 and thereafter.

INTEREST (DISCOUNT) RATE - The obligation as at December 31, 2009, the present value of future liabilities and the expense for the year ended December 31, 2009, were determined using a discount rate of 5.0%. The rate reflects the assumed long-term yeild on high quality bonds.

SALARY LEVELS - Future general salary and wage levels were assumed to increase at 3.8% per annum.

MEDICAL COSTS - Medical costs were assumed to increase at the CPI rate plus a further increase of 6.7% in 2009 graded down to 5.7% in 2010, 4.7% in 2011 3.7% in 2012 and 2.7% in 2013 and thereafter.

DENTAL COSTS - Dental costs were assumed to increase at the CPI rate plus a further increase of 2.7% in 2009 and thereafter.

12. Financial Instruments

Fair Value of Financial Instruments

The fair value of cash, receivables, accounts payable and accrued liabilities corresponds to their carrying value due to their short-term maturity.

It is not practicable within the constraints of timeliness or cost to determine the fair value of Long-term debt and due from/(to) affiliated companies with sufficient reliability.

Credit Risk

The company, in the normal course of business, monitors the financial condition of its customers and reviews the credit history of new customers. The company is currently holding customer deposits on hand in the amount of $2,056,263 of which $1,135,265 is long-term and $ 920,998 is current (2008 - $1,956,933, long-term $1,085,030 and $871,903 current) which are reflected on the balance sheet. Allowances are also maintained for potential credit losses. Management believes that it has adequately provided for any exposure to normal customer credit risk.

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2009

12. Financial Instruments - continued

Cash flow risk
The Corporation has a revolving smart meter loan with Scotia Bank that bears interest at Scotiabank prime plus 0.35%. Accordingly, the Corporation is exposed to the effects of interest rate fluctuations.

Operating Line of Credit

As at December 31, 2009, the company had a line of credit of $ 4,000,000 (2008 - $ 4,000,000) of which NIL has been drawn down. The line of credit is a revolving operating line that bears interest at the prime rate plus 0.25%. The line of credit is secured by the same security described in note 4.

13. Smart Meter Purchase Commitment

As at December 31, 2009, the Corporation has committed to the purchase of $2,083,622 of smart meters to be installed throughout Niagara Peninsula Energy service territory.

Table of Contents

EXHIBIT 2 – RATE BASE

Manager's Summary – Fixed Assets and Rate Base

Rate Base Overview

The rate base used for the purpose of calculating the revenue requirement used in this Application follows the definition used in the 2006 EDR Handbook as an average of the balances at the beginning and the end of the 2011 Test Year, plus a working capital allowance, which is 15% of the sum of the cost of power and controllable expenses.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The NPEI rate base calculation excludes any non-distribution assets, with the exception of the Kalar Transformer Station, which Niagara Falls Hydro put into service in 2004. The Kalar TS assets were approved by the Board in Niagara Falls Hydro's 2006 EDR Application (EB-2005-0394) to be deemed distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

NPEI has provided its rate base calculations for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Bridge Year and 2011 Test Year in Table 2-1 below. NPEI has calculated its 2011 rate base as $119,144,943.

Table 2-1 Summary of Rate Base

Description	2006 OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Gross Fixed Assets	137,223,877	157,629,412	167,151,025	178,834,502	189,633,833	200,448,806	209,551,599
Accumulated Depreciation	61,873,995	77,119,914	83,320,645	88,712,000	94,663,241	99,459,705	106,603,393
Net Book Value	75,349,882	80,509,498	83,830,379	90,122,501	94,970,591	100,989,102	102,948,206
Average Net Book Value	75,349,882	79,697,709	82,169,939	86,976,440	92,546,546	97,979,846	101,968,654
Working Capital	94,476,164	96,568,962	101,102,311	99,919,226	104,598,525	110,160,769	114,508,597
Working Capital Allowance	14,171,425	14,485,344	15,165,347	14,987,884	15,689,779	16,524,115	17,176,290
Rate Base	89,521,305	94,183,053	97,335,286	101,964,324	108,236,325	114,503,962	119,144,943

NPEI has provided a summary of its calculations of the cost of power and controllable expenses used in the calculations for determining working capital for the years 2006

Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Bridge Year and 2011 Test Year in Table 2-2, below. Details of NPEI's calculation of its working capital allowance are provided at Table 2-24.

Table 2-2 Summary of Working Capital Calculation

Description	2006 OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Cost of Power	81,948,027	84,040,651	87,873,081	87,102,560	91,563,338	96,311,017	99,990,688
Operations	2,811,476	3,603,532	3,718,160	3,198,913	3,152,389	3,392,217	3,573,690
Maintenance	2,509,155	1,952,232	2,231,951	2,320,969	2,390,126	2,542,929	2,568,416
Billing & Collecting	2,734,341	3,232,894	3,371,741	3,771,715	3,630,381	3,884,221	4,195,729
Community Relations	90,365	72,955	83,295	36,877	64,569	79,548	81,464
Administration & General Expense	4,177,410	3,471,836	3,622,877	3,256,921	3,582,468	3,718,838	3,876,135
Property Taxes	205,390	194,863	201,207	231,271	215,254	232,000	222,474
Working Capital	94,476,164	96,568,962	101,102,311	99,919,226	104,598,525	110,160,769	114,508,597

NPEI has not completed a lead-lag study pending OEB direction. The working capital allowance is based on 15% of cost of power and controllable expenses, in accordance with the Filing Requirements, and consistent with OEB Decisions on other distribution rate applications where a utility specific lead-lag study had not been completed.

The NPEI Distribution System

NPEI owns and operates the electricity distribution system in its licensed service area in the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham, serving approximately 64,026 Residential, General Service, Street Light, Sentinel Light and Unmetered Scattered Load customers/connections.

NPEI's distribution assets include one (1) Transformer Station (TS) that steps voltage down from 115kV to 13.8kV for distribution in the City of Niagara Falls. NPEI constructed, owns, and has maintained this TS since 2004. This new TS was approved to be a deemed distribution asset in the 2006 EDR rate application. The TS was built over a two year period from 2003 to 2004 and as a result of using the average of the opening and closing balances, half of the 2004 addition costs were included in the rate base for the 2006 EDR rate application.

In addition, NPEI receives power from two (2) Hydro One 115/13.8kV TS's, one (1) Hydro One 115/27.6kV TS, one (1) Hydro One 115/27.6kV Distribution Station (DS), one (1) Hydro One 27.6/8.32kV DS, three (3) Hydro One 27.6kV feeders, and (1) 230kV/27.6kV TS owned by Niagara West Transformer Corporation.

NPEI also owns and operates ten (10) 13.8kV/4.16kV Municipal Stations (MS's), four (4) 27.6kV/8.32kV MS's, and two (2) 27.6kV/4.16kV MS's.

Electricity is then distributed through NPEI's service area of 827 square kilometres through over 482 kilometres of underground cable and 1059 kilometres of overhead conductor. Voltage is stepped down from the primary feeders through approximately 7513 LDC owned distribution transformers. NPEI monitors its distribution system through a supervisory control system at its main office. Hydro One operates the Supervisory Control and Data Acquisition ("SCADA") system twenty-four hours a day, seven days a week.

NPEI owns and maintains approximately 50,403 meters installed on its customers' premises for the purpose of measuring consumption of electricity for billing purposes. Meters vary in type by customer and include meters capable of measuring kWh consumption, kW and kVA demand as well as hourly interval data. NPEI will have installed all of its residential smart meters by the fall of 2010 as part of the Province of Ontario's smart meter initiative. On June 25, 2008, Ontario Regulation 235/08 was filed by the Ontario Provincial Government giving NPEI authorization to proceed with its first phase of Smart Meter installation.

In managing its distribution system assets, NPEI's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, public and worker safety and customer service requirements. This Application incorporates NPEI's 2011 Capital and Expense Budgets in determining the revenue requirement to bring these plans to fruition. NPEI considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, and system configuration, to determine investment needs of the system.

On an annual basis, NPEI reviews capital projects identified for potential implementation and attempts to prioritize each project based on defined criteria on a relative basis. All members of the management team follow the criteria as they individually complete their work on preparing outlines of their recommendations, which are then discussed by the full group. After examining all recommended projects they are listed in order from higher to lower priority and then moved forward based on appropriate financial parameters.

In addition to the capital needs of the network, NPEI provides for maintenance planning for the assets. The same preparation and consideration steps are undertaken before the Finance department establishes the recommended budget amounts.

NPEI's assets fall into two broad categories – distribution plant, which includes assets such as substation building, wires, overhead and underground electricity distribution infrastructure, transformers, meters and substations; and general plant which includes assets such as, office building and service centre, computer equipment and software.

Service Quality and Reliability Performance

NPEI tracks and files its Service Quality Indicators with the Board through its RRR reporting. The results are reviewed by Senior Management to ensure that NPEI is maintaining the high level of service that its customers expect. When deficiencies are identified, NPEI's Senior Management team investigates to correct any issues that may exist. The NPEI Service Quality Indicators have been targeted to maintain performance at levels equal to or above the OEB's standards in 2010 and 2011.

NPEI tracks service reliability statistics SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) including and excluding Hydro One related incidents (loss of supply).

NPEI is committed to the reliability of the distribution system and continues to make capital investments in infrastructure in order to maintain or improve its reliability statistics.

NPEI's Service Quality Indicators are presented in Table 2-3, and the Service Reliability Indices are shown in Table 2-4.

Table 2-3 Service Quality Indicators

Measure	SQI Standard	2007	2008	2009
Appointments Met - at the appointed time	90% of the time	100.0%	100.0%	100.0%
Appointments Scheduled - within 5 working days (new 2009)	90% of the time	n/a	n/a	100.0%
Rescheduling a missed appointment - contact before missed and rescheduling within 1 day (new 2009)	90% of the time	n/a	n/a	n/a
Telephone Accessibility - answered in person within 30 seconds.	65% of the time	99.0%	99.1%	61.0%
Telephone Call Abandon Rate - calls abandoned before they are answered (new 2009)	10% or less	n/a	n/a	3.6%
Underground Cable Locates - within 5 working days	90% of the time	92.1%	98.7%	98.9%
Connection of New Low Voltage Services - within 5 working days	90% of the time	91.3%	89.4%	87.9%
Connection of New High Voltage Services - within 10 working days	90% of the time	100.0%	100.0%	90.0%
Emergency Response - Urban within 90 minutes	80% of the time	100.0%	87.0%	100.0%
Emergency Response - Rural within 120 minutes	80% of the time	100.0%	-	92.9%
Written Responses to Inquiries - within 10 working days	80% of the time	100.0%	100.0%	99.8%

Table 2-4 Service Reliability Indices

	2009			2008		
	SAIDI	**SAIFI**	**CAIDI**	**SAIDI**	**SAIFI**	**CAIDI**
Niagara Falls Territory	1.37	0.82	1.68	1.42	0.97	1.46
Peninsula West Territory	5.41	1.75	3.09	1.99	1.04	1.92
NPEI Combined	2.67	1.12	2.39	1.60	0.99	1.61

Capitalization Policy

NPEI's Capitalization Policy is as follows:

The purpose of capitalizing expenditures is to provide an equitable allocation of costs among existing and future customers. As capital assets are expected to provide future economic benefits for more than one year, any expenditure incurred for the acquisition, construction, development or betterment of the capital assets should be capitalized. These capitalized costs are allocated over the estimated useful life of the assets by amortization. The Company adopts the full cost accounting in accordance with guidance in the Canadian Institute of Chartered Accountants (CICA) Handbook.

- Asset Cost

  Costs for capital assets installed or erected by the Company include:
  - Direct material.
  - Direct labour.
  - Direct vehicle costs.
  - Indirect costs including overheads for material and labour.
  - Sub-contracting cost, if any.

Definition of cost (extract from CICA Handbook paragraph 3061.05):

Cost is the amount of consideration given up to acquire, construct, develop, or better a capital asset and includes all costs directly attributable to the acquisition, construction, development or betterment of the capital asset including installing it at the location and in the condition necessary for its intended use.

A betterment is a cost which is incurred to enhance the service potential of a capital asset. Expenditures for betterments are capitalized. This enhancement in service potential can include an increase in the physical output or service capacity, decrease in associated operations costs, extension in the useful life of the asset, or improvement in the quality of the asset's output.

Definition of betterment (extract from CICA Handbook paragraph 3061.26):

Cost incurred to enhance the service potential of a capital asset. Service potential may be enhanced when there is an increase in the previously assessed physical output or service capacity, associated operating costs are lowered, the life or useful life is extended, or the quality of output is improved. The cost incurred in the maintenance of the service potential of a capital asset is a repair, not betterment. If a cost has the attributes of both a repair and a betterment, the portion considered to be a betterment is included in the cost of the asset.

- Asset Recognition

  Property, plant and equipment that meet the definition of a capital asset as provided in the CICA Handbook are capitalized. Expenditures that do not meet the definition are expensed in the current year.

Definition of assets (extract CICA Handbook paragraph 1000.29):

Assets are economic resources controlled by an entity as a result of past transactions or events from which future economic benefits may be obtained. Assets have three essential characteristics:

a) They embody a future benefit that involves a capacity, singularly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows, and in the case of not-for-profit organizations, to provide services;

b) The entity can control access to the benefit; and

c) The transaction or event giving rise to the entity's right to, or control of, the benefit has already incurred.

In addition, in identifying a benefit there must be:

a) An ability to earn income or supply a service over its useful life;
b) A reasonable expectation that the benefit will be provided in future periods; and
c) The future period must be identifiable and greater than one year.

- Capitalization Threshold

Theoretically, any expenditure that meets the asset cost and asset recognition criteria would be recorded as a capital asset. However, for practical reasons, qualifying costs would only be capitalized if it has a useful life of more than one year; and the item cost is greater than $1,000 for readily identifiable assets or greater than $1,000 for like pooled assets, for example a number office chairs purchased at once. This threshold may be changed at the discretion of the VP Finance. Land will always be capitalized, regardless of cost.

- Spare transformers and meters

Spare transformers and meters are accounted for as capital assets since they form an integral part of the reliability program for a distribution system. They are not intended for resale and cannot be classified as inventory in accordance with CICA Handbook Section 3030.

- Amortization

Amortization is provided on a straight-line basis for capital assets available for use over their estimated service lives, at the following annual rates:

Land Rights 4% (25 years)
Transformer station equipment 2.5% (40 years)
Distribution station equipment 4% (25 years)
Distribution system 4% (25 years)
Meters 4% (25 years)
Buildings 2% (50 years)
Leasehold improvements 33.3% (3 years)
Furniture & Equipment 10% (10 years)
Computer Hardware 20% (5 years)
Computer Software 100% (1 year)
System Supervisory equipment 7% (14 years)
Communication equipment 25% (4 years)
Transportation Equipment 12.5% (8 years)
Other equipment 10% - 20% (5 to 10 years)

Prior to 2010, full amortization was recorded in the year of acquisition; no amortization is recorded in the year of disposition. Beginning in 2010, half a year of amortization is recorded in the year of acquisition.

- Disposals and Write Downs

For readily identifiable assets retired or disposed of, the asset cost and related accumulated amortization are removed from the applicable capital accounts. Differences between the proceeds, if any, and the unamortized asset amount plus removal costs are recorded as a gain or loss in the year of disposal.

For grouped assets, the assets and accumulated amortization are removed from the records at the end of their estimated average service life, regardless of actual service life.

- Betterment vs. Repair and Maintenance

The following questions are considered to determine if costs incurred are for betterment of the capital asset or expensed as maintenance and repairs:

- Increase in the previously assessed physical output or service capacity? Yes or No.
- Lower the associated operating costs? Yes or No.
- Substantial improvement in the quality or efficiency of output? (>10%) Yes or No.
- Is the life of the asset extended? Yes or No.

Criteria

At least one question must be answered “Yes” to qualify for betterment.

NPEI’s Project Accounting System

NPEI uses a Project Accounting system which is part of the Great Plains financial software. Projects are created and cost categories which correspond to the OEB main account numbers in the general ledger are assigned. Cost category types are labour, truck and equipment, material and outside purchases. Major projects are also assigned budget amounts by cost category type. Projects are also designated as billable or non-billable.

Capital Investment Drivers

Some of the general factors that influence NPEI's capital budget are listed below. More specific categories of capital cost drivers are provided later in this Exhibit.

- **Customer Demand:**

These are projects that NPEI undertakes to meet its customer service obligations in accordance with the OEB's Distribution System Code (the "DSC") and NPEI's Conditions of Service. Activities include connecting new customers and building new subdivisions. Capital contributions toward the cost of these projects are collected by NPEI in accordance with the DSC and the provisions of its Conditions of Service. NPEI uses the economic evaluation methodology from the DSC to determine the level of capital contribution for each project and those levels are injected into the annual capital budget.

- **Renewal:**

Renewal projects are completed when assets reach their end of useful life and must be replaced. NPEI completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available, and replaces assets based on these inspection and testing activities if warranted. In some cases the projects involve spot replacement of assets; in others, the projects involve complete asset replacement within a geographic area. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public.

- **Security:**

The probability and impact of asset failure are considered at peak load to determine the risk the failure creates. In these cases, projects are developed to add switching devices or create a backup feeder supply to reduce the risk to typical restoration times for NPEI.

- **Capacity:**

Load growth caused by new customer connections and increased demand of existing customers over time can result in a need for capacity improvements on the system. Projects can take the form of new or upgraded feeders, transformers or voltage conversion projects, substations or transformer stations. These projects are not customer-specific, but rather, they benefit many customers.

- **Reliability:**

The main driver for these investments is an analysis of what measures could be undertaken to improve NPEI's reliability performance as measured by SAIDI, SAIFI and CAIDI indices. These indices are indicators of the reliability of NPEI's distribution system. These activities will support maintenance of or improvement to the Service Quality Indices measured and submitted to the OEB each year by NPEI. The Asset Management Plan prepared for NPEI by Kinetrics, which will be provided as Appendix A to this Exhibit when available, supports the capital and maintenance programs needed to maintain and enhance the reliability of NPEI's distribution system.

- **Regulatory Requirements:**

These projects are system capital investments, which are being driven by regulatory requirements. These requirements may include, among others, directions from the OEB, the IESO, the Ministry of Energy or the Ministry of Environment and City of Niagara Falls, Town of Lincoln, Township of West Lincoln or Town of Pelham, relocating system plant for roadway reconstruction work. Where projects are municipally driven, NPEI follows the regulations pertaining to road reconstruction work collecting contributed capital for 50% of the labour and labour saving devices incurred.

- **Substations:**

Substation investments are undertaken to improve or maintain reliability to large numbers of customers and to maintain security and safety at the substations. The renewal or retirement of municipal substations is the subject of NPEI's annual asset review.

- **Customer Connections and Metering:**

Capital expenditures in this pool include meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities. NPEI has initiated a smart meter program, as approved by Ontario Regulation 235/08 (Authorized Discretionary Metering Activity & Procurement).

NPEI's capital projects for the 2011 Test Year are discussed in further detail. NPEI has provided project-specific justifications later in this Exhibit for the 2010 Bridge Year and 2011 Test Year. NPEI's 2011 base revenue requirement amounts to $30,235,583 and written explanations have been provided for rate base-related variances that exceed materiality of $150,000, as calculated in Table 2-5 (0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million, being the materiality threshold in the Filing Requirements).

Gross Assets – Property, Plant and Equipment and Accumulated Depreciation:

The 2010 Bridge and 2011 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. An analysis of the 2005 to 2011 capital programs is given below. The following comments provide an overview of NPEI's budgeting process.

Overall Budget Process

The budget is prepared annually by management and is reviewed and approved by the NPEI Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it does not change, but provides a plan against which actual results may be evaluated.

- **Responsibilities:**

  > It is the responsibility of the Finance department to coordinate the development of the operating budget, capital budget and forecast processes.

  > The VP Finance is responsible for presenting and recommending the budget to the Finance Committee and then to Board of Directors for approval.

  > It is the responsibility of the Board of Directors, on behalf of the shareholder, to approve the budget.

The budget is an important planning tool for NPEI. It puts capital and operational plans into a common financial plan. The final document provides a comprehensive package of department budgets that collectively ensure that appropriate resources are designated for the various capital and operational needs of the utility for the coming year.

The departmental Budget Plans represent the output of detailed work plans based on required activities for the year. NPEI notes that these Budget Plans address both capital and operating requirements.

Rate Base Variance Analysis

NPEI has calculated the materiality threshold on its rate base to be $150,000 for 2011 variance analysis purposes in accordance with the Filing Requirements. This calculation is summarized in Table 2-5 below:

Table 2-5 Materiality Threshold

Service Revenue Requirement (From Revenue Deficiency Calculation)	32,421,330	
Less: Revenue Offsets	(2,185,747)	
Base Revenue Requirement		30,235,583
Allocated to:		
Low Voltage Costs	360,512	
Other	29,875,071	
Total		30,235,583

Variance Calculation 0.5% of Distribution Revenue Requirement **151,178**

The following Table 2-6 sets out NPEI's rate base and working capital calculations for 2006 Board Approved and Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Bridge Year and 2011 Test Year, and the following variances:

- 2006 Actual against 2006 Board Approved;
- 2007 Actual against 2006 Actual;
- 2008 Actual against 2007 Actual;
- 2009 Actual against 2008 Actual;
- 2010 Bridge Year against 2009 Actual; and
- 2011 Test Year against 2010 Bridge Year.

Table 2-6 Rate Base Variances

Description	2006 OEB Approved	2006 Actual	Variance from 2006 OEB Approved		2007 Actual	Variance from 2006 Actual		2008 Actual	Variance from 2007 Actual		2009 Actual	Variance from 2008 Actual		2010 Bridge	Variance from 2009 Actual		2011 Test	Variance from 2010 Bridge	
			$	%		$	%		$	%		$	%		$	%		$	%
Gross Fixed Assets	137,223,877	157,629,412	20,405,535	14.9%	167,151,025	9,521,612	6.0%	178,834,502	11,683,477	7.0%	189,633,833	10,799,331	6.0%	200,448,806	10,814,974	5.7%	209,551,599	9,102,793	4.5%
Accumulated Depreciation	61,873,995	77,119,914	15,245,919	24.6%	83,320,645	6,200,732	8.0%	88,712,000	5,391,355	6.5%	94,663,241	5,951,241	6.7%	99,459,705	4,796,463	5.1%	106,603,393	7,143,688	7.2%
Net Book Value	75,349,882	80,509,498	5,159,616	6.8%	83,830,379	3,320,881	4.1%	90,122,501	6,292,122	7.5%	94,970,591	4,848,090	5.4%	100,989,102	6,018,510	6.3%	102,948,206	1,959,104	1.9%
Average Net Book Value	75,349,882	79,697,709	4,347,827	5.8%	82,169,939	2,472,230	3.1%	86,976,440	4,806,501	5.8%	92,546,546	5,570,106	6.4%	97,979,846	5,433,300	5.9%	101,968,654	3,988,807	4.1%
Working Capital	94,476,164	96,568,962	2,092,798	2.2%	101,102,311	4,533,349	4.7%	99,919,226	(1,183,085)	-1.2%	104,598,525	4,679,299	4.7%	110,160,769	5,562,244	5.3%	114,508,597	4,347,828	3.9%
Working Capital Allowance	14,171,425	14,485,344	313,919	2.2%	15,165,347	680,002	4.7%	14,987,884	(177,463)	-1.2%	15,689,779	701,895	4.7%	16,524,115	834,337	5.3%	17,176,290	652,174	3.9%
Rate Base	89,521,305	94,183,053	4,661,748	5.2%	97,335,286	3,152,232	3.3%	101,964,324	4,629,039	4.8%	108,236,325	6,272,001	6.2%	114,503,962	6,267,637	5.8%	119,144,943	4,640,981	4.1%

NPEI notes that the 2006 OEB Approved rate base was determined through the 2006 EDR process and is based on the 2004 year end rate base adjusted for Tier 1 Adjustments. Accordingly, the variance between 2006 Actual and 2006 OEB Approved spans a two-year period.

NPEI offers the following comments in respect of the relevant variances identified above. NPEI also explains projects under the materiality where relevant.

2011 Test Year

As shown in Table 2-6 above, the total rate base in the 2011 test year is forecast to be $119,144,943. Average net fixed assets accounts for $101,968,654 of this total. The allowance for working capital totals $17,176,290 and has been calculated as 15% of the sum of the cost of power and controllable expenses.

2011 Test Year vs. 2010 Bridge Year

The total rate base is expected to be $4,640,981 higher in the 2011 Test Year than in the 2010 Bridge Year. This increase is shown in Table 2-6 above and is attributable primarily to an increase in average net fixed assets of $3,988,807. The increase in fixed assets along with the required information for projects is discussed in detail by capital project later in this exhibit, beginning with Table 2-22.

The working capital allowance has increased by $652,174 from the 2010 Bridge Year. A detailed calculation of the working capital allowance for the 2011 Test Year can be found in Table 2-24.

2010 Bridge Year vs. 2009 Actual

The total rate base for the 2010 Bridge Year is expected to be $114,503,962, which represents an increase of $6,267,637 over the 2009 Actual year. This change results in part from an increase in average net assets of $5,433,300. This increase is primarily due to capital expenditures, as laid out in Table 2-21. The working capital allowance has increased by $834,337 from 2009. A detailed calculation of the working capital allowance for the 2010 Bridge Year can be found in Table 2-24.

2009 Actual vs. 2008 Actual

The rate base of $108,236,325 for 2009 Actual increased over 2008 Actual by $6,272,001. This increase is made up of a change in average net assets of $5,570,106 as a result of capital expenditures. Detailed information for these projects can be found later in this exhibit, beginning with Table 2-20. As detailed in Table 2-24, the amount of working capital allowance for 2009 increased by $701,895 over 2008.

2008 Actual vs. 2007 Actual

The rate base of $101,964,324 for 2008 Actual increased over 2007 Actual by $4,629,039. This increase is made up of a change in average net assets of $4,806,501 as a result of capital expenditures. Detailed information for these projects can be found later in this exhibit, beginning at Table 2-19. As detailed in Table 2-24, the amount of working capital allowance for 2008 decreased by $177,463 from 2007.

2007 Actual vs. 2006 Actual

The rate base of $97,335,286 for 2007 Actual increased over 2006 Actual by $3,152,232. This increase is made up of a change in average net assets of $2,472,230 as a result of capital expenditures. Detailed information for these projects can be found later in this exhibit, beginning at Table 2-18. As detailed in Table 2-24, the working capital allowance for 2007 increased by $680,002 over 2006.

2006 Actual vs. 2006 Board Approved

The rate base of $94,183,053 for 2006 Actual was higher than the 2006 Board Approved by $4,661,748, of which $4,347,827 relates to the change in average net assets. The difference reflects the normal 2005 capital investments, as well as the fact that the 2006 Board Approved amounts were calculated as the average of the 2003 and 2004 actual amounts. The working capital allowance for 2006 Actual was $313,319 higher than the Board Approved amount.

Capital Expenditures Overview

Table 2-7 below shows NPEI's actual capital expenditures and contributed capital by year from 2005 through 2009 and forecast capital expenditures and contributed capital for the years 2010 and 2011, by USoA account.

Capital expenditures, in general, have increased modestly year over year; however, Building and Fixture expenditures for the years 2008 and 2009 (USoA 1908) were higher than other years due to extensive renovations to NPEI's head office in Niagara Falls (2008) and the construction of a new Service Centre in the Peninsula West area (2008-2009).

Smart Meters

It should also be noted how the Smart Meter Initiative has impacted this analysis: NPEI books all smart meter related expenditures, expenses and recoveries to accounts 1555 and 1556. However, as further explained in Exhibit 9, NPEI is applying for approval to include an amount of $4,175,010 of smart meter capital in rate base for 2011. Accordingly, this balance is shown Table 2-7, as an addition to account 1860 in 2010. In this manner, if approved, the smart meter capital amount is then included as part of the 2011 opening balance, allowing for a full year of revenue requirement on this balance for 2011.

NPEI has recorded the net book value of stranded meters in a sub-account of 1555, relating to conventional meters that were replaced with smart meters in 2009, and the first half of 2010. In 2009, NPEI booked $230,761 of stranded meter costs to account 1555. This amount includes $206,761 net value removed from account 1860, representing 5217 smart meters installed in 2009, and $24,000 of stranded meter costs from NPEI's meter inventory. The amount of $206,761 removed from account 1860 is included in Table 2-11, the Fixed Asset Continuity Schedule for 2009, consisting of $607,139 in cost and ($400,378) in accumulated depreciation. The stranded meter costs for January to June 2010 were $958,531, representing 28,008 smart meters installed. The amount of $958,531 removed from account 1860 is included in Table 2-12, the Fixed Asset Continuity Schedule for 2010, consisting of $3,163,008 in cost and ($2,204,477) in accumulated depreciation. As discussed in Exhibit 9, NPEI is not applying to recover stranded meter costs in this application.

The following is a summary of the manner in which NPEI's Smart Meter treatment is reflected in the current 2011 COS application:

- The audited amount of Smart Meter capital expenditures of $4,175,010 has been added to account 1860 in 2010.
- Stranded Meter costs of $230,761 have been removed from 1860 in 2009.
- Stranded Meter costs of $958,531 have been removed from 1860 in 2010.

Capital Contributions

NPEI collects Contributions in Aid of Capital Expansions and Connections (Contributed Capital) in compliance with the provisions in the Distribution System Code and the utility's Conditions of Service. Presently, NPEI's requirements for capital contributions are based on separate conditions of service for each predecessor utility, Niagara Falls Hydro and Peninsula West Utilities. NPEI has now produced a harmonized Conditions of Service, and will commence collecting all capital contributions in accordance with the updated conditions on the same date that NPEI's 2011 approved rates become effective. With respect to capital contributions, the main differences in the separate conditions of service are that Niagara Falls customers received a basic entitlement, whereas Peninsula West customers did not. The updated conditions of service follow the Niagara Falls model for calculating capital contribution requirements of allowing a basic entitlement.

Contributed Capital is considered a source of working capital thus reducing the overall cash required to fund NPEI's capital expenditure programs. Contributions are tracked in USoA account 1995. In 2008 NPEI began using additional sub-accounts of 1995 to separate capital contributions according to: underground, overhead, meters or transformers.

Table 2-7 Summary of Capital Additions by Year

USoA	Description	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
1806	Land Rights	159,411	89,984	30,031	-	-	-	-
1808	Buildings and Fixtures	0	10,204	18,296	-	-	-	-
1815	Transformer Station Equipment	(301,622)	(218,750)	-	-	-	-	-
1820	Distribution Station Equipment	9,351	28,197	-	-	276,481	185,185	462,963
1830	Poles, Towers and Fixtures	635,300	1,639,570	2,901,140	1,856,704	1,982,247	2,860,613	2,482,838
1835	Overhead Conductors and Devices	850,779	1,487,310	2,527,454	2,865,321	2,060,811	1,231,327	972,176
1840	Underground Conduit	2,312,448	928,142	660,180	650,997	471,148	1,175,040	1,369,289
1845	Underground Conductors and Devices	1,803,836	2,293,204	1,978,131	1,738,623	2,200,580	1,723,794	1,572,596
1850	Line Transformers	1,581,156	1,378,952	2,048,116	1,189,608	1,222,298	1,384,010	1,284,894
1855	Services	547,476	567,794	701,366	342,962	324,654	486,923	499,935
1860	Meters	480,925	352,242	334,706	200,905	258,429	4,369,541	185,185
1905	Land	229,465	-	-	-	279,505	-	-
1908	Buildings and Fixtures	50,705	45,388	430,422	4,146,632	2,385,705	188,557	-
1915	Office Furniture and Equipment	65,635	73,858	18,181	174,930	161,652	70,564	92,593
1920	Computer Equipment - Hardware	183,075	119,227	101,762	525,453	185,269	273,500	291,898
1925	Computer Software	643,900	213,418	62,326	208,496	369,215	278,954	182,870
1930	Transportation Equipment	214,249	515,857	227,707	576,543	589,462	824,149	462,963
1935	Stores Equipment	(0)	-	-	-	18,090	18,900	-
1940	Tools, Shop and Garage Equipment	154,514	48,599	60,052	38,218	49,335	94,342	92,593
1945	Measurement and Testing Equipment	38,940	71,867	-	6,083	12,160	4,690	-
1955	Communication Equipment	(0)	-	1,866	28,326	45,272	2,843	-
1960	Miscellaneous Equipment	0	-	-	24,228	5,586	5,049	-
1995	Contributions and Grants	(3,920,772)	(1,354,458)	(1,683,128)	(1,712,904)	(1,197,961)	(1,200,000)	(850,000)
	Total Capital Additions	5,738,770	8,290,606	10,418,607	12,861,125	11,699,938	13,977,982	9,102,793
	Dollar increase (decrease)		2,551,836	2,128,000	2,442,518	(1,161,187)	2,278,044	(4,875,189)
	Percent increase (decrease)		44.5%	25.7%	23.4%	-9.0%	19.5%	-34.9%

NPEI utilizes the OEB USoA for recording and grouping its assets. The net fixed assets include only those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The NPEI rate base calculation excludes any non-distribution assets, with the exception of the Kalar Transformer Station, which Niagara Falls Hydro put into service in 2004. The Kalar TS assets were approved by the Board in Niagara Falls Hydro’s 2006 EDR Application (EB-2005-0394) to be deemed distribution assets. As the 2006 Board Approved Rate Base calculation involved the average of the opening and closing net asset values for 2004, only 50% of the cost of the Kalar TS was included in the 2006 Approved rate base.

Table 2-22a identifies the capital additions by year, detailing one-time expenditures versus ongoing.

Descriptions of USoA Accounts Used to Record Capital Expenditures

NPEI uses the following accounts in the calculation of its net fixed assets:

Distribution Plant

1805 - Land
This account is used to record the cost of land owned by NPEI, relating to land used in connection with power distribution.

1806 - Land Rights
This account is used to record easement land rights and privileges held by NPEI in land owned by others.

1808 - Buildings & Fixtures
This account is used to record the cost in place of buildings and fixtures owned by NPEI that are used in connection with distribution operations.

1815 - Transformer Station Equipment – Normally Primary Above 50 kV
This account is used to record the installed cost of transformer station equipment in NPEI's transformer station, which is used for stepping down transmission voltages to sub-transmission voltages. NPEI's transformer station was deemed as a distribution asset in Niagara Falls Hydro's 2006 Electricity Distribution Rate Order (EB-2005-0394).

1820 - Distribution Station Equipment – Normally Primary below 50 kV
This account is used to record the installed cost of equipment in each of NPEI's distribution stations, which are used for the purpose of stepping down to distribution voltages.

1830 - Poles, Towers and Fixtures

This account is used to record the installed cost of poles, towers, and fixtures used for supporting overhead distribution conductors and service wires in accordance with the example items from the Accounting Procedures Handbook issued by the OEB. NPEI owns approximately 26,500 poles.

1835 - Overhead Conductors and Devices

This account is used to record the installed cost of overhead conductors and devices used for distribution purposes in accordance with the example items from the Accounting Procedures Handbook issued by the OEB. NPEI has 1,059 kilometers of overhead line within its service territory.

1840 - Underground Conduit

This account is used to record the installed cost of underground conduit and structures used for housing distribution cables or wires in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1845 - Underground Conductors and Devices

This account is used to record the installed cost of underground conductors and devices used for distribution purposes in accordance with the example items from the Accounting Procedures Handbook issued by the OEB. NPEI has approximately 482 kilometers of underground cable within its service territory.

1850 - Distribution Transformers

This account is used to record the installed cost of overhead and underground distribution line transformers and distribution line voltage regulators for use in transforming electricity to the voltage at which it is to be used by the customer in accordance with the example items from the Accounting Procedures Handbook issued by the OEB. NPEI has approximately 7,513 distribution transformers within its service territory.

1855 - Services

This account is used to record the installed cost of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the transformer or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's electrical panel, in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1860 - Meters

This account is used to record the installed cost of meters or devices and appurtenances thereto, for use in measuring the electricity delivered to its users.

General Plant

1905 – Land

This account is used to record the cost of land owned by NPEI used for utility purposes, the cost of which is not properly included in other land account.

1908 – Buildings and Fixtures

This account is used to record the cost in place of buildings and fixtures used for utility purposes, the cost of which is not properly included in other Buildings and Fixtures accounts.

1910 – Leasehold Improvements

This account is used to record the cost of additions, improvements or alterations made to premises that NPEI leases from others.

1915 - Office Furniture and Equipment

This account contains the cost of general office furniture and equipment purchased by NPEI.

1920 - Computer Equipment Hardware

This account contains the cost of all computer hardware purchased.

1925 - Computer Software

This account contains the installed cost of all computer software purchased or developed in house.

1930 - Transportation Equipment

This account contains the cost of all vehicles owned by NPEI, including small trucks, truck chassis, special truck bodies, aerial ladders, trailers and other mobile equipment.

1935 - Stores Equipment

This account contains the cost of equipment used in NPEI's warehouse for shipping, receiving, handling and storage of materials.

1940 - Tools, Shop and Garage Equipment

This account contains the cost of all tools, implements and equipment used in construction, repair work, general shops and garages and not specifically provided for in other accounts, in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1945 - Measurement and Testing Equipment

This account contains the cost of all measurement and testing equipment purchased by NPEI in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1955 - Communication Equipment

This account contains the cost of all communication equipment purchased by NPEI.

1960 - Miscellaneous Equipment

This account contains the cost of all equipment of a capital nature purchased by NPEI that is not included in the other accounts.

1980 - System Supervisory Equipment

This account contains the cost of all control equipment used for the purposes of remote operation and control of utility transformer stations and distribution equipment.

1995 – Contributions and Grants

This account includes amounts relating to contribution or grants in cash, services or property from government or government agencies, corporations, individuals and others received in aid of construction or for acquisition of fixed assets (contributed capital).

2005 – Property Under Capital Leases

This account includes the amounts recorded under capital leases for plant leased from others and used by the utility in its utility operations.

Activity Drivers

NPEI's capital expenditures budget is prepared using categories of activity drivers that are used consistently each year. The main categories used by NPEI are:

1. Expansion and Reinforcement of the Primary Distribution System to Accommodate Load Growth and Reliability Requirements.
2. Line Extensions/Relocations due to Municipal Road Work Requirements.
3. Replacement of Poles Identified with Limited Structural Integrity.
4. Required Overhead Line Rebuild of Deteriorated Facilities Identified by the Pole Condition Survey
5. Replacement of Kiosks with EFD Switches and Posi-tects.
6. Minor Betterment Allowance.

7. Subdivisions and New Residential Services.
8. Demand Based System Reinforcements for New Commercial Service Connections and Expansions.
9. Metering.
10. Vehicles.
11. Other Capital Expenditures.

Further details on NPEI's drivers of capital expenditures follows below.

1. Expansion and Reinforcement of the Primary Distribution System to Accommodate Load Growth and Reliability Requirements.

This category includes expenditures for the addition of new overhead and underground feeder assets, rebuilds, voltage conversions, sectionalizing and replacement of distribution station equipment.

Normally projects are identified through the system planning process which includes monitoring and analyzing commercial activities, station and feeder peak loading, municipal development activities, developer activities and land development activities.

2. Line Extensions/Relocations due to Municipal Road Work Requirements.

This category includes expenditures to relocate/replace distribution assets that conflict with roadway construction activities. The level of spending is driven by the activities of the road authorities. Total expenditures can vary greatly from year to year and reimbursement is normally limited to 50% of labour and labour saving devices.

There are no alternatives to these activities. These expenditures are not discretionary as compliance is mandated by the Public Service Works on Highways Act, R.S.O. 1990

3. <u>Replacement of Poles Identified with Limited Structural Integrity.</u>

Natural degradation of utility poles is an ongoing issue that is monitored through a 5-year cyclic field evaluation process and addressed by replacing subject poles through the budget program.

4. <u>Required Overhead Line Rebuild of Deteriorated Facilities Identified by the Pole Condition Survey</u>

This rebuild program is directed at overhead distribution facilities identified as nearing the end if life expectancy. In these locations the existing overhead distribution facilities will be replaced with new overhead plant that will incorporate new poles, conductors and transformation to maximize safety, efficiency, reliability, and the capability of conversion to a higher distribution voltage when and where practical.

5. <u>Replacement of Kiosks with EFD Switches and Posi-tects.</u>

The Kiosk replacement program is an integral part of NPEI's underground system rehabilitation/replacement program. These locations represent the transformation, sectionalizing and circuit protection components of the underground network. As these legacy components are replaced with modern devices, safety, reliability and service quality are significantly improved. In 1994 the kiosk replacement program was initiated with 725 locations identified for replacement. In 2008 a Conditional Assessment Survey was completed which will be repeated on a 5-year cycle as required. The remaining 248 locations (as at the end of 2008) have been prioritized as a result of the survey.

6. <u>Minor Betterment Allowance.</u>

This category consists of an annual allowance for minor capital work initiated by unexpected failures of overhead and underground distribution facilities. Unplanned underground cable replacements due to repeated failure are the predominant item covered by this allowance. Minor overhead distribution system modifications and component replacements are also included in this category.

7. <u>Subdivisions and New Residential Services.</u>

This category includes capital expansions to the NPEI distribution system driven solely by residential customer demand. In accordance with the Distribution System Code, NPEI performs an economic evaluation for each project and provides the developer with an offer to connect. As this construction is customer driven, total expenditures vary with the level of economic activity in NPEI's service area.

8. <u>Demand Based System Reinforcements for New Commercial Service Connections and Expansions.</u>

This category includes an annual allowance for the construction of new distribution facilities to service new commercial customers requesting connection. Additions and reinforcement to the distribution system resulting from new customer connection requests fall under this category.

9. Metering.

The metering capital budget includes the typical revenue metering costs associated with new customer installations. Wholesale meter point upgrades are also included in this category.

10. Vehicles.

This category captures purchases of new and replacement vehicles and equipment as well as expenditures for major rebuilds that extend the useful service life of vehicles and equipment. These expenditures are required to ensure that NPEI's equipment and fleet remains available and in good condition for serving the needs of an expanding customer base.

11. Other Capital Expenditures.

This category includes expenditures in the following areas:

a) Land
b) Building
c) Office Furniture and Equipment
d) Computer Hardware
e) Computer Software
f) Tools, Shop and Garage Equipment

Fair Market Value Bump

On January 1, 2008, Niagara Falls Hydro Inc. ("NFH") acquired Peninsula West Utilities Ltd. ("PWU") and continued on as Niagara Peninsula Energy Inc. As a result, a fair market valuation of the PWU assets was completed and audited. The 2008 financial statements have the actual results of NPEI for 2008 compared to the actual 2007 results of just NFH.

The purchase equation of the merger resulted in a Fair Market Value bump to the former PWU assets. For 2008 and 2009 the fair market value bump on the assets was disclosed separately on the RRR Trial Balance in Account 2065 Other Electric Plant Adjustment and Account 2160 Accumulated Amortization of Other Electric Plant so as not to include these amounts in Rate Base. For 2008 these amounts are $45,735,559 and $25,239,221 respectively. For 2009 these amounts are $45,735,559 and $26,348,210. For the 2010 Bridge Year and 2011 Test year these amounts remain constant on the Trial Balance and are excluded from the calculation of Rate Base and the Fixed Asset Continuity Schedules.

The Rate Base and Revenue Requirement in this application do not in any way include amounts related to the fair market value bump on fixed assets that resulted from the merger. There are also zero tax implications as these amounts are not included in any UCC balances for 2008 or 2009.

Exhibit 1 contains a reconciliation of the 2009 fixed asset continuity schedule to the fixed asset balances from the 2009 financial statements, in which the details of the fair market value bump by USoA account are shown.

Construction Work In Progress

NPEI does not use the Construction Work in Progress (“CWIP”) account since, with few exceptions, NPEI’s capital projects are budgeted for, completed and in-service within the calendar year.

For larger projects, the work is normally broken down into different phases, where each phase can be completed and put into service by the end of the year.

Fixed Asset Continuity Schedules

NPEI’s Fixed Asset continuity schedules from 2006 Actual to the 2011 Test Year are given in Tables 2-8 to 2-13 below.

Table 2-8 2006 Fixed Asset Continuity Schedule

		Gross Costs				Accumulated Depreciation				
OEB	**Description**	**Opening Balance 2006**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	508,596	0	0	508,596	0	0	0	0	508,596
1806	Land Rights	1,478,155	89,984	0	1,568,139	410,130	53,694	0	463,824	1,104,315
1808	Buildings and Fixtures	410,595	10,204	0	420,799	326,828	8,930	0	335,758	85,041
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	6,777,264	(218,750)	0	6,558,514	176,401	141,097	0	317,498	6,241,016
1820	Distribution Station Equipment - Normally Primary below 50 kV	4,202,787	28,197	0	4,230,984	2,295,264	132,475	0	2,427,739	1,803,245
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	20,285,351	1,639,570	0	21,924,921	10,655,067	989,983	0	11,645,050	10,279,872
1835	Overhead Conductors and Devices	22,454,127	1,487,310	0	23,941,437	10,615,683	1,275,112	0	11,890,795	12,050,642
1840	Underground Conduit	7,657,174	928,142	0	8,585,316	2,198,893	266,806	0	2,465,699	6,119,617
1845	Underground Conductors and Devices	46,186,316	2,293,204	0	48,479,520	20,131,579	1,890,167	0	22,021,746	26,457,774
1850	Line Transformers	26,007,695	1,378,952	82,666	27,303,981	12,618,228	932,214	82,666	13,467,775	13,836,206
1855	Services	1,522,853	567,794	0	2,090,647	161,029	65,850	0	226,879	1,863,768
1860	Meters	6,340,652	352,242	153,776	6,539,118	3,673,849	205,573	153,822	3,725,600	2,813,519
1865	Other Installations on Customer's Premises	440	0	0	440	0	0	0	0	440
1905	Land	287,879	0	0	287,879	0	0	0	0	287,879
1906	Land Rights	0	0	0	0	0	0	0	0	0
1908	Buildings and Fixtures	5,708,011	45,388	0	5,753,399	1,490,648	105,802	0	1,596,450	4,156,949
1910	Leasehold Improvements	120,252	0	0	120,252	116,981	2,386	0	119,367	885
1915	Office Furniture and Equipment	783,637	73,858	0	857,495	533,070	48,690	0	581,761	275,734
1920	Computer Equipment - Hardware	1,693,129	119,227	0	1,812,356	1,205,809	173,787	0	1,379,596	432,760
1925	Computer Software	1,792,984	213,418	0	2,006,402	1,203,312	503,043	0	1,706,355	300,047
1930	Transportation Equipment	3,697,374	515,857	40,995	4,172,236	2,724,009	227,032	40,946	2,910,096	1,262,141
1935	Stores Equipment	182,171	0	0	182,171	175,424	1,716	0	177,140	5,031
1940	Tools, Shop and Garage Equipment	1,369,906	48,599	0	1,418,505	927,832	83,905	0	1,011,737	406,768
1945	Measurement and Testing Equipment	93,036	71,867	0	164,903	39,535	11,942	0	51,477	113,426
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	117,971	0	0	117,971	75,355	6,251	0	81,606	36,365
1960	Miscellaneous Equipment	38,089	0	0	38,089	38,089	0	0	38,089	0
1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	128,961	0	0	128,961	103,169	8,596	0	111,765	17,196
1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants	(10,372,198)	(1,354,458)	0	(11,726,656)	(1,165,861)	(468,028)	0	(1,633,889)	(10,092,767)
2005	Property under Capital Lease	143,036	0	0	143,036	0	0	0	0	143,036
	Total before Work in Process	**149,616,243**	**8,290,606**	**277,437**	**157,629,412**	**70,730,324**	**6,667,024**	**277,434**	**77,119,914**	**80,509,498**
	Work in Process				0	0	0	0	0	0
	Total after Work in Process	**149,616,243**	**8,290,606**	**277,437**	**157,629,412**	**70,730,324**	**6,667,024**	**277,434**	**77,119,914**	**80,509,498**

Table 2-9 2007 Fixed Asset Continuity Schedule

		Cost				Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	508,596	0	1,322	507,274	0	0	0	0	507,274
1806	Land Rights	1,568,139	30,031	0	1,598,170	463,824	55,811	0	519,636	1,078,534
1808	Buildings and Fixtures	420,799	18,296	327,457	111,638	335,758	64,246	327,457	72,547	39,091
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Prim	6,558,514	0	0	6,558,514	317,498	149,784	0	467,282	6,091,232
1820	Distribution Station Equipment - Normally Prima	4,230,984	0	0	4,230,984	2,427,739	132,474	0	2,560,214	1,670,771
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	21,924,921	2,901,140	0	24,826,061	11,645,050	1,404,991	0	13,050,041	11,776,020
1835	Overhead Conductors and Devices	23,941,437	2,527,454	0	26,468,891	11,890,795	1,070,561	0	12,961,356	13,507,535
1840	Underground Conduit	8,585,316	660,180	0	9,245,495	2,465,699	397,315	0	2,863,014	6,382,482
1845	Underground Conductors and Devices	48,479,520	1,978,131	0	50,457,651	22,021,746	1,879,270	0	23,901,017	26,556,635
1850	Line Transformers	27,303,981	2,048,116	105,800	29,246,297	13,467,775	1,018,706	105,800	14,380,682	14,865,615
1855	Services	2,090,647	701,366	0	2,792,013	226,879	79,824	0	306,703	2,485,310
1860	Meters	6,539,118	334,706	48,681	6,825,143	3,725,600	215,730	48,681	3,892,649	2,932,494
1865	Other Installations on Customer's Premises	440	0	0	440	0	0	0	0	440
1905	Land	287,879	0	58,415	229,465	0	0	0	0	229,465
1906	Land Rights	0	0	0	0	0	0	0	0	0
1908	Buildings and Fixtures	5,753,399	430,422	324,974	5,858,847	1,596,450	113,329	183,719	1,526,060	4,332,787
1910	Leasehold Improvements	120,252	0	0	120,252	119,367	885	0	120,252	(0)
1915	Office Furniture and Equipment	857,495	18,181	0	875,676	581,761	69,624	0	651,385	224,291
1920	Computer Equipment - Hardware	1,812,356	101,762	0	1,914,118	1,379,596	168,175	0	1,547,771	366,346
1925	Computer Software	2,006,402	62,326	0	2,068,728	1,706,355	216,665	0	1,923,020	145,708
1930	Transportation Equipment	4,172,236	227,707	30,345	4,369,598	2,910,096	268,303	30,345	3,148,054	1,221,544
1935	Stores Equipment	182,171	0	0	182,171	177,140	1,717	0	178,857	3,314
1940	Tools, Shop and Garage Equipment	1,418,505	60,052	0	1,478,557	1,011,737	89,528	0	1,101,265	377,292
1945	Measurement and Testing Equipment	164,903	0	0	164,903	51,477	14,131	0	65,608	99,295
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	117,971	1,866	0	119,837	81,606	1,942	0	83,548	36,289
1960	Miscellaneous Equipment	38,089	0	0	38,089	38,089	0	0	38,089	0
1970	Load Management Controls - Customer Premise	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	128,961	0	0	128,961	111,765	8,598	0	120,363	8,598
1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants	(11,726,656)	(1,683,128)	0	(13,409,784)	(1,633,889)	(524,878)	0	(2,158,767)	(11,251,017)
2005	Property under Capital Lease	143,036	0	0	143,036	0	0	0	0	143,036
	Total before Work in Process	**157,629,412**	**10,418,607**	**896,994**	**167,151,025**	**77,119,914**	**6,896,734**	**696,003**	**83,320,645**	**83,830,379**
0	Work in Process	0			0	0	0	0	0	0
	Total after Work in Process	**157,629,412**	**10,418,607**	**896,994**	**167,151,025**	**77,119,914**	**6,896,734**	**696,003**	**83,320,645**	**83,830,379**

Table 2-10 2008 Fixed Asset Continuity Schedule

		Cost				Accumulated Depreciation				
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land	507,274	0	0	507,274	0	0	0	0	507,274
1806	Land Rights	1,598,170	0	0	1,598,170	519,636	56,850	2,649	573,837	1,024,333
1808	Buildings and Fixtures	111,638	0	0	111,638	72,547	9,661	0	82,208	29,430
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Prim	6,558,514	0	0	6,558,514	467,282	145,353	0	612,635	5,945,879
1820	Distribution Station Equipment - Normally Prima	4,230,984	0	0	4,230,984	2,560,214	123,642	0	2,683,856	1,547,129
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	24,826,061	1,856,704	0	26,682,765	13,050,041	1,099,411	0	14,149,452	12,533,313
1835	Overhead Conductors and Devices	26,468,891	2,865,321	0	29,334,212	12,961,356	882,310	0	13,843,666	15,490,546
1840	Underground Conduit	9,245,495	650,997	0	9,896,492	2,863,014	130,117	0	2,993,131	6,903,362
1845	Underground Conductors and Devices	50,457,651	1,738,623	0	52,196,274	23,901,017	2,136,042	0	26,037,059	26,159,216
1850	Line Transformers	29,246,297	1,189,608	311,755	30,124,150	14,380,682	1,057,917	311,755	15,126,844	14,997,306
1855	Services	2,792,013	342,962	0	3,134,975	306,703	181,093	0	487,796	2,647,179
1860	Meters	6,825,143	200,905	0	7,026,048	3,892,649	221,880	0	4,114,529	2,911,519
1865	Other Installations on Customer's Premises	440	0	0	440	0	0	0	0	440
1905	Land	229,465	0	0	229,465	0	0	0	0	229,465
1906	Land Rights	0	0	0	0	0	0	0	0	0
1908	Buildings and Fixtures	5,858,847	4,146,632	0	10,005,479	1,526,060	169,300	0	1,695,360	8,310,119
1910	Leasehold Improvements	120,252	0	0	120,252	120,252	0	0	120,252	(0)
1915	Office Furniture and Equipment	875,676	174,930	104,959	945,647	651,385	50,620	139,460	562,545	383,102
1920	Computer Equipment - Hardware	1,914,118	525,453	0	2,439,571	1,547,771	189,220	0	1,736,991	702,579
1925	Computer Software	2,068,728	208,496	726,433	1,550,791	1,923,020	276,982	726,433	1,473,569	77,222
1930	Transportation Equipment	4,369,598	576,543	0	4,946,141	3,148,054	280,151	0	3,428,205	1,517,936
1935	Stores Equipment	182,171	0	0	182,171	178,857	1,717	0	180,574	1,597
1940	Tools, Shop and Garage Equipment	1,478,557	38,218	0	1,516,775	1,101,265	87,362	0	1,188,627	328,148
1945	Measurement and Testing Equipment	164,903	6,083	0	170,986	65,608	40,663	0	106,271	64,715
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	119,837	28,326	34,501	113,662	83,548	1,145	0	84,693	28,969
1960	Miscellaneous Equipment	38,089	24,228	0	62,317	38,089	3,654	0	41,743	20,574
1970	Load Management Controls - Customer Premise	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	128,961	0	0	128,961	120,363	8,598	0	128,961	0
1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants	(13,409,784)	(1,712,904)	0	(15,122,688)	(2,158,767)	(582,036)	0	(2,740,803)	(12,381,885)
2005	Property under Capital Lease	143,036	0	0	143,036	0	0	0	0	143,036
	Total before Work in Process	**167,151,025**	**12,861,125**	**1,177,648**	**178,834,502**	**83,320,645**	**6,571,652**	**1,180,297**	**88,712,000**	**90,122,501**
	Work in Process	0			0	0			0	0
	Total after Work in Process	**167,151,025**	**12,861,125**	**1,177,648**	**178,834,502**	**83,320,645**	**6,571,652**	**1,180,297**	**88,712,000**	**90,122,501**

Table 2-11 2009 Fixed Asset Continuity Schedule

		Cost				Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	507,274	0	0	507,274	0	0	0	0	507,274
1806	Land Rights	1,598,170	0	0	1,598,170	573,837	56,850	(2,649)	633,336	964,834
1808	Buildings and Fixtures	111,638	0	0	111,638	82,208	9,661	0	91,869	19,769
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primai	6,558,514	0	0	6,558,514	612,635	144,978	0	757,613	5,800,901
1820	Distribution Station Equipment - Normally Primary	4,230,984	276,481	0	4,507,465	2,683,856	125,870	0	2,809,726	1,697,740
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	26,682,765	1,982,247	0	28,665,012	14,149,452	312,244	0	14,461,696	14,203,316
1835	Overhead Conductors and Devices	29,334,212	2,060,811	0	31,395,023	13,843,666	1,646,871	0	15,490,537	15,904,486
1840	Underground Conduit	9,896,492	471,148	0	10,367,640	2,993,131	148,963	0	3,142,094	7,225,547
1845	Underground Conductors and Devices	52,196,274	2,200,580	0	54,396,854	26,037,059	2,277,679	0	28,314,738	26,082,117
1850	Line Transformers	30,124,150	1,222,298	242,762	31,103,686	15,126,844	1,097,089	242,762	15,981,171	15,122,515
1855	Services	3,134,975	324,654	0	3,459,629	487,796	138,383	0	626,179	2,833,450
1860	Meters	7,026,048	258,429	607,139	6,677,338	4,114,529	207,723	400,378	3,921,874	2,755,464
1865	Other Installations on Customer's Premises	440	0	0	440	0	0	0	0	440
1905	Land	229,465	279,505	0	508,970	0	0	0	0	508,970
1906	Land Rights	0	0	0	0	0	0	0	0	0
1908	Buildings and Fixtures	10,005,479	2,385,705	0	12,391,184	1,695,360	121,874	0	1,817,234	10,573,950
1910	Leasehold Improvements	120,252	0	0	120,252	120,252	0	0	120,252	(0)
1915	Office Furniture and Equipment	945,647	161,652	0	1,107,299	562,545	66,119	0	628,664	478,635
1920	Computer Equipment - Hardware	2,439,571	185,269	0	2,624,840	1,736,991	216,507	0	1,953,498	671,341
1925	Computer Software	1,550,791	369,215	0	1,920,006	1,473,569	261,821	0	1,735,390	184,616
1930	Transportation Equipment	4,946,141	589,462	50,706	5,484,897	3,428,205	329,135	50,706	3,706,634	1,778,263
1935	Stores Equipment	182,171	18,090	0	200,261	180,574	2,086	0	182,660	17,601
1940	Tools, Shop and Garage Equipment	1,516,775	49,335	0	1,566,110	1,188,627	68,599	0	1,257,226	308,884
1945	Measurement and Testing Equipment	170,986	12,160	0	183,146	106,271	27,150	0	133,421	49,725
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	113,662	45,272	0	158,934	84,693	7,686	0	92,379	66,555
1960	Miscellaneous Equipment	62,317	5,586	0	67,903	41,743	4,900	0	46,643	21,260
1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	128,961	0	0	128,961	128,961	0	0	128,961	0
1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants	(15,122,688)	(1,197,961)	0	(16,320,649)	(2,740,803)	(629,750)	0	(3,370,553)	(12,950,096)
2005	Property under Capital Lease	143,036	0	0	143,036	0	0	0	0	143,036
	Total before Work in Process	**178,834,502**	**11,699,938**	**900,607**	**189,633,833**	**88,712,000**	**6,642,438**	**691,197**	**94,663,241**	**94,970,591**
	Work in Process	0			0	0			0	0
	Total after Work in Process	**178,834,502**	**11,699,938**	**900,607**	**189,633,833**	**88,712,000**	**6,642,438**	**691,197**	**94,663,241**	**94,970,591**

Table 2-12 2010 Fixed Asset Continuity Schedule

		Cost				Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	507,274	0	0	507,274	0	0	0	0	507,274
1806	Land Rights	1,598,170	0	0	1,598,170	633,336	56,850	0	690,185	907,984
1808	Buildings and Fixtures	111,638	0	0	111,638	91,869	9,661	0	101,530	10,108
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary	6,558,514	0	0	6,558,514	757,613	144,978	0	902,591	5,655,923
1820	Distribution Station Equipment - Normally Primary	4,507,465	185,185	0	4,692,651	2,809,726	129,574	0	2,939,299	1,753,351
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	28,665,012	2,860,613	0	31,525,625	14,461,696	832,570	0	15,294,266	16,231,358
1835	Overhead Conductors and Devices	31,395,023	1,231,327	0	32,626,350	15,490,537	1,167,885	0	16,658,423	15,967,928
1840	Underground Conduit	10,367,640	1,175,040	0	11,542,680	3,142,094	172,464	0	3,314,558	8,228,123
1845	Underground Conductors and Devices	54,396,854	1,723,794	0	56,120,648	28,314,738	2,307,622	0	30,622,360	25,498,289
1850	Line Transformers	31,103,686	1,384,010	0	32,487,696	15,981,171	1,123,494	0	17,104,665	15,383,031
1855	Services	3,459,629	486,923	0	3,946,552	626,179	148,121	0	774,300	3,172,252
1860	Meters	6,677,338	4,369,541	3,163,008	7,883,872	3,921,874	231,863	2,204,477	1,949,260	5,934,612
1865	Other Installations on Customer's Premises	440	0	0	440	0	0	0	0	440
1905	Land	508,970	0	0	508,970	0	0	0	0	508,970
1906	Land Rights	0	0	0	0	0	0	0	0	0
1908	Buildings and Fixtures	12,391,184	188,557	0	12,579,740	1,817,234	210,633	0	2,027,867	10,551,874
1910	Leasehold Improvements	120,252	0	0	120,252	120,252	0	0	120,252	(0)
1915	Office Furniture and Equipment	1,107,299	70,564	0	1,177,863	628,664	74,524	0	703,188	474,675
1920	Computer Equipment - Hardware	2,624,840	273,500	0	2,898,340	1,953,498	247,358	0	2,200,856	697,484
1925	Computer Software	1,920,006	278,954	0	2,198,960	1,735,390	279,283	0	2,014,673	184,287
1930	Transportation Equipment	5,484,897	824,149	0	6,309,047	3,706,634	398,395	0	4,105,028	2,204,018
1935	Stores Equipment	200,261	18,900	0	219,161	182,660	3,509	0	186,169	32,992
1940	Tools, Shop and Garage Equipment	1,566,110	94,342	0	1,660,452	1,257,226	62,574	0	1,319,800	340,652
1945	Measurement and Testing Equipment	183,146	4,690	0	187,835	133,421	28,015	0	161,436	26,400
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	158,934	2,843	0	161,777	92,379	18,866	0	111,245	50,532
1960	Miscellaneous Equipment	67,903	5,049	0	72,952	46,643	6,448	0	53,091	19,861
1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	128,961	0	0	128,961	128,961	0	0	128,961	0
1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants	(16,320,649)	(1,200,000)	0	(17,520,649)	(3,370,553)	(653,746)	0	(4,024,298)	(13,496,350)
2005	Property under Capital Lease	143,036	0	0	143,036	0	0	0	0	143,036
	Total before Work in Process	**189,633,833**	**13,977,982**	**3,163,008**	**200,448,806**	**94,663,241**	**7,000,940**	**2,204,477**	**99,459,705**	**100,989,102**
	Work in Process	0			0	0			0	0
	Total after Work in Process	**189,633,833**	**13,977,982**	**3,163,008**	**200,448,806**	**94,663,241**	**7,000,940**	**2,204,477**	**99,459,705**	**100,989,102**

Table 2-13 2011 Fixed Asset Continuity Schedule

		Cost				Accumulated Depreciation				
OEB	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land	507,274	0	0	507,274	0	0	0	0	507,274
1806	Land Rights	1,598,170	0	0	1,598,170	690,185	56,850	0	747,035	851,135
1808	Buildings and Fixtures	111,638	0	0	111,638	101,530	4,111	0	105,641	5,997
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primar	6,558,514	0	0	6,558,514	902,591	144,978	0	1,047,569	5,510,945
1820	Distribution Station Equipment - Normally Primary	4,692,651	462,963	0	5,155,614	2,939,299	140,637	0	3,079,936	2,075,678
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	31,525,625	2,482,838	0	34,008,462	15,294,266	937,399	0	16,231,665	17,776,797
1835	Overhead Conductors and Devices	32,626,350	972,176	0	33,598,526	16,658,423	1,201,695	0	17,860,118	15,738,408
1840	Underground Conduit	11,542,680	1,369,289	0	12,911,969	3,314,558	223,350	0	3,537,908	9,374,061
1845	Underground Conductors and Devices	56,120,648	1,572,596	0	57,693,245	30,622,360	2,341,552	0	32,963,912	24,729,333
1850	Line Transformers	32,487,696	1,284,894	0	33,772,589	17,104,665	1,175,644	0	18,280,309	15,492,280
1855	Services	3,946,552	499,935	0	4,446,487	774,300	147,861	0	922,161	3,524,326
1860	Meters	7,883,872	185,185	0	8,069,057	1,949,260	253,645	0	2,202,905	5,866,152
1865	Other Installations on Customer's Premises	440	0	0	440	0	0	0	0	440
1905	Land	508,970	0	0	508,970	0	0	0	0	508,970
1906	Land Rights	0	0	0	0	0	0	0	0	0
1908	Buildings and Fixtures	12,579,740	0	0	12,579,740	2,027,867	212,204	0	2,240,071	10,339,670
1910	Leasehold Improvements	120,252	0	0	120,252	120,252	0	0	120,252	(0)
1915	Office Furniture and Equipment	1,177,863	92,593	0	1,270,456	703,188	79,154	0	782,342	488,113
1920	Computer Equipment - Hardware	2,898,340	291,898	0	3,190,238	2,200,856	276,548	0	2,477,404	712,834
1925	Computer Software	2,198,960	182,870	0	2,381,831	2,014,673	91,435	0	2,106,108	275,723
1930	Transportation Equipment	6,309,047	462,963	0	6,772,010	4,105,028	427,330	0	4,532,358	2,239,651
1935	Stores Equipment	219,161	0	0	219,161	186,169	3,509	0	189,679	29,482
1940	Tools, Shop and Garage Equipment	1,660,452	92,593	0	1,753,044	1,319,800	67,204	0	1,387,004	366,041
1945	Measurement and Testing Equipment	187,835	0	0	187,835	161,436	28,015	0	189,451	(1,615)
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	161,777	0	0	161,777	111,245	18,866	0	130,111	31,666
1960	Miscellaneous Equipment	72,952	0	0	72,952	53,091	6,448	0	59,538	13,414
1970	Load Management Controls - Customer Premises	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	128,961	0	0	128,961	128,961	0	0	128,961	0
1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants	(17,520,649)	(850,000)	0	(18,370,649)	(4,024,298)	(694,746)	0	(4,719,044)	(13,651,604)
2005	Property under Capital Lease	143,036	0	0	143,036	0	0	0	0	143,036
	Total before Work in Process	**200,448,806**	**9,102,793**	**0**	**209,551,599**	**99,459,705**	**7,143,688**	**0**	**106,603,393**	**102,948,206**
	Work in Process	0			0	0			0	0
	Total after Work in Process	**200,448,806**	**9,102,793**	**0**	**209,551,599**	**99,459,705**	**7,143,688**	**0**	**106,603,393**	**102,948,206**

Variance Analysis on Gross Assets and Accumulated Depreciation

The following Table 2-14 shows the year over year variances in NPEI's gross asset balances by USoA account. Table 2-15 sets out the year over year accumulated depreciation balances.

Table 2-14 Gross Asset Variances by Year

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006 Board Approved	2007 Actual ($)	Variance from 2006 Actual	2008 Actual ($)	Variance from 2007 Actual	2009 Actual ($)	Variance from 2008 Actual	2010 Bridge ($)	Variance from 2009 Actual	2011 Test ($)	Variance from 2010 Bridge
Land and Buildings													
1805-Land	467,422	508,596	41,174	507,274	(1,322)	507,274		507,274		507,274		507,274	
1806-Land Rights	1,280,156	1,568,139	287,983	1,598,170	30,031	1,598,170		1,598,170		1,598,170		1,598,170	
1808-Buildings and Fixtures	407,916	420,799	12,883	111,638	(309,161)	111,638		111,638		111,638		111,638	
1905-Land	58,415	287,879	229,464	229,465	(58,415)	229,465		508,970	279,505	508,970		508,970	
1906-Land Rights													
1810-Leasehold Improvements													
Sub-Total-Land and Buildings	2,213,909	2,785,413	571,504	2,446,546	(338,867)	2,446,546		2,726,051	279,505	2,726,051		2,726,051	
TS Primary Above 50													
1815-Transformer Station Equipment - Normally Primary above 50 kV	3,611,690	6,558,514	2,946,824	6,558,514		6,558,514		6,558,514		6,558,514		6,558,514	
Sub-Total-TS Primary Above 50	3,611,690	6,558,514	2,946,824	6,558,514		6,558,514		6,558,514		6,558,514		6,558,514	
DS													
1820-Distribution Station Equipment - Normally Primary below 50 kV	4,193,437	4,230,984	37,547	4,230,984		4,230,984		4,507,465	276,481	4,692,651	185,185	5,155,614	462,963
Sub-Total-DS	4,193,437	4,230,984	37,547	4,230,984		4,230,984		4,507,465	276,481	4,692,651	185,185	5,155,614	462,963
Poles and Wires													
1830-Poles, Towers and Fixtures	19,751,291	21,924,921	2,173,630	24,826,061	2,901,140	26,682,765	1,856,704	28,665,012	1,982,247	31,525,625	2,860,613	34,008,462	2,482,838
1835-Overhead Conductors and Devices	20,909,078	23,941,437	3,032,359	26,468,891	2,527,454	29,334,212	2,865,321	31,395,023	2,060,811	32,626,350	1,231,327	33,598,526	972,176
1840-Underground Conduit	4,849,779	8,585,316	3,735,537	9,245,495	660,180	9,896,492	650,997	10,367,640	471,148	11,542,680	1,175,040	12,911,969	1,369,289
1845-Underground Conductors and Devices	43,275,114	48,479,520	5,204,406	50,457,651	1,978,131	52,196,274	1,738,623	54,396,854	2,200,580	56,120,648	1,723,794	57,693,245	1,572,596
Sub-Total-Poles and Wires	88,785,262	102,931,194	14,145,932	110,998,098	8,066,904	118,109,743	7,111,645	124,824,529	6,714,786	131,815,303	6,990,774	138,212,202	6,396,899
Line Transformers													
1850-Line Transformers	23,789,242	27,303,981	3,514,739	29,246,297	1,942,316	30,124,150	877,853	31,103,686	979,536	32,487,696	1,384,010	33,772,589	1,284,894
Sub-Total-Line Transformers	23,789,242	27,303,981	3,514,739	29,246,297	1,942,316	30,124,150	877,853	31,103,686	979,536	32,487,696	1,384,010	33,772,589	1,284,894
Services and Meters													
1855-Services	823,700	2,090,647	1,266,947	2,792,013	701,366	3,134,975	342,962	3,459,629	324,654	3,946,552	486,923	4,446,487	499,935
1860-Meters	5,794,525	6,539,118	744,593	6,825,143	286,025	7,026,048	200,905	6,677,338	(348,710)	7,883,872	1,206,533	8,069,057	185,185
Sub-Total-Services and Meters	6,618,225	8,629,765	2,011,540	9,617,156	987,391	10,161,023	543,867	10,136,967	(24,056)	11,830,424	1,693,456	12,515,544	685,120
General Plant													
1908-Buildings and Fixtures	5,489,490	5,753,399	263,909	5,858,847	105,448	10,005,479	4,146,632	12,391,184	2,385,705	12,579,740	188,557	12,579,740	
1910-Leasehold Improvements	118,482	120,252	1,770	120,252		120,252		120,252		120,252		120,252	
Sub-Total-General Plant	5,607,972	5,873,651	265,679	5,979,099	105,448	10,125,731	4,146,632	12,511,436	2,385,705	12,699,992	188,557	12,699,992	
IT Assets													
1920-Computer Equipment - Hardware	1,445,912	1,812,356	366,444	1,914,118	101,762	2,439,571	525,453	2,624,840	185,269	2,898,340	273,500	3,190,238	291,898
1925-Computer Software	992,161	2,006,402	1,014,241	2,068,728	62,326	1,550,791	(517,937)	1,920,006	369,215	2,198,960	278,954	2,381,831	182,870
Sub-Total-IT Assets	2,438,073	3,818,758	1,380,685	3,982,846	164,088	3,990,362	7,516	4,544,846	554,484	5,097,300	552,455	5,572,069	474,769
Equipment													
1915-Office Furniture and Equipment	683,091	857,495	174,404	875,676	18,181	945,647	69,971	1,107,299	161,652	1,177,863	70,564	1,270,456	92,593
1930-Transportation Equipment	3,285,271	4,172,236	886,965	4,369,598	197,362	4,946,141	576,543	5,484,897	538,756	6,309,047	824,149	6,772,010	462,963
1935-Stores Equipment	182,171	182,171		182,171		182,171		200,261	18,090	219,161	18,900	219,161	
1940-Tools, Shop and Garage Equipment	1,197,597	1,418,505	220,908	1,478,557	60,052	1,516,775	38,218	1,566,110	49,335	1,660,452	94,342	1,753,044	92,593
1945-Measurement and Testing Equipment	79,826	164,903	85,077	164,903		170,986	6,083	183,146	12,160	187,835	4,690	187,835	
1950-Power Operated Equipment													
1955-Communication Equipment	117,971	117,971		119,837	1,866	113,662	(6,175)	158,934	45,272	161,777	2,843	161,777	
1960-Miscellaneous Equipment	38,089	38,089		38,089		62,317	24,228	67,903	5,586	72,952	5,049	72,952	
Sub-Total-Equipment	5,584,016	6,951,370	1,367,354	7,228,831	277,461	7,937,699	708,868	8,768,550	830,851	9,789,087	1,020,537	10,437,235	648,148
Other Distribution Assets													
1865-Other Installations on Customers Premises		440	440	440		440		440		440		440	
1970-Load Management Controls - Customer Premises													
1975-Load Management Controls - Utility Premises													
1980-System Supervisory Equipment	128,961	128,961		128,961		128,961		128,961		128,961		128,961	
1985-Sentinel Lighting Rental Units													
1990-Other Tangible Property													
1995-Contributions and Grants - Credit	(5,746,910)	(11,726,656)	(5,979,746)	(13,409,784)	(1,683,128)	(15,122,688)	(1,712,904)	(16,320,649)	(1,197,961)	(17,520,649)	(1,200,000)	(18,370,649)	(850,000)
2005-Property under Capital Lease		143,036	143,036	143,036		143,036		143,036		143,036		143,036	
Sub-Total-Other Distribution Assets	(5,617,949)	(11,454,219)	(5,836,270)	(13,137,347)	(1,683,128)	(14,850,251)	(1,712,904)	(16,048,212)	(1,197,961)	(17,248,212)	(1,200,000)	(18,098,212)	(850,000)
GROSS ASSET TOTAL	137,223,877	157,629,412	20,405,535	167,151,025	9,521,612	178,834,502	11,683,477	189,633,833	10,799,331	200,448,806	10,814,974	209,551,599	9,102,793

Table 2-15 Accumulated Depreciation by Year

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006 Board Approved	2007 Actual ($)	Variance from 2006 Actual	2008 Actual ($)	Variance from 2007 Actual	2009 Actual ($)	Variance from 2008 Actual	2010 Bridge ($)	Variance from 2009 Actual	2011 Test ($)	Variance from 2010 Bridge
Land and Buildings													
1805-Land													
1806-Land Rights	338,806	463,824	125,018	519,636	55,811	573,837	54,201	633,336	59,499	690,185	56,850	747,035	56,850
1808-Buildings and Fixtures	314,046	335,758	21,712	72,547	(263,211)	82,208	9,661	91,869	9,661	101,530	9,661	105,641	4,111
1905-Land													
1906-Land Rights													
1810-Leasehold Improvements													
Sub-Total-Land and Buildings	652,853	799,582	146,730	592,183	(207,400)	656,045	63,862	725,205	69,160	791,716	66,511	852,676	60,961
TS Primary Above 50													
1815-Transformer Station Equipment - Normally Primary above 50 kV	16,853	317,498	300,645	467,282	149,784	612,635	145,353	757,613	144,978	902,591	144,978	1,047,569	144,978
Sub-Total-TS Primary Above 50	16,853	317,498	300,645	467,282	149,784	612,635	145,353	757,613	144,978	902,591	144,978	1,047,569	144,978
DS													
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,095,717	2,427,739	332,022	2,560,214	132,474	2,683,856	123,642	2,809,726	125,870	2,939,299	129,574	3,079,936	140,637
Sub-Total-DS	2,095,717	2,427,739	332,022	2,560,214	132,474	2,683,856	123,642	2,809,726	125,870	2,939,299	129,574	3,079,936	140,637
Poles and Wires													
1830-Poles, Towers and Fixtures	9,764,918	11,645,050	1,880,132	13,050,041	1,404,991	14,149,452	1,099,411	14,461,696	312,244	15,294,266	832,570	16,231,665	937,399
1835-Overhead Conductors and Devices	8,318,031	11,890,795	3,572,764	12,961,356	1,070,561	13,843,666	882,310	15,490,537	1,646,871	16,658,423	1,167,885	17,860,118	1,201,695
1840-Underground Conduit	59,015	2,465,699	2,406,684	2,863,014	397,315	2,993,131	130,117	3,142,094	148,963	3,314,558	172,464	3,537,908	223,350
1845-Underground Conductors and Devices	19,248,443	22,021,746	2,773,303	23,901,017	1,879,270	26,037,059	2,136,042	28,314,738	2,277,679	30,622,360	2,307,622	32,963,912	2,341,552
Sub-Total-Poles and Wires	37,390,407	48,023,290	10,632,883	52,775,428	4,752,138	57,023,308	4,247,880	61,409,065	4,385,757	65,889,606	4,480,542	70,593,603	4,703,997
Line Transformers													
1850-Line Transformers	11,415,905	13,467,775	2,051,871	14,380,682	912,906	15,126,844	746,162	15,981,171	854,327	17,104,665	1,123,494	18,280,309	1,175,644
Sub-Total-Line Transformers	11,415,905	13,467,775	2,051,871	14,380,682	912,906	15,126,844	746,162	15,981,171	854,327	17,104,665	1,123,494	18,280,309	1,175,644
Services and Meters													
1855-Services	86,680	226,879	140,199	306,703	79,824	487,796	181,093	626,179	138,383	774,300	148,121	922,161	147,861
1860-Meters	3,385,675	3,725,600	339,925	3,892,649	167,049	4,114,529	221,880	3,921,874	(192,655)	1,949,260	(1,972,614)	2,202,905	253,645
Sub-Total-Services and Meters	3,472,355	3,952,479	480,124	4,199,352	246,873	4,602,325	402,973	4,548,053	(54,272)	2,723,560	(1,824,493)	3,125,066	401,506
General Plant													
1908-Buildings and Fixtures	1,333,437	1,596,450	263,013	1,526,060	(70,390)	1,695,360	169,300	1,817,234	121,874	2,027,867	210,633	2,240,071	212,204
1910-Leasehold Improvements	108,650	119,367	10,717	120,252	120,252	120,252	120,252	120,252	120,252	120,252	120,252	120,252	120,252
Sub-Total-General Plant	1,442,087	1,715,817	273,730	1,646,312	49,862	1,815,612	289,552	1,937,486	242,126	2,148,119	330,885	2,360,323	332,456
IT Assets													
1920-Computer Equipment - Hardware	976,410	1,379,596	403,186	1,547,771	168,175	1,736,991	189,220	1,953,498	216,507	2,200,856	247,358	2,477,404	276,548
1925-Computer Software	755,533	1,706,355	950,822	1,923,020	216,665	1,473,569	(449,451)	1,735,390	261,821	2,014,673	279,283	2,106,108	91,435
Sub-Total-IT Assets	1,731,943	3,085,952	1,354,009	3,470,792	384,840	3,210,561	(260,231)	3,688,889	478,328	4,215,529	526,640	4,583,512	367,983
Equipment													
1915-Office Furniture and Equipment	477,599	581,761	104,162	651,385	69,624	562,545	(88,840)	628,664	66,119	703,188	74,524	782,342	79,154
1930-Transportation Equipment	2,469,586	2,910,096	440,510	3,148,054	237,958	3,428,205	280,151	3,706,634	278,429	4,105,028	398,395	4,532,358	427,330
1935-Stores Equipment	172,849	177,140	4,291	178,857	1,717	180,574	1,717	182,660	2,086	186,169	3,509	189,679	3,509
1940-Tools, Shop and Garage Equipment	820,386	1,011,737	191,351	1,101,265	89,528	1,188,627	87,362	1,257,226	68,599	1,319,800	62,574	1,387,004	67,204
1945-Measurement and Testing Equipment	50,228	51,477	1,249	65,608	14,131	106,271	40,663	133,421	27,150	161,436	28,015	189,451	28,015
1950-Power Operated Equipment													
1955-Communication Equipment	44,053	81,606	37,553	83,548	1,942	84,693	1,145	92,379	7,686	111,245	18,866	130,111	18,866
1960-Miscellaneous Equipment	31,023	38,089	(31,023)	38,089		41,743	3,654	46,643	4,900	53,091	6,448	59,538	6,448
Sub-Total-Equipment	4,065,724	4,851,906	748,092	5,266,806	414,900	5,592,658	325,852	6,047,627	454,969	6,639,957	592,331	7,270,483	630,525
Other Distribution Assets													
1825-Storage Battery Equipment													
1970-Load Management Controls - Customer Premises													
1975-Load Management Controls - Utility Premises													
1980-System Supervisory Equipment	90,272	111,765	21,493	120,363	8,598	128,961	8,598	128,961		128,961		128,961	
1985-Sentinel Lighting Rental Units													
1990-Other Tangible Property													
1995-Contributions and Grants - Credit	(500,121)	(1,633,889)	(1,133,768)	(2,158,767)	(524,878)	(2,740,803)	(582,036)	(3,370,553)	(629,750)	(4,024,298)	(653,746)	(4,719,044)	(694,746)
2005-Property under Capital Lease													
Sub-Total-Other Distribution Assets	(409,848)	(1,522,124)	(1,112,275)	(2,038,404)	(516,280)	(2,611,842)	(573,438)	(3,241,592)	(629,750)	(3,895,337)	(653,746)	(4,590,083)	(694,746)
ACCUMULATED DEPRECIATION TOTAL	61,873,995	77,119,914	15,207,830	83,320,645	6,320,099	88,712,000	5,511,607	94,663,241	6,071,493	99,459,705	4,916,716	106,603,393	7,263,941

Variance Analysis on Accumulated Depreciation

Changes in accumulated depreciation are directly affected by changes in fixed assets due to additions of new investment in assets, and the disposition of identifiable assets. The 2006 Board Approved closing balance for accumulated depreciation is based on the average of NPEI's 2003 and 2004 year end account balances, plus Tier 1 capital adjustments approved in the 2006 EDR Applications. As such, the variance between 2006 Board Approved and 2006 Actual represents two years of depreciation changes, and in order to arrive at the annual impact, the variance must be divided by two.

From 2006 Actual to the 2011 Test Year, Table 2-15 illustrates the change in accumulated depreciation, which is a representation of the depreciation expense in the year for each of the above accounts. The change in accumulated depreciation is a result of capital expenditures over a seven year period, from January 1, 2005 to December 31, 2011. Depreciation is calculated on a straight line basis over the remaining useful life of the assets, using depreciation rates consistent with Appendix B of the 2006 Electricity Distribution Rate Handbook. A detailed analysis of capital expenditures and rate base is provided in this Exhibit. Further details of depreciation expense are included in Exhibit 4.

Change to Half Year Rule

In 2010, NPEI has changed the calculation of accumulated depreciation and depreciation expense to use the half year rule, where half a year's depreciation is taken in the year of acquisition. Prior to 2010, NPEI used a full year of depreciation in the year of acquisition. This change was done to minimize the timing differences between amortization and CCA calculated for tax purposes.

Capital Project Descriptions

In the following section, the capital projects by year are set out for 2005 to 2009 actual and 2010 to 2011 budgeted, and details are provided for those projects exceeding the materiality threshold.

Table 2-16 2005 Capital Projects

			1806	1808	1815	1820	1830	1835	1840	1845	1850	1855	1860
Project Number	**Project Description**	**Total Cost**	**Land Rights**	**Buildings and Fixtures**	**Transformer Station Equipment**	**Distribution Station Equipment**	**Poles, Towers and Fixtures**	**OH Conductors and Devices**	**UG Conduit**	**UG Conductors and Devices**	**Line Trans-formers**	**Services**	**Meters**
2005-0010	Kiosk Conversion-2005	373,166					10,518	9,932	109	242,408	110,199	-	-
2005-0011	Montrose- RMN Reconstruction	457,218					119,670	107,103	2,242	165,221	42,634	20,348	-
2005-0026	Great Wolf Lodge Servicing	948,108					5,539	11,833	330,675	401,154	188,909	4,399	5,599
2005-0031	RMN Stanley/Whirlpool Rebiuld	392,056					76,627	62,563	93,067	131,153	17,723	10,208	716
2005-0045	Garner Estates Phase V-Subd.	160,465					-	-	260	109,149	51,056	-	-
2005-0084	Dorchester--#420 to Morrison	343,748					23,756	53,257	92,790	148,987	13,173	11,784	-
2005-1007	U/G Capital Non-Project	178,668					286	737	7,678	127,498	-	41,990	479
2005-1008	O/H Capital Non-Project Relate	190,492					35,871	93,103	-	9,840	19,890	31,788	-
2005-1009	Services Non-Project Related	228,411					-	-	-	2,400	-	226,011	-
2005-1010	Transformers Non-Project Relat	143,633					-	-	-	2,286	141,346	-	-
	Beamsville TS Wholesale Meters	298,773											298,773
	Wade Road Conversion	217,257					89,558	127,699					
	PW Subdivisions Capital Contributions 2001	135,590							108,160		27,430		
	PW Subdivisions Capital Contributions 2002	542,417							419,019		123,398		
	PW Subdivisions Capital Contributions 2003	125,541							90,389		35,152		
	PW Subdivisions Capital Contributions 2004	401,994							293,248		108,746		
	PW Subdivisions Capital Contributions 2005	1,075,541							827,551		247,990		
	R&D Tax Credit for Kalar TS	(479,652)			(479,652)								
	Contributions and Grants	(3,920,772)											
	Land	229,465											
	Buildings and Fixtures	50,706											
	Office Furniture and Equipment	65,635											
	Computer Hardware	183,075											
	Computer Software	643,900											
	Transportation Equipment	214,249											
	All Projects Under Materiality Threshold	2,539,089	159,411	0	178,030	9,351	273,475	384,551	47,260	463,740	453,510	200,949	175,359
	Totals	**5,738,770**	**159,411**	**0**	**(301,622)**	**9,351**	**635,300**	**850,779**	**2,312,448**	**1,803,836**	**1,581,156**	**547,476**	**480,925**

		1905	1908	1915	1920	1925	1930	1935	1940	1945	1955	1960	1995	
Project Number	**Project Description**	**Land**	**Buildings and Fixtures**	**Office Furniture and Equipment**	**Computer Hardware**	**Computer Software**	**Trans-portation Equipment**	**Stores Equipment**	**Tools, Shop and Garage Equipment**	**Measure-ment and Testing Equipment**	**Comm-unication Equipment**	**Misc-ellaneous Equipment**	**Contrib-utions and Grants**	**Project Total**
2005-0010	Kiosk Conversion-2005												-	373,166
2005-0011	Montrose- RMN Reconstruction												-	457,218
2005-0026	Great Wolf Lodge Servicing												-	948,108
2005-0031	RMN Stanley/Whirlpool Rebiuld												-	392,056
2005-0045	Garner Estates Phase V-Subd.												-	160,465
2005-0084	Dorchester--#420 to Morrison												-	343,748
2005-1007	U/G Capital Non-Project												-	178,668
2005-1008	O/H Capital Non-Project Relate												-	190,492
2005-1009	Services Non-Project Related												-	228,411
2005-1010	Transformers Non-Project Relat												-	143,633
-	Beamsville TS Wholesale Meters													298,773
-	Wade Road Conversion													217,257
-	PW Subdivisions Capital Contributions 2001													135,590
-	PW Subdivisions Capital Contributions 2002													542,417
-	PW Subdivisions Capital Contributions 2003													125,541
-	PW Subdivisions Capital Contributions 2004													401,994
-	PW Subdivisions Capital Contributions 2005													1,075,541
-	R&D Tax Credit for Kalar TS													(479,652)
-	Contributions and Grants												(3,920,772)	(3,920,772)
-	Land	229,465												229,465
-	Buildings and Fixtures		50,706											50,706
-	Office Furniture and Equipment			65,635										65,635
-	Computer Hardware				183,075									183,075
-	Computer Software					643,900								643,900
-	Transportation Equipment						214,249							214,249
-	All Projects Under Materiality Threshold	-	(0)	-	-	-	-	(0)	154,514	38,940	(0)	0	-	2,539,089
		229,465	**50,705**	**65,635**	**183,075**	**643,900**	**214,249**	**(0)**	**154,514**	**38,940**	**(0)**	**0**	**(3,920,772)**	**5,738,770**

Details of 2005 Projects in Excess of Materiality

As explained in the Activity Drivers section of this Exhibit, NPEI has grouped typical drivers of capital expenditures into 11 categories, which are used consistently each year when preparing the capital budget. The details of the 2005 projects with cost in excess of NPEI's materiality threshold are arranged below according to these categories of activity drivers.

Category 1: Expansion and Reinforcement of the Primary Distribution System to Accommodate Load Growth and Reliability Requirements.

Project 2005: Wade Road Voltage Conversion, Total Cost $217,257.

This project provided a 27.6kV looped supply to an expanding residential subdivision along Wade Rd. and Regional Rd. 614. The works involved conversion of existing 8.32kV lines to 27.6kV.

Category 2: Line Extensions/Relocations due to Municipal Road Work Requirements.

Project 2005-0011: Montrose RMN Construction, Total Cost $457,218.

This project involved the relocation of primary distribution facilities on Montrose Road from Preakness Street to north of Chorozy Street due to road widening conflicts for Regional Municipality of Niagara.

Project 2005-0031: RMN Stanley/Whirlpool Rebuild, Total Cost $392,056.

This project involved the relocation of primary distribution facilities on Regional Road 102 (Stanley Ave) from Portage Road to Whirlpool Road due to road widening conflicts for Regional Municipality of Niagara.

Project 2005-0084: Dorchester – Hwy 420 to Morrison, Total Cost $343,748.

This project involved the relocation of primary distribution facilities on Dorchester Road from Highway 420 to Morrison Street due to road widening conflicts for the City of Niagara Falls.

Category 3: Replacement of Poles Identified with Limited Structural Integrity.

No individual projects in this category were in excess of the materiality threshold in 2005.

Category 4: Required Overhead Line Rebuild of Deteriorated Facilities Identified by the Pole Condition Survey

No individual projects in this category were in excess of the materiality threshold in 2005.

Category 5: Replacement of Kiosks with EFD Switches and Posi-tects.

Project 2005-0010: 2005 Kiosk and Submersible Conversions, Total Cost $373,166.

In 2005 approximately 21 kiosks and 4 submersibles were converted or eliminated from the distribution system.

Category 6: Minor Betterment Allowance.

Category 8: Demand Based System Reinforcements for New Commercial Service Connections and Expansions.

Project 2005-1007: Underground Capital-Non Project Related, Total Cost $178,668; Project 2005-1008: Overhead Capital Non-Project Related, Total Cost $190,492; Project 2005-1009: Services Non-Project Related, Total Cost

$228,411; Project 2005-1010: Transformers Non-Project Related, Total Cost $143,633.

All of the above project categories are for work initiated by unexpected failures and new connection requests, requiring the expansion of distribution facilities. The predominant items included here are facilities to service new connections, unplanned underground cable replacements, minor overhead distribution system modifications and component replacements.

Project 2005-0026: Great Wolf Lodge Servicing, Total Cost $948,108.
This project involved the extension of primary distribution facilities along Victoria Avenue and River Road to allow for servicing and supply redundancy for the new Great Wolf Lodge facility.

<u>Category 7: Subdivisions and New Residential Services.</u>

2005 Subdivision Projects

The following projects are directly related to the growth experienced in NPEI's service area. The capital costs are directly related to the underground system expansion and are required to accommodate the installation of these new residential/commercial subdivisions. Based on NPEI's subdivision agreement, developers bear the cost of the civil work and the installation of the Transformation, Switchgear and Primary and Secondary Distribution according to NPEI's engineering standards and specifications. NPEI contributes to the cost of these subdivisions using the economic evaluation methodology in accordance with the DSC and the provisions of its Conditions of Service for system expansions. Subdivisions energized in 2005 are listed below.

Subdivision projects in excess of the materiality threshold (included in Table 2-16 above):

- Peninsula West 2005 Subdivision Total $1,075,541
- 2005-0045 Garner Estates Ph V $ 160,465

Other 2005 Subdivisions (not itemized separately in Table 2-16):

- 2005-0046 Garner Village $ 142,741
- 2005-0064 St. Davids Neighbourhood $ 45,711
- 2005-0063 Golia Estates $ 39,553

Peninsula West Utilities also recorded, in 2005, the following subdivision contributions that related to previous years:

- Peninsula West Subdivisions 2001 $135,590
- Peninsula West Subdivisions 2002 $542,417
- Peninsula West Subdivisions 2003 $125,541
- Peninsula West Subdivisions 2004 $135,590

Category 9: Metering.

Project 2005: Beamsville TS Metering Upgrade, Total Cost $298,773.

This project involved the upgrade to existing primary metering at Beamsville Transformer Station (Hydro One owned) to current standard metering which involved new metering equipment being installed on each of the four individual feeders.

Category 10: Vehicles.

2005 Transportation Equipment, Total Cost $214,249.

The 2005 additions to account 1930 Transportation Equipment consist of the following:

- C4045 Derrick $ 139,646
- 2005 Ford F150 4x4 Pickup $ 34,618
- 2006 GMC Pickup $ 32,811
- Flat bed trailer $ 7,173

Category 11: Other Capital Expenditures.

2005 Land, Total Cost $229,465.

In 2005, Peninsula West purchased land in West Lincoln for future construction of a Service Centre.

2005 Buildings and Fixtures, Total Cost $50,706.

The 2005 additions to account 1908 Buildings and Fixtures consist of the following:

- CCTV and card access $ 26,728
- Gate $ 12,050
- Truck hoist $ 11,675
- Miscellaneous $ 252

2005 Office Furniture and Equipment, Total Cost $65,635.

The 2005 additions to account 1915 Office Furniture and Equipment consist of the following:

- Office furniture $ 32,204
- Photocopier $ 20,515
- Encoder machine $ 5,249
- Floor cleaner $ 4,536
- Letter opener $ 3,132

2005 Computer Hardware, Total Cost $183,075.

The 2005 additions to account 1920 Computer Hardware consist of the following:

• Servers	$ 90,756
• New / Replacement PCs	$ 33,081
• Meter reading devices	$ 27,530
• Printers	$ 10,066
• Harris Northstar CIS	$ 8,135
• Tape drive	$ 7,918
• Firewall / VPN	$ 3,240
• Miscellaneous	$ 1,820
• Video card	$ 529

2005 Computer Software, Total Cost $643,900.

The 2005 additions to account 1925 Computer Software consist of the following:

• Harris Northstar CIS	$ 393,491
• Great Plains Project Accounting	$ 69,332
• GIS	$ 49,075
• Netplot server	$ 29,691
• Operating systems & licenses	$ 29,150
• Vehicle diagnostic software	$ 17,799
• Work order management software	$ 17,766
• Laserfiche	$ 9,681
• Great Plains	$ 8,743
• Firewall / VPN	$ 7,086
• Great Plains Integration Manager	$ 5,161
• Reporting software	$ 3,580
• Storage manager	$ 3,345

2005 Kalar Transformer Station SR&ED Tax Credit: Total Amount ($479,652).

The Scientific Research and Experimental Development ("SR&ED") program is a federal tax incentive program to encourage Canadian businesses of all sizes and in all sectors to conduct research and development ("R&D") in Canada that will lead to new, improved, or technologically advanced products or processes.

Niagara Falls Hydro's expenditures for the Kalar TS qualified for this tax credit, and NFH received tax credits in the amounts of ($479,652) in 2005 and ($218,750) in 2006. These amounts were credited against the cost of the TS, in account 1815 Transformer Station Equipment.

2005 Contributions and Grants, Actual Amount ($3,920,772).

In 2005, NPEI collected a total of $3,920,772 of capital contributions, which were recorded in account 1995. These contributions were collected in accordance with the Distribution System Code and NPEI's Conditions of Service. Of the amount collected in 2005, $2,281,083 relates to capital contributions for Peninsula West subdivisions for 2001 to 2005, as follows:

- Peninsula West subdivisions capital contributions 2001 $ 135,590
- Peninsula West subdivisions capital contributions 2002 $ 542,417
- Peninsula West subdivisions capital contributions 2003 $ 125,541
- Peninsula West subdivisions capital contributions 2004 $ 401,994
- Peninsula West subdivisions capital contributions 2005 $ 1,075,541

Table 2-17 2006 Capital Projects

Project Number	Project Description	Total Cost	1806 Land Rights	1808 Buildings and Fixtures	1815 Transformer Station Equipment	1820 Distribution Station Equipment	1830 Poles, Towers and Fixtures	1835 OH Conductors and Devices	1840 UG Conduit	1845 UG Conductors and Devices	1850 Line Trans-formers	1855 Services	1860 Meters
001991	Moyer Road Extension	211,663					89,163	70,808		21	36,560	15,111	
06-1099	Caistor Centre Voltage Conversion	264,684					1,415	257,739				5,531	
06-1116	Caistor Centre Voltage Conversion	222,058					221,822	236					
06-1117	Caistor Centre Voltage Conversion	177,131									177,131		
06-1301	Fly Road Line Extension	195,891					92,885	60,983		8	29,885	12,130	
06-1360	Pole Replacement Program Ph II	175,760					153,276	11,023		7,236	2,522	1,703	
06-1362	Heritage Village - Sectionalizer	152,633					111	2,090		141,280	9,124	28	
06-1367	Thirty Road - Reconductor	221,319					35,192	84,717	9,100	43,457	32,135	16,719	
06-1417	Blue Ribbon Voltage Conversion	175,987					17,443	53,243		36,343	62,392	6,566	
06-1466	Pole Replacement Program Ph III	352,985					284,119	29,719		1,401	19,659	18,086	
06-1474	Fonthill Ph I Voltage Conversion	331,343					94,237	82,633	37	64,062	73,225	17,150	
2006-0007	Bender Hill U/G Upgrades	227,094					-	-	33,962	193,132	-	-	-
2006-0012	Line Rebuild of Surveyed Areas	465,348					152,640	154,516	45,587	41,410	28,280	42,914	-
2006-0018	3-PH TBM Supply Stanley Ave	273,410					106,381	131,923	4,763	24,595	3,053	-	2,695
2006-0025	Montrose-#420 to CNR Tracks	150,293					474	56	44,170	100,508	4,377	707	-
2006-0039	2006--Kiosk Conversions	390,944					-	757	1,434	295,576	90,792	-	2,385
2006-0057	Deerfield Estates Subdivision	240,627					-	2,753	227	175,154	62,493	-	-
2006-1007	U/G Capital Non-Project	406,965					-	136	55,604	97,449	203,493	50,283	-
2006-1008	O/H Capital Non-Project	249,226					37,679	81,298	41	1,438	80,886	47,884	-
2006-1009	Services Non-Project Related	177,473					-	-	-	80	177,393	-	-
2006-1010	Pole Replacement Non-project	270,392					222,449	24,420	-	1,193	22,330	-	-
	R&D Tax Credit for Kalar TS	(218,750)			(218,750)								
	Contributions and Grants	(1,354,458)											
	Buildings and Fixtures	55,592		10,204									
	Office Furniture and Equipment	73,858											
	Computer Hardware	119,227											
	Computer Software	213,418											
	Transportation Equipment	515,857											
	All Projects Under Materiality Threshold	3,552,634	89,984	-	-	28,197	130,284	438,260	733,218	1,068,859	263,222	332,982	347,162
	Totals	**8,290,606**	**89,984**	**10,204**	**(218,750)**	**28,197**	**1,639,570**	**1,487,310**	**928,142**	**2,293,204**	**1,378,952**	**567,794**	**352,242**

		1905	1908	1915	1920	1925	1930	1935	1940	1945	1955	1960	1995	
Project Number	**Project Description**	**Land**	**Buildings and Fixtures**	**Office Furniture and Equipment**	**Computer Hardware**	**Computer Software**	**Trans-portation Equipment**	**Stores Equipment**	**Tools, Shop and Garage Equipment**	**Measure-ment and Testing Equipment**	**Comm-unication Equipment**	**Misc-ellaneous Equipment**	**Contrib-utions and Grants**	**Project Total**
001991	Moyer Road Extension													211,663
06-1099	Caistor Centre Voltage Conversion													264,684
06-1116	Caistor Centre Voltage Conversion													222,058
06-1117	Caistor Centre Voltage Conversion													177,131
06-1301	Fly Road Line Extension													195,891
06-1360	Pole Replacement Program Ph II													175,760
06-1362	Heritage Village - Sectionalizer													152,633
06-1367	Thirty Road - Reconductor													221,319
06-1417	Blue Ribbon Voltage Conversion													175,987
06-1466	Pole Replacement Program Ph III													352,985
06-1474	Fonthill Ph I Voltage Conversion													331,344
2006-0007	Bender Hill U/G Upgrades												-	227,094
2006-0012	Line Rebuild of Surveyed Areas												-	465,348
2006-0018	3-PH TBM Supply Stanley Ave												-	273,410
2006-0025	Montrose-#420 to CNR Tracks												-	150,293
2006-0039	2006--Kiosk Conversions												-	390,944
2006-0057	Deerfield Estates Subdivision												-	240,627
2006-1007	U/G Capital Non-Project												-	406,965
2006-1008	O/H Capital Non-Project												-	249,226
2006-1009	Services Non-Project Related												-	177,473
2006-1010	Pole Replacement Non-project												-	270,392
-	R&D Tax Credit for Kalar TS													(218,750)
-	Contributions and Grants												(1,354,458)	(1,354,458)
-	Buildings and Fixtures		45,388											55,592
-	Office Furniture and Equipment			73,858										73,858
-	Computer Hardware				119,227									119,227
-	Computer Software					213,418								213,418
-	Transportation Equipment						515,857							515,857
-	All Projects Under Materiality Threshold	-	-	-	-	-	-	-	48,599	71,867	-	-	-	3,552,634
		-	**45,388**	**73,858**	**119,227**	**213,418**	**515,857**	**-**	**48,599**	**71,867**	**-**	**-**	**(1,354,458)**	**8,290,606**

Details of 2006 Projects in Excess of Materiality

As explained in the Activity Drivers section of this Exhibit, NPEI has grouped typical drivers of capital expenditures into 11 categories, which are used consistently each year when preparing the capital budget. The details of the 2006 projects with cost in excess of NPEI's materiality threshold are arranged below according to these categories of activity drivers.

<u>Category 1: Expansion and Reinforcement of the Primary Distribution System to Accommodate Load Growth and Reliability Requirements.</u>

Project 001991: Moyer Road Extension, Total Cost $211,663.

This project involved the construction of a new 27KV line along Moyer Road from Vineland Estates Winery to Victoria Avenue and along Victoria Avenue from Moyer Road to King Street. This work improved system reliability by creating a redundant feed for both the Vineland and Jordan areas.

Project 06-1099: Caistor Centre Voltage Conversion, Total Cost $264,684 (Overhead); Project 06-1116: Caistor Centre Voltage Conversion, Total Cost $222,058 (Poles, Towers & Fixtures); Project 06-1117: Caistor Centre Voltage Conversion, Total Cost $177,131 (Transformers).

The first phase of this voltage conversion focused on extending the 27.6kV 2508M2 feeder out of Niagara West Transformer Station west on Regional Road 20 from South Grimsby Road 12 to Abingdon Rd. This conversion allowed customer loads to be transferred from Woodburn DS to Niagara West Transformer Station.

NPEI notes that the project was actually broken into three separate project numbers, where each one captured a main element of the total project: poles towers & fixtures (06-1116), overhead (06-1099) and transformers (06-1117). The combined cost of the three projects is $663,873.

Project 06-1301: Fly Road Extension, Total Cost $195,891.

This project involved the construction of a new 27KV hydro line along Fly Road between Cosby Road and Mountain Road. The new line provides a backup feed for the Vineland F1 feeder from the Niagara West M5 feeder. The work also involved the replacement of existing hydro plant that was near the end of its service life.

Project 06-1362: Heritage Village Sectionalizer, Total Cost $152,633.

This project was to upgrade and repair the failing underground distribution system feeding a residential development in Vineland. The job involved re-terminating all primary cables within the development and replacing 8 existing below grade primary junction units with new above grade pad mounted units.

Project 06-1367: Thirty Road - Reconductor, Total Cost $221,319.

This project involved the re-conductoring of existing 27KV hydro line along Regional Road #14 from Young Street south to the Railroad tracks. Increased system capacity was required in this area.

Project 06-1417: Blue Ribbon Voltage Conversion, Total Cost $175,987.

This project involved converting from existing 8KV distribution system on West Street and Station Street to the 27kV system. This conversion provided load relief for Smithville DS.

Project 06-1474: Fonthill Voltage Conversion Ph I, Total Cost $331,343.

This project involved a voltage conversion of the Pelham Street DS F1 feeder and the Station Street DS F4 feeder from the 4kV to 27.6 distribution system.

Project 2006-0007: Bender Hill Underground Upgrades, Total Cost $227,094.

This project involved the replacement of 15kV underground primary distribution facilities due to increasing load in the area.

Project 2006-0018: 3 Phase TBM Supply Stanley Ave, Total Cost $273,410.

This project involved the construction of overhead distribution lines to supply power to the OPG tunnel project.

<u>Category 2: Line Extensions/Relocations due to Municipal Road Work Requirements.</u>

Project 2006-0025: Montrose Road – Hwy 420 to CNR Tracks, Total Cost $150,293.

This project involved the relocation of 15kV underground and conversion of overhead primary distribution facilities on the east side of Montrose Road, due to new road construction by the Regional Municipality of Niagara.

Category 3: Replacement of Poles Identified with Limited Structural Integrity.

Project 06-1466: Pole Replacement Program Ph III (Peninsula West), Total Cost $352,985.

This project involved replacing poles that were identified as requiring replacement under Pen West's annual Pole Inspection Program. The majority of the poles were located in the Caistor area of the Township of West Lincoln.

Project 06-1360: Pole Replacement Program Ph II (Peninsula West), Total Cost $175,760.

This project involved replacing poles that were identified as requiring replacement under Peninsula West's annual Pole Inspection Program. Approximately 60 poles were replaced. All of these poles were located in the Gainsborough area of the Township of West Lincoln.

Project 2006-1010: Pole Changes for Surveyed Area (Niagara Falls), Total Cost $270,392.

This project involved replacing poles that were identified as requiring replacement under Niagara Falls Hydro's annual Pole Inspection Program. Approximately 85 poles were replaced.

Category 4: Required Overhead Line Rebuild of Deteriorated Facilities Identified by the Pole Condition Survey

Project 2006-0012: Rebuild of Surveyed Area 2006, Total Cost $465,348.

This rebuild program was directed at overhead distribution locations identified as nearing the end of life expectancy. In these locations the existing overhead distribution facilities were replaced with new overhead plant that incorporated new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2006 this program targeted the areas identified from the 2004 pole testing results.

The streets identified for rebuilding included:

- Kieth St. from Portage Rd. to the east limit
- Coholan St. from Sinnicks to the east limit
- Vine St. from Sinnicks to the east limit
- Harold St. from Sinnicks to Frances
- Brooks St. from Sinnicks to Portage
- Carman St. from Sinnicks to Portage
- Atlas St. from Judith to Frances
- Frances Ave. from Mayfair to the south limit

Category 5: Replacement of Kiosks with EFD Switches and Posi-tects.

Project 2006-0039: 2006 Kiosk and Submersible Conversions, Total Cost $390,944.

In 2006 approximately 23 kiosks and 2 submersibles were converted or eliminated from the distribution system.

Category 6: Minor Betterment Allowance.

Category 8: Demand Based System Reinforcements for New Commercial Service Connections and Expansions.

Project 2006-1007: Underground Capital-Non Project Related, Total Cost $406,965; Project 2006-1008: Overhead Capital Non-Project Related, Total Cost $249,226; Project 2006-1009: Services Non-Project Related, Total Cost $177,473.

These project categories are for work initiated by unexpected failures and new connection requests, requiring the expansion of distribution facilities. The predominant items included here are facilities to service new connections, unplanned underground cable replacements, minor overhead distribution system modifications and component replacements.

Category 7: Subdivisions and New Residential Services.

2006 Subdivision Projects.

The following projects are directly related to the growth experienced in NPEI's service area. The capital costs are directly related to the underground system expansion and are required to accommodate the installation of these new residential/commercial subdivisions. Based on NPEI's subdivision agreement, developers bear the cost of the civil work and the installation of the

Transformation, Switchgear and Primary and Secondary Distribution according to NPEI's engineering standards and specifications. NPEI contributes to the cost of these subdivisions using the economic evaluation methodology in accordance with the DSC and the provisions of its Conditions of Service for system expansions. Subdivisions energized in 2006 are listed below.

Subdivision projects in excess of the materiality threshold (included in Table 2-17 above):

- 2006-0054 Deerfield Estates $ 240,627

Other 2006 Subdivisions (not itemized separately in Table 2-17):

- 2006-0017 Ailanthus Ave $ 31,667
- 06-1469 Smithville Estates $ 15,065
- 06-1498 Hillside Estates $ 12,375

Category 9: Metering.

There were no individual projects in this category with cost in excess of the materiality threshold.

Category 10: Vehicles.

2006 Transportation Equipment, Total Cost $515,857.

The 2006 additions to account 1930 Transportation Equipment consist of the following:

- 2006 Digger Derrick $ 196,755
- Versalift bucket truck $ 102,311
- Chassis & cab for Digger Derrick $ 86,140
- 2007 4400 cab & chassis $ 68,895
- 2006 Dodge 1500 4x4 pickup $ 32,062

- 2006 Chevrolet Colorado pickup $ 29,694

Category 11: Other Capital Expenditures.

2006 Buildings and Fixtures, Total Cost $55,592.

The 2006 additions to account 1908 Buildings and Fixtures consist of the following:

- Garage doors $ 16,200
- Portable storage building $ 14,636
- Racking $ 5,707
- Fire Alarm $ 5,650
- Storage room $ 4,590
- Roof $ 4,554
- Security camera $ 2,905
- Miscellaneous $ 1,350

2006 Office Furniture and Equipment, Total Cost $73,858.

The 2006 additions to account 1915 Office Furniture and Equipment consist of the following:

- Folder / Inserter $ 61,476
- Office furniture $ 12,382

2006 Computer Hardware, Total Cost $119,227.

The 2006 additions to account 1920 Computer Hardware consist of the following:

- Copiers / Printers $ 35,629

• Servers	$ 34,773
• New / Replacement PCs	$ 19,551
• Firewall / VPN	$ 13,566
• Laptop computers	$ 6,348
• Tape drive	$ 3,996
• Miscellaneous	$ 2,140
• Console computer for meter board	$ 1,447
• Fax machine	$ 967
• Printer	$ 810

2006 Computer Software, Total Cost $213,418.

The 2006 additions to account 1925 Computer Software consist of the following:

• GIS	$ 50,181
• Advanced CIS	$ 39,377
• Work plan & estimate system	$ 38,060
• Great Plains Project Accounting	$ 30,398
• Great Plains upgrade	$ 14,652
• AutoCAD	$ 11,819
• Laserfiche	$ 9,341
• Operating systems & licenses	$ 7,002
• Operations software	$ 6,000
• Miscellaneous	$ 3,133
• SQL Server	$ 2,376
• Vehicle diagnostic software	$ 1,080

2006 Kalar Transformer Station SR&ED Tax Credit: Total Amount ($218,750).

The Scientific Research and Experimental Development ("SR&ED") program is a federal tax incentive program to encourage Canadian businesses of all sizes and in all sectors to conduct research and development ("R&D") in Canada that will lead to new, improved, or technologically advanced products or processes.

Niagara Falls Hydro's expenditures for the Kalar TS qualified for this tax credit, and NFH received tax credits in the amounts of ($479,652) in 2005 and ($218,750) in 2006. These amounts were credited against the cost of the TS, in account 1815 Transformer Station Equipment.

2006 Contributions and Grants, Actual Amount ($1,354,458).

In 2006, NPEI collected a total of $1,354,458 of capital contributions, which were recorded in account 1995. These contributions were collected in accordance with the Distribution System Code and NPEI's Conditions of Service.

Table 2-18 2007 Capital Projects

Project Number	Project Description	Total Cost	1806 Land Rights	1808 Buildings and Fixtures	1820 Distribution Station Equipment	1830 Poles, Towers and Fixtures	1835 OH Conductors and Devices	1840 UG Conduit	1845 UG Conductors and Devices	1850 Line Trans-formers	1855 Services	1860 Meters
07-1116	Smithville Ph II Voltage Conversion	462,568				180,064	21,911		17,610	213,065	27,614	2,304
07-1120	Mud St. - Line Betterment	475,317				173,533	156,278	23,988	13,919	76,713	30,887	
07-1137	CN Rail - 9th Ave	162,033				40,732	18,080		52,562	45,718	4,940	
07-1156	Caistor Centre Voltage Conversion Ph II	861,888				390,474	236,171		71,540	118,210	45,494	
07-1237	OEB Pole Replacement Ph I	369,498				297,223	25,523		4,120	33,879	8,752	
07-1272	Claus Road - Line Betterment	268,587				76,538	102,899		28,397	44,055	16,699	
07-1352	Niagara West TS M2/M5 Tie	535,573				192,245	192,222		20,649	91,211	39,246	
2007-0002	Rebuild of Surveyed Area 2007	1,619,826				438,204	827,885	40,447	66,469	168,199	78,622	-
2007-0005	2007-Kiosk & Subm Conversions	733,300				2,916	1,900	1,366	541,086	186,031	-	-
2007-0016	Drummond-Lundys to Row Conv	250,427				37,609	172,933	10,433	12,346	14,496	2,610	-
2007-0019	Cropp St/Pettit Ave Rebuild	223,664				56,426	65,076	24,397	58,518	13,256	5,991	-
2007-1007	U/G Capital Non-Project	402,276				-	-	68,797	152,369	126,166	54,944	-
2007-1008	O/H capitla Non-Project Relate	384,863				80,943	117,265	-	-	128,451	58,204	-
2007-1009	Services Non-Project Related	203,164				-	-	-	360	-	202,804	-
2007-1010	Pole Changes for Surveyed Area	253,837				232,753	15,944	-	-	4,101	1,039	-
	Contributions and Grants	(1,683,128)										
	Buildings and Fixtures	448,718		18,296								
	Office Furniture and Equipment	18,181										
	Computer Hardware	101,762										
	Computer Software	62,326										
	Transportation Equipment	227,707										
	All Projects Under Materiality Threshold	4,036,222	30,031	-	-	701,479	573,367	490,752	938,186	784,566	123,521	332,402
	Totals	**10,418,607**	**30,031**	**18,296**	**-**	**2,901,140**	**2,527,454**	**660,180**	**1,978,131**	**2,048,116**	**701,366**	**334,706**

Project Number	Project Description	1905 Land	1908 Buildings and Fixtures	1915 Office Furniture and Equipment	1920 Computer Hardware	1925 Computer Software	1930 Trans-portation Equipment	1935 Stores Equipment	1940 Tools, Shop and Garage Equipment	1945 Measure-ment and Testing Equipment	1955 Comm-unication Equipment	1960 Misc-ellaneous Equipment	1995 Contrib-utions and Grants	Project Total
07-1116	Smithville Ph II Voltage Conversion													462,568
07-1120	Mud St. - Line Betterment													475,317
07-1137	CN Rail - 9th Ave													162,033
07-1156	Caistor Centre Voltage Conversion Ph II													861,888
07-1237	OEB Pole Replacement Ph I													369,498
07-1272	Claus Road - Line Betterment													268,587
07-1352	Niagara West TS M2/M5 Tie													535,573
2007-0002	Rebuild of Surveyed Area 2007												-	1,619,826
2007-0005	2007-Kiosk & Subm Conversions												-	733,300
2007-0016	Drummond-Lundys to Row Conv												-	250,427
2007-0019	Cropp St/Pettit Ave Rebuild												-	223,664
2007-1007	U/G Capital Non-Project												-	402,276
2007-1008	O/H capitla Non-Project Relate												-	384,863
2007-1009	Services Non-Project Related												-	203,164
2007-1010	Pole Changes for Surveyed Area												-	253,837
-	Contributions and Grants												(1,683,128)	(1,683,128)
-	Buildings and Fixtures		430,422											448,718
-	Office Furniture and Equipment			18,181										18,181
-	Computer Hardware				101,762									101,762
-	Computer Software					62,326								62,326
-	Transportation Equipment						227,707							227,707
-	All Projects Under Materiality Threshold	-	-	-	-	-	-	-	60,052	-	1,866	-	-	4,036,222
		-	**430,422**	**18,181**	**101,762**	**62,326**	**227,707**	**-**	**60,052**	**-**	**1,866**	**-**	**(1,683,128)**	**10,418,607**

Details of 2007 Projects in Excess of Materiality

As explained in the Activity Drivers section of this Exhibit, NPEI has grouped typical drivers of capital expenditures into 11 categories, which are used consistently each year when preparing the capital budget. The details of the 2007 projects with cost in excess of NPEI's materiality threshold are arranged below according to these categories of activity drivers.

Category 1: Expansion and Reinforcement of the Primary Distribution System to Accommodate Load Growth and Reliability Requirements.

Project 07-1116: Smithville Ph. II Voltage Conversion, Total Cost $462,568.

The second phase of this project focused on converting distribution lines in the Township of Smithville from 8.32kV to 27.6kV. This job allowed Pen West to off load a portion of Smithville MS and transfer that load directly to the 27kV distribution system via the Niagara West Transformer Station.

Project 07-1120: Mud Street – Line Betterment, Total Cost $475,317.

This project involved the construction of a new double circuit pole line along Mud Street from Mountain Road to Grassie Road. This new double circuit pole line replaced aging hydro facilities and eliminated a number of load transfer customers between Grimsby Power and Pen West Utilities.

Project 07-1156: Caistor Centre Voltage conversion Ph. II, Total Cost $861,888.

The second phase of this voltage conversion focused on extending the 27.6kV 2508M2 feeder out of Niagara West Transformer Station down Abingdon Rd.

from Twenty Rd. to Regional Rd. 65. This conversion allowed customer loads to be transferred from Woodburn DS to Niagara West Transformer Station.

Project 07-1272: Claus Road – Line Betterment, Total Cost $268,587.

This project involved re-conductoring and replacement of existing poles along Claus Road and Victoria Avenue from Cherry Avenue to 21st Street. The result was that existing load could be transferred from the 8kV distribution system to 27kV system, improving both system reliability and capacity for future growth in the areas of Vineland and Jordan. This project was completed in 2008.

Project 07-1352: Niagara West TS M2/M5 Tie, Total Cost $535,573.

This was an 8kV to 27.6kV voltage conversion along Regional Rd. 20 between South Grimsby Rd. 6 and South Grimsby Rd. 8 in West Lincoln. This build provided a backup loop feed between two 27kV feeders from Niagara West Transformer Station to the Township of Smithville.

Project 2007-0016: Drummond Road – Lundy's Lane to Right of Way Conversion, Total Cost $250,427.

This project involved constructing a new 13.8 KV feeder on the east side of the road for a distance of 1.0 km, starting at the Hydro One ROW and northerly along Drummond Rd. up to Lundy's Lane and rehabilitating and converting 4.16 KV plant to 13.8 KV in the quadrants east and west of the new feeder. The existing 4.16 KV plant was over 50 years old and needed to be completely rebuilt. This project was completed in 2008.

Project 2007-0019: Cropp Street / Pettit Avenue Rebuild, Total Cost $223,664.

Commercial development and resulting electrical demand on Dorchester Road between Morrision Street and Hwy 420 required capacity upgrades to the area supply circuit. This project involved rebuilding the existing overhead distribution circuit along Pettit Avenue and Cropp Street, which allows available capacity on the 12M31 circuit to be utilized for these loads.

<u>Category 2: Line Extensions/Relocations due to Municipal Road Work Requirements.</u>

Project 07-1137: CN Rail – 9th Avenue, Total Cost $162,033.

The relocation of Pen West's distribution plant at CN Rails track at 9th St., 11th St. and 13 St. was required to accommodate a CN Rail construction project. The three phase overhead primary crossing at the tracks on 9th St. was converted to underground; an extensive directional bore was required to cross the tracks. Minor work was required at 11th and 13th St.

<u>Category 3: Replacement of Poles Identified with Limited Structural Integrity.</u>

Project 07-1237: OEB Pole Replacement Ph. I, Total Cost $369,498.

This project involved replacing poles that were identified as requiring replacement under Peninsula West's annual Pole Inspection Program. Approximately 90 poles were replaced. All of these poles were located in the Township of West Lincoln.

Project 2007-1010: Pole Changes for Surveyed Area, Total Cost $253,837.

This project involved replacing poles that were identified as requiring replacement under Niagara Falls Hydro's annual Pole Inspection Program. Approximately 55 poles were replaced.

Category 4: Required Overhead Line Rebuild of Deteriorated Facilities Identified by the Pole Condition Survey

Project 2007-0002: Rebuild of Surveyed Area 2007, Total Cost $1,619,826.

This rebuild program was directed at overhead distribution locations identified as nearing the end of life expectancy. In these locations the existing overhead distribution facilities were replaced with new overhead plant that incorporated new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2007 this program targeted the areas identified from the 2005 pole testing results.

Due to greater demand driven work in 2006, some streets identified in the 2006 budget for rebuild were carried forward to 2007.

The areas identified for rebuilding in 2007 include;

- Portions of 5 streets in the area contained by Portage Road, Swayze Drive, Sinnicks avenue and Vine Street.
- Portions of 9 streets in the area contained by St. Paul Avenue, Riall Street, O'Neil Street and Dorchester Road.

Category 5: Replacement of Kiosks with EFD Switches and Posi-tects.

Project 2007-0005: 2007 Kiosk and Submersible Conversions, Total Cost $733,300.

In 2007 approximately 27 kiosks were converted or eliminated from the distribution system.

Category 6: Minor Betterment Allowance.

Category 8: Demand Based System Reinforcements for New Commercial Service Connections and Expansions.

Project 2007-1007: Underground Capital Non-Project Related, Total Cost $402,276; Project 2007-1008: Overhead Capital Non-Project Related, Total Cost $384,863; Project 2007-1009: Services Non-Project Related, Total Cost $203,164.

These project categories are for work initiated by unexpected failures and new connection requests, requiring the expansion of distribution facilities. The predominant items included here are facilities to service new connections, unplanned underground cable replacements, minor overhead distribution system modifications and component replacements.

Category 7: Subdivisions and New Residential Services.

2007 Subdivision Projects.

The following projects are directly related to the growth experienced in NPEI's service area. The capital costs are directly related to the underground system expansion and are required to accommodate the installation of these new residential/commercial subdivisions. Based on NPEI's subdivision agreement, developers bear the cost of the civil work and the installation of the Transformation, Switchgear and Primary and Secondary Distribution according to

NPEI's engineering standards and specifications. NPEI contributes to the cost of these subdivisions using the economic evaluation methodology in accordance with the DSC and the provisions of its Conditions of Service for system expansions. Subdivisions energized in 2007 are listed below.

No subdivision projects in 2007 were in excess of the materiality threshold, and are therefore not itemized separately in Table 2-18:

- 2007-0054 Deerfield Estates Ph II $ 95,621
- 2007-0063 Edgewood Estates $ 10,290
- 07-1241 Attema Acres $ 8,778

<u>Category 9: Metering.</u>

There were no individual projects in this category with cost in excess of the materiality threshold.

<u>Category 10: Vehicles.</u>

2007 Transportation Equipment, Total Cost $227,707.

The 2007 additions to account 1930 Transportation Equipment consist of the following:

- Two GM pickup trucks $ 80,139
- 2007 GMC cargo van $ 49,436
- 2008 GMC crew cab pickup $ 40,521
- 2007 GMC Sierra pickup $ 29,802
- 2007 Chevrolet Uplander van $ 23,541
- Vehicle outfitting $ 4,270

Category 11: Other Capital Expenditures.

2007 Buildings and Fixtures, Total Cost $448,718.

The 2007 additions to account 1908 Buildings and Fixtures consist of the following:

- Niagara Falls parking lot $ 212,842
- Niagara Falls interior renovations $ 200,313
- Niagara Falls garage ventilation $ 28,985
- Racking $ 4,682
- Miscellaneous $ 1,896

2007 Office Furniture and Equipment, Total Cost $18,181.

The 2007 additions to account 1915 Office Furniture and Equipment consist of the following:

- Office furniture $ 14,190
- Photocopier $ 3,991

2007 Computer Hardware, Total Cost $101,762.

The 2007 additions to account 1920 Computer Hardware consist of the following:

- New/Replacement PCs $ 67,596
- Servers $ 16,330
- Printers $ 14,791
- Network switches $ 3,045

2007 Computer Software, Total Cost $62,326.

The 2007 additions to account 1925 Computer Software consist of the following:

• Harris Northstar CIS	$	49,680
• GIS	$	10,379
• Web security	$	1,682
• Miscellaneous	$	585

2007 Contributions and Grants, Actual Amount ($1,683,128).

In 2007, NPEI collected a total of $1,683,128 of capital contributions, which were recorded in account 1995. These contributions were collected in accordance with the Distribution System Code and NPEI's Conditions of Service.

Table 2-19 2008 Capital Projects

Project Number	Project Description	Total Cost	1820 Distribution Station Equipment	1830 Poles, Towers and Fixtures	1835 OH Conductors and Devices	1840 UG Conduit	1845 UG Conductors and Devices	1850 Line Trans-formers	1855 Services	1860 Meters
2008-0001	Garner 3-Ph McLeod to ROW	488,419		138,717	206,513	4,576	71,783	44,344	22,486	-
2008-0002	Rebuild Surveyed Area 2008	966,057		216,699	287,926	164,147	101,771	95,893	99,622	-
2008-0005	2008 Kiosk & Subm Conversions	526,467		-	7,448	17,073	352,551	137,250	10,483	1,662
2008-0009	Drummond Conv-Lundys to ROW	585,573		57,560	287,868	78,871	116,518	39,676	5,079	-
2008-0010	Smithville Conv Ph II	170,877		4,340	166,537	-	-	-	-	-
2008-0011	Claus Road Rebuild	451,612		87,704	357,859	-	-	3,982	2,068	-
2008-0012	Caistor Cntr Conversion PhIII	723,601		105,083	576,199	-	-	40,784	1,535	-
2008-0013	durham Voltage Conversion	347,503		19,166	306,329	-	-	18,878	3,130	-
2008-0018	Edgewood Estates Subdivision	202,688		-	-	14,749	122,633	41,592	-	-
2008-0019	Deerfield Estates PH 2	228,249		-	-	967	139,226	47,898	1,688	-
2008-0035	Kalar Rd Pump Stn @ Brown Rd	159,186		11,356	143,375	-	-	4,455	-	-
2008-0072	St. Paul Ave U/G Extn	200,669		-	-	89,102	86,530	24,640	-	397
2008-0087	CNF Dorchester Rd Relocation	192,066		25,723	40,666	73,272	48,950	3,454	-	-
2008-0091	Edgewood Estates Subd Ph II	167,305		-	-	-	116,302	48,824	-	-
2008-1007	Capital Non-Project Betterment	287,475		5,726	31,365	3,353	100,907	107,615	21,878	16,631
2008-1008	Capital Non-Project Demand	298,277		48,832	93,799	140	13,155	95,903	46,448	-
2008-1009	Services Non-Project Related	162,410		-	-	-	406	-	162,004	-
2008-1010	Pole Replacement NFH 08	412,986		390,577	8,651	-	-	13,758	-	-
2008-2007	Capital Non-Proj Betterments	104,646		444	23,643	15,006	17,385	23,254	24,914	-
2008-2008	Capital Non-Proj Demand Work	430,520		47,728	170,393	-	156	160,049	49,718	2,477
2008-2009	Underground Servicing PW-Area	79,808		-	-	-	1,035	-	78,773	-
2008-2010	Pole Replacement-Pen West 08	478,477		423,369	48,949	-	-	6,159	-	-
	Scrap Transformers	(190,000)						(190,000)		
	Contributions and Grants	(1,712,904)								
	Buildings and Fixtures	4,146,632								
	Office Furniture and Equipment	174,930								
	Computer Hardware	525,453								
	Computer Software	208,496								
	Transportation Equipment	576,543								
	All Projects Under Materiality Threshold	1,467,104	-	273,679	107,801	189,740	449,314	421,201	(186,863)	179,739
	Totals	**12,861,125**	**-**	**1,856,704**	**2,865,321**	**650,997**	**1,738,623**	**1,189,608**	**342,962**	**200,905**

Project Description	1905 Land	1908 Buildings and Fixtures	1915 Office Furniture and Equipment	1920 Computer Hardware	1925 Computer Software	1930 Trans-portation Equipment	1935 Stores Equipment	1940 Tools, Shop and Garage Equipment	1945 Measure-ment and Testing Equipment	1955 Comm-unication Equipment	1960 Misc-ellaneous Equipment	1995 Contrib-utions and Grants	Project Total
Garner 3-Ph McLeod to ROW												-	488,419
Rebuild Surveyed Area 2008												-	966,057
2008 Kiosk & Subm Conversions												-	526,467
Drummond Conv-Lundys to ROW												-	585,573
Smithville Conv Ph II												-	170,877
Claus Road Rebuild												-	451,612
Caistor Cntr Conversion PhIII												-	723,601
durham Voltage Conversion												-	347,503
Edgewood Estates Subdivision												23,713	202,688
Deerfield Estates PH 2												38,471	228,249
Kalar Rd Pump Stn @ Brown Rd												-	159,186
St. Paul Ave U/G Extn												-	200,669
CNF Dorchester Rd Relocation												-	192,066
Edgewood Estates Subd Ph II												2,179	167,305
Capital Non-Project Betterment												-	287,475
Capital Non-Project Demand												-	298,277
Services Non-Project Related												-	162,410
Pole Replacement NFH 08												-	412,986
Capital Non-Proj Betterments												-	104,646
Capital Non-Proj Demand Work												-	430,520
Underground Servicing PW-Area												-	79,808
Pole Replacement-Pen West 08												-	478,477
Scrap Transformers													(190,000)
Contributions and Grants												(1,712,904)	(1,712,904)
Buildings and Fixtures		4,146,632											4,146,632
Office Furniture and Equipment			174,930										174,930
Computer Hardware				525,453									525,453
Computer Software					208,496								208,496
Transportation Equipment						576,543							576,543
All Projects Under Materiality Threshold	-	-	-	-	-	-	-	38,218	6,083	28,326	24,228	(64,363)	1,467,104
	-	**4,146,632**	**174,930**	**525,453**	**208,496**	**576,543**	**-**	**38,218**	**6,083**	**28,326**	**24,228**	**(1,712,904)**	**12,861,125**

Details of 2008 Projects in Excess of Materiality

As explained in the Activity Drivers section of this Exhibit, NPEI has grouped typical drivers of capital expenditures into 11 categories, which are used consistently each year when preparing the capital budget. The details of the 2008 projects with cost in excess of NPEI's materiality threshold are arranged below according to these categories of activity drivers.

Category 1: Expansion and Reinforcement of the Primary Distribution System to Accommodate Load Growth and Reliability Requirements.

Project 2008-0001: Garner 3-phase McLeod Road to Right of Way, Total Cost $488,419.

Due to the expanding residential subdivisions in this area it was necessary to build a three phase overhead circuit along Garner Road and a portion of the Hydro ROW to service the increasing electrical loads. This line was built to service the subdivision developments from the existing KM2 distribution circuit, and was designed to accommodate a future connection to Kalar TS to service future load growth to the west.

Project 2008-0009: Drummond Voltage Conversion – Lundy's Lane to Right of Way, Total Cost $585,583.

This project involved constructing a new 13.8 KV feeder on the east side of the road for a distance of 1.0 km, starting at the Hydro One ROW and northerly along Drummond Rd. up to Lundy's Lane and rehabilitating and converting 4.16 KV plant to 13.8 KV in the quadrants east and west of the new feeder. The existing 4.16 KV plant was over 50 years old and needed to be completely rebuilt.

Project 2008-0010: Smithville Conversion Phase 2, Total Cost $170,877.

This phase of voltage conversion project focused on the customers supplied by the Smithville D.S. 8.32 kV F-4 Feeder to facilitate a staged reduction of load supplied by this station. By rebuilding and converting 8.32 kV customer loads along St. Catharine Street, and Dufferin Street a reduction in loading was realized on the station.

Project 2008-0011: Claus Road Rebuild, Total Cost $451,612.

This work was undertaken to provide for additional capacity on the 27.6 kV, F2 feeder supplied from Vineland DS. This capacity increase provides for better system reliability and addresses load growth in the Vineland and Jordan areas. As well, aging 8.32 kV facilities were replaced and converted to the higher distribution voltage along the construction route.

Project 2008-0012: Caistor Centre Voltage Conversion Phase 3, Total Cost $723,601.

The third phase of the Caistor Center voltage conversion consisted of line rebuild along Silver Street from Abingdon Road to Westbrook Road. These line rebuilds provide for conversion of the remaining 8.32 kV loads supplied from the Woodburn MS to 27.6 kV from the M2 feeder supplied from the Niagara West transformer station.

Project 2008-0013: Durham Voltage Conversion Phase 1, Total Cost $347,503.

The first phase of this voltage conversion project focused on the customers supplied on the periphery of the area supplied by the Durham 27.6 / 8.32 kV station to facilitate a staged reduction and eventual elimination of load supplied by this station. The station was constructed on a temporary basis years ago to deal with increasing loads and was not constructed in a manner that would provide for a long-term reliable source of power. By rebuilding and converting 8.32 kV customer loads along King Street, Lincoln Avenue and Mountainview Road, a reduction in loading was realized on the station and additional 27.6 kV ties are available to provide increased reliability in this area.

<u>Category 2: Line Extensions/Relocations due to Municipal Road Work Requirements.</u>

Project 2008-0035: Kalar Road Pump Station at Brown Road, Total Cost $159,186.

This project was required for the City of Niagara Falls to supply the Garner South West Pump Station.

Project 2008-0087: CNF Dorchester Road Relocation, Total Cost $192,066.

This project involved the relocation of three phase overhead primary distribution facilities on Dorchester Road, due to new road construction by the City of Niagara Falls.

Category 3: Replacement of Poles Identified with Limited Structural Integrity.

Project 2008-1010: Pole Replacement Niagara Falls 2008, Total Cost $412,986; Project 2008-2010: Pole Replacement Peninsula West 2008, Total Cost $478,477.

These projects involved replacing poles that were identified as requiring replacement under NPEI's annual Pole Inspection Program. Approximately 201 poles were replaced in NPEI's two service areas.

Category 4: Required Overhead Line Rebuild of Deteriorated Facilities Identified by the Pole Condition Survey

Project 2008-0002: Rebuild of Surveyed Area 2008, Total Cost $966,057

This rebuild program was directed at overhead distribution locations identified as nearing the end of life expectancy. In these locations the existing overhead distribution facilities were replaced with new overhead plant that incorporated new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2008 this program targeted the areas identified from the 2006 pole testing results.

The areas identified for rebuilding in 2008 include;

- Portions of 6 streets south of Riall Street west of St. Paul Avenue.
- The remaining sections of Royal Manor, Windsor, Strathmore and Glamis Streets carrying over from the 2007 budget.
- Portions of streets in the area contained by Dorchester Road, Drummond Road, Lundy's lane and Frederica Street.

Category 5: Replacement of Kiosks with EFD Switches and Posi-tects.

Project 2008-0005: 2008 Kiosk and Submersible Conversions, Total Cost $526,467.

In 2008 approximately 13 kiosks were converted or eliminated from the distribution system.

Category 6: Minor Betterment Allowance.

Category 8: Demand Based System Reinforcements for New Commercial Service Connections and Expansions.

Project 2008-1007: Capital Non-Project Betterment Niagara Falls, Total Cost $287,475; Project 2008-1008: Capital Non-Project Demand Work Niagara Falls, Total Cost $298,277; Project 2008-1009: Services Non-Project Related, Total Cost $162,410; Project 2008-2007: Capital Non-Project Betterment Peninsula West, Total Cost $104,646; Project 2008-2008: Capital Non-Project Demand Work Peninsula West, Total Cost $430,520; Project 2008-2009: Underground Servicing Pen West Area, Total Cost $79,808.

The above project categories are for work initiated by unexpected failures and new connection requests, requiring the expansion of distribution facilities. The predominant items included here are facilities to service new connections, unplanned underground cable replacements, minor overhead distribution system modifications and component replacements.

Project 2008-0072: St. Paul Ave Underground Extension, Total Cost $200,669.

This project involved new underground primary service to accommodate a condominium development, including the installation and termination of 100 metres (x3) of primary cable in customer-installed duct bank, 500 kVa pad-mount transformer and termination of customers secondary. The work also included the elimination of a 4.16 kV radial feed from Riall Street and conversion of 3 kiosks.

Category 7: Subdivisions and New Residential Services.

2008 Subdivision Projects.

The following projects are directly related to the growth experienced in NPEI's service area. The capital costs are directly related to the underground system expansion and are required to accommodate the installation of these new residential/commercial subdivisions. Based on NPEI's subdivision agreement, developers bear the cost of the civil work and the installation of the Transformation, Switchgear and Primary and Secondary Distribution according to NPEI's engineering standards and specifications. NPEI contributes to the cost of these subdivisions using the economic evaluation methodology in accordance with the DSC and the provisions of its Conditions of Service for system expansions. Subdivisions energized in 2008 are listed below.

Subdivision projects in excess of the materiality threshold (included in Table 2-19 above):

- 2008-0019 Deerfield Estates Ph II & Ph III $ 228,249
- 2008-0018 Edgewood Estates $ 202,688
- 2008-0091 Edgewood Estates Ph II $ 167,305

Other 2008 Subdivisions (not itemized separately in Table 2-19):

- 2008-0086 Fernwood Estates $ 149,470
- 2008-0039 Miller Estates $ 97,718
- 2008-0024 Grandview Heights $ 29,366
- 2008-0030 Maplecrest $ 8,437
- 2008-0029 Steamside Estates $ 8,179

- 2008-0028 Town Manors $ 2,875
- 2008-0149 Golden Horseshoe $ 1,328
- 2008-0025 Anastasio Estates $ 894
- 2008-0148 Jordan Village $ 434
- 2008-0023 Attema Acres $ 136

Category 9: Metering.

There were no individual projects in this category with cost in excess of the materiality threshold.

Category 10: Vehicles.

2008 Transportation Equipment, Total Cost $576,543.

The 2008 additions to account 1930 Transportation Equipment consist of the following:

- Aerial device $ 138,722
- 2009 Freightliner M2 Quick Swap $ 102,005
- Cab and chassis only, 2009 Freightliner M2 $ 81,048
- Cab and chassis only, 2009 Freightliner M2 $ 73,008
- Cab and chassis only, 2009 International 7400 $ 71,464
- 2009 Ford F250 4x4 – On Call vehicle $ 33,061
- 2009 Ford F250 4x2 – Leadhand vehicle $ 27,929
- 2009 Chevrolet Uplander – Engineering vehicle $ 23,585
- Vehicle outfitting $ 15,128
- 10 ton lowbed trailer $ 10,593

The Aerial device was assembled on one of the Freightliner M2 cab and chassis that was acquired in 2008. The other Freightliner cab and chassis were subsequently fitted with an Aerial device that was purchased in 2009. The

International cab and chassis were subsequently fitted with a Radial Boom Derrick to be purchased in 2009.

<u>Category 11: Other Capital Expenditures.</u>

2008 Buildings and Fixtures, Total Cost $4,146,632.

The 2008 additions to account 1908 Buildings and Fixtures consist of the following:

- Construction of new service centre in Smithville $ 2,761,607
- Renovations to the NPEI head office in Niagara Falls $ 1,385,025

Further details on the building renovations and the new service centre can be found in Appendix B to this Exhibit.

2008 Office Furniture and Equipment, Total Cost $174,930.

The 2008 additions to account 1915 Office Furniture and Equipment consist of the following:

- Office furniture $ 141,874
- Lunchroom furniture $ 25,157
- Appliances for lunchroom $ 6,392
- Note counter $ 1,507

2008 Computer Hardware, Total Cost $525,453.

The 2008 additions to account 1920 Computer Hardware consist of the following:

- Telephone equipment $ 208,485
- Servers $ 138,167

• Network switches	$	54,411
• Storage Area Network (SAN)	$	49,027
• Meter reading equipment	$	21,938
• Tablet PCs	$	15,535
• Photocopier	$	14,035
• Replacement UPS batteries	$	8,666
• Firewall equipment	$	6,167
• New/Replacement PCs	$	3,821
• Projector	$	3,676
• Printers	$	1,526

2008 Computer Software, Total Cost $208,496.

The 2008 additions to account 1925 Computer Software consist of the following:

• GIS licenses	$	92,621
• Harris Northstar CIS	$	57,537
• Digital Orthomosaic	$	18,540
• Microsoft Great Plains licenses	$	18,410
• Backup software	$	11,120
• Disaster recovery software	$	9,655
• Telephone system software	$	613

2008 Contributions and Grants, Actual Amount ($1,712,904).

In 2008, NPEI collected a total of $1,712,904 of capital contributions, which were recorded in account 1995. These contributions were collected in accordance with the Distribution System Code and NPEI's Conditions of Service.

Table 2-20 2009 Capital Projects

Project Number	Project Description	Total Cost	1820 Distribution Station Equipment	1830 Poles, Towers and Fixtures	1835 OH Conductors and Devices	1840 UG Conduit	1845 UG Conductors and Devices	1850 Line Trans-formers	1855 Services	1860 Meters
2009-0001	Caistor Center Conversion Ph 4	269,384		60,266	71,374	-	13,746	105,706	18,291	-
2009-0002	Rebuild Survey Area 2009	726,884		190,124	296,222	39,709	37,136	95,236	68,456	-
2009-0003	Stanley-Portage to HWY #405	158,866		12,942	69,498	286	41,906	19,505	14,730	-
2009-0005	2009 Kiosk/Subm Conversion	868,509		1,572	2,841	16,824	630,403	216,869	-	-
2009-0010	North Service Rd Extension	303,080		77,714	168,044	-	12,439	44,884	-	-
2009-0013	Lundys Ln-Kalar-Garner Rebuild	737,092		197,540	180,877	26,069	208,790	99,516	11,854	12,444
2009-0014	Fonthill 27.6kV Extension	641,197		66,489	207,789	2,476	243,073	102,550	18,618	203
2009-0033	Mountain Rd-RMN Rebuild	262,020		49,494	61,074	61,990	72,511	15,959	992	-
2009-0040	Pelham DS Rebuild-Fonthill	271,281		2,043	62,443	-	29,853	176,942	-	-
2009-0042	Durham Ph11 Voltage Conversion	242,462		107,887	109,387	-	-	25,189	-	-
2009-0062	Renaissance Hotel 2500amp Ser	170,737		-	-	16,725	154,012	-	-	-
2009-1007	Non-Project System Betterments	534,199		29,294	43,848	47,877	291,346	104,969	16,864	-
2009-1008	Non-Project Demand Work	243,671		18,933	47,090	-	17,664	106,673	52,717	593
2009-1009	Services Non-Project Related	154,874		-	-	-	2,254	-	152,620	-
2009-1010	2009 Pole Replacement Program	451,176		391,821	32,380	-	-	26,231	744	-
2009-2007	Capital Non-Project Betterments	137,615		23,667	53,238	145	2,184	51,592	6,789	-
2009-2008	Capital Non-Project Demand Work	256,992		32,076	29,719	-	5,571	157,177	32,449	-
2009-2009	Underground Servicing PW area	59,096		-	-	-	-	-	59,096	-
2009-2010	Pole Replacement PW 2009	369,754		331,809	31,112	-	650	6,183	-	-
	Land Purchase - Montgomery Street	279,505								
	Scrap Transformers	(242,762)						(242,762)		
	Contributions and Grants	(1,197,961)								
	Buildings and Fixtures	2,385,705								
	Office Furniture and Equipment	161,652								
	Computer Hardware	185,269								
	Computer Software	369,215								
	Transportation Equipment	589,462								
	All Projects Under Materiality Threshold	2,310,965	276,481	388,577	593,875	259,048	437,042	109,878	(129,568)	245,189
	Totals	**11,699,938**	**276,481**	**1,982,247**	**2,060,811**	**471,148**	**2,200,580**	**1,222,298**	**324,654**	**258,429**

	1905	1908	1915	1920	1925	1930	1935	1940	1945	1955	1960	1995	
Project Description	**Land**	**Buildings and Fixtures**	**Office Furniture and Equipment**	**Computer Hardware**	**Computer Software**	**Trans-portation Equipment**	**Stores Equipment**	**Tools, Shop and Garage Equipment**	**Measure-ment and Testing Equipment**	**Comm-unication Equipment**	**Misc-ellaneous Equipment**	**Contrib-utions and Grants**	**Project Total**
Caistor Center Conversion Ph 4													269,384
Rebuild Survey Area 2009													726,884
Stanley-Portage to HWY #405													158,866
2009 Kiosk/Subm Conversion													868,509
North Service Rd Extension													303,080
Lundys Ln-Kalar-Garner Rebuild													737,092
Fonthill 27.6kV Extension													641,197
Mountain Rd-RMN Rebuild													262,020
Pelham DS Rebuild-Fonthill													271,281
Durham Ph11 Voltage Conversion													242,462
Renaissance Hotel 2500amp Ser													170,737
Non-Project System Betterments													534,199
Non-Project Demand Work													243,671
Services Non-Project Related													154,874
2009 Pole Replacement Program													451,176
Capital Non-Project Betterments													137,615
Capital Non-Project Demand Work													256,992
Underground Servicing PW area													59,096
Pole Replacement PW 2009													369,754
Land Purchase - Montgomery Street	279,505												279,505
Scrap Transformers													(242,762)
Contributions and Grants												(1,197,961)	(1,197,961)
Buildings and Fixtures		2,385,705											2,385,705
Office Furniture and Equipment			161,652										161,652
Computer Hardware				185,269									185,269
Computer Software					369,215								369,215
Transportation Equipment						589,462							589,462
All Projects Under Materiality Threshold	-	-	-	-	-	-	18,090	49,335	12,160	45,272	5,586	-	2,310,965
	279,505	**2,385,705**	**161,652**	**185,269**	**369,215**	**589,462**	**18,090**	**49,335**	**12,160**	**45,272**	**5,586**	**(1,197,961)**	**11,699,938**

Details of 2009 Projects in Excess of Materiality

As explained in the Activity Drivers section of this Exhibit, NPEI has grouped typical drivers of capital expenditures into 11 categories, which are used consistently each year when preparing the capital budget. The details of the 2009 projects with cost in excess of NPEI's materiality threshold are arranged below according to these categories of activity drivers.

<u>Category 1: Expansion and Reinforcement of the Primary Distribution System to Accommodate Load Growth and Reliability Requirements.</u>

Project 2009-0001: Caistor Centre Conversion Phase 4, Total Cost $269,384.

The fourth and final phase of the Caistor Center voltage conversion consisted of Single Phase line rebuild along Regional Road 2 from Regional Road 65 South to York Street, along with final conversion completed in 2008, on Regional Road 65 to Westbrook Road. This line rebuild provided for conversion of the remaining 8.32 kV loads supplied from the Woodburn MS to 27.6 kV from the M2 feeder supplied from the Niagara West transformer station. This final phase of the voltage conversion project resulted in the elimination of a wholesale metering point, and provides for greater reliability than what was provided from the Hydro One source at Woodburn. Future load growth and voltage regulation issues were also addressed by this work.

Project 2009-0003: Stanley – Portage to Hwy 405, Total Cost $158,866.

In 2004 Niagara Falls Hydro purchased from Hydro One a section of overhead line along Stanley Avenue from the Stanley transformer station to highway 405. Niagara Falls Hydro was a joint use tenant on this line and the Hydro One distribution facilities were being decommissioned. The purchase cost of the assets was minimal based upon condition assessment but significant restoration work was necessary to maintain the required NFH distribution apparatus. Due to the requirements of the OPG tunnel project a substantial portion of this line was rebuilt to accommodate the projects electrical demand. The remaining portion, identified above, required rebuilding to complete the line replacement. Construction of Phase I from Churches Lane to Whirlpool Road, along with Design of the remaining portion of this new line was completed in 2008. Due to additional line relocation requirements in 2008, this work was delayed and was completed in 2009.

Project 2009-0010: North Service Road Extension, Total Cost $303,080.

This project was designed to provide for an approximate 1KM 3-Phase 27.6KV Extension supplied by the F-1 from Vineland D.S., between Cherry Ave. and Martin Rd. on the North Service Road to eliminate a deteriorated Overhead 27.6 kV Highway Crossing, which was removed upon completion.

Project 2009-0013: Lundy's Lane – Kalar – Garner Rebuild, Total Cost $737,092.

Previously, the commercial customers along this section of Lundy's Lane were supplied from an overhead distribution line that utilized insulated conductors in a bundled configuration (known as “Hendrix Cable”) for improved appearance, and to minimize spacing required. Although the cabling system was in good condition, the concrete poles supporting the wire were in need of replacement. Based on the Road Authorities recommendations the intent to replace the poles and transfer the equipment on a pole for pole basis, was increased in scope to a line re-build/relocation to conform to Speed Limit Requirements, while still allowing for the re-utilization of the underground conductors supplying the individual customer loads. The build also incorporates a three-phase extension South on

Garner Road to tie in with work completed in 2008 to introduce the K-M-7 tie required at the R.O.W.

Project 2009-0014: Fonthill 27.6 kV Extension, Total Cost $641,197.

This project was designed to provide for an alternate 27.6 kV supply to the town of Fonthill. Previously, Fonthill was supplied from a single, radial feed 27.6 kV circuit from Hydro One sources. The work involved the construction of a new 27.6 kV express feeder connecting to the 45M6 feeder on Merrit Road and travelling underground along Pelham Road and overhead along Port Robinson Road and Station Street, and connecting to 45M7 feeder at Station Street and Regional Road 20.

Project 2009-0040: Pelham DS Rebuild - Fonthill, Total Cost $271,281.

This project involved the replacement of the 27.6/4.16 kV Distribution Station equipment supplying the Town of Fonthill, including a new 27.6/8.32/4.16 kV 5000 KVA Transformer (which can be moved elsewhere on the System in the future), and the replacement of both high and low voltage switchgear. This project was completed in 2010.

Project 2009-0042: Durham Phase 2 Voltage Conversion, Total Cost $242,462.

The station was constructed on a temporary basis years ago to deal with increasing loads and was not constructed in a manner that would provide for a long-term reliable source of power. By rebuilding and converting 8.32 kV customer loads along Durham Road, Greenlane Road and Mountainview Road, a reduction in loading was realized on the station and additional 27.6 kV ties made available to provide increased reliability in this area. This project was completed in 2010.

Category 2: Line Extensions/Relocations due to Municipal Road Work Requirements.

Project 2009-0033: Mountain Road – RMN Rebuild, Total Cost $262,020.

This project involved the relocation of primary distribution facilities on Mountain Road between Dorchester Road and Portage Road due to road widening conflicts for Regional Municipality of Niagara.

Category 3: Replacement of Poles Identified with Limited Structural Integrity.

Project 2009-1010: 2009 Pole Replacement Program Niagara Falls, Total Cost $451,176; Project 2009-2010: 2009 Pole Replacement Program Peninsula West, Total Cost $369,754.

This project involved replacing poles that were identified as requiring replacement under NPEI's annual Pole Inspection Program. Approximately 187 poles were replaced.

Category 4: Required Overhead Line Rebuild of Deteriorated Facilities Identified by the Pole Condition Survey

Project 2009-0002: Rebuild Survey Area 2009, Total Cost $726,884.

This rebuild program was directed at overhead distribution locations identified as nearing the end of life expectancy. In these locations the existing overhead distribution facilities were replaced with new overhead plant that incorporated new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2009 this program targeted the areas identified from the 2007 pole testing results.

The areas identified for rebuilding in 2009 include;

- Ker Street Drummond Road to Franklin St..
- Portions of 12 streets in the area contained by Dorchester Road, Drummond Road, Lundy's lane and Frederica Street.

Category 5: Replacement of Kiosks with EFD Switches and Posi-tects.

Project 2009-0005: 2009 Kiosk/Submersible Conversion, Total Cost $868,509.

In 2009 approximately 20 kiosks and 17 submersibles were converted or eliminated from the distribution system.

Category 6: Minor Betterment Allowance.

Category 8: Demand Based System Reinforcements for New Commercial Service Connections and Expansions.

Project 2009-1007: Capital Non-Project System Betterments Niagara Falls, Total Cost $534,199; Project 2009-1008: Capital Non-Project Demand Work Niagara Falls, Total Cost $243,671; Project 2009-1009: Services Non-Project Related Niagara Falls, Total Cost $154,874; Project 2009-2007: Capital Non-Project System Betterments Peninsula West, Total Cost $137,615; Project 2009-2008: Capital Non-Project Demand Work Peninsula West, Total Cost $256,992; Project 2009-2009: Services Non-Project Related Peninsula West, Total Cost $59,096.

These project categories are for work initiated by unexpected failures and new connection requests, requiring the expansion of distribution facilities. The predominant items included here are facilities to service new connections, unplanned underground cable replacements, minor overhead distribution system modifications and component replacements.

Project 2009-0062: Renaissance Hotel 2500 amp Service, Total Cost $170,737.

This project involved servicing the customer owned transformer and replacement of an existing NPEI switching station (85) with a below grade PVI unit.

<u>Category 7: Subdivisions and New Residential Services.</u>

2009 Subdivision Projects.

The following projects are directly related to the growth experienced in NPEI's service area. The capital costs are directly related to the underground system expansion and are required to accommodate the installation of these new residential/commercial subdivisions. Based on NPEI's subdivision agreement, developers bear the cost of the civil work and the installation of the Transformation, Switchgear and Primary and Secondary Distribution according to NPEI's engineering standards and specifications. NPEI contributes to the cost of these subdivisions using the economic evaluation methodology in accordance with the DSC and the provisions of its Conditions of Service for system expansions. Subdivisions energized in 2009 are listed below.

No subdivision projects in 2009 were in excess of the materiality threshold, and are therefore not itemized separately in Table 2-20:

- 2009-0031 Deerfield Estates Ph VIII $ 126,164

- 2009-0025 Cherryhill Gardens Ph III $ 31,976
- 2009-0149 Golden Horseshoe $ 14,540
- 2009-0008 Fernwood Estates Ph II $ 14,296
- 2009-0148 Jordan Village Estates $ 9,010
- 2009-0096 Maplecrest $ 1,411
- 2009-0097 Wesley Gardens $ 574
- 2009-0098 Smithville on the 20 Ph II $ 400

Category 9: Metering.

There were no individual projects in this category with cost in excess of the materiality threshold.

Category 10: Vehicles.

2009 Transportation Equipment, Total Cost $589,462.

The 2009 additions to account 1930 Transportation Equipment consist of the following:

- 55 ft Aerial Manlift and Body $ 204,820
- 45 ft Radial Boom Derrick and Body $ 182,293
- Cab and chassis only, 2010 International 7400 $ 85,871
- Cab and chassis only, 2010 Freightliner M2 $ 85,380
- 2010 Ford F150 pickup truck $ 31,097

The Aerial Manlift was purchased to assemble on the Freightliner M2 cab and chassis that was acquired in 2008. The Radial Boom Derrick was purchased to assemble on the International 7400 cab and chassis that was acquired in 2008. One cab and chassis only was purchased in 2009, with a Radial Boom Derrick and body to be purchased in 2010, to replace a 1990 Ford LS 8000 due to its age and condition. The other cab and chassis only was purchased in 2009, with an Aerial Manlift and body to be purchased in 2010, to replace a 1995

International due to its age. The new pickup truck was purchased to be used as the on-call vehicle. The previous on-call vehicle that was purchased in 2008 was rolled down to be used as a crew vehicle; one of the crew vehicles was then rolled down to be used by the maintenance person and the old maintenance vehicle was removed from service.

Category 11: Other Capital Expenditures.

2009 Land, Total Cost $279,505.

In 2009, NPEI purchased a parcel of land immediately adjacent to its current Niagara Falls property.

2009 Buildings and Fixtures, Total Cost $2,385,705.

The 2009 additions to account 1908 Buildings and Fixtures consist of the following:

• Construction of new service centre in Smithville	$ 2,291,557
• Replace roof on Niagara Falls building	$ 84,000
• New mailbox	$ 4,104
• Gate reader	$ 2,979
• Fire alarm	$ 2,615
• Final payment on 2008 Niagara Falls renovation	$ 450

2009 Office Furniture and Equipment, Total Cost $161,652.

The 2009 additions to account 1915 Office Furniture and Equipment consist of the following:

- Office furniture for new service centre $ 129,930
- New photocopier $ 13,495
- Office furniture for Niagara Falls office $ 5,355
- Filing cabinets/bookcases $ 5,288
- Appliances for new service centre $ 3,512
- Miscellaneous office equipment $ 2,312
- Fax machines $ 1,760

2009 Computer Hardware, Total Cost $185,269.

The 2009 additions to account 1920 Computer Hardware consist of the following:

- Integration of phone system to CIS IVR $ 47,517
- Network (Switches and Proxy AV) $ 47,340
- New/replacement PCs and Monitors $ 25,955
- Servers $ 21,000
- Telephone system $ 18,640
- Meter reading devices $ 14,828
- Replacement batteries for UPSs $ 8,089
- Miscellaneous Hardware $ 1,495
- Printers $ 406

2009 Computer Software, Total Cost $369,215.

The 2009 additions to account 1925 Computer Software consist of the following:

- Work Management/ Outage Management solution $ 269,018
- Microsoft Office upgrade $ 54,023
- Microsoft Great Plains Forecaster $ 24,482
- Oracle Database $ 15,854
- Harris Northstar API onetime cost for IVR integration $ 3,246

- Mapping software $ 2,592

2009 Contributions and Grants, Actual Amount ($1,197,161).

In 2009, NPEI collected a total of $1,197,161 of capital contributions, which were recorded in account 1995. These contributions were collected in accordance with the Distribution System Code and NPEI's Conditions of Service.

Table 2-21 2010 Capital Projects

Project Number	Project Description	Budgeted Total Cost	1820 Distribution Station Equipment	1830 Poles, Towers and Fixtures	1835 OH Conductors and Devices	1840 UG Conduit	1845 UG Conductors and Devices	1850 Line Trans-formers	1855 Services	1860 Meters
2010-0001	Robinson St. - Allendale to Fallsview	335,026		-	-	295,113	25,329	14,584	-	
2010-0002	High Street Area	231,242		69,152	74,579	-	11,182	34,727	41,602	
2010-0006	Switchgear Replacement - 4 Units	392,785	-	43,428	135,949	16,893	189,964	6,551	-	
2010-0007	Murray St. Area	232,573		175,189	13,665	8,217	33,087	846	1,569	
2010-0008	Oakwood Drive	200,502		59,786	67,198	36,602	35,515	1,402	-	
2010-0016	Dorchester NS&T to Morrison	179,549		54,242	67,480	8,703	35,120	14,004	-	
2010-0017	Campden DS Feeder Egress/Poles	163,692		163,692	-	-	-	-	-	
2010-0020	Kiosk Conversions	512,307	-	4,400	6,176	38,783	314,499	133,235	15,213	
2010-0023	Durham Voltage Conversion	269,145	-	106,961	90,046	-	288	60,705	11,145	
2010-0024	Cherry Ave.	181,680		64,774	77,938	8,949	2,402	21,695	5,923	
2010-0026	South Pelham St. Fonthill	690,966	-	50,943	24,545	301,880	221,814	76,243	15,541	
2010-0033	Fernwood Estates Ph II	204,595		-	-	7,247	119,334	78,014	-	
2010-0053	Oakwood Dr at McLeod - Relocate	158,191		43,434	56,917	17,340	31,267	9,233	-	
2010-1007	Minor Betterments	648,867		61,971	129,019	102,064	160,239	159,843	35,731	
2010-1008	Demand Work	275,083		29,772	19,585	3,158	61,753	125,109	35,705	
2010-1009	Subdivision Connections (combined)	163,207		-	-	-	71,811	91,396	-	
2010-1010	Pole Changes	371,552		273,958	56,891	112	148	40,443	-	
2010-2007	Minor Betterments	169,322		35,042	35,316	9,285	19,356	62,137	8,187	
2010-2008	Demand Work	135,919		13,260	15,266	-	4,662	75,847	26,883	
2010-2009	Underground Servicing PW Area	107,381		-	-	-	-	-	107,381	
2010-2010	Pole Changes	303,190		264,115	23,161	-	-	12,273	3,641	
	Meters	200,000								200,000
	Mobile Substation	200,000	200,000							
	New Lot Connections (combined)	200,000		-	-	100,000	100,000	-	-	
	Lot Rebates	150,000		-	-	-	-	-	150,000	
	Contributions and Grants	(1,200,000)								
	Buildings and Fixtures	200,000								
	Office Furniture and Equipment	75,250								
	Computer Hardware	285,382								
	Computer Software	300,000								
	Transportation Equipment	855,000								
	Tools & Equipment	126,428								
	Demand Projects Under Materiality	1,083,140		210,051	233,975	41,951	249,664	331,992	15,508	
	All Other Projects Under Materiality Threshold	1,788,528	-	1,211,603	127,494	251,124	70,233	115,181	12,894	-
	Total Budgeted	**10,190,503**	**200,000**	**2,935,774**	**1,255,199**	**1,247,421**	**1,757,666**	**1,465,460**	**486,923**	**200,000**
	Add: Smart Meters to Rate Base	4,175,010								4,175,010
	Less: Reduction for HST ITCs	(387,531)	(14,815)	(75,161)	(23,872)	(72,381)	(33,872)	(81,450)	-	(5,469)
	Revised Total	**13,977,982**	**185,185**	**2,860,613**	**1,231,327**	**1,175,040**	**1,723,794**	**1,384,010**	**486,923**	**4,369,541**

		1905	1908	1915	1920	1925	1930	1935	1940	1945	1955	1960	1995	
Project Number	**Project Description**	**Land**	**Buildings and Fixtures**	**Office Furniture and Equipment**	**Computer Hardware**	**Computer Software**	**Trans-portation Equipment**	**Stores Equipment**	**Tools, Shop and Garage Equipment**	**Measure-ment and Testing Equipment**	**Comm-unication Equipment**	**Misc-ellaneous Equipment**	**Contrib-utions and Grants**	**Project Total**
2010-0001	Robinson St. - Allendale to Fallsview													335,026
2010-0002	High Street Area													231,242
2010-0006	Switchgear Replacement - 4 Units													392,785
2010-0007	Murray St. Area													232,573
2010-0008	Oakwood Drive													200,502
2010-0016	Dorchester NS&T to Morrison													179,549
2010-0017	Campden DS Feeder Egress/Poles													163,692
2010-0020	Kiosk Conversions													512,307
2010-0023	Durham Voltage Conversion													269,145
2010-0024	Cherry Ave.													181,680
2010-0026	South Pelham St. Fonthill													690,966
2010-0033	Fernwood Estates Ph II													204,595
2010-0053	Oakwood Dr at McLeod - Relocate													158,191
2010-1007	Minor Betterments													648,867
2010-1008	Demand Work													275,083
2010-1009	Subdivision Connections (combined)													163,207
2010-1010	Pole Changes													371,552
2010-2007	Minor Betterments													169,322
2010-2008	Demand Work													135,919
2010-2009	Underground Servicing PW Area													107,381
2010-2010	Pole Changes													303,190
-	Meters													200,000
-	Mobile Substation													200,000
-	New Lot Connections (combined)													200,000
-	Lot Rebates													150,000
-	Contributions and Grants												(1,200,000)	(1,200,000)
-	Buildings and Fixtures		200,000											200,000
-	Office Furniture and Equipment			75,250										75,250
-	Computer Hardware				285,382									285,382
-	Computer Software					300,000								300,000
-	Transportation Equipment						855,000							855,000
-	Tools & Equipment							18,900	94,946	4,690	2,843	5,049		126,428
-	Demand Projects Under Materiality													1,083,140
-	All Other Projects Under Materiality Threshold	-	-	-	-	-	-	-	-	-	-	-	-	1,788,528
		-	**200,000**	**75,250**	**285,382**	**300,000**	**855,000**	**18,900**	**94,946**	**4,690**	**2,843**	**5,049**	**(1,200,000)**	**10,190,503**
														4,175,010
		-	(11,443)	(4,686)	(11,882)	(21,046)	(30,851)	-	(604)	(0)	-	-	-	(387,531)
		-	**188,557**	**70,564**	**273,500**	**278,954**	**824,149**	**18,900**	**94,342**	**4,690**	**2,843**	**5,049**	**(1,200,000)**	**13,977,982**

Harmonized Sales Tax

NPEI notes that a Harmonized Sales Tax ("HST") was implemented in Ontario, effective July 1, 2010, replacing the former Ontario Provincial Sales Tax ("PST"). Prior to July 1, 2010, any PST paid by NPEI in relation to capital expenditures was included as part of the capital cost. As of July 1, 2010, the full amount of HST paid by NPEI is recovered through Input Tax Credits ("ITCs"), subject to certain restrictions. The PST amounts that were formerly capitalized, and therefore included in rate base, are no longer included in rate base after July 1, 2010.

NPEI did not contemplate the impacts of implementing HST when the original 2010 capital budget was prepared. In order to remove the appropriate amount from the original budget, NPEI employed the following procedure:

a) The actual year-to-date capital expenditures, as at June 30, 2010, were deducted from the original 2010 budgeted amounts for each capital account, to determine a remaining budget amount. For each USoA capital account, NPEI maintains sub-accounts for:
   i) Labour
   ii) Truck Time
   iii) Materials
   iv) A/P Purchases

b) The budget-remaining amounts, for the accounts that are subject to HST (ie Materials and A/P Purchases), were divided by 1.08 to reflect the revised budget-remaining value with PST removed.

c) The revised budget-remaining amounts, which now reflect expected capital expenditures for July to December 2010 net of PST, were added back to the actual January to June expenditures to give the revised 2010 capital budget by account.

This procedure for adjusting for the impacts of HST can be seen in Table 2-21, above. The rows in the table that give the breakout of the individual projects reflect the costs that were originally budgeted, including the former PST. The original 2010 capital budget was $10,190,502. The reduction for HST is displayed as a separate row, indicating the amount that was removed from each account, for a total reduction to capital additions of $387,531.

NPEI is also requesting that $4,175,010 of Smart Meter capital expenditures be included in rate base for 2011. Accordingly, NPEI has incorporated this amount as an addition to account 1860 in 2010, so that the 2011 opening rate base balance includes the requested smart meter capital. This item is displayed on a separate line in Table 2-21. Further details on NPEI's proposed treatment of Smart Meters can be found in Exhibit 9.

Details of 2010 Projects in Excess of Materiality

As explained in the Activity Drivers section of this Exhibit, NPEI has grouped typical drivers of capital expenditures into 11 categories, which are used consistently each year when preparing the capital budget. The details of the 2010 projects with cost in excess of NPEI's materiality threshold are arranged below according to these categories of activity drivers.

Category 1: Expansion and Reinforcement of the Primary Distribution System to Accommodate Load Growth and Reliability Requirements.

Project 2010-0001: Underground Primary Extension-Robinson St.—Allendale to Fallsview, Estimated Cost $335,026.

Due to increasing load growth & proposed development within the Fallsview Tourist/Commercial Core the introduction of an additional feeder into the network was required. The proposal included the construction of a duct bank for extension of a 600 Amp 13,800 Volt distribution feeder using the Murray Station 3-M-54 from the existing double circuit pole line in the Hydro One Corridor to the manhole/switchgear assembly @ Station #33 on Fallsview Blvd., continuing to a new Manhole/Switchgear assembly on Clarke Ave, including replacement of high voltage switchgear at Old Stone Inn Stn. #48 and modifications to the Budget Inn Stn. #120. The construction provides load relief & alternate buss supply to loads currently supplied by the 3-M-29 feeder. This project carries into 2011.

Project 2010-0006: Pad-mounted Switchgear Replacements, Estimated Cost $392,785.

Results of the Underground Equipment Inspections Program have identified the requirement for the replacement of pad-mounted switchgear units. The project scope includes the installation of manholes and other civil works associated with the equipment replacements to current standards.

Project 2010-0016: Dorchester NS&T to Morrison, Estimated Cost $179,549.

Due to the age and clearance issues between the 4.16 KV and 13.8KV circuits in this area it was necessary to eliminate the three-phase overhead Spun 5KV circuit along Dorchester Road. The load from this line was transferred to the 12M32 distribution circuit by placement of 2-Pole Mounted Step Down transformers along Cherrygrove, and a small rebuild/conversion of line on Dianne/Queensway Gardens.

Project 2010-0017: Campden DS Feeder Egress/Poles, Estimated Cost $163,692.

This project involved the replacement of the 27.6/8.32 kV Distribution Station equipment supplying rural areas in the Town of Lincoln, including the replacement of both high and low voltage switchgear and high voltage and low voltage circuits egressing from the station. This project will be completed in 2011.

Project 2010-0023: Durham Voltage Conversion Phase 2, Estimated Cost $269,145.

The final phase of this voltage conversion project continued from 2009. This phase achieved a complete load conversion and elimination of the station.

Project 2010-0024: Cherry Ave 27.6 kV Supply Extension, Estimated Cost $181,680.

The project scope was extension of approximately 1 km of 3-Phase 8.32 KV supply from Yonge Street, on Cherry Avenue, to eliminate a deteriorated, inaccessible overhead 8.32 kV circuit through the Twenty Valley Golf Course property.

2010 Mobile 27.6 kV / 8.32 kV Substation, Estimated Cost $200,000.

A review of system configurations has revealed a lack of redundant supply points between the 5-existing Distribution Sub-Stations within the Western Service Area, namely Campden, Greenlane, Jordan, Smithville, and Durham. In the event of a failure, replacement procurement for this type of transformer is in the order of 20-weeks. A spare station type unit is not practical due to the varied primary & secondary circuit configurations involved, making a drop in place unit difficult. The proposed solution would involve the construction of a pad-mounted dead front transformer in the order of 3000 KVA, which could be installed on a trailer, with pre-terminated underground cable, which could be parked within or near a station compound and connected in the event of a failure. The unit could also be used at Pelham & Station St. D.S. & Margaret St. Stn. #14.

Category 2: Line Extensions/Relocations due to Municipal Road Work Requirements.

Project 2010-0008: Oakwood Drive – Smart Centre construction conflicts, Estimated Cost $200,502; Project 2010-0053: Oakwood Drive at McLeod Relocate, Estimated Cost $158,191.

The scope of work for these two projects involved the replacement of a portion of the existing 3-M-30 15 KV single circuit 3-phase pole line with a double circuit pole line using the K-M-6 & K-M-2 feeders. This also incorporates the relocation of a section of off-road line, south of the construction limits to the boulevard, improving access & facilitating road lighting. Construction was required due to construction conflicts with the Smart Centre road works, and system requirements for additional circuit inter-tie capabilities between Kalar M.T.S. and Murray T.S. improving feeder load balancing and contingency options.

Project 2010-0026: South Pelham St – Fonthill downtown core, Estimated Cost $690,966.

Scope involved the replacement of existing 3-phase overhead 5kV Distribution Feeder F-5 in downtown Fonthill. Construction required due to conflicts with Municipal road widening/improvement works. A combination of overhead & underground distribution plant was installed.

Category 3: Replacement of Poles Identified with Limited Structural Integrity.

Project 2010-1010: Pole Replacement – Niagara Falls area, Estimated Cost $371,552; Project 2010-2010: Pole Replacement – Peninsula West area, Estimated Cost $303,190.

These projects involved replacing poles that were identified as requiring replacement under NPEI's annual Pole Inspection Program. Approximately 150 poles are expected to be replaced.

Category 4: Required Overhead Line Rebuild of Deteriorated Facilities Identified by the Pole Condition Survey

Project 2010-0002: High St. Area, Estimated Cost $231,242; Project 2010-0007: Murray St. area, Estimated Cost $232,573.

This rebuild program (two projects) was directed at overhead distribution locations identified as nearing the end of life expectancy. In these locations the existing overhead distribution facilities were replaced with new overhead plant that incorporated new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2010 this program targeted the areas identified from the 2007 pole testing results.

The areas identified for rebuilding in 2010 include;

- Portions of streets in the area contained by Dunn Street, Drummond Road, Symmes and Main Street.
- Completion of the area contained by Dorchester Road, Drummond Road, Lundy's lane and Frederica Street

Category 5: Replacement of Kiosks with EFD Switches and Posi-tects.

Project 2010-0020: Kiosk Conversions, Estimated Cost $512,307.

In 2010 approximately 10 kiosks and 11 submersibles are expected to be converted or eliminated from the distribution system.

Category 6: Minor Betterment Allowance.

Category 8: Demand Based System Reinforcements for New Commercial Service Connections and Expansions.

Project 2010-1007: Minor Betterments – Niagara Falls area, Estimated Cost $648,867; Project 2010-1008: Demand Work – Niagara Falls area, Estimated Cost $275,083; Project 2010-2007: Minor Betterments – Peninsula West area, Estimated Cost $169,322; Project 2010-2008: Demand Work – Peninsula West area, Estimated Cost $135,919; Project 2010-2009: Underground Servicing – Peninsula West area, Estimated Cost $107,381.

These project categories are for work initiated by unexpected failures and new connection requests, requiring the expansion of distribution facilities. The predominant items included here are facilities to service new connections, unplanned underground cable replacements, minor overhead distribution system modifications and component replacements.

Category 7: Subdivisions and New Residential Services.

2010 Subdivisions and New Residential Services – combined area, Estimated Cost $163,207; 2010 New Lot Connections - combined area, Estimated Cost $200,000; 2010 Lot Rebates - combined area, Estimated Cost $150,000.

These projects are directly related to the growth experienced in NPEI's service area. The capital costs are directly related to the underground system expansion and are required to accommodate the installation of these new residential/commercial subdivisions. Based on NPEI's subdivision agreement, developers bear the cost of the civil work and the installation of the Transformation, Switchgear and Primary and Secondary Distribution according to NPEI's engineering standards and specifications. NPEI contributes to the cost of these subdivisions using the economic evaluation methodology in accordance with the DSC and the provisions of its Conditions of Service for system expansions.

In addition to the general subdivision projects listed above, NPEI also expects the following specific subdivision projects to be completed in 2010.

Subdivision projects in excess of the materiality threshold (included in Table 2-21 above):

- 2010-0033 Fernwood Estates Ph II $ 204,595

Other 2010 Subdivisions (not itemized separately in Table 2-21):

- 2010-0076 Deerfield Estates Ph 5 & 7 $ 72,161
- 2010-0096 Maplecrest $ 24,620
- 2010-0116 Maplecrest Ph II $ 22,865
- 2010-0098 Smithville on the 20 Ph II $ 6,799
- 2010-0077 Chippawa West Ph II $ 6,753
- 2010-0039 Edgewood Estates Ph II $ 4,187
- 2010-0093 Chestnut St $ 2,677
- 2010-0054 Highland Extension $ 803

Category 9: Metering.

2010 Metering, Estimated Amount $200,000.

The metering capital budget includes the typical revenue metering costs associated with new customer installations. Wholesale meter point upgrades, where required, are included in this budget item.

No individual projects are expected to exceed the materiality threshold in 2010.

Category 10: Vehicles.

2010 Transportation Equipment, Estimated Cost $855,000.

The expected 2010 additions to account 1930 Transportation Equipment consist of the following:

Proposed Vehicle Purchase for 2010

1) Purchase of a 47ft R.B.D. and Fibreglass Body to be installed on the 2010 Freightliner M2 cab and chassis purchased in 2009.	189,500.00
2) Purchase of a 46ft. Material Handling Aerial Manlift and Fiberglass Body to be installed on the 2010 International 7400 SBA chassis purchased in 2009.	179,600.00
3) Purchase of a 4x4 Pick-up. Roll truck 14 (2004) down to our Operations Supervisor and 27 (2004) down to one of our crews. Remove vehicle numbers 3, 23 and 36 from service.	35,900.00
4) Off Road Track machine with a C5048 Derrick, upper controls and a insulated bucket to assist in the safe maintenance of the vast amount of "off the road allowance poles" in the former Pen West service area	450,000.00
Total cost for new vehicles purchased in 2010	855,000.00

Item 4 in the proposed vehicle purchases for 2010 represents the estimated cost of a new off-road capable line vehicle with an aerial bucket and boom derrick configuration to facilitate off road (inaccessible) area access for pole replacement purposes. Evaluation of the pole location data through GIS system inquiry indicates that over 1,300 poles within the distribution system in the Lincoln and West Lincoln areas are inaccessible to our line truck fleet. Historically, the condition of these poles has not been evaluated to determine the risk they present to the utility if and when they fail. While the ideal solution to this inaccessible distribution plant would be relocation to the road allowance, it is not economically feasible and cannot be accomplished within a reasonable scope of time that would permit an approach of relocation only. Inaccessible poles, identified with limited structural integrity must be addressed within the pole replacement program to ensure the continuation of safe and reliable electricity distribution in these rural areas.

To date, off road equipment has been acquired through local private contractors to replace damaged poles during contingency periods. The process has been mostly reactionary in nature, repairing poles and lines that have failed during severe weather events, resulting in extended customer outages and increased public hazards. There is no guarantee that private equipment will be available for use when a contingency arises. A utility owned off road capable vehicle utilized for a planned inaccessible pole replacement program would provide for the necessary changes to maintain the plant appropriately and would guarantee vehicle access during a contingency event. Investigation into the required equipment configuration has begun with several equipment manufactures. As well, inquiry into used equipment has been made and is a favorable approach to minimize the initial purchase cost. Manufacturers have indicated an average life expectancy of new equipment is 20 to 25 years with proper maintenance, good quality used equipment could easily reach 15 to 20 years with the advantage of a significantly reduced initial cost.

Category 11: Other Capital Expenditures.

2010 Buildings and Fixtures, Estimated Cost $200,000.

NPEI expects to incur the following building costs in 2010, relating to the Niagara Falls building:

	TOTAL
Meter Shop	
REMOVE EXISTING FLOOR, CEILING & MILLWORK	1,800.00
NEW FLOOR METER SHOP	17,200.00
SUSPENDED CEILING METER SHOP	8,600.00
MILLWORK METER SHOP	6,800.00
MASONRY - CUTTING & PATCHING METER SHOP	3,700.00
DRYWALL - CUTTING & PATCHING	3,700.00
	41,800.00
Lighting	
ELECTRICAL DEMOLITION, METER SHOP, TRUCK BAY STORES, REPAIR BAY	16,000.00
LIGHTING & DISTRIBUTION TRUCK BAY	53,500.00
LIGHTING & DISTRIBUTION REPAIR BAY	16,500.00
LIGHTING & DISTRIBUTION STORES	29,500.00
LIGHTING & DISTRIBUTION METER SHOP	19,000.00
ELECTRICAL MISC.	13,500.00
	148,000.00
	$189,800.00
CONTINGENCY	$10,200.00
	$200,000.00

2010 Office Furniture and Equipment, Estimated Cost $75,250.

The 2010 expected additions to account 1915 Office Furniture and Equipment consist of the following:

Narrow aisle forklift for Smithville Service Centre	16,740
Dustbane floor cleaning machine	5,265
Cheque encorder	5,000
Cheque signing machine	3,250
Plotter	20,000
Outdoor furniture	24,745
	75,000

2010 Computer Hardware, Estimated Cost $285,382.

The expected 2010 additions to account 1920 Computer Hardware consist of the following:

HARDWARE

Network	Item	Purpose	Quantity	Approx Cost
	48 Port Nortel Switch	Hot Spare - Data	1	$ 5,500.00
	Backup internet link in Niagara Falls	Redundancy	1	$ 3,000.00
	Backup internet link in Smithville	Redundancy	1	$ 3,000.00
	KVM switch for Niagara Falls for Blade Chasis	Allows for remote access and control of blade servers	1	$ 3,800.00
	Proxim Wireless Access Points (quantity to be determined by designer)	Motorola 810 requirement for fleet communications (laptops in trucks)	1	$ 600.00
				$ 15,900.00

Servers	Item	Purpose	Quantity	Approx Cost
	LT04 Library Backup Solution	Improved backup system from using tape	1	$ 10,000.00
	Server	Backup server	1	$ 9,500.00
	Server	Migration server for G and Inservice	1	$ 9,500.00
	Server	Laserfiche/Lexus	1	$ 9,500.00
	Equallogic SAN	Extra storage	1	$ 60,000.00
	Harris to Move Billing from IBM to Dell Blade	Optimization Maintenance		$ 15,000.00
	Consolidate Informix / Jboss on 1 Server	Optimization Maintenance		$ 15,000.00
	Expand memory on IBM server to improve system performance	Optimization Maintenance	4GB	$ 2,587.34
	Web Server	Intranet, web based applications	1	$ 9,500.00
				$ 140,587.34

Printers	Item	Purpose	Quantity	Approx Cost
	HP9050 Printer for Billing Department	Replace current Lexmark T622 due to volumes of printing	1	$ 6,000.00
	Replacement of HP printer	Replacement of current HP	1	$ 2,500.00
	Replacement of T620	Replacement of current T620	1	$ 2,500.00
	Lexmark	Printer for Barb K	1	$ 650.00
	Lexmark	Printer for Suzanne	1	$ 400.00
				$ 12,050.00

Phones	Item	Purpose	Quantity	Approx Cost
	Professional Services	Integration of phone system to CIS/Outage Management/IVR	1	$ 25,000.00
	Recording Solution	Archive of Calls,etc	1	$ 8,000.00
	Mitel Headset	Ease of answering calls hands free	3	$ 1,095.00
	Mitel Cordless Handset & Mod Bundle for phone in Control room	Cordless handset for ease of answering the call regardless of user location	1	$ 440.00
	Bluetooth phone	handsfree for cell phones	25	$ 3,000.00
	Office phones required (3 5330 IP phone (backlit) + UC Basic User (3 license) + Professional services)	Add as required	3	$ 1,200.00
				$ 38,735.00
PC / Monitor	**Item**	**Purpose**	**Quantity**	**Approx Cost**
	PC Replacements	Add PCs as required	14	$ 7,000.00
	Motorola 810	Deployment of Inservice field use in Operations, and mcare in Metering	10	$ 55,000.00
				$ 62,000.00
LCD Projectors	NEC VT595 XGA 2000 ANSI LUNCENS PROJECTORS	Niagara Falls and West Lincoln Training Room LCD Projectors (not mounted)	2	$ 1,260.00
				$ 1,260.00
Equipment	Radix Handhelds	Meter reading	2	$ 9,500.00
	Northrup Probes	Meter reading	2	$ 4,750.00
	Verseprobe battery charger	Meter reading	5	$ 600.00
				$ 14,850.00
TOTAL HARDWARE				**$ 285,382.34**

2010 Computer Software, Estimated Cost $300,000.

The expected 2010 additions to account 1925 Computer Software consist of the following:

SOFTWARE	Item	Purpose	Quantity	Approx Cost
Customer Service	Interactive Queue	Realtime monitoring of ACD reps and allocating them real time	1	$ 8,500.00
Customer Service	Visual Queue	Interactive routing of calls based on metrics in system	1	$ 2,300.00
Customer Service	Intelligent Queue	Software needed for voice callback and time in queue notification	1	$ 20,000.00
Customer Service	Alertworks	Automated voice call back and survey for power outage, collections, scheduled maintenance	1	$ 10,500.00
Operations	Work Management/Outage Management Intergraph solution including software and professional services for installation and training	Work/Outage Management - TA module including primary and redundant including professional services	1	$ 65,000.00
Operations	Work Management/Outage Management Intergraph solution - remainder of project from 2009	Work/Outage Management	1	$ 33,300.00
Operations	Work Management/Outage Management Mobile software solution (inService mobile client)	Work/Outage Management	10	$ 3,000.00
Operations & Engineering	Oracle Licenses - Outage Management System	Per Device License	100	$ 22,000.00
Engineering & HR	Visio Licenses	Engineering and HR requirement	3	$ 900.00
Finance	Upgrade of Great Plains 9.00 to 11.00; Conversion of BRL License	Upgrade	1	$ 32,000.00
	Adobe Read/Write license	New requirement	5	$ 2,500.00
	DoubleTake for Linux	Needed for Billing Servers migration	1	$ 15,000.00
	Ebilling Harris Northstar module of Ecare for email billing + consultation on ebill	New requirement	1	$ 35,000.00
	Harris Northstar DSM module of E-care for web presentation of smart meter info	DSM/website link for bill presentment	1	$ 25,000.00
	Harris Northstar Professional Services	Implementation of Job Scheduler/misc as required		$ 25,000.00
TOTAL SOFTWARE				**$ 300,000.00**

2010 Tools and Equipment, Estimated Cost $126,428.

The expected 2010 additions to the other equipment accounts (1935, 1940, 1945, 1955, 1960) consist of the following:

1) Timberland Polemaster Payout Brake Spindles	**4**	**@**	**$825.00**	**3,300**
2) Timberland Poly-flex Rope and Reel	**4**	**@**	**$2,550.00**	**10,200**
3) Timberland Poly-flex Rope	**4**	**@**	**$1,500.00**	**6,000**
4) Gas Detectors	**2**	**@**	**$750.00**	**1,500**
5) Wire Cutters	**7**	**@**	**$100.00**	**700**
6) Wire Rack for Flat Bed Truck	**1**	**@**	**$5,600.00**	**5,600**
7) Lanetamer Sign System (Traffic)	**12**	**@**	**$325.00**	**3,900**
8) Chain Saws				
Sthl 200T	**4**	**@**	**$700.00**	**2,800**
Sthl O26	**3**	**@**	**$600.00**	**1,800**
9) Hastings 6790 High Voltage Amp Meter	**2**	**@**	**$1,000.00**	**2,000**
10) Megger (Insulation Resistance Tester) 1kv model # MIT 310-EN	**4**	**@**	**625.00**	**2,500**
11) Small Hand Cutters for ACSR Tri-Plex Service Wire	**26**	**@**	**250.00**	**6,500**
12) Miscellaneous Underground Cable Pulling Equipment				**6,000**
13) Required Tools to Stock New Material Handling Aerial Manlift				**15,000**
14) Miscellaneous tools				**36,428**
15) Insulated Cls 3 and Cls 4 Line Hose, Insulated Cls 4 Large and Small Blankets, Cls 4 Insulated Hoods (Most of the order is for the trucks in the Smithville location and is required to maintain ample cover-up on the trucks during the required annual testing of insulated cover-up. The remainder is to meet the minimum order requirement by the supplier.				**20,000**
16) Heart Start FRx Defibrillators	**1**	**@**	**2200**	**2,200**
Tools total				**126,428**

2010 Contributions and Grants, Estimated Amount ($1,200,000).

For 2010, NPEI expects to collect $1,200,000 in capital contributions to offset capital expenditures.

Table 2-22 2011 Capital Projects

Project Number	Project Description	Total Cost	1820 Distribution Station Equipment	1830 Poles, Towers and Fixtures	1835 OH Conductors and Devices	1840 UG Conduit	1845 UG Conductors and Devices	1850 Line Trans-formers	1855 Services	1860 Meters
2011-0001	KERR ST--LUNDY'S LANE--U/G REPLACEMENT	400,000		-	-	257,200	22,800	120,000	-	
2011-0002	LUNDY'S LANE-KALAR TO MONTROSE	500,000		185,000	65,000	83,000	17,000	50,000	100,000	
2011-0003	DOUBLE CCT - MONTROSE - MCLEOD TO CANADIAN	600,000		255,000	190,000	78,000	12,000	45,000	20,000	
2011-0004	ROBINSON ST - ALLENDALE TO FALLSVIEW	200,000				200,000				
2011-0005	RIALL ST--DORCHESTER TO ST PAUL O/H EXTN	290,000		150,000	69,500	29,000	-	29,000	12,500	
2011-0006	SWITCHGEAR REPLACEMENTS - 4 Units	400,000		-	-	68,000	332,000	-	-	
2011-0007	DUNN/DRUMMOND/SYMMES/MAIN	800,000		220,000	38,000	183,500	136,500	160,000	62,000	
2011-0009	KALAR RD-BEAVERDAMS TO NS&T ROW	550,000		185,000	131,000	37,500	100,000	55,000	41,500	
2011-0010	ROAD RELOCATION WORKS	200,000		143,000	54,000	-	-	-	3,000	
2011-0012	MISC ROAD RELOCATION WORK	200,000		89,500	77,500	-	-	15,000	18,000	
2011-0013	MUNICIPAL STATION REHABILITATION	500,000	500,000	-	-	-	-	-	-	
2011-0020	KIOSK CONVERSIONS	500,000		-	-	125,000	125,000	250,000	-	
2011-1007	MINOR BETTERMENTS	300,000		90,000	45,000	60,000	90,000	-	15,000	
2011-1008	DEMAND WORK	800,000		52,500	12,500	95,000	400,000	240,000	-	
2011-1009	SUBDIVISION CONNECTIONS COMBINED	650,000		-	-	100,000	232,000	168,000	150,000	
2011-1010	POLE CHANGES	500,000		380,000	45,000	32,500	14,500	16,500	11,500	
2011-2007	MINOR BETTERMENTS	200,000		58,000	57,000	25,500	34,500	-	25,000	
2011-2008	DEMAND WORK	400,000		95,000	49,000	15,000	77,500	132,500	31,000	
2011-2010	POLE CHANGES	750,000		565,500	33,750	25,500	34,500	64,500	26,250	
	Metering	200,000								200,000
	Contributions and Grants	(850,000)								
	Tools and Equipment	100,000								
	Office Furniture and Equipment	100,000								
	Computer Hardware	315,250								
	Computer Software	197,500								
	Transportation Equipment	500,000								
	All Projects Under Materiality Threshold	200,000	-	63,000	137,000	-	-	-	-	-
	Total Originally Budgeted	**9,502,750**	**500,000**	**2,531,500**	**1,004,250**	**1,414,700**	**1,628,300**	**1,345,500**	**515,750**	**200,000**
	Less: HST ITCs	(399,957)	(37,037)	(48,662)	(32,074)	(45,411)	(55,704)	(60,606)	(15,815)	(14,815)
	Revised Total	**9,102,793**	**462,963**	**2,482,838**	**972,176**	**1,369,289**	**1,572,596**	**1,284,894**	**499,935**	**185,185**

Project Number	Project Description	1905 Land	1908 Buildings and Fixtures	1915 Office Furniture and Equipment	1920 Computer Hardware	1925 Computer Software	1930 Trans-portation Equipment	1935 Stores Equipment	1940 Tools, Shop and Garage Equipment	1945 Measure-ment and Testing Equipment	1955 Comm-unication Equipment	1960 Misc-ellaneous Equipment	1995 Contrib-utions and Grants	Project Total
2011-0001	KERR ST--LUNDY'S LANE--U/G REPLACEMENT													400,000
2011-0002	LUNDY'S LANE-KALAR TO MONTROSE													500,000
2011-0003	DOUBLE CCT - MONTROSE - MCLEOD TO CANADIAN													600,000
2011-0004	ROBINSON ST - ALLENDALE TO FALLSVIEW													200,000
2011-0005	RIALL ST--DORCHESTER TO ST PAUL O/H EXTN													290,000
2011-0006	SWITCHGEAR REPLACEMENTS - 4 Units													400,000
2011-0007	DUNN/DRUMMOND/SYMMES/MAIN													800,000
2011-0009	KALAR RD-BEAVERDAMS TO NS&T ROW													550,000
2011-0010	ROAD RELOCATION WORKS													200,000
2011-0012	MISC ROAD RELOCATION WORK													200,000
2011-0013	MUNICIPAL STATION REHABILITATION													500,000
2011-0020	KIOSK CONVERSIONS													500,000
2011-1007	MINOR BETTERMENTS													300,000
2011-1008	DEMAND WORK													800,000
2011-1009	SUBDIVISION CONNECTIONS COMBINED													650,000
2011-1010	POLE CHANGES													500,000
2011-2007	MINOR BETTERMENTS													200,000
2011-2008	DEMAND WORK													400,000
2011-2010	POLE CHANGES													750,000
	Metering													200,000
-	Contributions and Grants												(850,000)	(850,000)
-	Tools and Equipment								100,000					100,000
-	Office Furniture and Equipment			100,000										100,000
-	Computer Hardware				315,250									315,250
-	Computer Software					197,500								197,500
-	Transportation Equipment						500,000							500,000
-	All Projects Under Materiality Threshold	-	-	-	-	-	-	-	-	-	-	-	-	200,000
		-	**-**	**100,000**	**315,250**	**197,500**	**500,000**	**-**	**100,000**	**-**	**-**	**-**	**(850,000)**	**9,502,750**
		-	-	(7,407)	(23,352)	(14,630)	(37,037)	-	(7,407)	-	-	-	-	(399,957)
		-	**-**	**92,593**	**291,898**	**182,870**	**462,963**	**-**	**92,593**	**-**	**-**	**-**	**(850,000)**	**9,102,793**

The individual project totals in Table 2-22 above were budgeted without considering the impact of HST Input Tax Credits, which results in a reduction to capital expenditures due to the avoidance of PST amounts that were formerly capitalized. The amount of HST that has been deducted from the originally budgeted amounts, $399,957, is shown as a separate line in the table.

Details of 2011 Projects in Excess of Materiality

As explained in the Activity Drivers section of this Exhibit, NPEI has grouped typical drivers of capital expenditures into 11 categories, which are used consistently each year when preparing the capital budget. The details of the 2011 projects with cost in excess of NPEI's materiality threshold are arranged below according to these categories of activity drivers.

<u>Category 1: Expansion and Reinforcement of the Primary Distribution System to Accommodate Load Growth and Reliability Requirements.</u>

Project 2011-0001: Kerr St – Lundy's Lane Underground Replacement, Estimated Cost $400,000.

Due to approaching end of life cycle and inherent operational issues of the legacy construction within the Commercial Core between Drummond Road & Franklin Ave a replacement of the Underground Network is required. The proposal would include the introduction of multiple points of supply from the recently rebuilt line on Kerr Street, construction of a 450 Metre long duct bank for extension of 200 Amp 13,800 Volt distribution feeders using the Murray Station 3-M-51. The Construction will eliminate existing switchgear assemblies @ Station #25, Station #53, Station #38, & Station #21, and provide the 13.8 KV source for future High St. voltage conversion.

Project 2011-0002: Lundy's Lane – Kalar to Montrose, Estimated Cost $500,000.

The project scope includes the replacement of plant based upon preliminary design submissions for Municipal Consent in 2010 to replace the 1.0 K.M. of directly buried underground feeder with an overhead Pole Line. Equipment replacements are required due to a number of cable faults, which have been experienced on this section of feeder, which is approaching end of life cycle. The replacement includes extending the existing K-M-7 13.8.KV 3-phase line on concrete poles on the North side of Lundy's Lane between Kalar & Montrose Road.

Project 2011-0003: Double Circuit Montrose Road– McLeod Road to Canadian Drive, Estimated Cost $600,000.

Due to increasing residential load growth & proposed Smart Centre Developments within the Area currently serviced by the Murray T.S. 3-M-30, the scope involves an extension of double circuit overhead line using Kalar M.T.S. Feeders K-M-6 & K-M-2, from the existing dead-end at McLeod Road, projecting south on Montrose Rd. to the Highway crossing opposite Niagara Square. Construction is in conjunction with the relocation of the Pole Line on Oakwood Drive, due to Road works for the Smart Centre currently under construction. Benefits include additional circuit inter-tie capabilities between Kalar & Murray Transformer Stations circuits for Feeder load balancing and contingency options.

Project 2011-0004: Underground Primary Extension-Robinson St.—Allendale to Fallsview, Estimated Cost $200,000.

Due to increasing load growth & proposed development within the Fallsview Tourist/Commercial Core the introduction of an additional feeder into the network was required. The proposal included the construction of a duct bank for extension of a 600 Amp 13,800 Volt distribution feeder using the Murray Station 3-M-54 from the existing double circuit pole line in the Hydro One Corridor to the manhole/switchgear assembly @ Station #33 on Fallsview Blvd., continuing to a new Manhole/Switchgear assembly on Clarke Ave, including replacement of high voltage switchgear at Old Stone Inn Stn. #48 and modifications to the Budget Inn Stn. #120. The construction provides load relief & alternate buss supply to loads currently supplied by the 3-M-29 feeder.

Project 2011-0005: Riall Street – Dorchester to St. Paul Overhead Extension, Estimated Cost $290,000.

Project scope involves the replacement of a section of existing directly buried 12-M-33 15KV underground primary cable from Stanley T.S. with an overhead Pole Line. Equipment replacements are required due to the plant approaching end of life cycle. The project also includes the rebuild of an existing 4.16KV 3-Phase pole line on the north side of Riall Street, to a 3-phase 13.8KV level, which will replace the Underground, and eliminate the 4.16KV radial-feed providing a 8.0 K.V. source to recently rebuilt lines between Riall & Stamford Green Drive.

Project 2011-0006: Switchgear Replacements – 4 Units, Estimated Cost $400,000.

Results of the Underground Equipment Inspections Program have identified the requirement for the replacement of pad-mounted switchgear units, which will continue from the 2010 Program at a rate of 4-Units per year. The project scope includes the installation of manholes and other civil works associated with the equipment replacements to current standards.

Project 2011-0009: Kalar Road – Beaverdams to NS&T ROW, Estimated Cost $550,000.

The rebuild of 1600 Metres of existing K-M-3 15 KV single circuit 3-phase pole line between Beaverdam's Rd. and the NS&T R.O.W with a double circuit concrete pole line built on the West side of Kalar Road using the K-M-3 & K-M-7 Feeders sourced from Kalar M.T.S.. Construction required is in conjunction with circuit extensions completed for CNF road widening works between Lundy's Lane & Beaverdam's Rd., the age of existing plant, clearance issues, and requirement of an additional circuit for inter-tie capabilities to Stanley T.S. circuits 12-M-32 & 12-M-42 for Feeder Load Balancing and Contingency purposes. 28-new poles & 556 MCM conductor.

Project 2011-0013: Municipal Station Rehabilitation, Estimated Cost $500,000.

This project will involve the replacement of the 27.6/4.16 kV Distribution Station equipment supplying the Town of Smithville. This work includes a new 27.6/8.32/4.16 kV 5000 KVA Transformer (which could be moved elsewhere on the System in the future), and new protection equipment. All equipment will be located within the existing compound after the present equipment is isolated and removed.

Category 2: Line Extensions/Relocations due to Municipal Road Work Requirements.

Project 2011-0010: Road Relocation Works – Niagara Falls Area, Estimated Cost $200,000; Project 2011-0012: Miscellaneous Road Relocation Work – Peninsula West Area, Estimated Cost $200,000.

An allowance in the annual budget is maintained for the construction of new distribution facilities to correct conflicts with planned road works by the M.T.O., Regional Municipality of Niagara and the various Municipal Agencies within the Service territory. Additions and reinforcement to the distribution system resulting from new construction requests fall under this budget allowance.

Category 3: Replacement of Poles Identified with Limited Structural Integrity.

Project 2011-1010: Pole Changes – Niagara Falls Area, Estimated Cost $500,000; Project 2011-2010: Pole Changes – Peninsula West Area, Estimated Cost $750,000.

This project involves replacing poles that were identified as requiring replacement under NPEI's annual Pole Inspection Program. Approximately 250 poles are expected to be replaced in 2011.

Category 4: Required Overhead Line Rebuild of Deteriorated Facilities Identified by the Pole Condition Survey

Project 2011-0007: Dunn/Drummond/Symmes/Main Area, Estimated Cost $800,000.

This rebuild program is directed at overhead distribution facilities identified as nearing the end of life expectancy. In these locations the existing overhead distribution facilities will be replaced with new overhead plant that will incorporate new poles, conductors and transformation to maximize efficiency, reliability and the capability of conversion to a higher distribution voltage when and where practical. For 2011 this program targets approximately 5 kilometers of urban distribution line requiring 150 pole changes, the installation of new single phase primary and secondary circuits, 30 distribution transformer replacements and results in upgraded supply to about 400 residential customers.

The areas identified for rebuilding in 2011 include portions of 9 streets in the area contained by Dunn Street, Drummond Road, Symmes and Main Street

<u>Category 5: Replacement of Kiosks with EFD Switches and Posi-tects.</u>

Project 2011-0020: Kiosk Conversions, Estimated Cost $500,000.

For 2011 the plan is to replace 10 to 15 units.

<u>Category 6: Minor Betterment Allowance.</u>

<u>Category 8: Demand Based System Reinforcements for New Commercial Service Connections and Expansions.</u>

Project 2011-1007: Minor Betterments – Niagara Falls Area, Estimated Cost $300,000; Project 2011-1008: Demand Work – Niagara Falls Area, Estimated Cost $800,000; Project 2011-2007: Minor Betterments – Peninsula West Area, Estimated Cost $200,000; Project 2011-2008: Demand Work – Peninsula West Area, Estimated Cost $400,000.

These project categories are for work initiated by unexpected failures and new connection requests, requiring the expansion of distribution facilities. The predominant items included here are facilities to service new connections, unplanned underground cable replacements, minor overhead distribution system modifications and component replacements.

<u>Category 7: Subdivisions and New Residential Services.</u>

Project 2011-1009: Subdivision Connections - Combined, Estimated Cost $650,000.

These projects are directly related to the growth experienced in NPEI's service area. The capital costs are directly related to the underground system expansion and are required to accommodate the installation of these new residential/commercial subdivisions. Based on NPEI's subdivision agreement, developers bear the cost of the civil work and the installation of the Transformation, Switchgear and Primary and Secondary Distribution according to NPEI's engineering standards and specifications. NPEI contributes to the cost of these subdivisions using the economic evaluation methodology in accordance with the DSC and the provisions of its Conditions of Service for system expansions.

<u>Category 9: Metering.</u>

2011 Metering, Estimated Amount $200,000.

The metering capital budget includes the typical revenue metering costs associated with new customer installations. Wholesale meter point upgrades, where required, are included in this budget item.

Category 10: Vehicles.

2011 Transportation Equipment, Estimated Amount $463,800.

1) Purchase of a 46ft. Material Handling Aerial Manlift and Fiberglass Body to be installed on a 2011 chassis	**$260,000.00**
2) Purchase of a 48ft, 5th Wheel, Gooseneck StyleTrailer to transport the Off Road Track Machine purchaseD in the 2010 budget.	**$54,760.00**
3) Purchase of a 2011 Cargo Van for the Engineering Department to replace vehicle number 22 which is a 2000 GMC Safari Van	**$34,040.00**
4) Purchase of a 2011, Pole Carrying Galvanized ExtendableTrailer, (8300kg) with Tandem Axle .	**$35,000.00**
5) Purchase of a 47ft Radial Boom Derrek (line truck) and Fibreglass Body to be installed on the 2011 cab and chassis (purchased in 2011) with the remaining balance ($200,000.00) to be paid in 2012.	**$80,000.00**
Total cost for new vehicles purchased in 2011	**$463,800.00**

Note: the Transportation Equipment budget figure of $463,800 reflects actual costs net of HST savings.

Category 11: Other Capital Expenditures.

2011 Office Furniture and Equipment, Estimated Cost $93,000.

The 2011 expected additions to account 1915 Office Furniture and Equipment consist of the following:

• Outside Storage Bin	$ 15,000
• PA System Equipment	$ 20,000
• Ergonomic Office Equipment	$ 10,000
• Photocopier – Engineering	$ 25,000
• Photocopier – Fax Room	$ 20,000
• General Equipment	$ 3,000
	$93,000

Note: the Office Furniture and Equipment budget figure of $93,000 reflects the actual cost net of HST savings.

Computer Hardware and Software

Purchases in computer hardware and software will focus on the achievement of the following goals:

- Effective and Efficient Business Processes leading to improved Customer Service
- Maintenance of Compliance standards
- Integrated, reliable, enterprise solutions
- Network Integration and Security
- Consideration of business continuity practices and creation and testing of a Disaster Recovery plan.

2011 Computer Hardware, Estimated Amount $292,000.

Spending of hardware will continue to focus on network infrastructure and disaster recovery. Purchases of hardware in 2011 are directly related to building on resiliency and redundancy achieving measurable results meeting the needs of software to be implemented and improved business practices. Costs are related to the following projects/business need:

- Improved Network Infrastructure resulting in purchase of switches and servers;
- Workforce/Outage Management Ongoing Implementation, integration and support (migration server);
- Phone system integration and support;
- Enterprise solutions such as update and implementation of web based tools linked to the website providing for time of use and usage presentment (Demand Side Management), along with the deployment of

web based tool Mcare, as well as, GIS tools (inService) into the field using ruggarized laptops, as well as, in vehicle mobile PC's in Operations and Metering;

- Upgrade of PC's and printers due to age and use;
- Wear and malfunction of handheld meter reading devices;
- Disaster Recovery and Business Continuity: In 2011, the focus will continue to be on building infrastructure to secure data and systems, while preparing for a failure. We will be creating and testing a full disaster recovery and business continuity plan.

Note: the Computer Hardware budget figure of $292,000 reflects the actual cost net of HST savings.

2011 HARDWARE

Network	Item	Purpose	Quantity	Approx Cost	Project
	48 Port Nortel Switch	Hot Spare - Data - PW	1	$ 5,500.00	Network Infrastructure
	Proxim Wireless Access Points (quantity to be determined by designer)	Motorola 810 requirement for fleet communications (laptops in trucks)	1	$ 600.00	Network Infrastructure
				$ 6,100.00	

Servers	Item	Purpose	Quantity	Approx Cost	Project
	Server	Backup servers	3	$ 33,000.00	Disaster Recovery
	Server	Migration server for G and Inservice	1	$ 13,000.00	Disaster Recovery
	Server	Laserfiche/Lexus	1	$ 20,000.00	Disaster Recovery
	Equallogic SAN for Smithville	Extra storage	1	$ 65,000.00	Disaster Recovery
	Harris to Move Billing from IBM to Dell Blade	Optimization Maintenance		$ 17,500.00	Disaster Recovery
	Consolidate Informix / Jboss on 1 Server	Optimization Maintenance		$ 17,500.00	Disaster Recovery
	Web Server	Intranet, web based applications	1	$ 9,500.00	Network infrastructure to enable Enterprise solutions including web based tools ecare, mcare, links to web-site, internal communication web-based tool (intranet)
				$ 175,500.00	

Printers	**Item**	**Purpose**	**Quantity**	**Approx Cost**	**Project**
	Replacement of T620	Replacement of current T620	1	$ 2,500.00	Replacement due to age and usage
	Lexmark	Printer for Sue F	1	$ 1,000.00	New Requirement
	Lexmark	Printer for Suzanne	1	$ 650.00	Replacement due to age and usage
				$ 4,150.00	

Phones	**Item**	**Purpose**	**Quantity**	**Approx Cost**	**Project**
	Professional Services	Integration of phone system to CIS/Outage Management/IVR	1	$ 25,000.00	Phase 3 of Phone System - added functionality to interface to CIS/Outage Management/IVR
Rebudget from 2009	Recording Solution	Archive of Calls,etc	1	$ 8,000.00	Phase 3 of Phone System - added functionality
	Mitel Headset	Ease of answering calls hands free	3	$ 1,095.00	
	Bluetooth phone	handsfree for cell phones	25	$ 3,000.00	
				$ 37,095.00	

PC / Monitor	**Item**	**Purpose**	**Quantity**	**Approx Cost**	**Project**
	PC Replacements	Add PCs as required	10	$ 7,000.00	Replacement due to age and usage as required
	Motorola 810	Deployment of Inservice field use in Operations, and mcare in Metering	6	$ 55,000.00	Deployment of field laptops for Mcare and Integraph Inservice product
				$ 62,000.00	

LCD Projectors	Item	Purpose	Quantity	Approx Cost	Project
	NEC VT595 XGA 2000 ANSI LUNCENS PROJECTORS	Niagara Falls and West Lincoln Training Room LCD Projectors (not mounted)	2	$ 1,260.00	Renovation of Niagara Falls and Service Center
				$ 1,260.00	

Equipment	Item	Purpose	Quantity	Approx Cost	Project
	Radix Handhelds	Meter reading	1	$ 3,250.00	Handheld replacement as needed (as handhelds impact reading schedule due to misfunction and downtime)
	Northrup Probes	Meter reading	1	$ 2,285.00	Handheld replacement as needed (as probes and cables impact reading schedule due to misfunction and downtime)
	Verseprobe battery charger	Meter reading	3	$ 360.00	Maintenance
				$ 5,895.00	
TOTAL HARDWARE				**$ 292,000.00**	

2011 Computer Software, Estimated Amount $183,000.

Software required for business process improvement projects, which promote efficiency and reliability include the following.

- Workforce/Outage Management – This software provides for recording and reporting of all work force tasks, as well as, details of an outage. It allows for the efficiency and reliability of reporting to regulatory agencies, as well as, efficiencies in management of resources required to complete tasks and oversee an outage. This solution accommodates our growth where current manual or other software has become too labour intensive in the security, scalability, costly to manage (does not accommodates changes in technology.) Workforce/Outage management compliments pilot field projects/exercises where ruggarized laptops/PCs are in the field. This solution will contribute to the provision of effective and efficient processes improving customer service.
- Document Management - This software provides the tools to improve efficiency in access to customer reports, correspondence, and e-billing.
- Enhanced backup solution promoting redundancy and business continuity
- Integrated Voice Recognition (IVR) – The IVR can be utilized for outgoing calls such as list of customers that will have a scheduled outage or list of customers past due. This allows for improved customer service providing outage information to the customer in a timely manner. Further collection practices are improved when the customer can be contacted directly at time of non-payment.
- Server migration – accommodating growth and change in technology; in support of delivery of reliable, integratable solutions.
- Web presentment tools providing bill presentment and usage information in a user- friendly manner highlighting demand side management (Enterprise solution.) Enterprise solution provides a scalable, easy to

manage programming solution to providing business management and information accessibility for internal and external customers such as ebills, and online access to account information. Implementation and integration to the phone system, the IVR, CIS/GIS web-based tools such as those used for operation in the field work, E-care/Demand side management used for account, time of use billing, usage, and bill presentment represent the proposed enterprise solutions that result from the IT capital expenditures. The solution addresses the problem of how to most efficiently get data to those who we want to have it. An effective enterprise solution will have the following characteristics:

- Security – information is secured and has access control
- Scalable – accommodates growth
- Cost – value for money
- Managable – provides the ability to manage implementation including version control
- Portable – accommodates changes in technology.

The enterprise solution has both application server (hardware) requirement, as well as, software components.

Note: the Computer Software budget amount of $183,000 reflects the actual cost net of HST savings.

SOFTWARE	**Item**	**Purpose**	**Quantity**	**Approx Cost**	**Project**
Customer Service	Interactive Queue	Realtime monitoring of ACD reps and allocating them real time	1	$ 8,500.00	Phase 3 of Phone System - added functionality
Customer Service	Visual Queue	Interactive routing of calls based on metrics in system	1	$ 2,300.00	Phase 3 of Phone System - added functionality
Customer Service	Alertworks	survey for power outage, collections, scheduled maintenance	1	$ 10,500.00	
Operations	Work Management/Outage Management Intergraph solution including software and professional services for installation and training	Work/Outage Management - TA module including primary and redundant including professional services	1	$ 75,000.00	Work/Outage Management Implementation
Operations	Work Management/Outage Management Mobile software solution (inService mobile client)	Work/Outage Management	6	$ 1,800.00	Work/Outage Management Implementation
Operations & Engineering	Autocad licenses	Per User License	8	$15,000.00	
Operations	VPN solution	Fleet rollout	1	$1,250.00	Business requirement
	Adobe Read/Write license	New requirement	2	$ 2,500.00	Business requirement
	DoubleTake for Linux	Needed for Billing Servers migration	1	$ 15,000.00	Server migration
	File Nexus Solution	Replacement of Laserfiche	1	$ 51,150.00	
TOTAL SOFTWARE				**$ 183,000.00**	

1

2011 Tools and Equipment, Estimated Cost $93,000.

The expected 2010 additions to the other equipment accounts (1935, 1940, 1945, 1955, 1960) consist of the following:

1) Lanetamer Sign System (Traffic)	6	@	$333.34	$2,000.04
2) Hastings 6790 High Voltage Amp Meter	2	@	$1,000.00	$2,000.00
3) Gas Drill	1	@	$500.00	$500.00
4) Volt Meters	6	@	$300.00	$1,800.00
5) Fiber Cover-up	20	@	$160.00	$3,200.00
6) Tampers	2	@	$1,200.00	$2,400.00
7) Megger (Insulation Resistance Tester) 1kv model # MIT 310-EN	4	@	$625.00	$2,500.00
8) Hydraulic Drills	4	@	$2,000.00	$8,000.00
9) P.I.'s	4	@	1,500.00	$6,000.00
10) Phasing Sticks	3	@	2,200.00	$6,600.00
11) New and Replacement tools				$25,000.00
12) Insulated Cls 3 and Cls 4 Line Hose, Insulated Cls 4 Large and Small Blankets, Cls 4 Insulated Hoods (Most of the order is for the trucks in the Smithville location and is required to maintain ample cover-up on the trucks during the required annual testing of insulated cover-up. The remainder is to meet the minimum order requirement by the supplier.				$10,700.00
13) New truck tools				$25,000.00
14) Safety Grounds and Related Equipment				$22,238.96
Total equipment cost for 2011				$93,000.00

Note: the Tools and Equipment budget figure of $93,000 reflects actual costs net of HST savings.

2011 Contributions and Grants, Estimated Amount ($850,000).

For 2011, NPEI expects to collect $850,000 in capital contributions to offset capital expenditures. This entire amount relates to projects with estimated cost in excess of the materiality threshold of $150,000, as detailed above.

- Demand Work ($300,000)
- Miscellaneous Road Relocation Work ($100,000)
- Montrose – McLeod to Canadian. ($150,000)
- Subdivisions and New Residential ($300,000)

NPEI notes that the amount of capital contributions expected in 2011 is $350,000 less than what is anticipated in 2010. This is due to the fact that NPEI is harmonizing its Conditions of Service in 2011. Presently, NPEI's requirements for capital contributions are based on separate conditions of service for each predecessor utility, Niagara Falls Hydro and Peninsula West Utilities, where customers in the Niagara Falls area receive a basic entitlement and customers in the Peninsula West area do not. Under NPEI's harmonized conditions of service, all customer connections will be allowed a basic entitlement. The will result in NPEI receiving a lower amount of capital contributions relating to development in the Peninsula West area.

One-Time versus Ongoing Capital Expenditures

The evidence presented above, regarding NPEI's capital additions for 2005 to 2011, includes a number of projects that are one-time or non-recurring. Projects of this nature occur infrequently, and do not represent NPEI's typical annual capital spend. Examples include: major building renovations and construction, land purchases and smart meter additions to rate base.

As well, the sections above include descriptions of many projects that are ongoing in nature. Although the specific projects may be non-recurring, they represent typical categories of capital expenditures that NPEI incurs each year. Examples include: betterments, pole replacement, demand work and kiosk replacement. Items such as computer hardware and software, tools, equipment and vehicles also represent typical ongoing expenditures.

In order to further clarify the nature of the capital additions from 2005 to 2011, NPEI has separated the projects for each year into the categories of one-time and ongoing, as set out in Table 2-22a below.

Table 2-22a One-Time versus Ongoing Capital Expenditures

Description	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
One-Time Capital Expenditures							
Kalar TS R&D tax credits	(479,652)	(218,750)					
Pen West subdivisions relating to 5 years recorded in 2005	2,281,083						
Contributions for subdivisions relating to 5 years recorded in 2005	(2,281,083)						
Land	229,465				279,505		
Off-road track vehicle						416,667	
Niagara Falls building renovations				1,385,025			
Construction of service centre in Smithville				2,761,607	2,291,557		
Mobile substation						185,185	
Transfer smart meter capital into rate base						4,175,010	
One-Time Expenditures Total	**(250,188)**	**(218,750)**	**-**	**4,146,632**	**2,571,062**	**4,776,862**	**-**
Ongoing Capital Expenditures							
Distribution Plant	6,277,628	8,765,396	11,181,123	8,845,120	8,796,648	9,056,238	8,829,876
Buildings and Fixtures	50,706	55,592	448,718	-	94,148	188,557	-
Office Furniture and Equipment	65,635	73,858	18,181	174,930	161,652	70,564	92,593
Computer Hardware	183,075	119,227	101,762	525,453	185,269	273,500	291,898
Computer Software	643,900	213,418	62,326	208,496	369,215	278,954	182,870
Transportation Equipment	214,249	515,857	227,707	576,543	589,462	407,483	462,963
Tools and Equipment	193,454	120,466	61,918	96,855	130,443	125,824	92,593
Contributions and Grants	(1,639,689)	(1,354,458)	(1,683,128)	(1,712,904)	(1,197,961)	(1,200,000)	(850,000)
Ongoing Expenditures Total	**5,988,958**	**8,509,356**	**10,418,607**	**8,714,493**	**9,128,876**	**9,201,120**	**9,102,793**
Total Capital Additions	**5,738,770**	**8,290,606**	**10,418,607**	**12,861,125**	**11,699,938**	**13,977,982**	**9,102,793**

Working Capital

Working Capital Overview

NPEI's working capital amount is forecast to be $114,508,597 for the 2011 Test Year. NPEI has not undertaken a Working Capital lead-lag study pending OEB direction and as such has calculated its working capital allowance using the 15% Allowance Approach as provided for in the OEB's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, dated June 28, 2010. NPEI submits that its working capital calculations are not only consistent with the Filing Guidelines but are also consistent with OEB Decisions in distributors' cost of service applications approved in 2008, 2009 and 2010, where a utility specific lead-lag study had not been undertaken. The working capital allowance is based on NPEI's proposed 2011 Test Year controllable expenses and cost of power. NPEI has provided the calculations by the OEB's USoA classification for each of 2006 Actual to 2009 Actual, the 2010 Bridge Year and the 2011 Test Year in Table 2-24 below. The 2011 Test Year Cost of Power calculations are provided in Table 2-27 below.

The following Table 2-23 sets out NPEI's year over year working capital variances for the 2006 OEB Approved, the four years 2006 to 2009 Actuals, 2010 Bridge Year and 2011 Test Year. The Applicant notes that the 2006 OEB Approved working capital was determined through the 2006 EDR process and is based on the 2004 year end OM&A and cost of power adjusted for Tier 1 Adjustments. Accordingly, the variance between 2006 Actual and 2006 OEB Approved spans a two-year period. As apparent from Table 2-23, the major variance in the change in working capital is in the year over year cost of power. The detailed working capital calculations by OEB USoA classification are provided in Table 2-24 below and the variances in the OM&A accounts are discussed in further detail in Exhibit 4.

Table 2-23 Working Capital Variances

Description	2006 OEB Approved	2006 Actual	Variance from 2006 OEB Approved	2007 Actual	Variance from 2006 Actual	2008 Actual	Variance from 2007 Actual	2009 Actual	Variance from 2008 Actual	2010 Bridge	Variance from 2009 Actual	2011 Test	Variance from 2010 Bridge
Cost of Power	81,948,027	84,040,651	2,092,624	87,873,081	3,832,431	87,102,560	(770,521)	91,563,338	4,460,778	96,311,017	4,747,679	99,990,688	3,679,671
Operations	2,811,476	3,603,532	792,056	3,718,160	114,628	3,198,913	(519,247)	3,152,389	(46,524)	3,392,217	239,828	3,573,690	181,473
Maintenance	2,509,155	1,952,232	(556,923)	2,231,951	279,718	2,320,969	89,018	2,390,126	69,157	2,542,929	152,803	2,568,416	25,488
Billing & Collecting	2,734,341	3,232,894	498,553	3,371,741	138,847	3,771,715	399,974	3,630,381	(141,334)	3,884,221	253,840	4,195,729	311,509
Community Relations	90,365	72,955	(17,410)	83,295	10,340	36,877	(46,418)	64,569	27,692	79,548	14,979	81,464	1,916
Administration & General Expense	4,177,410	3,471,836	(705,574)	3,622,877	151,041	3,256,921	(365,956)	3,582,468	325,547	3,718,838	136,369	3,876,135	157,298
Property Taxes	205,390	194,863	(10,527)	201,207	6,344	231,271	30,064	215,254	(16,017)	232,000	16,746	222,474	(9,526)
Working Capital	94,476,164	96,568,962	2,092,798	101,102,311	4,533,349	99,919,226	(1,183,085)	104,598,525	4,679,299	110,160,769	5,562,244	114,508,597	4,347,828

Table 2-24 Detailed Working Capital Calculations

Distribution Expenses - Operation	2006 Actual	WC Allowance 15%	2007 Actual	WC Allowance 15%	2008 Actual	WC Allowance 15%	2009 Actual	WC Allowance 15%	2010 Bridge	WC Allowance 15%	2011 Test	WC Allowance 15%
5005 Operation Supervision and Engineering	688,793	103,319	679,881	101,982	595,433	89,315	578,370	86,756	629,835	94,475	648,571	97,286
5010 Load Dispatching	32,118	4,818	32,248	4,837	31,450	4,718	44,478	6,672	42,867	6,430	43,800	6,570
5012 Station Buildings and Fixtures Expense	145,746	21,862	83,621	12,543	91,253	13,688	125,341	18,801	122,347	18,352	119,771	17,966
5014 Transformer Station Equipment - Operation Labour	9,975	1,496	12,995	1,949	1,410	212	6,819	1,023	10,889	1,633	11,507	1,726
5015 Transformer Station Equipment - Operation Supplies and Expenses	105,247	15,787	106,068	15,910	69,666	10,450	65,786	9,868	53,279	7,992	54,733	8,210
5016 Distribution Station Equipment - Operation Labour	8,718	1,308	9,281	1,392	-	-	-	-	-	-	-	-
5017 Distribution Station Equipment - Operation Supplies and Expenses	9,821	1,473	-	-	-	-	-	-	-	-	-	-
5020 Overhead Distribution Lines and Feeders - Operation Labour	448,578	67,287	348,440	52,266	142,135	21,320	154,815	23,222	193,626	29,044	197,358	29,604
5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	215,303	32,295	177,108	26,566	29,918	4,488	21,256	3,188	19,954	2,993	20,421	3,063
5030 Overhead Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-	-
5035 Overhead Distribution Transformers - Operation	53,333	8,000	39,711	5,957	-	-	-	-	-	-	-	-
5040 Underground Distribution Lines and Feeders - Operation Labour	163,656	24,548	117,786	17,668	38,985	5,848	58,365	8,755	71,410	10,711	72,606	10,891
5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses	172,707	25,906	159,100	23,865	247,672	37,151	243,103	36,465	193,121	28,968	194,991	29,249
5050 Underground Subtransmission Feeders - Operation	78	12	-	-	-	-	-	-	-	-	-	-
5055 Underground Distribution Transformers - Operation	11,925	1,789	6,796	1,019	-	-	-	-	-	-	-	-
5060 Street Lighting and Signal System Expense	-	-	-	-	-	-	-	-	-	-	-	-
5065 Meter Expense	492,554	73,883	750,758	112,614	584,964	87,745	403,418	60,513	521,545	78,232	489,927	73,489
5070 Customer Premises - Operation Labour	193,390	29,008	169,413	25,412	121,985	18,298	56,738	8,511	94,272	14,141	96,423	14,463
5075 Customer Premises - Materials and Expenses	9,212	1,382	16,839	2,526	-	-	-	-	-	-	-	-
5085 Miscellaneous Distribution Expense	809,586	121,438	974,347	146,152	1,244,042	186,606	1,393,900	209,085	1,439,073	215,861	1,623,583	243,537
5090 Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-	-	-	-	-	-
5095 Overhead Distribution Lines and Feeders - Rental Paid	32,792	4,919	33,766	5,065	-	-	-	-	-	-	-	-
5096 Other Rent	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Distribution Expenses - Operation	3,603,532	540,530	3,718,160	557,724	3,198,913	479,837	3,152,389	472,858	3,392,217	508,833	3,573,690	536,054

Distribution Expenses - Maintenance	2006 Actual	WC Allowance 15%	2007 Actual	WC Allowance 15%	2008 Actual	WC Allowance 15%	2009 Actual	WC Allowance 15%	2010 Bridge	WC Allowance 15%	2011 Test	WC Allowance 15%
5105 Maintenance Supervision and Engineering	256,633	38,495	286,909	43,036	407,008	61,051	398,759	59,814	448,874	67,331	462,681	69,402
5110 Maintenance of Buildings and Fixtures - Distribution Stations	-	-	-	-	-	-	-	-	-	-	-	-
5112 Maintenance of Transformer Station Equipment	-	-	-	-	-	-	-	-	-	-	-	-
5114 Maintenance of Distribution Station Equipment	14,824	2,224	10,775	1,616	3,969	595	2,867	430	4,871	731	4,767	715
5120 Maintenance of Poles, Towers and Fixtures	206,519	30,978	201,503	30,225	130,954	19,643	125,297	18,795	149,838	22,476	151,573	22,736
5125 Maintenance of Overhead Conductors and Devices	672,433	100,865	709,751	106,463	834,442	125,166	896,673	134,501	914,451	137,168	917,736	137,660
5130 Maintenance of Overhead Services	87,589	13,138	123,227	18,484	155,633	23,345	137,622	20,643	148,397	22,260	150,393	22,559
5135 Overhead Distribution Lines and Feeders - Right of Way	271,498	40,725	333,717	50,058	364,037	54,606	296,535	44,480	347,058	52,059	352,301	52,845
5145 Maintenance of Underground Conduit	60,893	9,134	30,092	4,514	46,304	6,946	47,652	7,148	43,016	6,452	42,841	6,426
5150 Maintenance of Underground Conductors and Devices	148,782	22,317	191,837	28,776	149,829	22,474	245,671	36,851	248,613	37,292	249,450	37,417
5155 Maintenance of Underground Services	74,452	11,168	123,898	18,585	80,916	12,137	92,502	13,875	89,602	13,440	91,252	13,688
5160 Maintenance of Line Transformers	143,209	21,481	192,418	28,863	128,445	19,267	133,947	20,092	133,749	20,062	132,000	19,800
5165 Maintenance of Street Lighting and Signal Systems	-	-	-	-	-	-	-	-	-	-	-	-
5170 Sentinel Lights - Labour	-	-	-	-	-	-	-	-	-	-	-	-
5172 Sentinel Lights - Materials and Expenses	-	-	-	-	-	-	-	-	-	-	-	-
5175 Maintenance of Meters	15,401	2,310	27,824	4,174	19,432	2,915	12,601	1,890	14,459	2,169	13,426	2,014
5178 Customer Installations Expenses - Leased Property	-	-	-	-	-	-	-	-	-	-	-	-
5195 Maintenance of Other Installations on Customer Premises	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Distribution Expenses - Maintenance	1,952,232	292,835	2,231,951	334,793	2,320,969	348,145	2,390,126	358,519	2,542,929	381,439	2,568,416	385,262

Billing and Collecting	2006 Actual	WC Allowance 15%	2007 Actual	WC Allowance 15%	2008 Actual	WC Allowance 15%	2009 Actual	WC Allowance 15%	2010 Bridge	WC Allowance 15%	2011 Test	WC Allowance 15%
5305 Supervision	285,450	42,818	307,325	46,099	512,242	76,836	366,304	54,946	336,369	50,455	490,012	73,502
5310 Meter Reading Expense	487,834	73,175	505,371	75,806	397,340	59,601	438,379	65,757	461,855	69,278	473,321	70,998
5315 Customer Billing	1,630,728	244,609	1,699,832	254,975	1,872,229	280,834	1,710,531	256,580	1,928,990	289,348	2,080,927	312,139
5320 Collecting	424,633	63,695	459,241	68,886	462,144	69,322	459,698	68,955	475,013	71,252	483,163	72,474
5325 Collecting - Cash Over and Short	(5,603)	(840)	333	50	495	74	56	8	-	-	-	-
5330 Collection Charges	-	-	-	-	-	-	-	-	-	-	-	-
5335 Bad Debt Expense	242,175	36,326	195,460	29,319	291,484	43,723	427,315	64,097	425,100	63,765	410,000	61,500
5340 Miscellaneous Customer Accounts Expenses	167,676	25,151	204,178	30,627	235,781	35,367	228,098	34,215	256,895	38,534	258,306	38,746
Subtotal Billing and Collecting	3,232,894	484,934	3,371,741	505,761	3,771,715	565,757	3,630,381	544,557	3,884,221	582,633	4,195,729	629,359

Community Relations (including sales expenses)	2006 Actual	WC Allowance 15%	2007 Actual	WC Allowance 15%	2008 Actual	WC Allowance 15%	2009 Actual	WC Allowance 15%	2010 Bridge	WC Allowance 15%	2011 Test	WC Allowance 15%
5405 Supervision	53,930	8,090	62,424	9,364	22,869	3,430	14,746	2,212	-	-	-	-
5410 Community Relations - Sundry	19,025	2,854	12,739	1,911	14,008	2,101	49,823	7,473	79,548	11,932	81,464	12,220
5415 Energy Conservation	-	-	8,131	1,220	-	-	-	-	-	-	-	-
5420 Community Safety Program	-	-	-	-	-	-	-	-	-	-	-	-
5425 Miscellaneous Customer Service and Informational Expenses	-	-	-	-	-	-	-	-	-	-	-	-
5505 Supervision	-	-	-	-	-	-	-	-	-	-	-	-
5510 Demonstrating and Selling Expense	-	-	-	-	-	-	-	-	-	-	-	-
5515 Advertising Expense	-	-	-	-	-	-	-	-	-	-	-	-
5520 Miscellaneous Sales Expense	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Community Relations	72,955	10,943	83,295	12,494	36,877	5,532	64,569	9,685	79,548	11,932	81,464	12,220

Administrative and General Expenses	2006 Actual	WC Allowance 15%	2007 Actual	WC Allowance 15%	2008 Actual	WC Allowance 15%	2009 Actual	WC Allowance 15%	2010 Bridge	WC Allowance 15%	2011 Test	WC Allowance 15%
5605 Executive Salaries and Expenses	349,122	52,368	331,218	49,683	312,533	46,880	279,924	41,989	311,388	46,708	323,267	48,490
5610 Management Salaries and Expenses	1,088,919	163,338	1,095,496	164,324	1,472,940	220,941	1,602,714	240,407	1,743,297	261,495	1,818,577	272,787
5615 General Administrative Salaries and Expenses	572,506	85,876	554,058	83,109	315,333	47,300	375,307	56,296	400,853	60,128	421,595	63,239
5620 Office Supplies and Expenses	174,696	26,204	260,525	39,079	117,200	17,580	133,823	20,073	132,496	19,874	126,460	18,969
5625 Administrative Expense Transferred-Credit	-	-	-	-	-	-	-	-	-	-	-	-
5630 Outside Services Employed	293,227	43,984	407,804	61,171	51,200	7,680	39,600	5,940	39,600	5,940	39,900	5,985
5635 Property Insurance	112,660	16,899	114,158	17,124	181,842	27,276	204,848	30,727	206,367	30,955	209,777	31,467
5640 Injuries and Damages	63,482	9,522	59,174	8,876	480	72	-	-	-	-	-	-
5645 Employee Pensions and Benefits	-	-	-	-	-	-	-	-	-	-	-	-
5650 Franchise Requirements	-	-	-	-	-	-	-	-	-	-	-	-
5655 Regulatory Expenses	165,077	24,762	114,851	17,228	173,238	25,986	192,187	28,828	190,000	28,500	268,429	40,264
5660 General Advertising Expenses	10,714	1,607	7,959	1,194	465	70	-	-	-	-	-	-
5665 Miscellaneous Expenses	118,896	17,834	157,306	23,596	79,711	11,957	101,292	15,194	101,759	15,264	103,810	15,571
5670 Rent	46,997	7,049	61,102	9,165	67,102	10,065	56,917	8,538	-	-	-	-
5675 Maintenance of General Plant	463,532	69,530	446,040	66,906	484,877	72,732	595,857	89,379	593,077	88,962	564,320	84,648
5680 Electrical Safety Authority Fees	12,009	1,801	12,185	1,828	-	-	-	-	-	-	-	-
5685 Independent Market Operator Fees and Penalties	-	-	1,000	150	-	-	-	-	-	-	-	-
5695 OM&A Contra Account	-	-	-	-	-	-	-	-	-	-	-	-
6205 Charitable Donations	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Administrative and General Expense	3,471,836	520,775	3,622,877	543,432	3,256,921	488,538	3,582,468	537,370	3,718,838	557,826	3,876,135	581,420

Cost of Power	2006 Actual	WC Allowance	2007 Actual	WC Allowance	2008 Actual	WC Allowance	2009 Actual	WC Allowance	2010 Bridge	WC Allowance	2011 Test	WC Allowance
		15%		15%		15%		15%		15%		15%
4705 Power Purchased	64,257,197	9,638,580	67,829,793	10,174,469	68,440,299	10,266,045	72,510,992	10,876,649	75,819,643	11,372,946	78,708,485	11,806,273
4708 Wholesale Market Services	6,360,461	954,069	6,445,119	966,768	7,143,057	1,071,459	7,515,608	1,127,341	8,031,734	1,204,760	8,337,946	1,250,692
4714 Transmission Network	7,278,075	1,091,711	7,573,991	1,136,099	5,941,731	891,260	6,314,614	947,192	6,598,076	989,711	6,850,285	1,027,543
4716 Transmission Connection	5,645,641	846,846	5,308,463	796,269	4,964,811	744,722	4,941,286	741,193	5,522,464	828,370	5,733,459	860,019
4750 LV Charges	499,276	74,891	715,716	107,357	612,662	91,899	280,838	42,126	339,100	50,865	360,512	54,077
Subtotal Cost of Power	84,040,651	12,606,098	87,873,081	13,180,962	87,102,560	13,065,384	91,563,338	13,734,501	96,311,017	14,446,653	99,990,688	14,998,603

Total Eligible Distribution Expense	96,568,962	14,485,344	101,102,311	15,165,347	99,919,226	14,987,884	104,598,525	15,689,779	110,160,769	16,524,115	114,508,597	17,176,290

Cost of Power

NPEI has calculated cost of power for the 2010 Bridge year and 2011 Test Year based on the results of the load forecast which is discussed in detail in Exhibit 3. The electricity prices used in the calculation ($0.06215 per kWh for RPP Supply Cost and $0.06062 per kWh for Non-RPP Supply Cost) are the published prices in the OEB's Regulated Price Plan Price Report – November 1, 2009 to October 31, 2010, issued October 15, 2009. At a late stage in preparing this application, NPEI realized that the cost of power calculation has not been adjusted to reflect the most current RPP Price Report. However, NPEI expects that several other elements of the application may have to be adjusted prior to the Board's decision, such as the regulated rate of return on equity. NPEI proposes to update the cost of power forecast at that time to reflect the most recent RPP Report available.

To determine the split between RPP kWh and Non-RPP kWh for the 2010 Bridge Year and the 2011 Test Year, NPEI has applied the actual 2009 split for each rate class to the 2010 and 2011 forecasts.

The cost of power calculations for the 2010 Bridge Year and a cost of power summary are provided in the following Tables 2-25 and 2-26, respectively. The cost of power calculations for the 2011 Test Year and a cost of power summary are provided in the following Tables 2-27 and 2-28, respectively.

Table 2-25 2010 Cost of Power Calculation

Electricity - Commodity Class per Load Forecast	2010 Forecasted Metered kWhs - RPP	2010 Loss Factor	2010		
Residential	373,972,233	1.056	394,825,816	$0.06215	$24,538,424
Street Lighting	6,483,017	1.056	6,844,526	$0.06215	$425,387
Sentinel Lighting	179,491	1.056	189,500	$0.06215	$11,777
GS<50kW	99,628,494	1.056	105,184,016	$0.06215	$6,537,187
GS>50kW	84,637,353	1.056	89,356,934	$0.06215	$5,553,533
Intermediate		1.056	0	$0.06215	$0
Unmetered Scattered Load	1,217,072	1.056	1,284,939	$0.06215	$79,859
TOTAL	**566,117,661**		**597,685,730**		**$37,146,168**

Electricity - Commodity Class per Load Forecast	2010 Forecasted Metered kWhs - Non-RPP	2010 Loss Factor	2010		
Residential	68,152,925	1.056	71,953,295	$0.06062	$4,361,809
Street Lighting	885,881	1.056	935,280	$0.06062	$56,697
Sentinel Lighting	114,053	1.056	120,413	$0.06062	$7,299
GS<50kW	19,188,801	1.056	20,258,814	$0.06062	$1,228,089
GS>50kW	514,799,710	1.056	543,506,168	$0.06062	$32,947,344
Intermediate		1.056	0	$0.06062	$0
Unmetered Scattered Load	1,128,699	1.056	1,191,638	$0.06062	$72,237
TOTAL	**604,270,070**		**637,965,608**		**$38,673,475**

Transmission - Network Class per Load Forecast		Volume Metric	2010		
Residential		kWh	466,779,111	$0.0053	$2,473,929
Street Lighting		kW	19,842	$1.5063	$29,888
Sentinel Lighting		kW	811	$1.5139	$1,228
GS<50kW		kWh	125,442,830	$0.0049	$614,670
GS>50kW		kW	1,735,456	$1.9973	$3,466,226
Intermediate		kW		$0.0000	$0
Unmetered Scattered Load		kWh	2,476,577	$0.0049	$12,135
TOTAL					**$6,598,076**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**	**2010**		
Residential		kWh	466,779,111	$0.0046	$2,147,184
Street Lighting		kW	19,842	$1.2583	$24,967
Sentinel Lighting		kW	811	$1.2847	$1,042
GS<50kW		kWh	125,442,830	$0.0041	$514,316
GS>50kW		kW	1,735,456	$1.6277	$2,824,802
Intermediate		kW	0	$0.0000	$0
Unmetered Scattered Load		kWh	2,476,577	$0.0041	$10,154
TOTAL					**$5,522,464**

Wholesale Market Service					
Class per Load Forecast			**2010**		
Residential		kWh	466,779,111	$0.0052	$2,427,251
Street Lighting		kWh	7,779,805	$0.0052	$40,455
Sentinel Lighting		kWh	309,913	$0.0052	$1,612
GS<50kW		kWh	125,442,830	$0.0052	$652,303
GS>50kW		kWh	632,863,102	$0.0052	$3,290,888
Intermediate		kWh	0	$0.0052	$0
Unmetered Scattered Load		kWh	2,476,577	$0.0052	$12,878
TOTAL					**$6,425,387**

Rural Rate Assistance					
Class per Load Forecast			**2010**		
Residential		kWh	466,779,111	$0.0013	$606,813
Street Lighting		kWh	7,779,805	$0.0013	$10,114
Sentinel Lighting		kWh	309,913	$0.0013	$403
GS<50kW		kWh	125,442,830	$0.0013	$163,076
GS>50kW		kWh	632,863,102	$0.0013	$822,722
Intermediate		kWh	0	$0.0013	$0
Unmetered Scattered Load		kWh	2,476,577	$0.0013	$3,220
TOTAL					**$1,606,347**

Table 2-26 2010 Cost of Power Summary

Cost of Power Account	2010 Cost
4705-Power Purchased	$75,819,643
4708-Charges-WMS	$8,031,734
4714-Charges-NW	$6,598,076
4716-Charges-CN	$5,522,464
4750-Low Voltage	$339,100
TOTAL	**96,311,017**

Table 2-27 2011 Cost of Power Calculation

Electricity - Commodity	**2011 Forecasted**				
Class per Load Forecast	**Metered kWhs - RPP**	**2011 Loss Factor**		**2011**	
Residential	388,590,040	1.056	410,347,303	$0.06215	$25,503,085
Street Lighting	6,569,845	1.056	6,937,692	$0.06215	$431,178
Sentinel Lighting	179,047	1.056	189,072	$0.06215	$11,751
GS<50kW	101,825,576	1.056	107,526,818	$0.06215	$6,682,792
GS>50kW	88,078,213	1.056	93,009,737	$0.06215	$5,780,555
Intermediate		1.056	0	$0.06215	$0
Unmetered Scattered Load	1,211,706	1.056	1,279,549	$0.06215	$79,524
TOTAL	**586,454,426**		**619,290,171**		**$38,488,884**

Electricity - Commodity	**2011 Forecasted**				
Class per Load Forecast	**Metered kWhs - Non-RPP**	**2011 Loss Factor**		**2011**	
Residential	70,816,883	1.056	74,781,940	$0.06062	$4,533,281
Street Lighting	897,746	1.056	948,011	$0.06062	$57,468
Sentinel Lighting	113,770	1.056	120,140	$0.06062	$7,283
GS<50kW	19,611,967	1.056	20,710,046	$0.06062	$1,255,443
GS>50kW	535,728,457	1.056	565,724,040	$0.06062	$34,294,191
Intermediate		1.056	0	$0.06062	$0
Unmetered Scattered Load	1,123,722	1.056	1,186,640	$0.06062	$71,934
TOTAL	**628,292,545**		**663,470,818**		**$40,219,601**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**		**2011**	
Residential		kWh	485,129,243	$0.0053	$2,571,185
Street Lighting		kW	20,107	$1.5063	$30,288
Sentinel Lighting		kW	809	$1.5139	$1,225
GS<50kW		kWh	128,236,864	$0.0049	$628,361
GS>50kW		kW	1,806,009	$1.9973	$3,607,143
Intermediate		kW		$0.0000	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0049	$12,084
TOTAL					**$6,850,285**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**	**2011**		
Residential		kWh	485,129,243	$0.0046	$2,231,595
Street Lighting		kW	20,107	$1.2583	$25,301
Sentinel Lighting		kW	809	$1.2847	$1,039
GS<50kW		kWh	128,236,864	$0.0041	$525,771
GS>50kW		kW	1,806,009	$1.6277	$2,939,642
Intermediate		kW	0	$0.0000	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0041	$10,111
TOTAL					**$5,733,459**

Wholesale Market Service					
Class per Load Forecast			**2011**		
Residential		kWh	485,129,243	$0.0052	$2,522,672
Street Lighting		kWh	7,885,703	$0.0052	$41,006
Sentinel Lighting		kWh	309,212	$0.0052	$1,608
GS<50kW		kWh	128,236,864	$0.0052	$666,832
GS>50kW		kWh	658,733,777	$0.0052	$3,425,416
Intermediate		kWh	0	$0.0052	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0052	$12,824
TOTAL					**$6,670,357**

Rural Rate Assistance					
Class per Load Forecast			**2011**		
Residential		kWh	485,129,243	$0.0013	$630,668
Street Lighting		kWh	7,885,703	$0.0013	$10,251
Sentinel Lighting		kWh	309,212	$0.0013	$402
GS<50kW		kWh	128,236,864	$0.0013	$166,708
GS>50kW		kWh	658,733,777	$0.0013	$856,354
Intermediate		kWh	0	$0.0013	$0
Unmetered Scattered Load		kWh	2,466,189	$0.0013	$3,206
TOTAL					**$1,667,589**

Table 2-28 2011 Cost of Power Summary

Cost of Power Account	2011 Cost
4705-Power Purchased	$78,708,485
4708-Charges-WMS	$8,337,946
4714-Charges-NW	$6,850,285
4716-Charges-CN	$5,733,459
4750-Low Voltage	$360,512
TOTAL	**99,990,688**

Low Voltage Charges

As indicated in Tables 2-26 and 2-28 above, the forecast amount of LV charges to be paid by NPEI to Hydro One in 2010 and 2011 are $339,100 and $360,512, respectively.

The 2010 forecast amount was calculated as follows:

- For January to March 2010, actual Hydro One invoices were used.
- For April to December 2010, the 2009 actual monthly charge determinants were multiplied by the Hydro One Sub-Transmission rates that were approved for May 1, 2010.

The 2011 LV forecast was obtained by using 12 months of actual charge determinants (April 2009 to March 2010) and the Hydro One Sub-Transmission class rates that were approved for May 1, 2010.

Tables 2-29 and 2-30 below give the details of the 2010 and 2011 LV forecasts, respectively.

Table 2-29 Forecast LV Charges for 2010

Component	Charge Determinant per Month	Rate	Jan to March 2010 Actual Charge Determinants	Monthly/ Yearly	Multiplier	LV Charge
Service Charge	$/Delivery Point	$118.27	10	Month	3	$3,548.10
Meter Charge	$/Meter	$346.34	2	Month	3	$2,078.04
Common ST Lines Charge	$/KW	$0.35	58,629	Year	1	$20,520.15
Specific Primary Lines Charge	$/KM	$339.96				
LVDS	$/KW	$0.78	13,947	Year	1	$10,878.66
Specific ST Lines Charges	$/KM	$438.64	0.13	Month	3	$171.07
HVDS Low	$/KW	$1.66				
HVDS High	$/KW	$0.89	35,483	Year	1	$31,579.87
				Total, January to March		**$68,775.89**

Component	Charge Determinant per Month	Rate	April - Dec 2010 Forecast Charge Determinants	Monthly/ Yearly	Multiplier	LV Charge
Service Charge	$/Delivery Point	$211.47	10	Month	9	$19,032.30
Meter Charge	$/Meter	$252.71	2	Month	9	$4,548.78
Common ST Lines Charge	$/KW	$0.44	169,667	Year	1	$74,992.81
Specific Primary Lines Charge	$/KM	$279.80				
LVDS	$/KW	$1.43	40,758	Year	1	$58,161.67
Specific ST Lines Charges	$/KM	$361.05	0.13	Month	9	$422.43
HVDS Low	$/KW	$2.79				
HVDS High	$/KW	$1.03	110,406	Year	1	$113,166.15
				Total, Forecast April to Dec		**$270,324.14**
				Total 2010 Forecast		**$339,100.03**

Table 2-30 Forecast LV Charges for 2011

Component	Charge Determinant per Month	Rate	2011 Forecast Charge Determinants	Monthly/ Yearly	Multiplier	LV Charge
Service Charge	$/Delivery Point	$211.47	10	Month	12	$25,376.40
Meter Charge	$/Meter	$252.71	2	Month	12	$6,065.04
Common ST Lines Charge	$/KW	$0.44	228,296	Year	1	$100,906.83
Specific Primary Lines Charge	$/KM	$279.80				
LVDS	$/KW	$1.43	54,705	Year	1	$78,064.04
Specific ST Lines Charges	$/KM	$361.05	0.13	Month	12	$563.24
HVDS Low	$/KW	$2.79				
HVDS High	$/KW	$1.03	145,889	Year	1	$149,536.23
				Total		**$360,511.77**

Appendix A – Asset Management Plan

NPEI will submit its Asset Management Plan once the final report is received from the outside 3rd party, Kinetrics.

Insert Kinetics Asset Management Report report here when received

Appendix B – Building Renovations and Service Centre

Prior to the amalgamation of NPEI, Peninsula West Utilities ("PWU") owned a property on Quarry Road in the Town of Lincoln, which housed PWU's stores and garage departments. The property had been purchased by the former Lincoln Hydro-Electric Commission from the Town in 1991, and subsequently transferred to PWU as part of a merger in 2000. At the time of the NPEI amalgamation, it was known that there was excessive leachate in the soil, which would require site restoration expenses estimated at $350,000. As a result, it was agreed that ownership of Quarry Road would not transfer to NPEI during the amalgamation, and the property was purchased from PWU by its parent company, Peninsula West Power Inc.

The building at Quarry Road was in deteriorating condition, and was insufficient in size to adequately accommodate NPEI's needs for the Peninsula West service area. In addition, PWU was renting office space in Beamsville, which was used by the customer service, billing, finance, engineering and administrative departments. This building was also in poor condition. Neither building was linked by electronic network to the NPEI head office, which was the former Niagara Falls Hydro ("NFH") building.

Subsequent to the merger, after assessing the requirements of the amalgamated company, NPEI decided to:

- Renovate the head office in Niagara Falls to accommodate the majority of NPEI's office staff.
- Construct a new service centre in Smithville, to house the stores and garage operations for the Peninsula West service area, as well as office space for several customer service, billing and operations employees.

Contracts for both projects were determined using a bid process.

The renovation to the head office building was accomplished in 2008. During this time, NPEI continued to lease the Beamsville office space for $57,000 per year. Once all office staff members were moved to the Niagara Falls office, the lease was terminated.

The need for the service centre in Smithville had been identified by PWU prior to the NPEI merger; PWU had purchased the land in 2005 for this purpose. The service centre was designed and constructed during 2008 and 2009. During this time, NPEI continued to rent the Quarry Road property from Peninsula West Power Inc, for the nominal amount of $6000 per year. Upon completion of the new service centre, the Quarry Road lease was terminated.

The new Smithville Service Centre occupies approximately 24,700 square feet: 7,500 square feet of office space, inventory storage of 5,200 square feet and 12,000 of garage space. The facility was constructed to include a number of energy efficient features, including: T5 fluorescent lights with occupancy sensors, insulation in the wall cavity and roof (even in the garage area), double glazed windows with Low E coating to reflect solar heat but permit light and high performance HVAC systems.

In summary, NPEI spent a total of approximately $6.4 million on these two projects: approximately $1.4 million to renovate the head office and approximately $5.0 million to construct the service centre. Given that these projects resulted in modern and safe facilities of adequate size for its operations, NPEI submits that this amount is reasonable and was prudently incurred. NPEI further notes that neither project required NPEI to acquire additional debt; both were financed internally.

Table of Contents

EXHIBIT 3 – OPERATING REVENUE

Overview of Operating Revenue

This Exhibit provides the details of NPEI's operating revenue for 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, the 2010 Bridge Year and the 2011 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue does not include revenue from commodity sales.

A summary of operating revenues is presented in Table 3-1. Revenue for the 2010 Bridge Year is based on forecasted actual revenue. The proposed distribution revenue for the 2011 Test Year is based on: proposed 2011 rates, forecast 2011 customer counts and forecast consumption and demand. NPEI notes that the following several items are presented separately in Table 3-1 for the purpose of reconciling to the Gross Profit figures from the Audited (2006 to 2009) and Pro-forma (2010 and 2011) statements:

- Carrying charges on deferral and variance accounts.
- Load transfer payments incorrectly presented as debits to other revenue on the 2006 to 2008 income statements.
- Other reconciling adjustments of ($25,616) relating to retailer revenue that Peninsula West did not include under revenue on the 2007 financial statements, and ($3,034) of General Service energy sales incorrectly included under Other Revenue in 2007.

Throughput Revenue

Information related to NPEI's throughput revenue includes details such as weather normalized forecasting methodology, normalized volume based on historical number of customers billed throughout the year, CDM adjustments and known economic conditions. Details of Throughout Revenue for the 2010 Bridge Year and the 2011 Test Year are set out in Tables 3-25, 3-26 and 3-27.

Other Revenue

Other revenues include Late Payment Charges, Miscellaneous Service Revenues and Retail Services Revenues. A summary of these operating revenues together with a materiality analysis of variances is presented later in this Exhibit, including Tables 3-29 through 3.37.

Table 3-1 Summary of Operating Revenue

Summary of Operating Revenue Table	2006 Board Approved ($)	2006 Actual ($)	Variance From 2006 Board Approved ($)	2007 Actual ($)	Variance From 2006 Actual ($)	2008 Actual ($)	Variance From 2007 Actual ($)	2009 Actual ($)	Variance From 2008 Actual ($)	Bridge Year 2010 ($)	Variance from 2009 Actual ($)	Test Year 2011 ($)	Variance From 2010 Test ($)
Distribution Revenue													
Residential	13,983,016	12,764,815	(1,218,201)	13,617,975	853,160	13,578,074	(39,902)	13,389,651	(188,422)	13,540,558	150,907	16,982,230	3,441,672
GS<50 kW	3,441,378	3,146,857	(294,521)	3,322,765	175,908	3,437,777	115,012	3,343,780	(93,997)	3,348,264	4,484	3,716,300	368,036
GS>50 kW	8,552,807	7,990,014	(562,793)	8,457,732	467,718	8,272,528	(185,204)	8,579,548	307,020	8,669,495	89,947	9,155,837	486,342
Streetlighting	85,642	81,137	(4,505)	85,858	4,721	106,990	21,132	67,282	(39,708)	86,542	19,259	182,318	95,776
Sentinel Lights	9,293	5,513	(3,780)	5,906	393	5,901	(5)	5,923	22	5,147	(776)	55,565	50,417
Unmetered Scattered Load	136,360	125,067	(11,293)	128,210	3,143	132,612	4,402	131,182	(1,430)	129,929	(1,253)	143,333	13,404
Total	26,208,498	24,113,404	(2,095,094)	25,618,446	1,505,042	25,533,882	(84,564)	25,517,367	(16,515)	25,779,935	262,568	30,235,583	4,455,648
Other Distribution Revenue													
Late Payment Charges	432,381	506,487	74,106	552,366	45,879	350,024	(202,342)	500,364	150,340	518,557	18,193	518,557	-
Specific Service Charges	734,394	858,366	123,973	907,332	48,965	963,121	55,789	951,925	(11,196)	884,942	(66,983)	956,878	71,935
Other Distribution Revenue	581,301	628,623	47,322	690,070	61,447	615,526	(74,544)	552,999	(62,527)	558,164	5,165	558,164	-
Other Income and Expenses	1,231,304	343,882	(887,422)	997,358	653,476	461,066	(536,292)	293,632	(167,434)	202,805	(90,827)	152,148	(50,657)
Total	2,979,380	2,337,359	(642,022)	3,147,126	809,767	2,389,737	(757,389)	2,298,920	(90,817)	2,164,469	(134,451)	2,185,747	21,278
Grand Total	29,187,878	26,450,762	(2,737,115)	28,765,572	2,314,810	27,923,619	(841,953)	27,816,287	(107,332)	27,944,404	128,117	32,421,330	4,476,926
Carrying Charges on Regulatory Assets		107,949		(427,916)		(206,779)		198,081		45,195		45,195	
Load Transfers Included on Income Statement as Other Revenue		(14,543)		(28,412)		(25,272)							
Other PWU adustment				(28,650)									
Total Gross Profit per Financial Statements		26,544,168		28,280,593		27,691,568		28,014,368		27,989,599		32,466,525	

Variance Analysis on Operating Revenue

2006 Board Approved

NPEI's 2006 Board Approved operating revenue was forecast to be $29,187,878 as shown in Table 3-1. Distribution revenue totaled $26,208,498 or 89.8% of total revenues. Other operating revenues account for the remaining revenue of $2,979,380.

2006 Actual

NPEI's operating revenue in fiscal 2006 was $26,450,792 as shown in Table 3-1. Distribution revenue totaled $24,113,404 or 91.2% of total revenues. Other operating revenues account for the remaining revenue of $2,337,359.

Comparison to 2006 Board Approved

As shown in Table 3-1, the total operating revenue for 2006 was $2,737,115 lower than the 2006 Board Approved forecasted level. Of this amount, $2,095,094 relates to lower distribution revenue than approved, and $642,022 relates to other revenues.

As shown in Table 3-24, the total 2006 actual billed kWh quantity (1,184 GWh) is greater than the total Board Approved kWh (1,166 GWh). However, for each rate class, the actual 2006 distribution revenue is less than the Board Approved amount. The lower levels of revenue are mainly explained by the fact that in comparing the 2006 Actual to 2006 Board Approved, the 2006 Actual revenue represents a calendar year which consists of four months at 2005 rates and eight months at 2006 rates, whereas the 2006 Board Approved figures represent a full rate year from May 1, 2006 to April 30, 2007. The 2006 EDR decisions for Niagara Falls Hydro Inc. (EB-2005-0394) and Peninsula West Utilities Limited (EB-2005-0405) resulted in typical increases in monthly distribution charges in the range of 15% - 30%. Therefore, it is reasonable to expect that the 2006 Actual distribution revenues, which include four months at substantially lower 2005 rates, would be less than the 2006 Board Approved amounts.

The shortfall in Other Revenues of $642,022 is largely due to the fact that Peninsula West Utilities' 2006 Board Approved Other Income & Deductions amount of $820,184, which is based on 2004 actual revenue, is higher than a typical year. Peninsula West recorded several unusual, non-recurring entries to account 4390 Miscellaneous Non-Operating Income in 2004, totaling $602,941.

2007 Actual

NPEI's operating revenue in fiscal 2007 was $28,765,572, as shown in Table 3-1. Distribution revenue totaled $25,618,446 or 89.1% of total revenues. Other operating revenues account for the remaining revenue of $3,147,126.

Comparison to 2006 Actual

As shown in Table 3-1, the 2007 total operating revenue was $2,314,810 higher than the 2006 actual operating revenue, consisting of an increase in distribution revenue of $1,505,042 and an increase in other revenue of $809,767. The greater distribution revenue resulted from higher distribution rates and a general increase in consumption (1,220 GWh billed in 2007 versus 1,184 GWh billed in 2006), as shown in Table 3-24. The increase in other revenue is attributed to a greater amount of bank interest earned ($769,014 in 2007 versus $455,887 in 2006), a decrease in account 4380 Expenses of Non-Utility Operations of $182,603, and an increase of $156,689 over 2006 in account 4355 Gain on Disposition of Utility and Other Property, mainly relating to the sale of a parcel of land by Peninsula West Utilities for a gain of $171,178.

2008 Actual

NPEI's operating revenue in fiscal 2008 is $27,923,619, as shown in Table 3-1. Distribution revenue totals $25,533,882 or 91.4% of total revenues. Other operating revenues account for the remaining revenue of $2,389,737.

Comparison to 2007 Actual

As shown in Table 3-1, the 2008 total operating revenue was $841,953 lower than the 2007 actual operating revenue, consisting of a decrease in distribution revenue of $84,564 and a decrease in other revenue of $757,389. The lower distribution revenue mainly resulted from slightly lower distribution rates and a decrease in kW billed for the General Service > 50 kW class. The decrease in other revenue is attributed to a lower amount of bank interest earned ($461,947 in 2008 versus $769,014 in 2007), a decrease of $189,178 over 2007 in account 4355 Gain on Disposition of Utility and Other Property, a decrease of $202,342 over 2007 in account 4225 Late Payment Charges, and a decrease of $42,166 over 2007 in account 4390 Miscellaneous Non-Operating Income.

2009 Actual

NPEI's operating revenue in fiscal 2009 is $27,816,287, as shown in Table 3-1. Distribution revenue totals $25,517,367 or 91.7% of total revenues. Other operating revenues account for the remaining revenue of $2,298,920.

Comparison to 2008 Actual

As shown in Table 3-1, the 2009 total operating revenue was $107,332 lower than the 2008 actual operating revenue, consisting of a decrease in distribution revenue of $16,515 and a decrease in other revenue of $90,817. The decrease in other revenue is attributed to a lower amount of bank interest earned ($81,675 in 2009 versus $461,947 in 2008), offset by an increase of $150,340 over 2008 in account 4225 Late Payment Charges, and an increase of $131,324 over 2008 in account 4375 Revenues from Non-Utility Operations.

2010 Bridge

NPEI's operating revenue in 2010 is forecast to be $27,944,404, as shown in Table 3-1. Distribution revenue totals $25,779,935 or 92.3% of total revenues. Other operating revenues account for the remaining revenue of $2,164,469.

Comparison to 2009 Actual

As shown in Table 3-1, the total operating revenue is expected to be $128,717 higher than the actual year level in fiscal 2009, consisting of an increase in distribution revenue of $262,568 and a decrease in other revenue of $134,451. The increase in distribution revenue is attributed to greater forecast consumption in 2010. The lower amount of other revenue is largely due to decreases of $67,110 in account 4235 Miscellaneous Service Revenues, which relates to an accrual recorded in 2010 for pole rental charges related to 2009, and $66,023 in account 4375 Revenue from Non-Utility operations. Account 4375 includes OPA incentives in 2009 that relate to both 2007 and 2008.

2011 Test Year

NPEI's 2011 operating revenue, based on its proposed revenue requirement, is forecast to be $32,421,330. Distribution revenue totals $30,235,583 or 93.3% of total revenues. Other operating revenues account for the remaining revenue of $2,185,747.

Comparison to 2010 Bridge Year

As shown in Table 3-1, the total operating revenue is expected to be $ 4,476,926 above the 2010 Bridge Year level. This consists of an increase in distribution revenue of $4,455,648 and an increase in other revenue of $21,278. The forecast increase in distribution revenue is due to:

- A forecast increases in customer / connection counts in 2011.
- A forecast increases in consumption in 2011.
- NPEI's revenue deficiency, as discussed in Exhibit 6.

The forecast increase in distribution revenue of $4,455,648 given in Table 3-1 is based on comparing the 2011 Test Year, which is the rate year from May 1, 2011 to April 30, 2012, to the 2010 actual calendar year. The pro-rated amount of expected increase in distribution revenue for calendar 2011 is $2,970,432. This figure is obtained by multiplying $4,455,648 by 8 / 12, to reflect the fact that calendar 2011 includes 4 months at existing 2010 rates, and 8 months at the approved 2011 rates.

Weather Normalization Methodology

The purpose of this evidence is to present the process used by NPEI to prepare the weather-normalized load and customer/connection forecast used to design the proposed distribution rates. In summary, NPEI reviewed the various processes used by the 2008, 2009 and 2010 cost of service applicants and is proposing to adopt a weather normalization forecasting method that is generally similar, but not identical, to the one used by Toronto Hydro-Electric System Limited in its 2008 and 2009 rate application (EB-2007-0680).

Rationale as to why the Multifactor Regression model was chosen

The Multifactor Regression model is widely used and applied in economic forecasting. The method uses independent variables (e.g. economic, social, and seasonal) which contribute to and affect the dependent variable (electricity consumption). The method provides flexibility in choosing the drivers that have historically affected consumption in NPEI's service area and continue to be indicators for future electricity sales. NPEI understands that the Multifactor Regression Model and weather normalization methodologies have been accepted by the Board, and NPEI submits that this approach is appropriate for this Application. A similar method was also approved by the Board for the following 2010 cost of service applicants:

a) Burlington Hydro Inc. (EB-2009-0259)

b) Kitchener Wilmot Hydro Inc. (EB-2009-0267)

c) Oakville Hydro Electric Distribution Inc. (EB-2009-0271).

In summary, NPEI has used the same regression analysis methodology used by the distributors mentioned above to determine a prediction model. With regards to the overall process of load forecasting, it is NPEI's view that conducting a regression analysis on historical purchases to produce an equation that will predict future purchases is appropriate. NPEI knows by month precisely the amount of kWh purchased from the IESO. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month.

The results of regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for NPEI for the bridge and test year which is converted to billed kWh by rate class. A detailed explanation of the process is provided later on in this evidence.

During the review process of the 2009 and 2010 cost of service applications, some Interveners' expressed concerns with the load forecasting weather normalized process being proposed by NPEI. Interveners suggested the weather normalization should be conducted on an individual rate class basis and the regression analysis should be based on monthly billed kWh by rate class. In NPEI's view, conducting a regression analysis which relates the monthly billed kWh of a class is problematic. The monthly billed amount does not correspond to the amount consumed in the month. The amount billed is based on billing cycle meter reading schedules whose reading dates vary by customer within a rate class and typically are not at month end. The amount billed could include consumption from the month before or even further back. This issue is further exacerbated by the fact that Niagara Falls residential customers were billed bi-monthly until May 2010, while Peninsula West customers were billed monthly. Using a regression analysis to relate rate class billing data to a variable such as heating degree days does not appear to be logical, since the resulting regression model would attempt to relate heating degree days in a month to the amount billed in the month, not the amount consumed. In NPEI's view, variables such as heating degree days impact the amount consumed not the amount billed. It is possible to estimate the amount consumed in a month based on the amount billed, but until smart meters are fully deployed this would only be an estimate which in the Applicant's view would reduce the accuracy of a regression model.

NPEI did attempt to estimate monthly consumption by class for the Residential, General Service < 50 kW and General Service > 50 kW classes, and performed linear regression analyses on the individual class consumption against the same explanatory variables used in the proposed purchased-based model. The results proved to be unsatisfactory. In general, the class-specific models displayed lower measures of goodness-of-fit, as well as several counter-intuitive or statistically insignificant coefficients. The regression outputs for the individual class models are shown below in Table 3-2:

Table 3-2 R-Square Values for Individual Class Regression Analyses

	Residential	GS<50 kW	GS>50 kW
Multiple R	0.9004	0.7414	0.9081
R Square	0.8108	0.5497	0.8247
Adjusted R Square	0.7934	0.5082	0.8085

Explanation of results returned by the Regression tool:

Multiple R: The Coefficient of Correlation estimates the strength of the relationship between actual load and other variables.

R Square: Square of Multiple R: The percentage of the variation in load that is explained by the variables.

Adjusted R Square: Adding more variables to a model increases the value of R-square. The Adjusted R-Square provides a relative measure of fit adjusted for number of variables (degrees of freedom).

Standard Error: Typical deviation of the points about the sample regression line. Useful when compared to the mean to calculate the % error.

Observations: Number of observations in the sample.

Degrees of freedom (df):

Regression: Number of independent variables in the model.

Residual: Number of observations – number of independent variables in the model – 1

Total: Number of observations – 1.

Sum of Squares (SS): Provides the individual components of the sum of squares.

Mean Square (MS): Sum of squares divided by the degrees of freedom.

F-Test (F): The average explained variation in relationship to the explained variation.

Significance F: The probability that the model does not explain the variation in load.

Coefficients: Values that yield the greatest correlation coefficient squared (R-Square).

Standard Error: Typical deviation of the points about the sample regression line.

T Stat: Measures the significance of each independent variable.

P-value: The probability that the variable does not explain the variation in load.

Lower 95% / Upper 95%: There is a 95% probability that the true value of the coefficient lies between the Lower 95% and Upper 95% values. The probability is 2.5% that it lies below the lower value, and 2.5% that it lies above.

NPEI understands that to a certain degree the process of developing a load forecast for cost of service rate applications is an evolving science for electricity distributors in the province. NPEI expects to include additional improvements to the load forecasting methodology in future cost of service rate applications by taking into consideration data provided by smart meters and benchmarking how others are conducting load forecasts. However, based on the Board's approval of this methodology in a number of 2009 and 2010 applications as well as the discussions that followed, NPEI submits the load forecasting methodology is reasonable at this time for the purposes of the is application.

Table 3-3 below provides a summary of the weather normalized load and customer/connection count forecast used in this application.

Table 3-3 Summary of Load and Customer/Connection Forecast

Year	Billed (kWh)	Growth (kWh)	Percentage Change (%)	Customer/ Connection (Count)	Growth (Count)	Percentage Change (%)
2003	1,108,347,420			59,715		
2004	1,135,405,804	27,058,384	2.44%	60,323	608	1.02%
2005	1,208,894,249	73,488,445	6.47%	61,003	680	1.13%
2006	1,184,184,647	-24,709,603	-2.04%	61,856	853	1.40%
2007	1,220,452,820	36,268,173	3.06%	62,459	603	0.97%
2008	1,188,897,732	-31,555,088	-2.59%	63,057	598	0.96%
2009	1,161,778,118	-27,119,614	-2.28%	64,026	968	1.54%
2010	1,170,387,731	8,609,613	0.74%	64,775	749	1.17%
2011	1,214,746,971	44,359,240	3.79%	65,533	758	1.17%

2003 to 2009 are weather actual and 2010 and 2011 are weather normalized. NPEI currently does not have a process to adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this application.

On a rate class basis, actual and forecasted billed amount and number of customers are shown in Table 3-4 and customer usage is shown in Table 3-5. The streetlight, sentinel lights and unmetered scattered loads are measured as connections.

Table 3-4 Billed Energy and Number of Customers/Connections by Rate Class

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Billed Energy (kWh)							
2003	418,838,012	126,366,945	553,710,685	6,713,622	298,685	2,419,471	1,108,347,420
2004	404,285,804	122,937,633	598,431,001	7,027,058	299,222	2,425,087	1,135,405,804
2005	463,562,202	125,194,926	609,950,002	7,458,446	336,743	2,391,930	1,208,894,249
2006	450,017,939	122,020,708	601,216,533	8,236,754	317,191	2,375,520	1,184,184,647
2007	462,721,168	125,994,115	622,092,059	7,023,291	295,243	2,326,944	1,220,452,820
2008	450,470,690	122,663,804	605,669,659	7,504,236	286,832	2,302,512	1,188,897,732
2009	438,952,918	119,930,976	592,972,281	7,271,510	294,273	2,356,161	1,161,778,118
2010	442,125,159	118,817,295	599,437,064	7,368,898	293,544	2,345,772	1,170,387,731
2011	459,406,923	121,437,543	623,806,670	7,467,591	292,817	2,335,428	1,214,746,971
Number of Customers/Connections							
2003	42,507	3,982	864	11,358	582	422	59,715
2004	42,859	4,033	819	11,588	602	422	60,323
2005	43,068	4,437	802	11,752	522	422	61,003
2006	43,724	4,438	871	11,807	594	422	61,856
2007	44,325	4,339	853	11,933	569	440	62,459
2008	44,955	4,260	847	11,986	564	445	63,057
2009	45,761	4,257	852	12,136	566	454	64,026
2010	46,327	4,304	850	12,271	563	460	64,775
2011	46,900	4,352	848	12,408	560	465	65,533

Table 3-5 Annual Usage per Customer/Connection by Rate Class

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Energy Usage per Customer/Connection (kWh)						
2003	9,853	31,735	640,869	591	513	5,733
2004	9,433	30,483	730,685	606	497	5,747
2005	10,763	28,216	760,536	635	645	5,668
2006	10,292	27,495	690,260	698	534	5,629
2007	10,439	29,038	729,299	589	519	5,289
2008	10,020	28,794	715,076	626	508	5,175
2009	9,592	28,175	695,793	599	520	5,190
2010	9,550	27,622	705,394	600	522	5,104
2011	9,507	27,080	715,128	602	523	5,020
Annual Growth Rate in Usage per Customer/Connection						
2003						
2004	-4.27%	-3.94%	14.01%	2.59%	-3.15%	0.23%
2005	14.11%	-7.44%	4.09%	4.66%	29.79%	-1.37%
2006	-4.38%	-2.56%	-9.24%	9.92%	-17.22%	-0.69%
2007	1.43%	5.61%	5.66%	-15.63%	-2.83%	-6.05%
2008	-4.01%	-0.84%	-1.95%	6.38%	-2.03%	-2.15%
2009	-4.27%	-2.15%	-2.70%	-4.30%	2.37%	0.29%
2010	-0.45%	-1.96%	1.38%	0.23%	0.23%	-1.65%
2011	-0.45%	-1.96%	1.38%	0.23%	0.23%	-1.65%

Load Forecast Methodology

NPEI’s weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather, and economic data. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast. The forecast of customers by rate class is determined using time-series econometric methodologies. For those rate classes that use kW for the distribution volumetric billing determinant an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh. The following will explain the forecasting process in more detail.

Purchased KWh Load Forecast

The forecast of total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days), economic output (GDP growth), and population, calendar variables (days in month, seasonal, number of peak hours) and CDM kWh savings. The regression model uses monthly kWh and monthly values of independent variables from January 2002 to December 2009 to determine the monthly regression coefficients.

Data for NPEI's total system load is available as far back as January 2002. This provides 96 monthly data points, which is a reasonable data set for use in a multiple regression analysis. Based on the recent global activity surrounding climate change, historical weather data is showing that there is a warming of the global climate system. In this regard it is NPEI's view that it is appropriate to review the impact of weather since 2002 on the energy usage and then determine the average weather conditions from 1998 to 2009 which would be applied in the forecasting process to determine a weather normalized forecast.

The multifactor regression model has determined primary drivers of year-over-year changes in NPEI's load growth are economic conditions and weather. Both of these effects are captured within the multifactor regression model.

Economic growth, which encompasses population trends in the NPEI’s service area as well as general economic conditions, is captured in the model using an index of economic output, Ontario Real Gross Domestic Product ("GDP"), and population statistics.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

The third main factor determining energy use in the monthly model can be classified as "calendar factors". For example, the number of days in a particular month will impact energy use. The modeling of purchased energy uses number of days in the month, the number of peak hours in the month and a “flag” variable to capture the typically lower usage in the spring and fall months.

Another element that NPEI incorporated into the weather normalization model is the effect of CDM initiatives. One approach to including the expected effects of CDM programs is to first derive a weather normalized load forecast, and then manually adjust it down to reflect forecast CDM energy savings. In NPEI’s view, one problem with this approach is that historical CDM energy savings are already reflected in the historical actual usage, and therefore the linear regression model will capture some element of CDM results. It may be difficult to determine how much of forecast CDM energy savings in the test year have already been captured by the linear regression coefficients, and how much must be subsequently adjusted manually. Instead, the approach taken by the Applicant is to attempt to model CDM savings as one of the explanatory variables in the regression analysis. In this manner, CDM effects are accounted for in the model and assigned a coefficient in the regression equation, and there is no manual adjustment required to the resulting load forecast.

The process of developing a model of energy usage involves estimating multifactor models using different input variables to determine the best fit. Using stepwise regression techniques different explanatory variables were tested with the ultimate model being determined both by model statistics and by forecast accuracy. The model chosen as the best predictor of kWh purchased by NPEI is as follows:

NPEI's Monthly Predicted kWh Purchases

= Heating Degree Days	x	24,605.27
+ Cooling Degree Days	x	195,869.35
+ Ontario Real GDP Monthly Index	x	814,325.39
+ Population	x	680.78
+ Number of Days in the Month	x	2,812,228.43
+ Spring Fall Flag	x	(5,186,781.44)
+ CDM kWh Saved in the Month	x	(9.00)
+ Constant of		(188,586,464.77).

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various explanatory variables are:

a) Environment Canada website for monthly heating degree day and cooling degree day information. Data for the Port Weller weather station was used where available. For 13 of the 144 months used (a 12 year average), Port Weller data was not available, so data for the Grimsby Mountain weather station was used instead.

b) The historical Ontario Real GDP Data was taken from the Ontario Economic Outlook and Fiscal Review reports published by the Ministry of Finance. The 2010 and 2011 forecast changes in Real GDP (increases of 2.7% and 3.2%, respectively) were taken from the 2010 Ontario Budget.

c) The historical population data was obtained using Census Canada data for the 1996, 2001 and 2006 population figures:

		Census Data - Population	
	1996	2001	2006
City of Niagara Falls	76,917	78,815	82,184
Town of Lincoln	18,801	20,612	21,722
Township of West Lincoln	11,513	12,268	13,167
Town of Pelham	14,393	15,272	16,155
Total	121,624	126,967	133,228
Weighted Growth %		4.39%	4.93%

Based on the Census data, there was a 4.93% growth in the population of the four cities in NPEI's service area[1] from 2001 to 2006. Based on a report obtained from the Region of Niagara's web page[2], the Region is predicting a population growth rate of 5.63% from 2006 to 2011. The Region's report contains the following projected population figures:

Niagara 2031 - Region of Niagara Growth Management Strategy - Option D:Preferred Growth Option							
	2001	2006	2011	2016	% Growth 2001-2006	% Growth 2006-2011	% Growth 2011-2016
Niagara Falls	78,800	82,200	85,700	89,100	4.31%	4.26%	3.97%
Lincoln	20,600	21,700	23,200	25,200	5.34%	6.91%	8.62%
West Lincoln	12,300	13,200	14,500	15,300	7.32%	9.85%	5.52%
Pelham	15,300	16,200	17,400	19,000	5.88%	7.41%	9.20%
Total	127,000	133,300	140,800	148,600	4.96%	5.63%	5.54%

For modeling purposes, NPEI adopted the population growth rate projected by Niagara Region to derive monthly population figures from 2007 to 2011.

d) The calendar provided information related to the number of days in the month and the spring/fall flag.

e) Annual CDM energy savings for 2005 to 2009 were taken from the following sources:

i) 2005 'Annual Conservation and Demand Management' Reports filed with the OEB

ii) '2006 – 2008 OPA Conservation Results Niagara Peninsula Energy' spreadsheet provided by the OPA

[1] NPEI's service area population included in the regression model is slightly lower than the total of the municipal populations, due to the fact that approximately 900 people in the Town of Pelham are customers of Hydro One Networks.

[2] "Niagara 2031 – Region of Niagara Growth Management Strategy – Option D: Preferred Growth Option – Population, Household and Employment Forecasts, Residential Land Needs Analysis and Employment Land Needs Analysis", prepared by Dillon Consulting, Watson and Associates, EDP Consulting, October 24, 2008

iii) 'Preliminary 2009 Results Niagara Peninsula Energy Inc.' spreadsheet provided by the OPA.

The persistence savings from the 2006 to 2009 initiatives are included in the data provided by the OPA. For forecasting, NPEI assumed that for 2010 and 2011, the CDM program initial year results would grow at an annual rate of 1.2%, which is the same as the assumed population growth rate. The reason for this assumption is explained in greater detail below. The persistence of the 2010 programs in 2011 is based on the 2009 persistence data provided by the OPA. For modeling purposes, NPEI divided the annual energy savings in each year by 12 to include as a monthly explanatory variable in the regression model.

The following Table 3-6 summarizes the historical CDM results and forecasts for the 2010 Bridge and 2011 Test years that were included in the regression models:

Table 3-6 CDM kWh Saved in the Year

Notes	Year	Residential	Non-Residential	NPEI Total
1	2005 Total	768,907		768,907
2	2006 Total	4,178,894		4,178,894
2	2006 Programs Persistence	4,178,894		4,178,894
2	2007 Initiatives	3,677,890	8,792	3,686,683
	2007 Total	7,856,785	8,792	7,865,577
2	2006 Programs Persistence	4,178,894		4,178,894
2	2007 Programs Persistence	3,661,374	8,792	3,670,167
2	2008 Initiatives	2,534,853	496,645	3,031,498
	2008 Total	10,375,121	505,438	10,880,559
2	2006 Programs Persistence	4,178,894		4,178,894
2	2007 Programs Persistence	1,953,239	8,792	1,962,032
2	2008 Programs Persistence	1,975,227	496,642	2,471,869
3	2009 Initiatives	921,697	1,415,292	2,336,988
	2009 Total	9,029,057	1,920,726	10,949,783
2	2006 Programs Persistence	4,178,894		4,178,894
2	2007 Programs Persistence	1,953,239	8,792	1,962,032
2	2008 Programs Persistence	1,975,227	496,642	2,471,869
3	2009 Programs Persistence	921,697	1,414,560	2,336,257
4	2010 Initiatives	932,757	1,432,275	2,365,032
	2010 Total	9,961,814	3,352,270	13,314,084
2	2006 Programs Persistence	2,653,450		2,653,450
2	2007 Programs Persistence	1,953,239	8,792	1,962,032
2	2008 Programs Persistence	1,975,227	496,642	2,471,869
3	2009 Programs Persistence	921,322	1,263,387	2,184,709
4	2010 Programs Persistence	932,465	1,431,827	2,364,292
4	2011 Initiatives	943,950	1,449,462	2,393,412
	2011 Total	9,379,654	4,650,111	14,029,765

1. Source: Niagara Falls Hydro and Peninsula West Utilities '2005 Annual Conservation & Demand Management Reports' that were filed with the OEB.
2. Source: '2006 - 2008 OPA Conservation Results Niagara Peninsula Energy Inc.' spreadsheet provided by the OPA.
3. Source: 'Preliminary 2009 Results.Niagara Peninsula Energy Inc.' spreadsheet provided by the OPA.
4. Assumed that 2010-2014 Initiatives initial year results are based on annual growth of 1.012, and that future programs have the same persistence as 2009.

Some preliminary calculations indicate that, in order to meet the OEB's CDM target of energy savings for 2011 to 2014 of 59 GWh[3], NPEI will have to achieve an increase in CDM results of 35% per year, for each year from 2010 to 2014. NPEI notes, however, that these CDM targets are still preliminary at this time, and the Applicant does not have much information about expected 2010 results or what CDM programs will be implemented in 2011. Given this uncertainty, as well as the modeling implications discussed below, the Applicant has opted to set the 2010 and 2011 forecast CDM kWh saved, for load forecasting purposes, assuming an annual growth rate in the initial year results of 1.2%.

In the following section, the Applicant provides further details relating to the various versions of regression models tested.

NPEI notes that in several recent cost-of-service applications, interveners and Board staff have expressed concern that certain distributors have placed too much emphasis on achieving a high R-Squared value in their proposed multi-factor regression models, without examining whether or not the resulting regression coefficients are both plausible and statistically significant. For example, several recent applications have included regression models where the coefficient for Population, Number of Customers or GDP Index was negative. Such negative coefficients would imply that as population or customer counts increased, or as economic conditions strengthened, then total system purchases would decrease. These counter-intuitive results may cause the validity of the associated regression models to be questioned.

In considering models that reflect various combinations of explanatory variables, it was NPEI's goal to select a regression model that displayed a high goodness-of-fit value (with emphasis on the Adjusted R-Squared) in which the explanatory variables were limited to those that were plausible in both sign and magnitude, and statistically

[3] See Appendix C to this Exhibit: the OPA's CDM Target Advice of the Board letter to All Licensed Electricity Distributors dated June 22, 2010.

significant. For the purposes of these regression analyses, NPEI defined an explanatory variable as being statistically significant if the absolute value of the t Stat is greater than 2.0 and the P-value is less than 0.05.

The first version of multifactor regression model that NPEI examined (V1) included the following variables as predictors of total system purchases: Heating Degree Days, Cooling Degree Days, Ontario Real GDP Monthly Index, Service Area Population, and Number of Days in the Month, Spring/Fall Flag and Number of Peak Hours. The CDM explanatory variable was initially omitted from the first set of models tested, to allow for a more thorough understanding of the effect that adding the CDM variable has on the load forecast.

This model results in a prediction of 1,265 GWh purchased for the 2011 Test Year. The summary output of the regression is shown below.

Model V1 – Population included

Regression Statistics	
Multiple R	0.964047826
R Square	0.92938821
Adjusted R Square	0.923771363
Standard Error	2854012.595
Observations	96

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	7	9.4344E+15	1.34777E+15	165.4644014	7.98385E-48
Residual	88	7.16794E+14	8.14539E+12		
Total	95	1.01512E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-60258615.06	20940539.33	-2.877605687	0.005027955	-101873535.8	-18643694.36
Heating Degree Days	24299.44887	2170.478554	11.19543376	1.3149E-18	19986.07893	28612.81881
Cooling Degree Days	196543.8422	11405.04408	17.23306292	6.04556E-30	173878.7141	219208.9702
Ontario Real GDP Monthly %	803445.9394	129209.1746	6.218180265	1.64432E-08	546669.8618	1060222.017
Number of Days in Month	2803726.872	393307.281	7.128591326	2.68208E-10	2022111.315	3585342.429
Spring Fall Flag	-5085694.703	788243.9762	-6.451929677	5.80803E-09	-6652163.935	-3519225.471
Population	-347.4780299	245.5128011	-1.415315325	0.160505301	-835.3831211	140.4270612
Number of Peak Hours	15438.26732	19547.46064	0.789783778	0.431777036	-23408.20229	54284.73692

NPEI notes that in this version of the model the Population coefficient is -347.48 which, as mentioned in the discussion above, is counter-intuitive. In addition, the Population coefficient does not appear to be statistically significant (t Stat = -1.42; P-value = 0.16).

The next version modeled by the Applicant (V2) includes customer counts as an explanatory variable. This version results in a prediction of 1,274 GWh purchased in the 2011 Test Year. The summary output of the regression follows.

Model V2 – Customer Counts included

Regression Statistics	
Multiple R	0.964996393
R Square	0.931218039
Adjusted R Square	0.925746747
Standard Error	2816790.535
Observations	96

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	7	9.45298E+15	1.35043E+15	170.2007459	2.52685E-48
Residual	88	6.98219E+14	7.93431E+12		
Total	95	1.01512E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-70094101.13	14571372.26	-4.810398078	6.18603E-06	-99051640.93	-41136561.32
Heating Degree Days	24717.02376	2115.928846	11.68140592	1.38358E-19	20512.0599	28921.98763
Cooling Degree Days	197354.3237	11125.98398	17.73814559	8.34611E-31	175243.7689	219464.8784
Ontario Real GDP Monthly %	665952.8943	52359.49615	12.71885605	1.2182E-21	561899.4004	770006.3881
Number of Days in Month	2757220.64	387449.1205	7.116342492	2.83761E-10	1987246.946	3527194.334
Spring Fall Flag	-5077979.312	775417.7518	-6.548701394	3.76152E-09	-6618959.119	-3536999.506
Number of Peak Hours	319.3742333	20740.63967	0.015398476	0.987749137	-40898.2879	41537.03637
Number of Customers	-231.1157551	110.211435	-2.097021557	0.038860848	-450.1378184	-12.09369186

NPEI notes that in this version of the model, although the Number of Customers coefficient appears to be statistically significant (t Stat = -2.10; P-value = 0.04), it gives a counter-intuitive result. The Applicant rejects this model, since the coefficient of -231.12 computes that, as customer count increases, overall system purchases decreases, which is a potential indication of improper modeling.

The next model version considered (V3) does not include either population or customer counts as an explanatory variable. In addition, the Number of Peak Hours variable has been omitted, since it was not statistically significant in either V1 or V2. This version results in a prediction of 1,281 GWh purchased in the 2011 Test Year. The summary output of the regression follows.

Model V3 – Population and Customer Counts Excluded, Peak Hours Excluded

Regression Statistics	
Multiple R	0.962922418
R Square	0.927219582
Adjusted R Square	0.923176226
Standard Error	2865131.959
Observations	96

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	5	9.41239E+15	1.88248E+15	229.3192733	1.30784E-49
Residual	90	7.38808E+14	8.20898E+12		
Total	95	1.01512E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-80137925.13	12946767.21	-6.189801967	1.75484E-08	-105858937.4	-54416912.9
Heating Degree Days	24613.16261	2142.593801	11.48755429	2.4636E-19	20356.52614	28869.79907
Cooling Degree Days	198804.5418	11256.84475	17.66076962	5.40479E-31	176440.8554	221168.2282
Ontario Real GDP Monthly %	631367.4622	50925.03459	12.39797807	3.56943E-21	530195.9947	732538.9297
Number of Days in Month	2871982.847	374066.1729	7.677740076	1.8722E-11	2128835.121	3615130.573
Spring Fall Flag	-4969998.423	786932.8351	-6.315657705	1.00064E-08	-6533377.817	-3406619.028

The Applicant notes that all of the variables in this model appear to be statistically significant and the coefficients are all plausible in sign.

Next, the linear regression analysis was applied to a set of explanatory variables that includes the CDM energy savings discussed above. The next version of the model tested (V4) includes: Heating Degree Days, Cooling Degree Days, Ontario Real GDP Monthly Index, Service Area Population, and Number of Days in the Month, Spring/Fall Flag and CDM Energy Savings. The Number of Peak Hours in the month is again omitted, as it continues to be statistically insignificant.

This version results in a prediction of 1,277 GWh purchased in the test year. The summary output of the regression follows.

Model V4 – CDM Included, Population Included, Peak Hours Excluded

Regression Statistics	
Multiple R	0.970449647
R Square	0.941772518
Adjusted R Square	0.937140786
Standard Error	2591679.428
Observations	96

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	7	9.56012E+15	1.36573E+15	203.3305495	1.70325E-51
Residual	88	5.91079E+14	6.7168E+12		
Total	95	1.01512E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-188586464.8	35162173.56	-5.363333539	6.52242E-07	-258463894.4	-118709035.1
Heating Degree Days	24605.26999	1964.526414	12.52478451	2.92786E-21	20701.18664	28509.35334
Cooling Degree Days	195869.3535	10336.55825	18.94918491	8.23254E-33	175327.6165	216411.0905
Ontario Real GDP Monthly %	814325.3909	117359.0616	6.938751722	6.4084E-10	581098.9221	1047551.86
Number of Days in Month	2812228.433	339492.9977	8.283612481	1.21858E-12	2137557.454	3486899.413
CDM kWh Saved in month	-8.999091103	2.039305153	-4.412822225	2.883E-05	-13.05178148	-4.946400726
Spring Fall Flag	-5186781.438	716120.0021	-7.24289424	1.58328E-10	-6609919.43	-3763643.446
Population	680.7806023	323.4476441	2.104762903	0.038163055	37.99639097	1323.564814

In the next version considered (V5), population was replaced with customer counts. This version results in a prediction of 1,252 GWh purchased in the test year. In this scenario, the regression coefficient for number of customers remains negative. The summary output of the regression follows.

Model V5 – CDM Included, Customer Counts Included, Peak Hours Excluded

Regression Statistics	
Multiple R	0.970942238
R Square	0.942728829
Adjusted R Square	0.938173167
Standard Error	2570308.83
Observations	96

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	7	9.56983E+15	1.36712E+15	206.9356692	8.23964E-52
Residual	88	5.81371E+14	6.60649E+12		
Total	95	1.01512E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-111868506.5	15832281.69	-7.065848669	3.57905E-10	-143331838.8	-80405174.23
Heating Degree Days	24105.19939	1927.993258	12.5027405	3.23533E-21	20273.71801	27936.68077
Cooling Degree Days	191911.7463	10197.79277	18.81894942	1.34127E-32	171645.7765	212177.7161
Ontario Real GDP Monthly %	999302.9311	92542.20564	10.79834789	8.39424E-18	815394.7476	1183211.115
Number of Days in Month	2758961.24	338659.9836	8.146699858	2.32385E-12	2085945.701	3431976.779
CDM kWh Saved in month	-5.859960539	1.393366388	-4.205613533	6.24454E-05	-8.628983383	-3.090937696
Spring Fall Flag	-5367394.414	710640.4954	-7.552896926	3.75751E-11	-6779643.038	-3955145.789
Number of Customers	-228.5174109	93.49918439	-2.4440578	0.01651826	-414.3273885	-42.70743326

In the next version considered (V6), population and customer counts are excluded, and CDM kWh Saved is included. This version results in a prediction of 1,257 GWh purchased in the test year. The summary output of the regression follows.

Model V6 – CDM Included, Customer Counts and Population Excluded, Peak Hours Excluded

Regression Statistics	
Multiple R	0.968938221
R Square	0.938841276
Adjusted R Square	0.934718216
Standard Error	2641148.484
Observations	96

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	6	9.53036E+15	1.58839E+15	227.7049717	9.29527E-52
Residual	89	6.20834E+14	6.97567E+12		
Total	95	1.01512E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-122054894.7	15694806.92	-7.776769433	1.24422E-11	-153240141.1	-90869648.32
Heating Degree Days	24002.85163	1980.662843	12.1185954	1.55154E-20	20067.31683	27938.38642
Cooling Degree Days	193330.1728	10461.86866	18.47950677	3.24701E-32	172542.663	214117.6825
Ontario Real GDP Monthly %	966774.4604	94104.17358	10.27344935	8.73907E-17	779791.476	1153757.445
Number of Days in Month	2870430.629	344823.5235	8.324346901	9.35561E-13	2185273.648	3555587.611
CDM kWh Saved in month	-5.887877239	1.43172051	-4.112448761	8.70693E-05	-8.732675336	-3.043079142
Spring Fall Flag	-5261982.523	728880.163	-7.219269765	1.68257E-10	-6710251.851	-3813713.196

The following Table 3-7 summarizes the predicted purchases and regression statistics of the various models considered:

Table 3-7 Summary of Results of Regression Models Considered

Model Version	V1	V2	V3	V4	V5	V6
Explanatory Variables Included	HDD, CDD, GDP Index, Number of Days, Spring/Fall, Peak Hours, Population	HDD, CDD, GDP Index, Number of Days, Spring/Fall, Peak Hours, Customers	HDD, CDD, GDP Index, Number of Days, Spring/Fall	HDD, CDD, GDP Index, Number of Days, CDM, Spring/Fall, Population	HDD, CDD, GDP Index, Number of Days, CDM, Spring/Fall, Customers	HDD, CDD, GDP Index, Number of Days, CDM, Spring/Fall
2010 Bridge Year Predicted Purchases (GWh)	1,231.36	1,244.42	1,249.52	1,230.38	1,208.73	1,213.60
2011 Test Year Predicted Purchases (GWh)	1,264.66	1,274.81	1,280.79	1,277.01	1,251.47	1,257.28
Adjusted R-Squared Value	0.924	0.926	0.923	0.937	0.938	0.935
Population regression coefficient	(347.48)	n/a	n/a	680.78	n/a	n/a
Customer Count regression coefficient	n/a	(231.12)	n/a	n/a	(228.52)	n/a
CDM kWh Saved Coefficient	n/a	n/a	n/a	(9.00)	(5.86)	(5.89)

The version of the Multifactor Regression model that NPEI submits should be adopted for the purposes of determining 2011 distribution rates is V4, resulting in predicted 2011 Test Year purchases of 1,277 GWh.

The Applicant notes the following about this version:

i) It includes Population and CDM Energy Savings as variables;

ii) There appears to be good explanatory power (Adjusted R-Squared of 0.937);

iii) All of the resulting coefficients are plausible in sign; and

iv) All of the resulting coefficients appear to be statistically significant.

<u>Discussion of the CDM Energy Saved Explanatory Variable and Multicollinearity</u>

NPEI observes that, in the proposed Multifactor Regression Model V4, both of the explanatory variables of Population and CDM kWh Saved are statistically significant and plausible in sign. The Applicant also notes that the coefficient of the CDM variable is approximately -9.0. This specifies that, for each additional kWh of CDM savings forecast in the test year, the total forecast consumption for 2011 will decrease by approximately 9 kWh.

As mentioned above, the Applicant has determined that, in order to meet its 2011-2014 CDM target of 59 GWh, NPEI will have to achieve an annual increase in initial-year savings results of approximately 35%. However, under this scenario, the total 2011 CDM kWh Saved, including persistence results for prior years, would then become 16,685,168 kWh (or 1,390,431 kWh per month), compared to the 2011 value of 14,029,765 kWh (or 1,169,147 kWh per month) that the Applicant is proposing be included in the model. This would be an increase of 2,655,403 kWh in CDM savings which, due to the regression coefficient of -9, would decrease 2011 forecast consumption by approximately 24 million kWh. This result prompted the Applicant to conduct further analysis of the model specification, with the conclusion that the proposed regression model exhibits the condition of Multicollinearity, which is the statistical phenomenon in which two or more predictor variables in a multiple regression model are highly correlated.

To begin with, NPEI examined the correlation table of the predictor variables from V4 of the weather normalization model:

	Heating Degree Days	*Cooling Degree Days*	*Ontario Real GDP Monthly %*	*Number of Days in Month*	*CDM kWh Saved in month*	*Spring Fall Flag*	*Population*
Heating Degree Days	1.00						
Cooling Degree Days	(0.72)	1.00					
Ontario Real GDP Monthly %	(0.04)	(0.03)	1.00				
Number of Days in Month	(0.18)	0.20	0.03	1.00			
CDM kWh Saved in month	(0.01)	(0.07)	0.87	0.01	1.00		
Spring Fall Flag	(0.06)	(0.41)	0.01	0.08	-	1.00	
Population	(0.05)	(0.05)	0.92	0.04	0.94	0.02	1.00

Highlighted values indicate correlation that is less than -0.9 or greater than 0.9.

The correlation table suggests that Ontario Real GDP and Population are highly correlated, and also that CDM kWh Saved and Population are highly correlated.

Next, NPEI notes that the regression coefficient for Population was -348 in V1 of the model, changing to +681 in V4 of the model once the CDM variable was added. One indicator that multicollinearity may be present in a model is that there are large changes in the estimated regression coefficients when a predictor variable is added or deleted[4]. Another method of detecting multicollinearity is by computing the variance inflation factors (VIF) of the explanatory variables. The VIF of each variable is given by:

$$VIF = 1 / (1- R^2),$$

where the R^2 value here refers to the square of the coefficient of correlation obtained when each explanatory variable is regressed on all of the other explanatory variables.

[4] http://en.wikipedia.org/wiki/Multicollinearity

VIF values greater than 5, or alternatively greater than 10[5], indicate that multicollinearity is present. The table of VIF values for the predictor variables in NPEI's model is as follows:

Dependant Variable	R Square*	VIF
Heating Degree Days	0.68	3.10
Cooling Degree Days	0.74	3.87
Ontario Real GDP	0.85	6.58
Number of Days in the Month	0.08	1.09
CDM kWh Saved	0.88	8.68
Spring/Fall Flag	0.45	1.83
Population	0.93	14.10
Mean of VIF		5.61
Max of VIF		14.10

*R square value of the regression analysis when each explanatory variable is regressed against all of the other explanatory variables.

The results of the above analysis lead NPEI to conclude that multicollinearity is present in the proposed weather normalization model, particularly between CDM kWh Saved and Population. Remedies to the presence of multicollinearity include[6]:

i) Leave the model as is, despite multicollinearity. The presence of multicollinearity doesn't affect the fitted model provided that the predictor variables follow the same pattern of multicollinearity as the data on which the regression model is based.

ii) Drop one of the variables. An explanatory variable may be dropped to produce a model with significant coefficients. However, information is lost (because a variable has been dropped). Omission of a relevant variable results in biased coefficient estimates for the remaining explanatory variables.

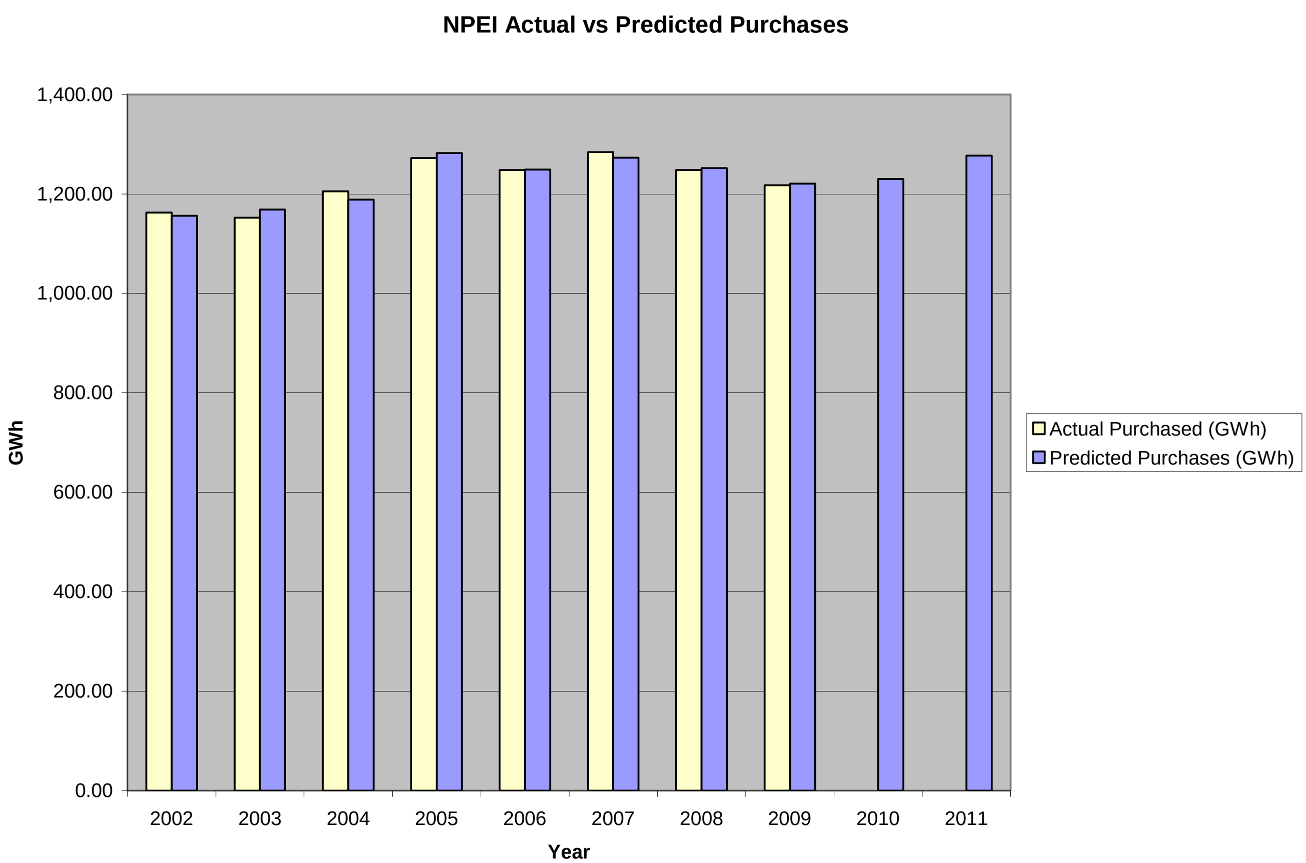
NPEI has opted to leave all of the explanatory variables in the model (version V4), and has attempted to maintain the same pattern of relationship between CDM kWh and Population by only increasing the predicted CDM savings by 1.2% per year for 2010

[5] http://en.wikipedia.org/wiki/Variance_inflation_factor
[6] http://en.wikipedia.org/wiki/Multicollinearity

and 2011, to match population growth, despite the fact that NPEI will need to achieve significantly greater CDM savings to meet the OEB's 2011-2014 target of 58 GWh.
With respect to option ii) above (dropping explanatory variables), NPEI notes that dropping the CDM variable from Model V4 gives Model V1, dropping the Population variable from Model V4 gives Model V6, and dropping both CDM and Population gives Model V3.

The annual results of the above prediction formula compared to the actual annual purchases from 2002 to 2009 are shown in the chart below.

Chart 3.1 Actual versus Predicted Purchases



The following Table 3-8 outlines the data that supports the above chart. In addition, the weather normalized forecast of total system purchases for NPEI is provided for 2010 and 2011.

Table 3-8 NPEI's Total System Purchases

Year	Actual Purchased (GWh)	Predicted Purchases (GWh)	% Difference
2002	1,162.71	1,155.92	-0.58%
2003	1,152.04	1,168.64	1.44%
2004	1,205.24	1,188.47	-1.39%
2005	1,272.19	1,282.30	0.79%
2006	1,248.06	1,249.21	0.09%
2007	1,283.92	1,272.71	-0.87%
2008	1,248.34	1,252.14	0.30%
2009	1,217.54	1,220.67	0.26%
2010	0.00	1,230.38	
2011	0.00	1,277.01	

The forecasted weather normalized amount for 2010 and 2011 is determined by using a forecast of the dependent variables in the prediction formula on a monthly basis. In order to incorporate weather normal conditions, the average of the monthly heating degree days and cooling degree days from 1998 to 2009 is applied in the prediction formula.

Comparison of Weather Data

In selecting the various explanatory variables to include in the multifactor regression models, NPEI considered that it would be reasonable to use a 12 year average of both Heating Degree Days and Cooling Degree days for weather normalization. As per the filing requirements, the following Table 3-9 compares the 12-year average HDD and CDD values used in NPEI's proposed model to the 10-year and 20-year averages.

Table 3-9 Comparison of Average Weather Data

Month	12 Year Average HDD	12 Year Average CDD	10 Year Average HDD	10 Year Average CDD	20 Year Average HDD	20 Year Average CDD
Jan	639.6	0.0	635.0	0.0	606.9	0.0
Feb	563.7	0.0	571.1	0.0	560.3	0.0
Mar	513.0	0.0	512.6	0.0	507.9	0.3
Apr	330.9	0.0	332.7	0.1	314.6	1.3
May	175.7	5.7	179.5	4.9	170.7	9.2
Jun	34.9	58.5	36.6	57.0	33.6	58.5
Jul	0.8	124.2	0.9	118.2	2.3	120.6
Aug	2.1	109.1	2.1	110.9	2.7	104.0
Sep	29.4	50.8	29.9	49.9	41.1	44.8
Oct	205.6	4.9	206.0	5.3	201.6	4.1
Nov	354.3	0.0	357.6	0.0	365.1	0.0
Dec	553.4	0.0	557.2	0.0	532.6	0.0

To determine the sensitivity of the 2011 predicted purchases to changes in the period used for average weather conditions, NPEI replaced the 12-year averages in the proposed forecast with the 10-year and 20-year values. The resulting 2011 forecast purchases are set out in Table 3-10 below.

Table 3-10 Sensitivity of Predicted Purchases to Average Weather

	2011 Predicted Purchases		
	12 Year Avg Proposed	10 Year Avg	20 Year Avg
2011 Predicted Purchases (GWh)	1,277.0	1,276.1	1,273.4
GWh Variance from Proposed Forecast		(0.9)	(3.6)
% Variance from Proposed Forecast		-0.1%	-0.3%

As can be seen in Table 3-10, using a 10-year average reduces the forecast by 0.9 GWh (0.1%), while using a 20-year average reduces the forecast by 3.6 GWh (0.3%). Based on these results, NPEI has opted to maintain the 12-year average in the proposed regression model, giving a 2011 weather normalized purchased forecast of 1,277 GWh.

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. As outlined in Table 3-11 below, historically the NPEI distribution loss factor average for the past 5 years has been 5.13%.

Table 3-11 Historical Distribution Loss Factor

Year	Actual Purchases (GWh)	Actual Billed (GWh)	Loss Factor
2005	1,272	1,209	5.24%
2006	1,248	1,184	5.39%
2007	1,284	1,220	5.20%
2008	1,248	1,189	5.00%
2009	1,218	1,162	4.80%
		Average	5.13%

With this average loss factor the total weather normalized billed energy can be calculated for 2010 and 2011, as indicated in Table 3-11a below.

Table 3-11a Weather Normalized Billed Energy

Year	Predicted Purchases (kWh)	Average Distribution Loss Factor	Weather Normalized Billed Energy (kWh)
	A	B	C = A / B
2010	1,230,381,346	1.0513	1,170,387,731
2011	1,277,014,423	1.0513	1,214,746,971

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in Table 3-12 below.

Table 3-12 Historical Customer/Connection Data

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Number of Customers/Connections							
2003	42,507	3,982	864	11,358	582	422	59,715
2004	42,859	4,033	819	11,588	602	422	60,323
2005	43,068	4,437	802	11,752	522	422	61,003
2006	43,724	4,438	871	11,807	594	422	61,856
2007	44,325	4,339	853	11,933	569	440	62,459
2008	44,955	4,260	847	11,986	564	445	63,057
2009	45,761	4,257	852	12,136	566	454	64,026

From the historical customer/connection data, the growth rate in customer/connection can be evaluated and is provided in Table 3-13 below.

Table 3-13 Growth Rate in Customer/Connections

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Growth Rate in Customer/Connections						
2003						
2004	0.83%	1.28%	-5.21%	2.03%	3.44%	0.00%
2005	0.49%	10.02%	-2.08%	1.42%	-13.29%	0.00%
2006	1.52%	0.02%	8.60%	0.47%	13.79%	0.00%
2007	1.37%	-2.23%	-2.07%	1.07%	-4.21%	4.27%
2008	1.42%	-1.82%	-0.70%	0.44%	-0.83%	1.13%
2009	1.79%	-0.08%	0.62%	1.26%	0.22%	2.03%
2004 - 2009 Geometric Mean of Growth Rate	1.0124	1.0112	0.9977	1.0111	0.9952	1.0123

The resulting geometric mean is applied to the 2009 customer/connection numbers to determine the forecast of customer/connections for 2010 and 2011, as the following example demonstrates:

2009 Residential customer count = 45,761 (from Table 3-12).

2010 Residential customer count = 45,761 * 1.0124 = 46,327

2011 Residential customer count = 46,327 * 1.0124 = 46,900

Table 3-14 outlines the forecast of customers by rate class for 2010 and 2011.

Table 3-14 Customer/Connection Forecast

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Number of Customers/Connections							
2010	46,327	4,304	850	12,271	563	460	64,775
2011	46,900	4,352	848	12,408	560	465	65,533

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following Table 3-15 provides the average annual usage per customer by rate class from 2003 to 2009.

Table 3-15 Historical Annual Usage per Customer

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Annual kWh Usage per Customer/Connection						
2003	9,853	31,735	640,869	591	513	5,733
2004	9,433	30,483	730,685	606	497	5,747
2005	10,763	28,216	760,536	635	645	5,668
2006	10,292	27,495	690,260	698	534	5,629
2007	10,439	29,038	729,299	589	519	5,289
2008	10,020	28,794	715,076	626	508	5,175
2009	9,592	28,175	695,793	599	520	5,190

Usage per customer/connection can only be determined for 2003 and onward since historical billed energy by rate class is only available from 2003. As can been seen from the above table usage per customer generally declines slightly for the residential class after 2005. It is NPEI's view that this decline is partially due to the CDM programs.

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed which is provided on the following Table 3-16

Table 3-16 Growth Rate in Usage Per Customer/Connection

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Annual Growth Rate in Usage per Customer/Connection						
2003						
2004	-4.27%	-3.94%	14.01%	2.59%	-3.15%	0.23%
2005	14.11%	-7.44%	4.09%	4.66%	29.79%	-1.37%
2006	-4.38%	-2.56%	-9.24%	9.92%	-17.22%	-0.69%
2007	1.43%	5.61%	5.66%	-15.63%	-2.83%	-6.05%
2008	-4.01%	-0.84%	-1.95%	6.38%	-2.03%	-2.15%
2009	-4.27%	-2.15%	-2.70%	-4.30%	2.37%	0.29%

For the forecast of usage per customer/connection the historical geometric mean was used for all rate classes.

Table 3-17 Forecast Annual kWh Usage per Customer/Connection

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Forecast Annual Usage per Customer/Connection (kWh)						
2010	9,550	27,622	705,394	600	522	5,104
2011	9,507	27,080	715,128	602	523	5,020

With the preceding information the non-normalized weather billed energy forecast can be determined by multiplying the forecast number of customers/connections from Table 3-14 by the forecast of annual usage per customer/connection from Table 3-17. The resulting non-normalized weather billed energy forecast is shown in Table 3-18 below.

Table 3-18 Non-Normalized Weather Billed Energy Forecast

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Non-Normalized Weather Billed Energy Forecast (kWh)							
2010	442,398,095	118,890,644	599,781,373	7,368,898	293,544	2,345,772	1,171,078,325
2011	445,870,313	117,859,337	606,668,653	7,467,591	292,817	2,335,428	1,180,494,138

The non-normalized weather billed energy forecast has now been determined, but needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 1,170,387,731 kWh for 2010 and 1,214,746,971 kWh for 2011. The difference between the normalized and non-normalized forecast is -690,594 kWh in 2010 (i.e. 1,170,387,731 – 1,171,078,325) and 34,252,833 kWh in 2011 (i.e. 1,214,746,971 – 1,180,494,138). This difference will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for Niagara Falls Hydro for the cost allocation study, it was determined that the General Service > 50 kW class is 87% weather sensitive. NPEI submits that, while it is intuitively improbable that the Residential and General Service < 50 kW classes are 100% weather sensitive, it is reasonable to assume that the consumption for these classes is more sensitive to weather conditions than the GS>50 class. Therefore, for the purposes of weather-normalizing the load forecast, NPEI has assigned a weather sensitivity value of 93.5% to the Residential and GS<50 classes, which is half way between 100% and the GS>50 sensitivity of 87%. All other classes are assigned a weather sensitivity value of zero. This gives the following weather sensitivity values by rate class, as shown below in Table 3-19:

Table 3-19 Weather Sensitivity by Rate Class

Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load
Weather Sensitivity					
93.5%	93.5%	87.0%	0.0%	0.0%	0.0%

As a result, the difference between the non-normalized and normalized forecast has been assigned on a prorated basis to each rate class based on the above level of weather sensitivity. The following Table 3-20 outlines how the weather sensitive rate classes have been adjusted to align the non-normalized forecast with the weather normalized forecast.

Table 3-20 Alignment of Non-Normal to Weather Normal Forecast

Year	Residential	General Service < 50 kW	General Service > 50 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Non-Normalized Weather Billed Energy Forecast (kWh)							
2010	442,398,095	118,890,644	599,781,373	7,368,898	293,544	2,345,772	1,171,078,325
2011	445,870,313	117,859,337	606,668,653	7,467,591	292,817	2,335,428	1,180,494,138
Adjustment for Weather (kWh)							
2010	-272,936	-73,349	-344,309	0	0	0	-690,594
2011	13,536,610	3,578,206	17,138,017	0	0	0	34,252,833
Weather Normalized Billed Energy Forecast (kWh)							
2010	442,125,159	118,817,295	599,437,064	7,368,898	293,544	2,345,772	1,170,387,731
2011	459,406,923	121,437,543	623,806,670	7,467,591	292,817	2,335,428	1,214,746,971

Billed KW Forecast

There are three rate classes that are charged volumetric distribution on a per kW basis: General Service > 50 kW, Streetlights and Sentinel Lights. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following Table 3-21 outlines the annual demand units by applicable rate class for 2003 to 2009.

Table 3-21 Historical Annual kW per Applicable Rate Class

Year	General Service > 50 kW	Streetlights	Sentinel Lights
2003	1,573,551	17,588	968
2004	1,673,046	19,480	933
2005	1,719,941	19,789	892
2006	1,777,691	19,932	831
2007	1,884,479	20,188	825
2008	1,735,816	20,371	733
2009	1,753,191	20,319	695

The following is the historical ratio of kW/kWh as well as the average ratio from 2003 to 2009.

Table 3-22 Historical kW/KWh Ratio per Applicable Rate Class

Year	General Service > 50 kW	Streetlights	Sentinel Lights
2003	0.2842%	0.2620%	0.3241%
2004	0.2796%	0.2772%	0.3118%
2005	0.2820%	0.2653%	0.2649%
2006	0.2957%	0.2420%	0.2620%
2007	0.3029%	0.2874%	0.2794%
2008	0.2866%	0.2715%	0.2556%
2009	0.2957%	0.2794%	0.2362%
Average	0.2895%	0.2693%	0.2763%

The average ratio was applied to the weather normalized billed energy forecast in Table 3-20 to provide the forecast of kW by rate class as shown below.

The following Table 3-23 outlines the forecast of kW for the applicable rate classes.

Table 3-23 kW Forecast by Applicable Rate Class

	General Service > 50 kW			Streetlights			Sentinel Lights		
	Weather Normalized Billed Forecast (kWh)	Average kW / kWh Ratio	Resulting Forecast kW	Weather Normalized Billed Forecast (kWh)	Average kW / kWh Ratio	Resulting Forecast kW	Weather Normalized Billed Forecast (kWh)	Average kW / kWh Ratio	Resulting Forecast kW
Year	A	B	C = A*B	D	E	F = D*E	G	H	I = G*H
2010	599,437,064	0.2895%	1,735,456	7,368,898	0.2693%	19,842	293,544	0.2763%	811
2011	623,806,670	0.2895%	1,806,009	7,467,591	0.2693%	20,107	292,817	0.2763%	809

Table 3-24 below provides a summary of NPEI's billing determinants for: 2006 Board Approved, 2006 to 2009 Actual, 2010 Bridge Year Weather Normalized Forecast and 2011 Test Year Weather Normalized Forecast.

Table 3-24 Summary of Forecast Data

	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Weather Normal	2011 Weather Normal
Actual kWh Purchases	1,227,609,037	1,248,057,840	1,283,916,366	1,248,342,618	1,217,543,467		
Predicted kWh Purchases		1,249,207,495	1,272,711,204	1,252,144,937	1,220,665,728	1,230,381,346	1,277,014,423
% Difference		0.1%	-0.9%	0.3%	0.3%		
Purchased kWh	1,227,609,037	1,248,057,840	1,283,916,366	1,248,342,618	1,217,543,467	1,230,381,346	1,277,014,423
Distribution Losses	(61,911,265)	(63,873,193)	(63,463,547)	(59,444,887)	(55,765,350)	(59,993,615)	(62,267,452)
Billed kWh	1,165,697,772	1,184,184,647	1,220,452,820	1,188,897,732	1,161,778,118	1,170,387,731	1,214,746,971

By Class

Residential							
Customers	42,323	43,724	44,325	44,955	45,761	46,327	46,900
kWh	432,238,428	450,017,939	462,721,168	450,470,690	438,952,918	442,125,159	459,406,923
Usage per Customer	10,213	10,292	10,439	10,020	9,592	9,544	9,795
General Service < 50 kW							
Customers	4,204	4,438	4,339	4,260	4,257	4,304	4,352
kWh	128,799,263	122,020,708	125,994,115	122,663,804	119,930,976	118,817,295	121,437,543
Usage per Customer	30,637	27,495	29,038	28,794	28,175	27,605	27,902
General Service > 50 kW							
Customers	773	871	853	847	852	850	848
kWh	595,139,448	601,216,533	622,092,059	605,669,659	592,972,281	599,437,064	623,806,670
kW	1,678,133	1,777,691	1,884,479	1,735,816	1,753,191	1,735,456	1,806,009
Usage per Customer	769,909	690,260	729,299	715,076	695,793	704,989	735,330
Sentinel Lights							
Connections	602	594	569	564	566	563	560
kWh	315,411	317,191	295,243	286,832	294,273	293,544	292,817
kW	974	831	825	733	695	811	809
Usage per Connection	524	534	519	508	520	522	523
Streetlighting							
Connections	11,588	11,807	11,933	11,986	12,136	12,271	12,408
kWh	7,053,237	8,236,754	7,023,291	7,504,236	7,271,510	7,368,898	7,467,591
kW	19,630	19,932	20,188	20,371	20,319	19,842	20,107
Usage per Connection	609	698	589	626	599	600	602
Unmetered Scattered Load							
Connections	422	422	440	445	454	460	465
kWh	2,151,985	2,375,520	2,326,944	2,302,512	2,356,161	2,345,772	2,335,428
Usage per Connection	5,099	5,629	5,289	5,175	5,190	5,104	5,020
Total of Above							
Customer/Connections	59,912	61,856	62,459	63,057	64,026	64,775	65,533
kWh	1,165,697,772	1,184,184,647	1,220,452,820	1,188,897,732	1,161,778,118	1,170,387,731	1,214,746,971
kW from applicable classes	1,698,737	1,798,454	1,905,492	1,756,920	1,774,205	1,756,109	1,826,926

2010 Throughput Revenue

NPEI's Throughput Revenue for the 2010 Bridge Year, as shown below in Table 3-25, has been calculated using its most recently approved rates, estimated number of customers (from Table 3-14), estimated weather normalized consumption (from Table 3-20) and forecast demand (from Table 3-23). In particular, distribution rates are based on the Board's decisions for NPEI's 2010 IRM Applications (EB-2009-0205 and EB-2009-0206), dated April 8, 2010. The Applicant notes that there is a difference between the 2010 Throughout Revenue in Table 3-25 and the revenue included in the 2010 Pro Forma Income Statement in Exhibit 1 and also in Table 3-1. This is due to the fact that the revenue in Table 3-25 is based on a weather normalized forecast, whereas the 2010 revenue included in the Pro Forma statement and Table 3-1 is forecast 2010 actual revenue.

2011 Throughput Revenue

NPEI's Throughput Revenue for the 2011 Test Year at existing rates, as shown below in Table 3-26, has been calculated using its most recently approved rates, estimated number of customers (from Table 3-14), estimated weather normalized consumption (from Table 3-20) and forecast demand (from Table 3-23). In particular, distribution rates are based on the Board's decisions for NPEI's 2010 IRM Applications (EB-2009-0205 and EB-2009-0206), dated April 8, 2010. The Applicant notes that there is a difference between the 2011 Revenue at Existing Rates in Exhibit 6 - Calculation of Revenue Deficiency or Surplus (Table 6-5) and that in Table 3-26. This is due to the fact that transformer allowance credits in the amount of $392,476 are not included in Table 3-26.

NPEI's Throughput Revenue for the 2011 Test Year at proposed rates, as shown below in Table 3-27, has been calculated using its proposed rates, estimated number of customers (from Table 3-14), estimated weather normalized consumption (from Table

3-20) and forecast demand (from Table 3-23). In particular, distribution rates are based on Exhibit 8 – Rate Design. The Applicant notes that there is a difference of $765,729 between the 2011 Revenue Requirement in Exhibit 6 - Calculation of Revenue Deficiency or Surplus (Table 6-5) and that in Table 3-27. This difference consists of $392,476 for Transformer Allowance, $360,512 for Low Voltage charges and $12,742 due to rounding.

Table 3-25 2010 Throughput Weather Normalized Revenue at Existing 2010 Rates

	Class	Fixed Rate	Variable Rate	Number of Customers/ Connections	Weather Normalized kWh	Weather Normalized kW	Fixed Revenue	Variable Revenue	Total Throughput Revenue
Niagara Falls Only	Residential	15.96	0.0136	32,052	265,233,948		6,138,598	3,607,182	9,745,780
	GS<50 kW	47.27	0.0100	2,818	91,227,039		1,598,624	912,270	2,510,894
	GS>50 kW	280.14	3.0124	622	505,417,630	1,356,151	2,092,134	4,085,270	6,177,403
	Sentinel Lights	1.10	4.0830	25	53,192	98	332	401	733
	Streetlighting	0.32	1.6919	9,613	5,851,961	15,636	36,914	26,455	63,369
	Unmetered/Scattered	23.65	0.0100	314	1,672,880		89,113	16,729	105,842
	Niagara Falls Total				**869,456,650**	**1,371,885**	**9,955,715**	**8,648,306**	**18,604,021**
Pen West only	Residential - Urban	10.04	0.018	9,421	88,445,605		1,135,088	1,592,021	2,727,109
	Residential - Suburban	10.65	0.0134	4,853	88,445,605		620,269	1,185,171	1,805,440
	GS<50 kW	10.35	0.0176	1,486	27,590,255		184,555	485,588	670,144
	GS>50 kW	22.75	6.3575	228	94,019,433	379,305	62,225	2,411,431	2,473,656
	Sentinel Lights	1.04	0.927	538	240,352	713	6,710	661	7,371
	Streetlighting	0.59	0.7961	2,658	1,516,937	4,206	18,821	3,348	22,169
	Unmetered/Scattered	5.18	0.0173	146	672,892		9,048	11,641	20,689
	Pen West Total				**300,931,081**	**384,223**	**2,036,716**	**5,689,861**	**7,726,577**
NPEI Combined	Residential			46,327	442,125,159		7,893,956	6,384,374	14,278,329
	GS<50 kW			4,304	118,817,295		1,783,179	1,397,859	3,181,038
	GS>50 kW			850	599,437,064	1,735,456	2,154,359	6,496,700	8,651,059
	Sentinel Lights			563	293,544	811	7,042	1,062	8,104
	Streetlighting			12,271	7,368,898	19,842	55,735	29,803	85,538
	Unmetered/Scattered			460	2,345,772		98,161	28,370	126,531
	NPEI Total 2010 Throughput Revenue				**1,170,387,731**	**1,756,109**	**11,992,432**	**14,338,167**	**26,330,599**

Table 3-26 2011 Throughput Revenue at Existing 2010 Rates

	Class	Fixed Rate	Variable Rate	Number of Customers/ Connections	Weather Normalized kWh	Weather Normalized kW	Fixed Revenue	Variable Revenue	Total Throughput Revenue
	Residential	15.96	0.0136	32,508	300,327,339		6,226,019	4,084,452	10,310,471
	GS<50 kW	47.27	0.0100	2,806	81,577,671		1,591,719	815,777	2,407,495
	GS>50 kW	280.14	3.0124	627	486,897,093	1,345,798	2,108,953	4,054,081	6,163,035
	Sentinel Lights	1.10	4.0830	20	52,321	96	265	392	657
	Streetlighting	0.32	1.6919	9,667	5,753,278	15,555	37,121	26,318	63,439
Niagara	Unmetered/Scattered	23.65	0.0100	314	1,587,974		89,107	15,880	104,987
Falls Only	**Niagara Falls Total**				**876,195,676**	**1,361,449**	**10,053,184**	**8,996,900**	**19,050,084**
	Residential - Urban	10.04	0.018	9,498	79,539,792		1,144,356	1,431,716	2,576,073
	Residential - Suburban	10.65	0.0134	4,893	79,539,792		625,334	1,065,833	1,691,167
	GS<50 kW	10.35	0.0176	1,546	39,859,872		192,042	701,534	893,576
	GS>50 kW	22.75	6.3575	221	136,909,577	460,212	60,329	2,925,795	2,986,124
	Sentinel Lights	1.04	0.927	540	240,496	713	6,740	661	7,401
	Streetlighting	0.59	0.7961	2,741	1,714,312	4,552	19,404	3,624	23,028
Pen West	Unmetered/Scattered	5.18	0.0173	151	747,453		9,400	12,931	22,331
only	**Pen West Total**				**338,551,295**	**465,477**	**2,057,605**	**6,142,095**	**8,199,700**
	Residential			46,900	459,406,923		7,995,709	6,582,001	14,577,711
	GS<50 kW			4,352	121,437,543		1,783,761	1,517,310	3,301,071
	GS>50 kW			848	623,806,670	1,806,009	2,169,282	6,979,877	9,149,159
	Sentinel Lights			560	292,817	809	7,005	1,053	8,058
	Streetlighting			12,408	7,467,591	20,107	56,525	29,942	86,467
NPEI	Unmetered/Scattered			465	2,335,428		98,507	28,811	127,318
Combined	**NPEI Total 2011 Throughput Revenue**				**1,214,746,971**	**1,826,926**	**12,110,790**	**15,138,994**	**27,249,784**

Table 3-27 2011 Throughput Revenue at Proposed 2011 Rates

Class	Proposed Fixed Rate	Proposed Variable Rate	Number of Customers/ Connections	Weather Normalized kWh	Weather Normalized kW	Fixed Revenue	Variable Revenue	Total Throughput Revenue
Residential	16.55	0.0170	46,900	459,406,923		9,314,307	7,809,918	17,124,224
GS<50 kW	38.45	0.0144	4,352	121,437,543		2,008,156	1,748,701	3,756,856
GS>50 kW	222.81	4.1353	848	623,806,670	1,806,009	2,268,212	7,468,391	9,736,603
Sentinel Lights	7.19	9.0642	560	292,817	809	48,302	7,333	55,635
Streetlighting	0.80	3.2199	12,408	7,467,591	20,107	119,188	64,744	183,932
Unmetered/Scattered	19.87	0.0142	465	2,335,428		110,898	33,163	144,061
NPEI Total 2011 Throughout Revenue				**1,214,746,971**	**1,826,926**	**13,869,063**	**17,132,249**	**31,001,312**

Transformer Ownership Allowance

When customers maintain ownership of their own transformers, they are entitled to receive a credit equivalent to the cost of transformation. NPEI currently gives a Transformer Allowance for Ownership Credit at its Board Approved rate of ($0.60) per kW of demand per month to all customers who own their transformers.

NPEI is proposing to maintain this rate of ($0.60) per kW of demand per month. The estimated demand associated with the transformer ownership for 2011 is based on 2009 actual transformer allowance kW billed. The historical and forecast Transformer Allowance credit data is shown in Table 3-28 below.

Table 3-28 Transformer Ownership Allowance Data

Rate Class	2006 Actual kW	2006 Actual $	2007 Actual kW	2007 Actual $	2008 Actual kW	2008 Actual $	2009 Actual kW	2009 Actual $	2010 Bridge kW	2010 Bridge $	2011 Test kW	2011 Test $
General Service > 50 kW	682,635	(409,581)	708,624	(425,175)	698,292	(418,975)	654,126	(392,475)	654,126	(392,475)	654,126	(392,475)
Rate per kW per month	(0.60)		(0.60)		(0.60)		(0.60)		(0.60)		(0.60)	

SSS Administrative Charge

NPEI proposes to maintain the current Board Approved Standard Supply Service Administrative charge of $0.25 per month, and estimates associated revenues of $126,000 for the 2010 Bridge Year and $126,000 for the 2011 Test Year. The 2008 actual SSS Administrative Charge revenue was $136,567; the 2009 actual SSS Administrative Charge revenue was $114,808. NPEI submits that the estimate of $126,000 for each of 2010 and 2011 is reasonable. Table 3-31 shows the forecast revenues for 2010 and 2011 by customer class.

Other Revenue Variance Analysis

This section provides the details of NPEI's Other Operating Revenue, which includes Specific Service Charges, Late Payment Charges, Other Distribution Revenues and Other Income and Expenses. Table 3-29 below provides a summary of revenue offsets for each year. NPEI notes that for 2006 and 2007 there were some differences in the accounts used by Peninsula West Utilities and Niagara Falls Hydro to record certain transactions. Peninsula West booked Pole Rental revenue to account 4210, while Niagara Falls used account 4235. Peninsula West booked Scrap Sales to either 4355 or 4390, while Niagara Falls used 4215. In addition, NPEI recorded OPA Incentive revenue in account 4235 in 2008, while account 4375 was used in 2009.

Table 3-29 Other Operating Revenues

Uniform System of Account #	Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
4080	SSS Administrative Charge	(126,178)	(125,297)	(124,047)	(136,567)	(114,808)	(126,094)	(126,094)
4235	Miscellaneous Service Revenues	(734,394)	(858,366)	(907,332)	(963,121)	(951,925)	(884,942)	(956,878)
4225	Late Payment Charges	(432,381)	(506,487)	(552,366)	(350,024)	(500,364)	(518,557)	(518,557)
4082	RS Rev	(44,777)	(54,443)	(86,142)	(83,876)	(80,996)	(80,748)	(80,748)
4084	Serv Tx Requests	(462)	(4,742)	(5,376)	(2,492)	(1,124)	(2,970)	(2,970)
4090	Electric Services Incidental to Energy Sales	-	-	-	-	-	-	-
4205	Interdepartmental Rents	-	-	-	-	-	-	-
4210	Rent from Electric Property	(55,911)	(115,733)	(120,711)	-	-	-	-
4215	Other Utility Operating Income	(320,130)	(328,407)	(353,795)	(392,591)	(356,071)	(348,352)	(348,352)
4220	Other Electric Revenues	(33,843)	-	-	-	-	-	-
4240	Provision for Rate Refunds	-	-	-	-	-	-	-
4245	Government Assistance Directly Credited to Income	-	-	-	-	-	-	-
4305	Regulatory Debits	-	-	-	-	-	-	-
4310	Regulatory Credits	-	-	-	-	-	-	-
4315	Revenues from Electric Plant Leased to Others	-	-	-	-	-	-	-
4320	Expenses of Electric Plant Leased to Others	-	-	-	-	-	-	-
4325	Revenues from Merchandise, Jobbing, Etc.	(132,165)	-	-	881	-	-	-
4330	Costs and Expenses of Merchandising, Jobbing, Etc	-	-	-	-	-	-	-
4335	Profits and Losses from Financial Instrument Hedges	-	-	-	-	-	-	-
4340	Profits and Losses from Financial Instrument Investments	-	-	-	-	-	-	-
4345	Gains from Disposition of Future Use Utility Plant	-	-	-	-	-	-	-
4350	Losses from Disposition of Future Use Utility Plant	-	-	-	-	-	-	-
4355	Gain on Disposition of Utility and Other Property	(11,984)	(29,489)	(186,178)	-	(2,450)	-	-
4360	Loss on Disposition of Utility and Other Property	-	-	-	-	-	-	-
4365	Gains from Disposition of Allowances for Emission	-	-	-	-	-	-	-
4370	Losses from Disposition of Allowances for Emission	-	-	-	-	-	-	-
4375	Revenues from Non-Utility Operations	-	-	-	-	(182,223)	(116,200)	(65,480)
4380	Expenses of Non-Utility Operations	-	182,603	-	-	-	-	-
4385	Expenses of Non-Utility Operations	-	-	-	-	-	-	-
4390	Miscellaneous Non-Operating Income	(612,150)	(41,110)	(42,166)	-	(27,284)	(39,937)	(40,000)
4395	Rate-Payer Benefit Including Interest	-	-	-	-	-	-	-
4398	Foreign Exchange Gains and Losses, Including Amortization	-	-	-	-	-	-	-
4405	Interest and Dividend Income	(475,005)	(455,887)	(769,014)	(461,947)	(81,675)	(46,668)	(46,668)
4415	Equity in Earnings of Subsidiary Companies	-	-	-	-	-	-	-
	Total	**(2,979,380)**	**(2,337,359)**	**(3,147,126)**	**(2,389,737)**	**(2,298,920)**	**(2,164,469)**	**(2,185,747)**
Specific Service Charges		(734,394)	(858,366)	(907,332)	(963,121)	(951,925)	(884,942)	(956,878)
Late Payment Charges		(432,381)	(506,487)	(552,366)	(350,024)	(500,364)	(518,557)	(518,557)
Other Distribution Revenues		(581,301)	(628,623)	(690,070)	(615,526)	(552,999)	(558,164)	(558,164)
Other Income and Expenses		(1,231,304)	(343,882)	(997,358)	(461,066)	(293,632)	(202,805)	(152,148)
Total		**(2,979,380)**	**(2,337,359)**	**(3,147,126)**	**(2,389,737)**	**(2,298,920)**	**(2,164,469)**	**(2,185,747)**

Specific Service Charges: Account 4235.

Late Payment Charges: Account 4225.

Other Distribution Revenues: Accounts 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, 4395, 4398, 4405, 4415.

Note: In Table 3-29 above, the SSS Administrative charge has also been included under Other Distribution Revenues.

To allow for more a more relevant comparison and variance analysis, the Applicant has reallocated several amounts within the Other Revenue accounts to achieve consistency in how the transactions noted above are presented. The Pole Rental revenues that Peninsula West included under account 4210 in 2006 and 2007, as well as the corresponding 2006 Board Approved amount of ($52,017), have been reallocated to account 4235. The Scrap Sales revenue that Peninsula West included under accounts 4355 and 4390 in 2006 and 2007 have been reallocated to account 4215. The OPA incentive revenue that NPEI recorded in 4235 in 2008 has been reallocated to 4375. In addition, the Peninsula West Board Approved amount of $132,159 for account 4325 Revenues from Merchandising, Jobbing, Etc. has been reallocated to account 4235. This amount relates to revenue for Billable Work, which Pen West actually recorded in account 4235, but included in account 4325 in the 2006 EDR Model. Table 3-30 below shows the restated balances.

Table 3-30 Other Operating Revenues – Restated for Consistency

Note:	Uniform System of Account #	Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
	4080	SSS Administrative Charge	(126,178)	(125,297)	(124,047)	(136,567)	(114,808)	(126,094)	(126,094)
A	4235	Miscellaneous Service Revenues	(918,570)	(974,099)	(1,028,043)	(912,222)	(951,925)	(884,942)	(956,878)
	4225	Late Payment Charges	(432,381)	(506,487)	(552,366)	(350,024)	(500,364)	(518,557)	(518,557)
	4082	RS Rev	(44,777)	(54,443)	(86,142)	(83,876)	(80,996)	(80,748)	(80,748)
	4084	Serv Tx Requests	(462)	(4,742)	(5,376)	(2,492)	(1,124)	(2,970)	(2,970)
	4090	Electric Services Incidental to Energy Sales	-	-	-	-	-	-	-
	4205	Interdepartmental Rents	-	-	-	-	-	-	-
	4210	Rent from Electric Property	(3,894)	-	-	-	-	-	-
B	4215	Other Utility Operating Income	(320,130)	(369,759)	(374,635)	(392,591)	(356,071)	(348,352)	(348,352)
	4220	Other Electric Revenues	(33,843)	-	-	-	-	-	-
	4240	Provision for Rate Refunds	-	-	-	-	-	-	-
	4245	Government Assistance Directly Credited to Income	-	-	-	-	-	-	-
	4305	Regulatory Debits	-	-	-	-	-	-	-
	4310	Regulatory Credits	-	-	-	-	-	-	-
	4315	Revenues from Electric Plant Leased to Others	-	-	-	-	-	-	-
	4320	Expenses of Electric Plant Leased to Others	-	-	-	-	-	-	-
D	4325	Revenues from Merchandise, Jobbing, Etc.	(6)	-	-	881	-	-	-
	4330	Costs and Expenses of Merchandising, Jobbing, Etc	-	-	-	-	-	-	-
	4335	Profits and Losses from Financial Instrument Hedges	-	-	-	-	-	-	-
	4340	Profits and Losses from Financial Instrument Investments	-	-	-	-	-	-	-
	4345	Gains from Disposition of Future Use Utility Plant	-	-	-	-	-	-	-
	4350	Losses from Disposition of Future Use Utility Plant	-	-	-	-	-	-	-
	4355	Gain on Disposition of Utility and Other Property	(11,984)	(10)	(186,178)	-	(2,450)	-	-
	4360	Loss on Disposition of Utility and Other Property	-	-	-	-	-	-	-
	4365	Gains from Disposition of Allowances for Emission	-	-	-	-	-	-	-
	4370	Losses from Disposition of Allowances for Emission	-	-	-	-	-	-	-
C	4375	Revenues from Non-Utility Operations	-	-	-	(50,899)	(182,223)	(116,200)	(65,480)
	4380	Expenses of Non-Utility Operations	-	182,603	-	-	-	-	-
	4385	Expenses of Non-Utility Operations	-	-	-	-	-	-	-
	4390	Miscellaneous Non-Operating Income	(612,150)	(29,237)	(21,326)	-	(27,284)	(39,937)	(40,000)
	4395	Rate-Payer Benefit Including Interest	-	-	-	-	-	-	-
	4398	Foreign Exchange Gains and Losses, Including Amortization	-	-	-	-	-	-	-
	4405	Interest and Dividend Income	(475,005)	(455,887)	(769,014)	(461,947)	(81,675)	(46,668)	(46,668)
	4415	Equity in Earnings of Subsidiary Companies	-	-	-	-	-	-	-
		Total	**(2,979,380)**	**(2,337,359)**	**(3,147,126)**	**(2,389,737)**	**(2,298,920)**	**(2,164,469)**	**(2,185,747)**
	Specific Service Charges		(918,570)	(974,099)	(1,028,043)	(912,222)	(951,925)	(884,942)	(956,878)
	Late Payment Charges		(432,381)	(506,487)	(552,366)	(350,024)	(500,364)	(518,557)	(518,557)
	Other Distribution Revenues		(529,284)	(554,241)	(590,199)	(615,526)	(552,999)	(558,164)	(558,164)
	Other Income and Expenses		(1,099,145)	(302,531)	(976,518)	(511,965)	(293,632)	(202,805)	(152,148)
	Total		**(2,979,380)**	**(2,337,359)**	**(3,147,126)**	**(2,389,737)**	**(2,298,920)**	**(2,164,469)**	**(2,185,747)**

(115,733) 2006
(120,711) 2007
These amounts have been reallocated to 4235.

B Pen West included Scrap Sales in 4355 or 4390:
(29,479) 2006 in 4355
(11,873) 2006 in 4090
(20,840) 2007 in 4090
These amounts have been reallocated to 4215.

C NPEI included OPA Incentive Fees in 4235 in 2008:
(50,899) 2008
This amount has been reallocated to 4375.

D In the 2006 EDR Model, Pen West included revenue for Billable Work in account 4325. Revenue was actually recorded in 4235.
The Pen West Board Approved amount of ($132,159) in 4325 has been reallocated to 4235.

The following Table 3-31 shows the detailed breakdown of the Other Operating Revenue accounts.

Table 3-31 Details of Other Operating Revenue

4080 - SSS Admin Charges	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Residential	(111,776)	(110,201)	(121,195)	(102,122)	(112,268)	(112,268)
General Service < 50 kW	(10,884)	(11,074)	(12,175)	(9,498)	(10,829)	(10,829)
General Service > 50 kW	(2,066)	(1,879)	(2,296)	(2,432)	(2,469)	(2,469)
Sentinel	(57)	(840)	(849)	(720)	(510)	(510)
Streetlighting	(515)	(54)	(53)	(36)	(18)	(18)
Total	(125,297)	(124,047)	(136,567)	(114,808)	(126,094)	(126,094)

4082 - Retail Service Revenue	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Retailer Service Revenues	(71,714)	(86,142)	(83,876)	(80,996)	(80,748)	(80,748)
	-	-	-	-	-	-
	-	-	-	-	-	-
Total	(71,714)	(86,142)	(83,876)	(80,996)	(80,748)	(80,748)

4084 - Service Transaction Requests	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Request Fee	(2,372)	(2,798)	(1,562)	(673)	(1,215)	(1,215)
Processing Fee	(2,249)	(2,578)	(940)	(452)	(1,755)	(1,755)
Information Requests	-	-	10	-	-	-
Total	(4,621)	(5,375)	(2,492)	(1,124)	(2,970)	(2,970)

4215 - Other Utility Operating Income	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Water Billing Admin Charge	(266,425)	(297,745)	(295,727)	(295,806)	(295,169)	(295,169)
Sale of Scrap Meterials	(70,882)	(44,949)	(65,224)	(28,916)	(24,484)	(24,484)
Transformer Rental	(7,612)	(7,363)	(7,832)	(8,325)	(7,932)	(7,932)
Water & Sewer Revenue: Occupant Change	(24,840)	(24,579)	(23,808)	(23,025)	(20,766)	(20,766)
Total	(369,758)	(374,635)	(392,591)	(356,071)	(348,352)	(348,352)

4225 - Late Payment Charges	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Late Payment Charges	(506,487)	(552,366)	(350,024)	(500,364)	(518,557)	(518,557)
Total	(506,487)	(552,366)	(350,024)	(500,364)	(518,557)	(518,557)

4235 - Miscellaneous Service Revenues	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Pole Rental Revenues	(284,721)	(309,006)	(382,628)	(277,068)	(239,845)	(313,630)
Lawyers Letters Fees	(15,652)	(17,615)	(14,532)	(12,170)	(13,926)	(13,926)
Collection and Reconnection Charges	(147,803)	(202,769)	(182,293)	(202,444)	(256,242)	(256,242)
Returned Cheque Charges	(11,204)	(14,295)	(15,680)	(11,815)	(12,375)	(12,375)
Connection Charges	-	-	(34,825)	(49,600)	(49,995)	(49,995)
Occupancy Change Charges	(131,953)	(205,530)	(190,134)	(188,820)	(189,030)	(189,030)
Miscellaneous	(382,996)	(278,824)	(92,129)	(210,008)	(121,680)	(121,680)
Total	(974,329)	(1,028,038)	(912,222)	(951,925)	(883,092)	(956,878)

4325 - Revenue from Merchandising, Jobbing, Etc.	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Revenues from Merchandising, Jobbing, Etc.	-	(4)	881	-	-	-
Total	-	(4)	881			

4355 - Gain from Disposition of Utility and Other Property	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Vehicles	-	(8,800)	-	(500)	-	-
Equipment	-	(6,200)	-	(1,950)	-	-
Land	-	(171,178)	-	-	-	-
Pole Renal	(10)	-	-	-	-	-
Total	(10)	(186,178)		(2,450)		

4375 - Revenue from Non-Utility Operations	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
OPA Incentives	-	-	(50,899)	(182,223)	(65,480)	(65,480)
Installation of poles for Bell Canada	-	-	-	-	(50,720)	-
Total			(50,899)	(182,223)	(116,200)	(65,480)

4380 - Expenses of Non-Utility Operations	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Expenses of Non-Utility Operations	182,603	-	-	-	-	-
Total	182,603					

4390 - Miscellaneous Non-Operating Revenue	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Miscellaneous	(29,237)	(21,326)	-	(27,284)	(39,937)	(40,000)
Total	(29,237)	(21,326)		(27,284)	(39,937)	(40,000)

4405 - Interest and Dividend Income	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Bank Interest	(455,887)	(769,014)	(461,948)	(81,675)	(46,668)	(46,668)
Interest on Deferral and Variance accounts	-	-	-	-	-	-
Total	(455,887)	(769,014)	(461,948)	(81,675)	(46,668)	(46,668)

Total Other Operating Revenue	**(2,354,739)**	**(3,147,125)**	**(2,389,737)**	**(2,298,921)**	**(2,162,619)**	**(2,185,747)**

As discussed in Exhibit 1, NPEI has calculated its materiality threshold, in accordance with the Filing Requirements, of 0.5% of Distribution Revenue to be $150,000, which has been used for variance analysis on Capital Assets. For analyzing variances in Other Operating Revenue, since the associated dollar amounts are typically smaller, the Applicant has opted to utilize a materiality threshold of $75,000. The balances that exceed this threshold are highlighted in Tables 3-32 to 3-37 below.

Table 3-32 Other Revenue – Comparison of 2006 Actual to 2006 Board Approved

2006 Actual to 2006 Board Approved			
Account	**2006 Board Approved**	**2006 Actual**	**Variance**
4080 - SSS Administrative Charge	(126,178)	(125,297)	881
4235 - Miscellaneous Service Revenues	(918,570)	(974,099)	(55,530)
4225 - Late Payment Charges	(432,381)	(506,487)	(74,106)
4082 - RS Rev	(44,777)	(54,443)	(9,666)
4084 - Serv Tx Requests	(462)	(4,742)	(4,281)
4210 - Rent from Electric Property	(3,894)	-	3,894
4215 - Other Utility Operating Income	(320,130)	(369,759)	(49,629)
4220 - Other Electric Revenues	(33,843)	-	33,843
4325 - Revenues from Merchandise, Jobbing, Etc.	(6)	-	6
4355 - Gain on Disposition of Utility and Other Property	(11,984)	(10)	11,974
4375 - Revenues from Non-Utility Operations	-	-	-
4380 - Expenses of Non-Utility Operations	-	182,603	182,603
4390 - Miscellaneous Non-Operating Income	(612,150)	(29,237)	582,913
4405 - Interest and Dividend Income	(475,005)	(455,887)	19,118
Total	(2,979,380)	(2,337,359)	642,022

Table 3-33 Other Revenue – Comparison of 2007 Actual to 2006 Actual

2007 Actual to 2006 Actual			
Account	**2006 Actual**	**2007 Actual**	**Variance**
4080 - SSS Administrative Charge	(125,297)	(124,047)	1,251
4235 - Miscellaneous Service Revenues	(974,099)	(1,028,043)	(53,943)
4225 - Late Payment Charges	(506,487)	(552,366)	(45,879)
4082 - RS Rev	(54,443)	(86,142)	(31,699)
4084 - Serv Tx Requests	(4,742)	(5,376)	(634)
4210 - Rent from Electric Property	-	-	-
4215 - Other Utility Operating Income	(369,759)	(374,635)	(4,877)
4220 - Other Electric Revenues	-	-	-
4325 - Revenues from Merchandise, Jobbing, Etc.	-	-	-
4355 - Gain on Disposition of Utility and Other Property	(10)	(186,178)	(186,168)
4375 - Revenues from Non-Utility Operations	-	-	-
4380 - Expenses of Non-Utility Operations	182,603	-	(182,603)
4390 - Miscellaneous Non-Operating Income	(29,237)	(21,326)	7,911
4405 - Interest and Dividend Income	(455,887)	(769,014)	(313,127)
Total	(2,337,359)	(3,147,126)	(809,767)

Table 3-34 Other Revenue – Comparison of 2008 Actual to 2007 Actual

2008 Actual to 2007 Actual			
Account	**2007 Actual**	**2008 Actual**	**Variance**
4080 - SSS Administrative Charge	(124,047)	(136,567)	(12,521)
4235 - Miscellaneous Service Revenues	(1,028,043)	(912,222)	115,821
4225 - Late Payment Charges	(552,366)	(350,024)	202,342
4082 - RS Rev	(86,142)	(83,876)	2,266
4084 - Serv Tx Requests	(5,376)	(2,492)	2,884
4210 - Rent from Electric Property	-	-	-
4215 - Other Utility Operating Income	(374,635)	(392,591)	(17,956)
4220 - Other Electric Revenues	-	-	-
4325 - Revenues from Merchandise, Jobbing, Etc.	-	881	881
4355 - Gain on Disposition of Utility and Other Property	(186,178)	-	186,178
4375 - Revenues from Non-Utility Operations	-	(50,899)	(50,899)
4380 - Expenses of Non-Utility Operations	-	-	-
4390 - Miscellaneous Non-Operating Income	(21,326)	-	21,326
4405 - Interest and Dividend Income	(769,014)	(461,947)	307,067
Total	(3,147,126)	(2,389,737)	757,389

Table 3-35 Other Revenue – Comparison of 2009 Actual to 2008 Actual

2009 Actual to 2008 Actual			
2009 Actual	**2008 Actual**	**2009 Actual**	**Variance**
4080 - SSS Administrative Charge	(136,567)	(114,808)	21,759
4235 - Miscellaneous Service Revenues	(912,222)	(951,925)	(39,703)
4225 - Late Payment Charges	(350,024)	(500,364)	(150,340)
4082 - RS Rev	(83,876)	(80,996)	2,880
4084 - Serv Tx Requests	(2,492)	(1,124)	1,368
4210 - Rent from Electric Property	-	-	-
4215 - Other Utility Operating Income	(392,591)	(356,071)	36,520
4220 - Other Electric Revenues	-	-	-
4325 - Revenues from Merchandise, Jobbing, Etc.	881	-	(881)
4355 - Gain on Disposition of Utility and Other Property	-	(2,450)	(2,450)
4375 - Revenues from Non-Utility Operations	(50,899)	(182,223)	(131,324)
4380 - Expenses of Non-Utility Operations	-	-	-
4390 - Miscellaneous Non-Operating Income	-	(27,284)	(27,284)
4405 - Interest and Dividend Income	(461,947)	(81,675)	380,272
Total	(2,389,737)	(2,298,920)	90,817

Table 3-36 Other Revenue – Comparison of 2010 Bridge to 2009 Actual

2010 Bridge to 2009 Actual			
Account	**2009 Actual**	**2010 Bridge**	**Variance**
4080 - SSS Administrative Charge	(114,808)	(126,094)	(11,286)
4235 - Miscellaneous Service Revenues	(951,925)	(884,942)	66,983
4225 - Late Payment Charges	(500,364)	(518,557)	(18,193)
4082 - RS Rev	(80,996)	(80,748)	248
4084 - Serv Tx Requests	(1,124)	(2,970)	(1,846)
4210 - Rent from Electric Property	-	-	-
4215 - Other Utility Operating Income	(356,071)	(348,352)	7,719
4220 - Other Electric Revenues	-	-	-
4325 - Revenues from Merchandise, Jobbing, Etc.	-	-	-
4355 - Gain on Disposition of Utility and Other Property	(2,450)	-	2,450
4375 - Revenues from Non-Utility Operations	(182,223)	(116,200)	66,023
4380 - Expenses of Non-Utility Operations	-	-	-
4390 - Miscellaneous Non-Operating Income	(27,284)	(39,937)	(12,653)
4405 - Interest and Dividend Income	(81,675)	(46,668)	35,007
Total	(2,298,920)	(2,164,469)	134,451

Table 3-37 Other Revenue – Comparison of 2011 Test to 2010 Bridge

2011 Test to 2010 Bridge			
Account	2010 Bridge	2011 Test	Variance
4080 - SSS Administrative Charge	(126,094)	(126,094)	-
4235 - Miscellaneous Service Revenues	(884,942)	(956,878)	(71,935)
4225 - Late Payment Charges	(518,557)	(518,557)	-
4082 - RS Rev	(80,748)	(80,748)	-
4084 - Serv Tx Requests	(2,970)	(2,970)	-
4210 - Rent from Electric Property	-	-	-
4215 - Other Utility Operating Income	(348,352)	(348,352)	-
4220 - Other Electric Revenues	-	-	-
4325 - Revenues from Merchandise, Jobbing, Etc.	-	-	-
4355 - Gain on Disposition of Utility and Other Property	-	-	-
4375 - Revenues from Non-Utility Operations	(116,200)	(65,480)	50,720
4380 - Expenses of Non-Utility Operations	-	-	-
4390 - Miscellaneous Non-Operating Income	(39,937)	(40,000)	(63)
4405 - Interest and Dividend Income	(46,668)	(46,668)	-
Total	(2,164,469)	(2,185,747)	(21,278)

Year-over-Year Variance Analysis of Other Distribution Revenues

2006 Actual versus 2006 Board Approved

Account 4380 Expenses of Non-Utility Operations

This account includes an expense of $182,603 in 2006 Actual, and no amount in 2006 Board Approved. This relates to the write-off of 10% of the principal balance of account 1570 Qualifying Transition costs for Niagara Falls Hydro, arising from the approved disposition of regulatory assets in the 2006 EDR application, which were recorded in the general ledger in 2006.

Account 4390 Miscellaneous Non-Operating Income

The 2006 Actual revenue is $582,913 less than the 2006 Board Approved amount. This difference largely relates to the Peninsula West 2006 Board Approved revenue of $612,150, which was based on the 2004 actual value in account 4390. In 2004, Peninsula West recorded several unusual, non-recurring revenue items, including $406,567 relating to the reallocation of LV charges. Therefore, the Board Approved amount does not represent a typical year of Miscellaneous Non-Operating Income. The 2006 Actual revenue is $29,237, which is more typical of what was earned in subsequent years.

2007 Actual versus 2006 Actual

Account 4355 Gain on Disposal of Utility and Other Property

The 2007 Actual revenue is $186,168 greater than the 2006 Actual, largely due to a gain of $171,178 by Peninsula West Utilities on the sale of a parcel of land.

Account 4380 Expenses of Non-Utility Operations

This account is $182,603 less than the 2006 Actual, due to a non-recurring item (write off of 10% of qualifying transition costs) being recorded in 2006, as approved in the Niagara Falls Hydro 2006 EDR rate application.

<u>Account 4405 Interest and Dividend Income</u>

This account increased in 2007 by $313,127, due mainly to larger average cash balances earning interest. NPEI's average operating cash balance was $14.8 million in 2007, versus $8.6 million in 2006. In addition, interest rates were slightly higher in 2007: a monthly average rate of 4.25% in 2007 versus 3.96% in 2006.

2008 Actual versus 2007 Actual

<u>Account 4235 Miscellaneous Service Revenues</u>

This account decreased by $115,821 from 2007 Actual, due to a reduction in the amount of revenue from billable work.

<u>Account 4225 Late Payment Charges</u>

This account decreased by $202,342 from 2007 Actual.

<u>Account 4355 Gain on Disposition of Utility and Other Property</u>

This account decreased by $186,178 from 2007 Actual. The Applicant did not dispose of any property for gains in 2008.

<u>Account 4405 Interest and Dividend Income</u>

This account decreased by $307,067 from 2007 Actual, due to smaller average cash balances earning interest (average operating cash balance of $11.9 million in 2008 versus $14.8 million in 2007), and a lower rate of bank interest (an average monthly rate of 2.88% in 2008 versus 4.73% in 2007). As can be seen from NPEI's Audited Financial Statements, included in Exhibit 1, the main drivers of decreasing cash balances are capital expenditures and long-term debt repayment.

2009 Actual versus 2008 Actual

Account 4225 Late Payment Charges

This account increased by $150,340 from 2008 Actual.

Account 4375 Revenues from Non-Utility Operations

This account increased by $131,324 from 2008 Actual, due to an increase in OPA incentive revenues received for CDM programs.

Account 4405 Interest and Dividend Income

This account decreased by $380,272 from 2008 Actual, due to smaller average cash balances earning interest (average operating cash balance of $9.4 million in 2009 versus $11.9 million in 2008), and a lower rate of bank interest (an average monthly rate of 0.55% in 2009 versus 2.88% in 2008). As can be seen from NPEI's Audited Financial Statements, included in Exhibit 1, the main drivers of decreasing cash balances are capital expenditures and long-term debt repayment.

2010 Bridge versus 2009 Actual

The Other Operating Revenues for the 2010 Bridge Year do not differ materially from the 2009 Actual revenues.

2011 Test versus 2010 Bridge

The Other Operating Revenues for the 2011 Test Year do not differ materially from the 2010 Bridge Year revenues.

Appendix A Monthly Data Used for Regression Analysis

APPENDIX A Monthly Data used for Regression Analysis

Month	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	CDM kWh Saved in month	Spring Fall Flag	Population	Predicted Purchases
Jan-02	98,398,774	530.3	-	121.50	31	-	-	126,248	96,531,879
Feb-02	87,515,454	492.3	-	121.86	28	-	-	126,351	87,523,186
Mar-02	94,028,461	513.5	-	122.22	31	-	1	126,455	91,658,579
Apr-02	86,184,466	314.1	-	122.59	30	-	1	126,558	84,304,785
May-02	85,447,299	224.5	2.4	122.95	31	-	1	126,662	85,748,062
Jun-02	95,651,673	39.3	54.8	123.31	30	-	-	126,765	94,195,740
Jul-02	119,450,096	-	191.6	123.68	31	-	-	126,869	123,203,251
Aug-02	114,483,163	-	155.0	124.04	31	-	-	126,972	116,402,652
Sep-02	96,936,653	9.8	92.3	124.41	30	-	1	127,076	96,732,866
Oct-02	90,917,731	234.6	11.4	124.78	31	-	1	127,179	89,600,511
Nov-02	90,920,618	381.2	-	125.14	30	-	1	127,283	88,533,373
Dec-02	102,776,286	567.2	-	125.51	31	-	-	127,386	101,480,719
Jan-03	104,493,535	707.7	-	125.66	31	-	-	127,490	105,126,725
Feb-03	96,011,347	625.7	-	125.81	28	-	-	127,593	94,861,510
Mar-03	95,684,640	547.7	-	125.95	31	-	1	127,697	96,381,442
Apr-03	86,343,957	398.3	-	126.10	30	-	1	127,800	90,082,564
May-03	84,100,206	235.4	-	126.24	31	-	1	127,904	89,076,110
Jun-03	90,485,413	74.1	44.6	126.39	30	-	-	128,007	96,407,259
Jul-03	107,838,219	3.4	105.0	126.54	31	-	-	128,111	109,500,196
Aug-03	111,720,633	-	143.5	126.68	31	-	-	128,215	117,147,438
Sep-03	90,994,824	26.8	27.4	126.83	30	-	1	128,318	87,257,485
Oct-03	90,574,201	245.3	-	126.98	31	-	1	128,422	90,269,352
Nov-03	91,660,392	348.0	-	127.12	30	-	1	128,525	90,174,431
Dec-03	102,135,791	510.1	-	127.27	31	-	-	128,629	102,352,440
Jan-04	110,906,403	750.2	-	127.53	31	-	-	128,732	108,544,127
Feb-04	98,773,310	578.9	-	127.80	29	-	-	128,836	98,989,188
Mar-04	100,169,246	479.8	-	128.06	31	-	1	128,939	97,273,324
Apr-04	89,485,333	332.5	0.5	128.32	30	-	1	129,043	91,219,957
May-04	90,686,143	169.7	1.2	128.59	31	-	1	129,146	90,449,282
Jun-04	96,517,444	45.6	26.3	128.85	30	-	-	129,250	94,972,812
Jul-04	110,297,642	1.9	79.3	129.12	31	-	-	129,353	107,377,479
Aug-04	109,063,695	1.8	85.0	129.38	31	-	-	129,457	108,778,533
Sep-04	103,094,592	14.6	65.3	129.65	30	-	1	129,560	97,523,349
Oct-04	93,329,246	196.4	2.6	129.92	31	-	1	129,664	92,815,759
Nov-04	94,434,399	341.0	-	130.19	30	-	1	129,767	93,340,593
Dec-04	108,483,621	566.7	-	130.45	31	-	-	129,871	107,181,861
Jan-05	111,357,551	693.3	-	130.74	31	64,076	-	129,974	110,026,858
Feb-05	97,354,644	582.0	-	131.03	28	64,076	-	130,078	99,158,724
Mar-05	103,696,307	576.1	-	131.33	31	64,076	1	130,182	102,571,100
Apr-05	91,002,648	345.1	-	131.62	30	64,076	1	130,285	94,383,224
May-05	90,914,555	215.3	-	131.91	31	64,076	1	130,389	94,310,387
Jun-05	117,110,314	10.4	107.8	132.20	30	64,076	-	130,492	113,067,264
Jul-05	130,492,623	-	183.5	132.50	31	64,076	-	130,596	130,760,667
Aug-05	125,304,430	-	165.7	132.79	31	64,076	-	130,699	127,584,483
Sep-05	103,515,709	7.3	76.6	133.09	30	64,076	1	130,803	102,623,955
Oct-05	95,683,703	216.6	13.4	133.38	31	64,076	1	130,906	98,518,481
Nov-05	95,832,424	369.3	-	133.68	30	64,076	1	131,010	97,150,721
Dec-05	109,926,431	640.8	-	133.98	31	64,076	-	131,113	112,142,492

Jan-06	105,189,786	520.4	-	134.25	31	348,241	-	131,217	106,917,992
Feb-06	97,673,987	564.7	-	134.53	28	348,241	-	131,320	99,866,990
Mar-06	102,138,407	488.7	-	134.81	31	348,241	1	131,424	101,543,027
Apr-06	89,654,385	296.7	-	135.08	30	348,241	1	131,527	94,303,185
May-06	96,375,371	135.3	29.2	135.36	31	348,241	1	131,631	99,160,572
Jun-06	106,149,796	15.9	65.6	135.64	30	348,241	-	131,734	106,024,432
Jul-06	129,944,898	0.6	166.8	135.92	31	348,241	-	131,838	128,580,177
Aug-06	120,333,539	1.4	103.8	136.20	31	348,241	-	131,941	116,558,559
Sep-06	95,914,535	45.9	17.0	136.48	30	348,241	1	132,045	92,951,961
Oct-06	99,436,287	234.4	0.4	136.76	31	348,241	1	132,149	97,450,259
Nov-06	98,699,343	341.9	-	137.04	30	348,241	1	132,252	97,504,628
Dec-06	106,547,506	445.2	-	137.33	31	348,241	-	132,356	108,345,714
Jan-07	110,076,804	578.0	-	137.57	31	655,465	-	132,480	109,136,088
Feb-07	106,214,903	657.8	-	137.82	28	655,465	-	132,604	102,950,878
Mar-07	105,901,314	515.5	-	138.07	31	655,465	1	132,729	102,987,876
Apr-07	96,871,140	362.1	-	138.33	30	655,465	1	132,853	96,690,071
May-07	96,387,835	157.9	13.6	138.58	31	655,465	1	132,978	97,431,050
Jun-07	113,036,516	10.9	81.7	138.83	30	655,465	-	133,103	109,817,104
Jul-07	116,239,482	-	109.0	139.08	31	655,465	-	133,227	117,998,594
Aug-07	124,879,950	6.8	142.5	139.33	31	655,465	-	133,352	125,018,210
Sep-07	104,023,176	19.2	54.7	139.59	30	655,465	1	133,478	100,418,106
Oct-07	99,226,202	103.0	20.6	139.84	31	655,465	1	133,603	98,904,695
Nov-07	100,079,144	385.4	-	140.09	30	655,465	1	133,728	99,298,125
Dec-07	110,979,900	567.1	-	140.35	31	655,465	-	133,854	112,060,406
Jan-08	109,593,071	562.4	-	140.30	31	906,713	-	133,979	109,731,093
Feb-08	104,778,875	599.9	-	140.25	29	906,713	-	134,105	105,076,766
Mar-08	105,424,609	548.0	-	140.21	31	906,713	1	134,231	104,284,954
Apr-08	86,811,986	303.3	-	140.16	30	906,713	1	134,357	95,499,435
May-08	95,673,539	192.7	-	140.11	31	906,713	1	134,483	95,638,032
Jun-08	106,441,284	30.4	62.5	140.07	30	906,713	-	134,609	106,308,790
Jul-08	120,363,654	-	115.4	140.02	31	906,713	-	134,735	118,782,405
Aug-08	112,977,083	4.5	85.7	139.97	31	906,713	-	134,862	113,123,801
Sep-08	101,476,765	38.6	39.6	139.93	30	906,713	1	134,988	96,982,339
Oct-08	95,543,325	207.1	0.4	139.88	31	906,713	1	135,115	96,310,656
Nov-08	97,619,273	420.9	-	139.83	30	906,713	1	135,242	98,728,959
Dec-08	111,639,154	620.1	-	139.79	31	906,713	-	135,369	111,677,705
Jan-09	117,706,103	723.9	-	139.39	31	912,482	-	135,496	113,943,773
Feb-09	97,637,232	537.0	-	138.99	28	912,482	-	135,623	100,673,311
Mar-09	102,033,201	509.1	-	138.60	31	912,482	1	135,750	103,002,668
Apr-09	92,234,007	315.4	-	138.21	30	912,482	1	135,877	95,191,330
May-09	90,740,353	185.9	-	137.82	31	912,482	1	136,005	94,585,094
Jun-09	97,871,861	66.8	33.0	137.43	30	912,482	-	136,133	100,261,751
Jul-09	106,379,010	0.6	56.8	137.04	31	912,482	-	136,260	105,876,686
Aug-09	118,375,480	3.9	118.8	136.65	31	912,482	-	136,388	117,872,649
Sep-09	96,821,587	32.4	30.7	136.26	30	912,482	1	136,516	93,090,642
Oct-09	93,959,689	241.2	-	135.87	31	912,482	1	136,644	94,800,080
Nov-09	93,794,433	320.8	-	135.49	30	912,482	1	136,772	93,720,221
Dec-09	109,990,512	570.9	-	135.11	31	912,482	-	136,901	107,647,524

Jan-10	-	653.3	-	135.41	31	1,109,507	-	137,029	108,237,195
Feb-10	-	551.1	-	135.71	28	1,109,507	-	137,158	97,621,487
Mar-10	-	513.0	-	136.02	31	1,109,507	1	137,287	100,271,326
Apr-10	-	330.9	0.0	136.33	30	1,109,507	1	137,415	93,323,181
May-10	-	175.7	5.7	136.63	31	1,109,507	1	137,544	93,761,561
Jun-10	-	34.9	58.5	136.94	30	1,109,507	-	137,673	103,342,450
Jul-10	-	0.8	124.2	137.25	31	1,109,507	-	137,803	118,532,457
Aug-10	-	2.1	109.1	137.56	31	1,109,507	-	137,932	115,945,868
Sep-10	-	29.4	50.8	137.87	30	1,109,507	1	138,061	97,539,107
Oct-10	-	205.6	4.9	138.18	31	1,109,507	1	138,191	96,031,827
Nov-10	-	354.3	-	138.49	30	1,109,507	1	138,320	96,267,669
Dec-10	-	553.4	-	138.80	31	1,109,507	-	138,450	109,507,219
Jan-11	-	639.6	-	139.17	31	1,169,147	-	138,580	111,481,097
Feb-11	-	563.7	-	139.54	28	1,169,147	-	138,710	101,568,223
Mar-11	-	513.0	-	139.91	31	1,169,147	1	138,840	103,962,357
Apr-11	-	330.9	0.0	140.29	30	1,169,147	1	138,971	97,069,810
May-11	-	175.7	5.7	140.66	31	1,169,147	1	139,101	97,564,038
Jun-11	-	34.9	58.5	141.03	30	1,169,147	-	139,232	107,201,026
Jul-11	-	0.8	124.2	141.41	31	1,169,147	-	139,362	122,447,385
Aug-11	-	2.1	109.1	141.79	31	1,169,147	-	139,493	119,917,400
Sep-11	-	29.4	50.8	142.17	30	1,169,147	1	139,624	101,567,498
Oct-11	-	205.6	4.9	142.55	31	1,169,147	1	139,755	100,117,331
Nov-11	-	354.3	-	142.93	30	1,169,147	1	139,886	100,410,542
Dec-11	-	553.4	-	143.31	31	1,169,147	-	140,017	113,707,718

	Actual Purchases Total	Predicted Purchases Total	Difference kWh	Difference %
2002	1,162,710,674	1,155,915,603	-6,795,071	-0.6%
2003	1,152,043,160	1,168,636,951	16,593,791	1.4%
2004	1,205,241,074	1,188,466,265	-16,774,809	-1.4%
2005	1,272,191,339	1,282,298,357	10,107,018	0.8%
2006	1,248,057,840	1,249,207,495	1,149,655	0.1%
2007	1,283,916,366	1,272,711,204	-11,205,163	-0.9%
2008	1,248,342,618	1,252,144,937	3,802,319	0.3%
2009	1,217,543,467	1,220,665,728	3,122,260	0.3%
2010		1,230,381,346		
2011		1,277,014,423		

Appendix B OPA CDM Results 2006 - 2009

APPENDIX B OPA CDM Results 2006 - 2009

OPA Conservation & Demand Management Programs

Initiative Results

For: Niagara Peninsula Energy Inc.

#	Initiative Name	Program Name	Program Year	Results Status	Allocation Methodology	Net Annual Energy Savings (MWh) 2006	2007	2008	2009	2010	2011
1	2006 Every Kilowatt Counts (spring)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	1,525	1,525	1,525	1,525	1,525	0
2	2006 Cool Savings Rebate Program	Consumer	2006	Final	2006 LDC Residential Energy Throughput	116	116	116	116	116	116
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006	Final	2006 LDC Residential Energy Throughput	62	62	62	62	62	62
4	2006 Every Kilowatt Counts (fall)	Consumer	2006	Final	2006 LDC Residential Energy Throughput	2,475	2,475	2,475	2,475	2,475	2,475
6	2006 Demand Response 1	Industrial, Business	2006	Final	2006 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
2006 Subtotal						**4,179**	**4,179**	**4,179**	**4,179**	**4,179**	**2,653**
7	2007 Great Refrigerator Roundup	Consumer	2007	Final	LDC Participation	0	170	170	170	170	170
8	2007 Cool Savings Rebate	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	311	311	311	311	311
9	2007 Aboriginal – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0
10	2007 Every Kilowatt Counts	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	1,362	1,345	1,345	1,345	1,345
11	2007 peaksaver®	Consumer, Business	2007	Final	LDC Participation	0	0	0	0	0	0
12	2007 Summer Savings	Consumer	2007	Final	Evaluation Contractor Determined	0	1,708	1,708	0	0	0
13	2007 Affordable Housing – Pilot	Consumer	2007	Final	LDC Participation	0	0	0	0	0	0
14	2007 Social Housing – Pilot	Consumer	2007	Final	2007 LDC Residential Energy Throughput	0	123	123	123	123	123
15	2007 Energy Efficiency Assistance for Houses – Pilot	Consumer	2007	Final	LDC Participation	0	4	4	4	4	4
16	2007 Toronto Comprehensive	Business	2007	Final	LDC Participation	0	0	0	0	0	0
17	2007 Electricity Retrofit Incentive Program	Business	2007	Final	LDC Participation	0	9	9	9	9	9
18	2007 Demand Response 1	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
19	2007 Other Demand Response	Industrial, Business	2007	Final	2007 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007	Final	LDC Participation	0	0	0	0	0	0
2007 Subtotal						**0**	**3,687**	**3,670**	**1,962**	**1,962**	**1,962**
21	2008 Great Refrigerator Roundup	Consumer	2008	Final	LDC Participation	0	0	268	268	268	268
22	2008 Cool Savings Rebate	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0	0	228	228	228	228
23	2008 Aboriginal	Consumer	2008	Final	LDC Participation	0	0	0	0	0	0
24	2008 Summer Sweepstakes	Consumer	2008	Final	LDC Participation	0	0	868	313	313	313
25	2008 Every Kilowatt Counts Power Savings Event	Consumer	2008	Final	2008 LDC Residential Energy Throughput	0	0	1,171	1,166	1,166	1,166
26	2008 peaksaver®	Consumer, Business	2008	Final	LDC Participation	0	0	11	11	11	11
27	2008 Electricity Retrofit Incentive	Business	2008	Final	LDC Participation	0	0	482	482	482	482
28	2008 Toronto Comprehensive	Business	2008	Final	LDC Participation	0	0	0	0	0	0
29	2008 High Performance New Construction	Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	3	3	3	3
30	2008 Power Savings Blitz	Business	2008	Final	LDC Participation	0	0	0	0	0	0
31	2008 Chiller Plant Re-Commissioning	Business	2008	Final	LDC Participation	0	0	0	0	0	0
32	2008 Demand Response 1	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
33	2008 Demand Response 3	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
34	2008 Other Demand Response	Industrial, Business	2008	Final	2008 LDC Non-Residential Energy Throughput	0	0	0	0	0	0
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008	Final	LDC Participation	0	0	0	0	0	0
2008 Subtotal						**0**	**0**	**3,031**	**2,472**	**2,472**	**2,472**
Overall Total						**4,179**	**7,866**	**10,881**	**8,613**	**8,613**	**7,087**

Measure Level Energy Demand & Persistence (LDC Specific Results)

#	Program	Initiative	Measure Name	Net Annual Energy Savings (kWh) 2009	2010	2011
1	**Consumer**					
	1	**The Great Refrigerator Roundup**				
		1	Bottom Freezer Fridge	2,067	2,067	2,067
		2	Chest Freezer	37,389	37,389	37,389
		3	Side by Side Fridge-Freezer	12,818	12,818	12,818
		4	Single Door Fridge	29,772	29,772	29,772
		5	Small Freezer (under 10 cubic feet)	0	0	0
		6	Small Fridge (under 10 cubic feet)	0	0	0
		7	Top Freezer Fridge	152,167	152,167	152,167
		8	Upright Freezer	5,270	5,270	5,270
		9	Window Air Conditioner	1,145	1,145	1,145
		10	Dehumidifier	1,374	1,374	1,374
	Initiative Total			**242,002**	**242,002**	**242,002**
	2	**Cool Savings**				
		1	Energy Star® Central Air Conditioner, Tier 2	10,912	10,912	10,912
		2	Energy Star® Central Air Conditioner, Tier 1	28,054	28,054	28,054
		3	Efficient Furnace with ECM	318,674	318,674	318,674
		4	Programmable Thermostat	4,314	4,314	4,314
	Initiative Total			**361,954**	**361,954**	**361,954**
	3	**Every Kilowatt Counts Power Savings Event (EKC PSE) & Rewards for Recycing (R4R)**				
		1	Standard CFL (single pack)	11,884	11,884	11,884
		2	Standard CFL (multi (6) pack)	133,777	133,777	133,777
		3	Energy Star Specialty CFL	89,046	89,046	89,046
		4	Energy Star Light Fixtures	13,486	13,486	13,486
		5	Energy Star Hard–Wired Indoor Light Fixtures	14,616	14,616	14,616
		6	Energy Star Ceiling Fans	4,333	4,333	4,333
		7	Weather Stripping (packages)	281	281	0
		8	Weather Stripping (door kits)	94	94	0

	9	Pipe Wrap – Purchase of 3	1,984	1,984	1,984
	10	Water Heater Blanket	2,496	2,496	2,496
	11	Window Film	392	392	392
	12	Lighting and Appliance Controls – Unspecified	0	0	0
	13	Lighting and Appliance Controls – Power Bar with Integrated Timer	1,111	1,111	1,111
	14	Lighting and Appliance Controls – Hard Wired Indoor Timer	1,936	1,936	1,936
	15	Lighting and Appliance Controls – Hard Wired Motion Sensor	1,277	1,277	1,277
	16	Lighting and Appliance Controls – Heavy Duty Outdoor Timer includes Pool Timers	11,661	11,661	11,661
	17	Programmable Thermostat (single pack)	1,821	1,821	1,821
	18	Programmable Thermostat (multi (3) pack)	1,753	1,753	1,753
	19	Clothes Line Kit or Cloths Line Umbrella Stand	9,298	9,298	9,298
	20	Energy Star Dehumidifier Recycling	7,378	7,378	7,378
	21	Energy Star Room Air Conditioner Recycling	2,128	2,128	2,128
	22	Halogen Floor Lamp Recycling	2,303	2,303	2,303
Initiative Total			**313,056**	**313,056**	**312,682**
4	***peaksaver***® **- Consumer Sector**				
	1	Residential Air Conditioner - Switch	623	623	623
	2	Residential Air Conditioner - Thermostat	2,149	2,149	2,149
	3	Residential Electric Water Heater	0	0	0
Initiative Total			**2,771**	**2,771**	**2,771**
2	**Multi-Unit Residential Buildings**				
1	**Electricity Retrofit Incentive Program (ERIP) - Multi-Unit Residential Buildings (MURB) Stream**				
	94	2009 – Lighting System Dimmable CFLs, 21-29W	0	0	0
	95	2009 – Lighting System Standard Performance T8, Single Lamp	1,101	1,101	1,101
	96	2009 – Lighting System Standard Performance T8, Double Lamp	227	227	227
	97	2009 – Lighting System Standard Performance T8, Triple Lamp	0	0	0
	98	2009 – Lighting System Standard Performance T8, Quadruple Lamp	0	0	0
	99	2009 – Lighting System High Performance T8, Single Lamp	0	0	0
	100	2009 – Lighting System High Performance T8, Double Lamp	140	140	140
	101	2009 – Lighting System High Performance T8, Triple Lamp	0	0	0
	131	2009 – Lighting System 49-60W Infrared Coated Halogen PAR Lamp	0	0	0
	132	2009 – Lighting System Occupancy Sensors, Switch plate mounted occupancy sensor	444	444	444
	133	2009 – Lighting System Occupancy Sensors, Ceiling mounted occupancy sensor	0	0	0
Initiative Total			**1,913**	**1,913**	**1,913**
2	**Multi-Family Energy Efficiency Retrofit (MEER) - Multi-Unit Residential Buildings (MURB) Stream**				
	235	Custom Project	0	0	0

Initiative Total					**0**	**0**	**0**
4	**Business**						
	1	**Electricity Retrofit Incentive Program (ERIP) - Business Sector**					
		1	2008 – Lighting System Exit Signs, 5 W or less		0	0	0
		2	2008 – Lighting System ENERGY STAR® Rated CFLs, Screw in. All sizes < 40 W		9,252	9,252	9,252
		79	2008 – Agribusiness Photocell and Timer for Lighting Control		0	0	0
		80	2009 – Lighting System ENERGY STAR® Rated Exit Signs		206	206	206
		81	2009 – Lighting System Refrigeratred Display Case LED Strip Lights		0	0	0
		82	2009 – Lighting System Screw-In & GU-24 base CFLs		0	0	0
		83	2009 – Lighting System PAR CFLs, <= 11W		0	0	0
		84	2009 – Lighting System PAR CFLs, 12-20W		0	0	0
		85	2009 – Lighting System PAR CFLs, 20-39W		0	0	0
		86	2009 – Lighting System 2 Pin CFLs, <14W		0	0	0
		87	2009 – Lighting System 2 Pin CFLs, 14-26W		0	0	0
		88	2009 – Lighting System 2 Pin CFLs, 29-39W		0	0	0
		89	2009 – Lighting System 4 Pin CFLs, <14W		0	0	0
		90	2009 – Lighting System 4 Pin CFLs, 14-26W		0	0	0
		91	2009 – Lighting System 4 Pin CFLs, 29-39W		0	0	0
		92	2009 – Lighting System Dimmable CFLs, <=16W		10,648	10,648	10,648
		93	2009 – Lighting System Dimmable CFLs, 17-20W		0	0	0
		94	2009 – Lighting System Dimmable CFLs, 21-29W		0	0	0
		95	2009 – Lighting System Standard Performance T8, Single Lamp		0	0	0
		96	2009 – Lighting System Standard Performance T8, Double Lamp		0	0	0
		97	2009 – Lighting System Standard Performance T8, Triple Lamp		0	0	0
		98	2009 – Lighting System Standard Performance T8, Quadruple Lamp		397	397	397
		99	2009 – Lighting System High Performance T8, Single Lamp		361	361	361
		100	2009 – Lighting System High Performance T8, Double Lamp		12,457	12,457	12,457
		101	2009 – Lighting System High Performance T8, Triple Lamp		3,987	3,987	3,987
		102	2009 – Lighting System High Performance T8, Quadruple Lamp		6,939	6,939	6,939
		103	2009 – Lighting System Standard Performance Medium Bay T8, 4 Lamp		0	0	0
		104	2009 – Lighting System Standard Performance Medium Bay T8, 6 Lamp		0	0	0
		105	2009 – Lighting System Standard Performance Medium Bay T8, 8 Lamp		0	0	0
		106	2009 – Lighting System High Performance Medium Bay T8, 4 Lamp		0	0	0
		107	2009 – Lighting System High Performance Medium Bay T8, 6 Lamp		0	0	0
		108	2009 – Lighting System High Performance Medium Bay T8, 8 Lamp		0	0	0
		109	2009 – Lighting System T5, 1-3 Lamps		997	997	997
		110	2009 – Lighting System Medium and High Bay T5, 4 Lamps		25,178	25,178	25,178
		111	2009 – Lighting System Medium and High Bay T5, 6 Lamps		825	825	825

30	30) From: 40 - 60W standard halogen PAR Lights - Track lighting or product highlighting to: 32 Watt IR coated hal	0	0	0
31	31) From: 75W standard incandescent PAR Lights - Track lighting or product highlighting to: 18W CFL Energy Sta	1,158	1,158	347
32	32) From: 75W standard incandescent PAR Lights - Track lighting or product highlighting to: 50 Watt Halogen Ene	731	0	0
33	33) From: 90 Watt Halogen PAR Lights - Track lighting or product highlighting to: 23 to 28 watt CFL Par 38/30 Ene	0	0	0
34	34) From: 90 Watt Halogen PAR Lights - Track lighting or product highlighting to: 60 watt Halogen IR Energy Star r	0	0	0
35	35) From: 100W standard incandescent or greater PAR Lights - Track lighting or product highlighting to: 26W CFL	2,104	2,104	631
36	36) From: 100W standard incandescent or greater PAR Lights - Track lighting or product highlighting to: 50-75 watt	0	0	0
48	48) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 2 - 8' lamps with 90% ballast factor T8-Electronic Ballast; Re	292	292	292
49	49) From: 4 Lamps 8' -T12-75W-Magnetic Ballasts to: 4 - 8' lamps with 2 electronic ballasts of 90% ballast factor T	0	0	0
50	50) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 2 - 8' 59wat lamps + reflector with 90% ballast factor T8-Ele	5,850	5,850	5,850
51	51) From: 4 Lamps 8' -T12-60W-Magnetic Ballasts to: 4 - 8' lamps with 2 electronic ballasts of 90% ballast factor T	28,436	28,436	28,436
52	52) From: 2 Lamps 4' -T8 32W-Magnetic Ballasts to: 2 - 4' 25 watt lamps with electronic ballasts T8-Electronic Bal	21,449	21,449	21,449
53	53) From: 2 - 4' T12 High Output Lamps High Output T12-Magnetic Ballasts to: 2 - 4' High Output T8 lamps with ele	0	0	0
54	54) From: 2 - 8' T12 High Output Lamps High Output T12-Magnetic Ballasts to: 2 - 8' High Output T8 lamps with ele	0	0	0
55	55) From: 175W Metal Halide Metal Halide to: 1 - 150W Metal Halide Direct Lamp replacement Metal Halide Dire	508	508	508
56	56) From: 400W Metal Halide Metal Halide to: 1 - 350W Metal Halide Direct Lamp replacement Metal Halide Dire	0	0	0
57	57) From: 250W Metal Halide Metal Halide to: 4 - 4' Lamps with either 32 watt ballast of 80% ballast factor or 25 v	1,682	1,682	1,682
58	58) From: 400W Metal Halide Metal Halide to: 6 - 4' Lamps with either 32 watt ballast of 80% ballast factor or 25 v	0	0	0
69	02) From: 1 Lamp 8' -T12-75W-Magnetic Ballasts to: 1 - 8' lamp with 80% ballast factor T8-Electronic Ballast; Food	0	0	0
70	03) From: 1 Lamp 8' -T12-75W-Magnetic Ballasts to: 2 - 4' end to end 25 watt lamp with 90% ballast factor T8-Elec	426	426	426
71	04) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 4 - 4' end to end 32 watt lamps with 80% ballast factor T8-El	22,375	22,375	22,375
72	05) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + reflector with 90% ballast factor T8-El	0	0	0
73	06) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor	0	0	0
74	07) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + Reflector with 90% ballast factor T8-E	1,450	1,450	1,450
75	08) From: 1 Lamp 4' -T12-40W-Magnetic Ballasts to: 1 - 4' lamp with either 32 watt ballast of 80% ballast factor or	242	242	242
76	09) From: 2 Lamps 4' -T12-40W-Magnetic Ballasts to: 1 - 4' 32 watt lamp + reflector with 90% ballast factor T8-Ele	0	0	0
77	10) From: 2 Lamps 4' -T12-40W-Magnetic Ballasts to: 2 - 4' lamps with either 32 watt ballast of 80% ballast factor	0	0	0
78	11) From: 4 Lamps 4' -T12-40W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + reflector T8-Electronic Ballast; Food S	0	0	0
79	12) From: 4 Lamps 4' -T12-40W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor	0	0	0
80	13) From: 1 Lamp 4' -T12-34W-Magnetic Ballasts to: 1 - 4' lamp with either 32 watt ballast of 80% ballast factor or	104	104	104
81	14) From: 2 Lamps 4' -T12-34W-Magnetic Ballasts to: 1 - 4' 32 watt lamp + reflector with 90% ballast factor T8-Ele	0	0	0
82	15) From: 2 Lamps 4' -T12-34W-Magnetic Ballasts to: 2 - 4' lamps with either 32 watt ballast of 80% ballast factor	0	0	0
83	16) From: 4 Lamps 4' -T12-34W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + reflector T8-Electronic Ballast; Food S	0	0	0
84	17) From: 4 Lamps 4' -T12-34W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor	0	0	0
85	18) From: 2 Lamps U-Shaped 34-40W-Magnetic Ballasts to: 2 U-Tube Lamps 2' -T8-32W-Electronic Ballast; Food	0	0	0
86	19) From: 2 Lamps U-Shaped 34-40W-Magnetic Ballasts to: 2 Linear 2' + Reflector F17T8 2' -T8-32W-Electronic B	0	0	0
87	20) From: 2-15W Lamps Exit Sign - incandescent to: 3W LED Energy Star rated LED Exit Sign; Food Service Sec	32,027	32,027	32,027
88	21) From: 2-15W Lamps Exit Sign - incandescent to: Replace entire fixture with LED sign Energy Star rated LED E	28,078	28,078	28,078
89	22) From: 40W Standard Incandescent (A Lamp) to: 11W ENERGY STAR® rated CFL (Screw-in replacement); Fo	10,681	10,681	3,204
90	23) From: 60W Standard Incandescent (A Lamp) to: 13W ENERGY STAR® rated CFL (Screw-in replacement); Fo	0	0	0
91	24) From: 100W Standard Incandescent (A Lamp) to: 23W ENERGY STAR® rated CFL (Screw-in replacement); F	0	0	0
92	25) From: 150W Standard Incandescent (A Lamp) to: 28W ENERGY STAR® rated CFL (Screw-in replacement); F	27,382	27,382	8,214
93	26) From: 60W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 15W CFLPAR38/30 ENERGY S	0	0	0
94	27) From: 75W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 18W CFLPAR38/30 ENERGY S	0	0	0
95	28) From: 100W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 26W CFL PAR38/30 ENERGY	10,646	10,646	3,194
96	29) From: 40 - 60W standard incandescent PAR Lights - Track lighting or product highlighting to: 15W CFL Energy	0	0	0
97	30) From: 40 - 60W standard halogen PAR Lights - Track lighting or product highlighting to: 32 Watt IR coated hal	0	0	0

	131	2009 – Lighting System 49-60W Infrared Coated Halogen PAR Lamp			0	0	0
	132	2009 – Lighting System Occupancy Sensors, Switch plate mounted occupancy sensor			3,643	3,643	3,643
	133	2009 – Lighting System Occupancy Sensors, Ceiling mounted occupancy sensor			5,151	5,151	5,151
	147	2009 – Motor Open Drip-Proof (ODP), 60 HP			0	0	0
	148	2009 – Motor Open Drip-Proof (ODP), 75 HP			13,885	13,885	13,885
	191	2009 – Custom Project			0	0	0
Initiative Total					**93,926**	**93,926**	**93,926**
	6	**High Performance New Construction (HPNC)**					
	1	Custom Projects			88,982	88,982	88,982
Initiative Total					**88,982**	**88,982**	**88,982**
	7	**Power Savings Blitz (PSB)**					
	1	01) From: 1 Lamp 8' -T12-75W-Magnetic Ballasts to: 2 - 4' Lamps, end to end 32 watt - with 80% ballast factor T8-I			301	301	301
	2	02) From: 1 Lamp 8' -T12-75W-Magnetic Ballasts to: 1 - 8' lamp with 80% ballast factor T8-Electronic Ballast; Reta			1,052	1,052	1,052
	3	03) From: 1 Lamp 8' -T12-75W-Magnetic Ballasts to: 2 - 4' end to end 25 watt lamp with 90% ballast factor T8-Elec			601	601	601
	4	04) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 4 - 4' end to end 32 watt lamps with 80% ballast factor T8-El			271,715	271,715	271,715
	5	05) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + reflector with 90% ballast factor T8-El			0	0	0
	6	06) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor			7,312	7,312	7,312
	7	07) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + Reflector with 90% ballast factor T8-E			73,705	73,705	73,705
	8	08) From: 1 Lamp 4' -T12-40W-Magnetic Ballasts to: 1 - 4' lamp with either 32 watt ballast of 80% ballast factor or			1,962	1,962	1,962
	9	09) From: 2 Lamps 4' -T12-40W-Magnetic Ballasts to: 1 - 4' 32 watt lamp + reflector with 90% ballast factor T8-Ele			0	0	0
	10	10) From: 2 Lamps 4' -T12-40W-Magnetic Ballasts to: 2 - 4' lamps with either 32 watt ballast of 80% ballast factor			0	0	0
	11	11) From: 4 Lamps 4' -T12-40W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + reflector T8-Electronic Ballast; Retail			4,278	4,278	4,278
	12	12) From: 4 Lamps 4' -T12-40W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor			0	0	0
	13	13) From: 1 Lamp 4' -T12-34W-Magnetic Ballasts to: 1 - 4' lamp with either 32 watt ballast of 80% ballast factor or			5,484	5,484	5,484
	14	14) From: 2 Lamps 4' -T12-34W-Magnetic Ballasts to: 1 - 4' 32 watt lamp + reflector with 90% ballast factor T8-Ele			0	0	0
	15	15) From: 2 Lamps 4' -T12-34W-Magnetic Ballasts to: 2 - 4' lamps with either 32 watt ballast of 80% ballast factor			0	0	0
	16	16) From: 4 Lamps 4' -T12-34W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + reflector T8-Electronic Ballast; Retail			0	0	0
	17	17) From: 4 Lamps 4' -T12-34W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor			0	0	0
	18	18) From: 2 Lamps U-Shaped 34-40W-Magnetic Ballasts to: 2 U-Tube Lamps 2' -T8-32W-Electronic Ballast; Retail			7,312	7,312	7,312
	19	19) From: 2 Lamps U-Shaped 34-40W-Magnetic Ballasts to: 2 Linear 2' + Reflector F17T8 2' -T8-32W-Electronic B			1,990	1,990	1,990
	20	20) From: 2-15W Lamps Exit Sign - incandescent to: 3W LED Energy Star rated LED Exit Sign; Retail Sector			201,593	201,593	201,593
	21	21) From: 2-15W Lamps Exit Sign - incandescent to: Replace entire fixture with LED sign Energy Star rated LED E			178,779	178,779	178,779
	22	22) From: 40W Standard Incandescent (A Lamp) to: 11W ENERGY STAR® rated CFL (Screw-in replacement); Re			75,631	75,631	22,689
	23	23) From: 60W Standard Incandescent (A Lamp) to: 13W ENERGY STAR® rated CFL (Screw-in replacement); Re			0	0	0
	24	24) From: 100W Standard Incandescent (A Lamp) to: 23W ENERGY STAR® rated CFL (Screw-in replacement); R			0	0	0
	25	25) From: 150W Standard Incandescent (A Lamp) to: 28W ENERGY STAR® rated CFL (Screw-in replacement); R			18,337	18,337	5,501
	26	26) From: 60W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 15W CFLPAR38/30 ENERGY S			366	366	110
	27	27) From: 75W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 18W CFLPAR38/30 ENERGY S			0	0	0
	28	28) From: 100W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 26W CFL PAR38/30 ENERGY			22,545	22,545	6,764
	29	29) From: 40 - 60W standard incandescent PAR Lights - Track lighting or product highlighting to: 15W CFL Energy			183	183	55

		30	30) From: 40 - 60W standard halogen PAR Lights - Track lighting or product highlighting to: 32 Watt IR coated hal	0	0	0
		31	31) From: 75W standard incandescent PAR Lights - Track lighting or product highlighting to: 18W CFL Energy Sta	1,158	1,158	347
		32	32) From: 75W standard incandescent PAR Lights - Track lighting or product highlighting to: 50 Watt Halogen Ene	731	0	0
		33	33) From: 90 Watt Halogen PAR Lights - Track lighting or product highlighting to: 23 to 28 watt CFL Par 38/30 Ene	0	0	0
		34	34) From: 90 Watt Halogen PAR Lights - Track lighting or product highlighting to: 60 watt Halogen IR Energy Star r	0	0	0
		35	35) From: 100W standard incandescent or greater PAR Lights - Track lighting or product highlighting to: 26W CFL	2,104	2,104	631
		36	36) From: 100W standard incandescent or greater PAR Lights - Track lighting or product highlighting to: 50-75 watt	0	0	0
		48	48) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 2 - 8' lamps with 90% ballast factor T8-Electronic Ballast; Re	292	292	292
		49	49) From: 4 Lamps 8' -T12-75W-Magnetic Ballasts to: 4 - 8' lamps with 2 electronic ballasts of 90% ballast factor T	0	0	0
		50	50) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 2 - 8' 59wat lamps + reflector with 90% ballast factor T8-Ele	5,850	5,850	5,850
		51	51) From: 4 Lamps 8' -T12-60W-Magnetic Ballasts to: 4 - 8' lamps with 2 electronic ballasts of 90% ballast factor T	28,436	28,436	28,436
		52	52) From: 2 Lamps 4' -T8 32W-Magnetic Ballasts to: 2 - 4' 25 watt lamps with electronic ballasts T8-Electronic Bal	21,449	21,449	21,449
		53	53) From: 2 - 4' T12 High Output Lamps High Output T12-Magnetic Ballasts to: 2 - 4' High Output T8 lamps with ele	0	0	0
		54	54) From: 2 - 8' T12 High Output Lamps High Output T12-Magnetic Ballasts to: 2 - 8' High Output T8 lamps with ele	0	0	0
		55	55) From: 175W Metal Halide Metal Halide to: 1 - 150W Metal Halide Direct Lamp replacement Metal Halide Dire	508	508	508
		56	56) From: 400W Metal Halide Metal Halide to: 1 - 350W Metal Halide Direct Lamp replacement Metal Halide Dire	0	0	0
		57	57) From: 250W Metal Halide Metal Halide to: 4 - 4' Lamps with either 32 watt ballast of 80% ballast factor or 25	1,682	1,682	1,682
		58	58) From: 400W Metal Halide Metal Halide to: 6 - 4' Lamps with either 32 watt ballast of 80% ballast factor or 25	0	0	0
		69	02) From: 1 Lamp 8' -T12-75W-Magnetic Ballasts to: 1 - 8' lamp with 80% ballast factor T8-Electronic Ballast; Food	0	0	0
		70	03) From: 1 Lamp 8' -T12-75W-Magnetic Ballasts to: 2 - 4' end to end 25 watt lamp with 90% ballast factor T8-Elec	426	426	426
		71	04) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 4 - 4' end to end 32 watt lamps with 80% ballast factor T8-El	22,375	22,375	22,375
		72	05) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + reflector with 90% ballast factor T8-El	0	0	0
		73	06) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor	0	0	0
		74	07) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + Reflector with 90% ballast factor T8-E	1,450	1,450	1,450
		75	08) From: 1 Lamp 4' -T12-40W-Magnetic Ballasts to: 1 - 4' lamp with either 32 watt ballast of 80% ballast factor or	242	242	242
		76	09) From: 2 Lamps 4' -T12-40W-Magnetic Ballasts to: 1 - 4' 32 watt lamp + reflector with 90% ballast factor T8-Ele	0	0	0
		77	10) From: 2 Lamps 4' -T12-40W-Magnetic Ballasts to: 2 - 4' lamps with either 32 watt ballast of 80% ballast factor	0	0	0
		78	11) From: 4 Lamps 4' -T12-40W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + reflector T8-Electronic Ballast; Food S	0	0	0
		79	12) From: 4 Lamps 4' -T12-40W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor	0	0	0
		80	13) From: 1 Lamp 4' -T12-34W-Magnetic Ballasts to: 1 - 4' lamp with either 32 watt ballast of 80% ballast factor or	104	104	104
		81	14) From: 2 Lamps 4' -T12-34W-Magnetic Ballasts to: 1 - 4' 32 watt lamp + reflector with 90% ballast factor T8-Ele	0	0	0
		82	15) From: 2 Lamps 4' -T12-34W-Magnetic Ballasts to: 2 - 4' lamps with either 32 watt ballast of 80% ballast factor	0	0	0
		83	16) From: 4 Lamps 4' -T12-34W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + reflector T8-Electronic Ballast; Food S	0	0	0
		84	17) From: 4 Lamps 4' -T12-34W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor	0	0	0
		85	18) From: 2 Lamps U-Shaped 34-40W-Magnetic Ballasts to: 2 U-Tube Lamps 2' -T8-32W-Electronic Ballast; Food	0	0	0
		86	19) From: 2 Lamps U-Shaped 34-40W-Magnetic Ballasts to: 2 Linear 2' + Reflector F17T8 2' -T8-32W-Electronic B	0	0	0
		87	20) From: 2-15W Lamps Exit Sign - incandescent to: 3W LED Energy Star rated LED Exit Sign; Food Service Sec	32,027	32,027	32,027
		88	21) From: 2-15W Lamps Exit Sign - incandescent to: Replace entire fixture with LED sign Energy Star rated LED E	28,078	28,078	28,078
		89	22) From: 40W Standard Incandescent (A Lamp) to: 11W ENERGY STAR® rated CFL (Screw-in replacement); Fo	10,681	10,681	3,204
		90	23) From: 60W Standard Incandescent (A Lamp) to: 13W ENERGY STAR® rated CFL (Screw-in replacement); Fo	0	0	0
		91	24) From: 100W Standard Incandescent (A Lamp) to: 23W ENERGY STAR® rated CFL (Screw-in replacement); F	0	0	0
		92	25) From: 150W Standard Incandescent (A Lamp) to: 28W ENERGY STAR® rated CFL (Screw-in replacement); F	27,382	27,382	8,214
		93	26) From: 60W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 15W CFLPAR38/30 ENERGY S	0	0	0
		94	27) From: 75W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 18W CFLPAR38/30 ENERGY S	0	0	0
		95	28) From: 100W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 26W CFL PAR38/30 ENERGY	10,646	10,646	3,194
		96	29) From: 40 - 60W standard incandescent PAR Lights - Track lighting or product highlighting to: 15W CFL Energy	0	0	0
		97	30) From: 40 - 60W standard halogen PAR Lights - Track lighting or product highlighting to: 32 Watt IR coated hal	0	0	0

		98	31) From: 75W standard incandescent PAR Lights - Track lighting or product highlighting to: 18W CFL Energy Sta	0	0	0
		99	32) From: 75W standard incandescent PAR Lights - Track lighting or product highlighting to: 50 Watt Halogen Ene	0	0	0
		100	33) From: 90 Watt Halogen PAR Lights - Track lighting or product highlighting to: 23 to 28 watt CFL Par 38/30 Ene	0	0	0
		101	34) From: 90 Watt Halogen PAR Lights - Track lighting or product highlighting to: 60 watt Halogen IR Energy Star r	0	0	0
		102	35) From: 100W standard incandescent or greater PAR Lights - Track lighting or product highlighting to: 26W CFL	17,034	17,034	5,110
		103	36) From: 100W standard incandescent or greater PAR Lights - Track lighting or product highlighting to: 50-75 watt	0	0	0
		118	51) From: 4 Lamps 8' -T12-60W-Magnetic Ballasts to: 4 - 8' lamps with 2 electronic ballasts of 90% ballast factor T	0	0	0
		119	52) From: 2 Lamps 4' -T8 32W-Magnetic Ballasts to: 2 - 4' 25 watt lamps with electronic ballasts T8-Electronic Bal	4,259	4,259	4,259
		136	02) From: 1 Lamp 8' -T12-75W-Magnetic Ballasts to: 1 - 8' lamp with 80% ballast factor T8-Electronic Ballast; Offic	0	0	0
		137	03) From: 1 Lamp 8' -T12-75W-Magnetic Ballasts to: 2 - 4' end to end 25 watt lamp with 90% ballast factor T8-Elec	653	653	653
		138	04) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 4 - 4' end to end 32 watt lamps with 80% ballast factor T8-El	12,963	12,963	12,963
		139	05) From: 2 Lamps 8' -T12-75W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + reflector with 90% ballast factor T8-El	0	0	0
		140	06) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor	0	0	0
		141	07) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 2 - 4' 32 watt lamps + Reflector with 90% ballast factor T8-E	890	890	890
		151	17) From: 4 Lamps 4' -T12-34W-Magnetic Ballasts to: 4 - 4' lamps with either 32 watt ballast of 80% ballast factor	0	0	0
		152	18) From: 2 Lamps U-Shaped 34-40W-Magnetic Ballasts to: 2 U-Tube Lamps 2' -T8-32W-Electronic Ballast; Office	169	169	169
		153	19) From: 2 Lamps U-Shaped 34-40W-Magnetic Ballasts to: 2 Linear 2' + Reflector F17T8 2' -T8-32W-Electronic B	0	0	0
		154	20) From: 2-15W Lamps Exit Sign - incandescent to: 3W LED Energy Star rated LED Exit Sign; Office Sector	39,266	39,266	39,266
		155	21) From: 2-15W Lamps Exit Sign - incandescent to: Replace entire fixture with LED sign Energy Star rated LED E	47,163	47,163	47,163
		156	22) From: 40W Standard Incandescent (A Lamp) to: 11W ENERGY STAR® rated CFL (Screw-in replacement); Off	22,216	22,216	6,665
		157	23) From: 60W Standard Incandescent (A Lamp) to: 13W ENERGY STAR® rated CFL (Screw-in replacement); Off	0	0	0
		158	24) From: 100W Standard Incandescent (A Lamp) to: 23W ENERGY STAR® rated CFL (Screw-in replacement); O	0	0	0
		159	25) From: 150W Standard Incandescent (A Lamp) to: 28W ENERGY STAR® rated CFL (Screw-in replacement); O	1,292	1,292	388
		160	26) From: 60W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 15W CFLPAR38/30 ENERGY S	0	0	0
		161	27) From: 75W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 18W CFLPAR38/30 ENERGY S	0	0	0
		162	28) From: 100W PAR38/30 PAR Lights - Flood or Spot - recessed down lighting to: 26W CFL PAR38/30 ENERGY	2,612	2,612	784
		163	29) From: 40 - 60W standard incandescent PAR Lights - Track lighting or product highlighting to: 15W CFL Energy	0	0	0
		164	30) From: 40 - 60W standard halogen PAR Lights - Track lighting or product highlighting to: 32 Watt IR coated hal	0	0	0
		165	31) From: 75W standard incandescent PAR Lights - Track lighting or product highlighting to: 18W CFL Energy Sta	1,207	1,207	362
		166	32) From: 75W standard incandescent PAR Lights - Track lighting or product highlighting to: 50 Watt Halogen Ene	0	0	0
		167	33) From: 90 Watt Halogen PAR Lights - Track lighting or product highlighting to: 23 to 28 watt CFL Par 38/30 Ene	1,751	1,751	525
		183	49) From: 4 Lamps 8' -T12-75W-Magnetic Ballasts to: 4 - 8' lamps with 2 electronic ballasts of 90% ballast factor T	0	0	0
		184	50) From: 2 Lamps 8' -T12-60W-Magnetic Ballasts to: 2 - 8' 59wat lamps + reflector with 90% ballast factor T8-Ele	1,271	1,271	1,271
		185	51) From: 4 Lamps 8' -T12-60W-Magnetic Ballasts to: 4 - 8' lamps with 2 electronic ballasts of 90% ballast factor T	6,425	6,425	6,425
		186	52) From: 2 Lamps 4' -T8 32W-Magnetic Ballasts to: 2 - 4' 25 watt lamps with electronic ballasts T8-Electronic Bal	2,965	2,965	2,965
		187	53) From: 2 - 4' T12 High Output Lamps High Output T12-Magnetic Ballasts to: 2 - 4' High Output T8 lamps with ele	0	0	0
		188	54) From: 2 - 8' T12 High Output Lamps High Output T12-Magnetic Ballasts to: 2 - 8' High Output T8 lamps with ele	0	0	0
		189	55) From: 175W Metal Halide Metal Halide to: 1 - 150W Metal Halide Direct Lamp replacement Metal Halide Dire	0	0	0
		190	56) From: 400W Metal Halide Metal Halide to: 1 - 350W Metal Halide Direct Lamp replacement Metal Halide Dire	0	0	0
		191	57) From: 250W Metal Halide Metal Halide to: 4 - 4' Lamps with either 32 watt ballast of 80% ballast factor or 25	0	0	0
		192	58) From: 400W Metal Halide Metal Halide to: 6 - 4' Lamps with either 32 watt ballast of 80% ballast factor or 25	0	0	0

	193	59) From: 40W Standard Incandescent (A Lamp) to: 11W ENERGY STAR® rated CFL New Fixture (2-pin / 4-pin b	0	0	0
	194	60) From: 60W Standard Incandescent (A Lamp) to: 13W ENERGY STAR® rated CFL New Fixture (2-pin / 4-pin b	0	0	0
	195	61) From: 100W Standard Incandescent (A Lamp) to: 23W ENERGY STAR® rated CFL New Fixture (2-pin / 4-pin	815	815	245
	196	62) From: 150W Standard Incandescent (A Lamp) to: 28W ENERGY STAR® rated CFL New Fixture (2-pin / 4-pin	0	0	0
	197	63) From: 65 - 75W Incandescent R Lamp Incandescent R Lamp on Dimmers to: 14 - 16W Dimmable CFL R Lamp	0	0	0
	198	64) From: 100 - 150W Incandescent R Lamp Incandescent R Lamp on Dimmers to: 22 - 26W Dimmable CFL R La	0	0	0
	199	65) From: 40 - 60W standard halogen PAR Lights - Track lighting or product highlighting to: 32 Watt halogen IR M	0	0	0
	200	66) From: 4' T12 Tube Guard T12 Tube Guard to: 4' T8 Tube Guards T8-Electronic Ballast; Office Sector	0	0	0
	201	67) From: 8' T12 Tube Guard T12 Tube Guard to: 8' T8 Tube Guards T8-Electronic Ballast; Office Sector	0	0	0
Initiative Total			**1,231,718**	**1,230,986**	**1,079,813**
9		***peaksaver*® - Business Sector**			
	1	Commercial Air Conditioner - Switch	0	0	0
	2	Commercial Air Conditioner - Thermostat	666	666	666
	3	Commercial Electric Water Heater	0	0	0
Initiative Total			**666**	**666**	**666**

Province Wide Initiative Porfolio

1	**Consumer Program**	919,784	919,784	919,409
2	**Multi-Family Stream**	1,913	1,913	1,913
3	**Low-Income Program**	0	0	0
4	**Business Program**	1,415,292	1,414,560	1,263,387
5	**Industrial Program**	0	0	0
Total Portfolio		**2,336,988**	**2,336,257**	**2,184,709**

Appendix C OEB Proposed CDM Targets

APPENDIX C OEB Proposed CDM Targets

This was included in a letter from the OEB to All licensed Electricity Distributors re: Electricity Conservation and Demand Management Targets EB-2010-0216, dated June 22, 2010.

Energy Savings Target

The projected residential sector contribution to LDC provincial aggregate energy savings target is 1,150 GWh. The projected non-residential sector contribution to LDC provincial aggregate energy savings target is 4,850 GWh. The 2011-2014 LDC provincial aggregate energy savings target is 6,000 GWh.

#	Local Distribution Company	Energy Target Allocation Factors (Per 2008 OEB Distributors Yearbook + HONI Adjustment)		2011-2014 Energy Savings Target (GWh)	Overall Portion of Provincial Total (%)
		Portion of Total 2008 Residential Energy Consumption by all LDCs that have CDM Targets (%)	Portion of Total 2008 Non-Residential Energy Consumption by all LDCs that have CDM Targets (%)		
1	Algoma Power Inc.	0.22%	0.11%	8	0.13%
2	Atikokan Hydro Inc.	0.03%	0.02%	1	0.02%
3	Attawapiskat Power Corporation	0.01%	0.00%	0.1	0.00%
4	Bluewater Power Distribution Corporation	0.64%	1.00%	56	0.93%
5	Brant County Power Inc.	0.20%	0.24%	14	0.23%
6	Brantford Power Inc.	0.72%	0.88%	51	0.85%
7	Burlington Hydro Inc.	1.37%	1.41%	84	1.40%
8	COLLUS Power Corporation	0.28%	0.25%	15	0.25%
9	Cambridge and North Dumfries Hydro Inc.	0.95%	1.37%	77	1.28%
10	Canadian Niagara Power Inc.	0.50%	0.41%	25	0.42%
11	Centre Wellington Hydro Ltd.	0.11%	0.14%	8	0.13%
12	Chapleau Public Utilities Corporation	0.04%	0.02%	1	0.02%
13	Chatham-Kent Hydro Inc.	0.57%	0.70%	41	0.68%
14	Clinton Power Corporation	0.03%	0.02%	1	0.02%
15	Cooperative Hydro Embrun Inc.	0.05%	0.01%	1	0.02%
16	E.L.K. Energy Inc.	0.23%	0.19%	12	0.20%
17	ENWIN Utilities Ltd.	1.57%	2.19%	124	2.07%
18	Enersource Hydro Mississauga Inc.	3.91%	7.87%	427	7.12%
19	Erie Thames Powerlines Corporation	0.28%	0.34%	20	0.33%
20	Espanola Regional Hydro Distribution Corporation	0.08%	0.04%	3	0.05%
21	Essex Powerlines Corporation	0.64%	0.34%	24	0.40%
22	Festival Hydro Inc.	0.35%	0.55%	30	0.50%
23	Fort Albany Power Corporation	0.01%	0.00%	0.1	0.00%
24	Fort Frances Power Corporation	0.10%	0.05%	4	0.07%
25	Greater Sudbury Hydro Inc.	1.01%	0.67%	44	0.73%
26	Grimsby Power Inc.	0.22%	0.11%	8	0.13%

#	Local Distribution Company	Energy Target Allocation Factors (Per 2008 OEB Distributors Yearbook + HONI Adjustment)		2011-2014 Energy Savings Target (GWh)	Overall Portion of Provincial Total (%)
		Portion of Total 2008 Residential Energy Consumption by all LDCs that have CDM Targets (%)	Portion of Total 2008 Non-Residential Energy Consumption by all LDCs that have CDM Targets (%)		
27	Guelph Hydro Electric Systems Inc.	0.90%	1.49%	83	1.38%
28	Haldimand County Hydro Inc.	0.42%	0.22%	15	0.25%
29	Halton Hills Hydro Inc.	0.54%	0.34%	23	0.38%
30	Hearst Power Distribution Company Limited	0.07%	0.07%	4	0.07%
31	Horizon Utilities Corporation	4.04%	5.25%	301	5.02%
32	Hydro 2000 Inc.	0.04%	0.01%	1	0.02%
33	Hydro Hawkesbury Inc.	0.14%	0.17%	10	0.17%
34	Hydro One Brampton Networks Inc.	2.80%	3.35%	194	3.24%
35	Hydro One Networks Inc.	30.54%	13.66%	1,014	16.91%
36	Hydro Ottawa Limited	5.48%	6.42%	374	6.24%
37	Innisfil Hydro Distribution Systems Limited	0.39%	0.10%	9	0.15%
38	Kashechewan Power Corporation	0.01%	0.00%	0.1	0.00%
39	Kenora Hydro Electric Corporation Ltd.	0.10%	0.08%	5	0.08%
40	Kingston Hydro Corporation	0.49%	0.65%	37	0.62%
41	Kitchener-Wilmot Hydro Inc.	1.62%	1.53%	93	1.55%
42	Lakefront Utilities Inc.	0.19%	0.25%	14	0.23%
43	Lakeland Power Distribution Ltd.	0.20%	0.17%	10	0.17%
44	London Hydro Inc.	2.76%	2.66%	161	2.69%
45	Middlesex Power Distribution Corporation	0.15%	0.17%	10	0.17%
46	Midland Power Utility Corporation	0.12%	0.20%	11	0.18%
47	Milton Hydro Distribution Inc.	0.56%	0.58%	34	0.57%
48	Newmarket - Tay Power Distribution Ltd.	0.66%	0.55%	34	0.57%
49	Niagara Peninsula Energy Inc.	0.99%	0.99%	59	0.98%
50	Niagara-on-the-Lake Hydro Inc.	0.16%	0.13%	8	0.13%
51	Norfolk Power Distribution Inc.	0.35%	0.28%	18	0.30%
52	North Bay Hydro Distribution Limited	0.53%	0.43%	27	0.45%
53	Northern Ontario Wires Inc.	0.10%	0.10%	6	0.10%
54	Oakville Hydro Electricity Distribution Inc.	1.45%	1.21%	75	1.25%
55	Orangeville Hydro Limited	0.21%	0.20%	12	0.20%
56	Orillia Power Distribution Corporation	0.27%	0.25%	15	0.25%
57	Oshawa PUC Networks Inc.	1.21%	0.81%	53	0.88%
58	Ottawa River Power Corporation	0.19%	0.14%	9	0.15%

1

#	Local Distribution Company	Energy Target Allocation Factors (Per 2008 OEB Distributors Yearbook + HONI Adjustment)		2011-2014 Energy Savings Target (GWh)	Overall Portion of Provincial Total (%)
		Portion of Total 2008 Residential Energy Consumption by all LDCs that have CDM Targets (%)	Portion of Total 2008 Non-Residential Energy Consumption by all LDCs that have CDM Targets (%)		
59	PUC Distribution Inc.	0.85%	0.43%	31	0.52%
60	Parry Sound Power Corporation	0.08%	0.06%	4	0.07%
61	Peterborough Distribution Incorporated	0.71%	0.64%	39	0.65%
62	PowerStream Inc.	6.46%	6.92%	410	6.84%
63	Renfrew Hydro Inc.	0.08%	0.08%	5	0.08%
64	Rideau St. Lawrence Distribution Inc.	0.11%	0.08%	5	0.08%
65	Sioux Lookout Hydro Inc.	0.08%	0.05%	3	0.05%
66	St. Thomas Energy Inc.	0.30%	0.27%	16	0.27%
67	Thunder Bay Hydro Electricity Distribution Inc.	0.87%	0.78%	48	0.80%
68	Tillsonburg Hydro Inc.	0.13%	0.20%	11	0.18%
69	Toronto Hydro-Electric System Limited	12.84%	24.11%	1,317	21.97%
70	Veridian Connections Inc.	2.32%	1.87%	117	1.95%
71	Wasaga Distribution Inc.	0.19%	0.05%	4	0.07%
72	Waterloo North Hydro Inc.	1.00%	1.16%	68	1.13%
73	Welland Hydro-Electric System Corp.	0.39%	0.37%	22	0.37%
74	Wellington North Power Inc.	0.06%	0.08%	5	0.08%
75	West Coast Huron Energy Inc.	0.07%	0.15%	8	0.13%
76	West Perth Power Inc.	0.04%	0.06%	3	0.05%
77	Westario Power Inc.	0.52%	0.31%	21	0.35%
78	Whitby Hydro Electric Corporation	0.85%	0.61%	39	0.65%
79	Woodstock Hydro Services Inc.	0.27%	0.36%	21	0.35%
Total		**100%**	**100%**	**6,000**	**100%**

Table of Contents

EXHIBIT 4 – OPERATING COSTS

Managers Summary-Operating Costs

NPEI's mission is to provide safe and reliable electricity distribution services at competitive rates. However, NPEI's operating costs have been steadily increasing each year, particularly Distribution Operating and Maintenance, due to a number of reasons including an aging workforce, ongoing maintenance associated with an aging infrastructure, steady growth and additional costs associated with regulatory and legislated requirements.

LDCs have been operating in an ever-changing atmosphere since market opening in 2002. This has put additional cost pressures on all distribution utilities in the province, particularly in the area of regulation and compliance. NPEI has incurred considerable increases in expenses over the past number of years to comply with regulatory and legislative changes arising from rate applications, RRR reporting, embedded generation, Smart Meters, ESA Regulations and increasing regulatory fees.

NPEI will have increased payroll costs, as it will fill an additional Engineering Supervisor position in 2011.

NPEI has increased its employee complement since 2004 as demonstrated in the sections below. The effect of an aging workforce, long trainee or apprenticeship periods and the increased regulatory environment has culminated with increases in staff in 2010. Apprenticeships for Power line Workers occur over a five year period.

Operating Costs:

The operating costs presented in this Exhibit represent the annual expenditures required to sustain NPEI's distribution operations. A summary of NPEI's operating costs for the 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Bridge Year and the 2011 Test Year including the determination of the variance amount for analysis, in accordance with the Filing Requirements, is provided in Table 4-1 below.

Note that the Cost of Power is not included in Distribution Expenses in Table 4-1 but rather is used for the Working Capital calculation illustrated in Exhibit 2.

Table 4-1 includes Operation, Maintenance, and Administration Expenses of $14,295,435 for 2011 which are the same amounts that are included in Table 6-5 of Exhibit 6 – Calculation of Revenue Deficiency.

Total OM&A expenditures have increased from $12.5M in 2006 to $14.3M in 2011 or 2.88% per year. Wages have increased annually 3.0% per year and inflation has averaged 1.92% since 2006.

In recording its costs, NPEI follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between Operations and Maintenance. Detailed information with respect to the OM&A costs and variances, arranged by USoA account, is provided in Table 4-5.

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements as 0.5% of the Base Revenue Requirement, which is calculated at $151,178 (see Table 4-2). NPEI has adopted a variance analysis threshold of $75,000 for Operating Costs, which is approximately one-half of the materiality threshold required.

NPEI has adjusted its 2010 OM&A Bridge Year Costs for the impacts of the Harmonized Sales Tax (HST) which is effective July 1, 2010. As a result of the April 8, 2010 Board Decisions EB-2009-0205 and EB-2009-0206 on NPEI's May 1, 2010 distribution rate application, NPEI is required to record the incremental input tax credit (ITC) it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST into the deferral account 1592 (PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits (ITCs). NPEI expects that 50% of the confirmed balances in this account will be returned to the ratepayers in the future.

NPEI has reviewed each line item in its 2010 OM&A Bridge Year Costs as at June 30, 2010 and adjusted for impacts of the HST. NPEI repeated this process for each line item in the 2011 Test Year costs. The impact for 2010 resulted in an estimated reduction of OM&A by $98,570. These impacts include removal of any Provincial Sales Tax (PST) that had been included in the original budgeted cost where the PST portion of the HST is recoverable by NPEI as an input tax credit. NPEI notes that as a company with sales in excess of $10,000,000 it is subject to input tax credit (ITC) restrictions. These restrictions include non-recovery of the PST portion of the HST on energy costs (not IESO energy costs), on telecommunication costs (excluding 1-800 numbers and internet charges), on certain costs for road vehicles weighing less than 3,000 kilograms, and on costs for meals and entertainment.

NPEI notes that where expenses previously included PST that is now fully recoverable through HST, costs will be reduced.

However, with the ITC restrictions above, some costs that previously were not subject to PST are now subject to HST, and the PST portion of the HST is not recoverable. The net effect of this restriction is that it adds costs to our business. This is not a material amount in this filing.

In addition, some costs previously did not attract PST (i.e. audit fees), thus, the charging of HST is simply a pass-through, and there is no impact to the OM&A costs as it is no different than when the Goods & Services Tax (GST) only was charged.

This application has been filed in accordance with Canadian Generally Accepted Accounting Principles (CGAAP) as allowed for in the Board's July 28, 2009 EB-2008-0408 *Report of the Board: Transition to International Financial Reporting Standards*. The Filing Requirements for Rate Applications Section states "The Board will require electricity distributors filing for 2011 rates to provide the required years, the 2010 bridge year and the 2011 forecasts in CGAAP based format. An electricity distributor may choose to present modified IFRS based forecasts for 2010 and 2011, if the distributor prefers to have rates set on the basis of modified IFRS."

NPEI has chosen to provide the required years, the 2010 Bridge Year and the 2011 Test Year in CGAAP based format. The CGAAP based format extends itself to all costs in this application, including Rate Base, Depreciation and OM&A Costs and is prepared under the same CGAAP basis that its audited financial statements are prepared under. NPEI submits that the application of the format is not severable, an example of which is that capitalization of direct and indirect costs (overheads) cannot be on a CGAAP basis, while depreciation rates are subject to the new IFRS componentization rules. NPEI notes that the Board's letter of April 30, 2010 "*Depreciation Study for Electricity Distributors (EB-2010-0178) – Transition to International Financial Reporting Standards ("IFRS")* clearly defines the depreciation study, and any changes as a result of the application of the study, under the realm of IFRS.

NPEI is not submitting an updated depreciation study and thus, has adhered to the depreciation rates contained in the 2006 EDR Handbook, Appendix B.
NPEI does not have any political donations or charitable donations included in its OM&A expenses.

Table 4-1 Summary of Operating Costs - Appendix 2E

	2006 Board Approved	2006 Actuals	Variance 2006BA - 2006 Actuals	2007 Actuals	Variance 2007 - 2006 Actuals	2008 Actuals	Variance 2008 - 2007 Actuals	2009 Actuals	Variance 2009 - 2008 Actuals	Bridge Year 2010	Variance Bridge 2010 - 2009 Actuals	Test Year 2011	Variance Test 2011 - Bridge 2010
Operation	2,811,476	3,603,532	792,055	3,718,160	114,628	3,198,913	(519,247)	3,152,389	(46,524)	3,392,217	239,828	3,573,690	181,473
Maintenance	2,509,155	1,952,232	(556,923)	2,231,951	279,718	2,320,969	89,018	2,390,126	69,157	2,542,929	152,803	2,568,416	25,488
Billing and Collecting	2,971,181	3,232,894	261,713	3,371,741	138,847	3,771,715	399,974	3,630,381	(141,334)	3,884,221	253,840	4,195,729	311,509
Community Relations	98,291	72,955	(25,336)	83,295	10,340	36,877	(46,418)	64,569	27,692	79,548	14,979	81,464	1,916
Administrative and General	4,138,033	3,691,084	(446,949)	3,816,177	125,093	3,464,139	(352,038)	3,833,199	369,060	3,802,684	(30,516)	3,876,135	73,452
Total OM&A Expenses	12,528,137	12,552,697	24,560	13,221,323	668,626	12,792,613	(428,710)	13,070,664	278,051	13,701,598	630,934	14,295,435	593,837
Variance from Previous Year			24,560		668,626		(428,710)		278,051		630,934		593,837
Percent Change (year over year)			0.20%		5.33%		-3.24%		2.17%		4.83%		4.33%
Percent Change (2011 Test vs 2009 actuals)												9.37%	
Percent Change (2011 Test vs 2006 Board Approved)												14.11%	
Average for 2007, 2008, 2009		1.42%											
Compound Annual Growth Rate (for 2007, 2008, 2009)		1.36%											
Inflation Rate		2.1%		1.9%		2.1%		2.3%		1.3%		2.0%	

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements as 0.5% of Total Base Revenue Requirement including PILs, which is calculated at $151,178 (see Table 4-2).

Table 4-2 Materiality Threshold for OM&A variances

Service Revenue Requirement	32,421,330
(from Revenue Deficiency Calculation)	
Less Revenue Offsets	(2,185,747)
Base Revenue Requirement	**30,235,583**
Allocated to:	
Low Voltage Wheeling Costs	-
Directly Assigned CDM	-
Other	30,235,583
Total	**30,235,583**
Variance Calculation 0.5% of Distribution Revenue Requirement	**151,178**

NPEI has selected a materiality factor of $75,000 in its variance analysis of OM&A which is approximately one-half of the variance calculation above.

OM&A Costs

OM&A costs in this Exhibit represent NPEI's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. OM&A costs also include providing services to customers connected to NPEI's distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A cost expenditures for the 2011 Test Year are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place.

NPEI is proposing recovery of 2011 Test Year OM&A costs of $14,295,435 plus amortization of $ 7,000,940, excluding PILs and Interest for a total of $21,296,395.

OM&A Budgeting Process Used by NPEI

The operating budget is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it does not change, but provides a plan against which actual results may be evaluated.

Operating Work Plans

The operating budget is completed by the Finance Department with input and assistance from all departments. The capital budget is mainly prepared by the Engineering and Operations department with input and assistance from other departments. The following directives are used:

- Expenses for all department budgets are built from the bottom up using previous year actual, current year forecast and current year budget as the base;
- Significant variances in spending from prior years are explained and documented;
- Staffing changes are reviewed and adjusted for;
- Finance prepares a total operating budget by USofA account using projected wages and benefit costs.

Departmental and Corporate OM&A Activities

Operations and Maintenance

The expenses for this department include all costs relating to the operation (5000-5095) and maintenance (5105-5195) of the NPEI electrical system. This includes both direct labor costs and non-capital material spending to support both scheduled and reactive maintenance events. In addition, costs are allocated from support departments to cover the costs of Labour Burden, Vehicle Maintenance and Stores. The Engineering Department is not allocated to other departments. All engineering costs are expensed to account 5085. NPEI's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program (including predictive and preventative actions).

NPEI's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with NPEI's capital project work, so that where maintenance programs have identified matters the correction of which require capital investments, NPEI may adjust its capital spending priorities to address those matters.

Predictive Maintenance:

Predictive maintenance activities involve the testing of elements of NPEI's distribution system. These activities include infrared thermograph testing, transformer oil analysis, planned visual inspections and pole inspections and testing. These evaluation tools are all administered using a grid system with appropriate frequency levels. Any identified deficiencies found are prioritized and addressed within a suitable time frame.

Preventative Maintenance:

Preventative maintenance activities include inspection, servicing and repair of network components. This includes overhead and pad-mounted load break switch maintenance and cleaning/inspection of underground vaults. Also included are regular inspection and repair of substation components and ancillary equipment. The work is performed using a combination of time and condition based methodologies.

Emergency Maintenance:

This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include those related to repairs caused by storm damage, emergency tree trimming and on-call premiums. NPEI constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance. An answering service company has been contracted to contact "on call" lineperson and supervisory staff in the event of service problems outside of normal business hours.

Service Work:

The majority of costs related to this work pertain to service upgrades requested by customers, and requests to provide safety coverage for work (overhead line cover ups). This includes service disconnections and reconnections by NPEI for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

Network Control Operations:

Network operating costs will continue to be contracted out in 2011 and charged to account 5010.

Metering:

NPEI is certified by Measurement Canada to operate its meter department. This department is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes.

Revenue Protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power.

Substation Services:

Substation services activities address the maintenance of all equipment at NPEI's substations. This includes both labor costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, NPEI's substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of NPEI's planned maintenance program (including predictive and preventative actions) for its substations.

ENGINEERING DEPARTMENT

Since 2004 the Engineering department has been keeping asset related data up to date on an electronic Geographic Information System ("GIS"). This GIS system is currently being upgraded in 2009 and 2010 with workforce and outage management modules. These modules will be completed by the end of 2010. The GIS system is used for asset management activities, troubleshooting system problems in the control room, delivering underground utility locating services for excavating contractors and for design and construction activities including new capital projects and customer connections. Engineering also delivers drafting services to the design technicians for capital projects and provides distribution system asset information to many departments within NPEI. NPEI's GIS system is interfaced with both its Harris billing system and its financial system of Great Plains. This department tracks their time as direct labour charged to either account 5085 and/or to specific capital projects.

STORES/WAREHOUSE

NPEI's stores area consists of a Purchasing Manager and two storekeepers, one located in Niagara Falls' warehouse and one located at the service center located in Smithville. This department is accountable for managing the procurement, control, and movement of materials within NPEI's service area. This would include monitoring inventory levels, issuing material receipts, material issues, and material returns as required. The cost of the stores department is allocated to all departmental, capital and Third Party receivable accounts as an overhead cost based on direct material costs. A standard overhead percentage is set at the beginning of the year and adjusted to actual at year end.

GARAGE/TRANSPORTATION FLEET

NPEI has its' own garage and fully licensed mechanics. This department performs the repairs and maintenance of all of NPEI's vehicles. Its objectives include keeping maintenance schedules to ensure vehicle reliability and safety, and the minimization of vehicle down time. Vehicle costs are allocated to operations, maintenance, capital and Third Party receivable accounts based on number of hours used. A standard hourly cost/hr is set for all vehicles within the fleet. Costs are adjusted to actual at year end.

LABOUR BURDEN

This department collects the cost of all employee benefits and payroll taxes such as EI, CPP, EHT, WSIB, vacation, sick, floater days, post-retirement benefits, pension, health, dental and long term disability premiums and group insurances. Costs are allocated to all departments, capital and Third Party receivable amounts based on direct labour. An overhead rate is set at the beginning of each year and adjusted to actual at year end.

CUSTOMER SERVICE

The Customer Service group is responsible for the customer care activities for the approximately 52,000 customers in NPEI's service area. These activities include meter reading, billing, call centre, collections, and other back office functions. NPEI aspires to achieve customer service excellence in its processes and customer programs. The costs associated with the Customer Service department are collected in accounts 5305 to 5515. This department also includes labour and expenses related to CDM activities undertaken by NPEI that are not funded by current OPA programs.

Meter Reading:

Meter reading services are contracted out to two non-affiliated third parties under two separate service contract agreements. On average the contractor reads 25,000 electric service meters per month. The meter contract is negotiated every year.

Billing:

NPEI in May of 2010 converted the former Niagara Falls territory residential and several GS<50 customers to monthly billing. Prior to this time these customers were billed bi-monthly. The former Peninsula West customers were all on monthly billing. Billing is read one month and estimated the next for all residential customers. GS>50 customers are billed on actual reads monthly. NPEI issues approximately 627,000 bills annually to its customers. This includes total final bills for customers moving within or outside of NPEI's service territory. An annual billing schedule is created based on the meter reading schedule to ensure timely billing of services. The billing functions include the VEE processes; EBT and retailer settlement functions for 7,000 retailer accounts; account adjustments; processing meter changes; and other various account related field service orders and mailing services. NPEI offers customers a number of billing and payment options including an equal payment plan and a preauthorized payment plan.

Collections:

Collections involve a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. Credit risk is a concern for NPEI. In an effort to minimize credit losses, NPEI enforces a prudent credit policy in accordance with the Distribution System Code. Active overdue accounts are collected by in-house staff through notices, letters and direct telephone contact. Final bill collections are turned over to a collection agency after collection methods are exhausted.

NPEI is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. NPEI maintains a presence in the communities it serves, where NPEI staff is available to answer customer questions in a friendly environment.

Since LDCs are the "face-to-the-customer" for the electricity industry, NPEI has an important role to play in educating the public about electricity safety and energy conservation. NPEI continues to participate with the OPA in administering programs directed at Energy Conservation. NPEI is very active in the community promoting conservation initiatives, attending a number of community events each year, distributing compact florescent light bulbs and energy conservation handbooks.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Within NPEI, the following functional areas are considered to be part of general administration and, as such, all expenses incurred within these functional areas are accounted for as administrative and general expenses:

- Executive Management (5605);
- Finance and Regulatory Services (5610);
- Administrative Services (5615);
- Outside services employed (5630)
- Insurance (5635)
- Regulatory Costs (5655)
- Miscellaneous General Expenses (5665)
- Maintenance of General Plant (5675)

Executive Salaries and Expenses: 5605

The President & the Board of Directors are responsible for all aspects of the company. Expenses include salaries and all related expenses for all employees within the above noted functional areas.

Management Salaries and Expenses: 5610

Financial Services:

The Finance department is responsible for the preparation of statutory, management and Board of Directors financial reporting in accordance with GAAP; all daily accounting functions, including accounts payable, accounts receivable, and general accounting; treasury functions including cash management, risk management, accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and supporting tax compliance. The department is also responsible for all regulatory reporting and compliance with applicable codes and legislation governing NPEI. Regulatory reporting includes development and preparation of rate filings, performance reporting, and compliance. This department also includes the Human Resources Manager, and the Health Wellness Specialist. Expenses include salaries and all related expenses associated with the Vice President of Finance, the HR department, all Executive assistants and the IT department salaries and benefits.

Bank service charges, legal fees and consulting, and telephone expenses are all recorded as sub-accounts in 5610.

Administrative Services: 5615

This department assists the finance department with daily and monthly accounting services, accounts payable and accounts receivable, inventories and project accounting. Expenses include salary and related costs associated with the VP of Finance.

Outside Service Employed: 5630

Outside Services Employed include, but are not limited to auditors, and tax consultants.

Employee Post-Retirement Benefits:

Employee Post-Retirement Benefits include annual expenses for post-retirement benefits provided to eligible NPEI employees in accordance with company policy and as provided in the collective bargaining agreement between NPEI and its union. The annual expense and liability are determined in accordance with Section 3461 of the CICA Handbook and supported by an actuarial valuation that is completed every three years. This expense was allocated to the various departments in 2006, 2007, 2008 and 2009. In 2010, these expenses have become part of the payroll overhead burden rate which is charged to operations, maintenance, billing, general administration and capital and will continue to be apart of the payroll overhead in 2011.

Regulatory Expenses: 5655

Regulatory Expenses include those expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies, including annual assessment fees paid to a regulatory body. Annual fees assessed by the OEB are included in this expenditure category. Costs related to the 2011 COS rate application have been included in this account.

Miscellaneous General Expense: 5665

Health and Safety Costs include Health & Safety program supplies as well labour costs associated with safety meetings. NPEI is committed to maximizing productivity and reducing risk of injury by initiating safety and health measures that focus on preventative actions. The commitment to safety and health is significant, and involves documenting unsafe behaviors, monitoring conformance to established standards and policies, determining the effectiveness of safety training and monitoring the resolution of safety recommendations/audits; commitment to continuous improvement in training; and identifying and correcting root causes for system deficiencies. NPEI was recently award the Bronze Medal for safety by E&USA in the quest for zero lost time accidents. Newsletter costs and other miscellaneous expenses are recorded in account 5665.

The capital taxes for NPEI are recorded in a sub-account of 5665. NPEI has included property taxes in account 6105 as Taxes Other Than Income Taxes on the RRR Trial Balance.

Cost Drivers

NPEI has identified the incremental OM&A cost drivers in the preparation of this application, which are detailed in Table 4-3. While there are many cost drivers, certain items are significant enough to warrant special comment. It should be noted that NPEI's cost drivers do not equal the actual OM&A cost increases year over year since some cost drivers are allocated to capital and it is not possible for Table 4-3 to balance completely for each years OM&A without detailing every expense or credit. The variance has been identified in Table 4-3. Successful efforts at cost containment have allowed NPEI to keep its OM&A costs under control.

OM&A Costs Table

Table 4-3 OM&A Incremental Cost Driver Table-Appendix 2G

OM&A	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Opening Balance 2005	12,448,658	12,552,697	13,221,323	12,792,614	13,070,665	13,701,598
OMERS	53,248	43,286	48,029	24,245	47,969	15,526
Employee benefits (health, dental, life)	41,094	43,511	38,725	11,944	60,591	15,740
Post retirement benefits	8,124	8,899	58,310	8,755	13,349	7,209
Net New positions in 2005 full year in 2006	78,586	78,586	78,586	78,586	78,586	78,586
Net New positions hired/retired in 2006	90,726	81,817	81,817	81,817	81,817	81,817
Net New positions hired/retired in 2007		(112,806)	(174,142)	(174,142)	(174,142)	(174,142)
Net New positions hired/retired in 2008			217,262	180,437	180,437	180,437
Net New positions hired/retired in 2009				(17,960)	39,136	39,136
Net New positions hired/retired in 2010					80,769	154,529
Net New positions hired/retired in 2011						75,880
Inflationary payroll increases	114,446	114,317	126,721	131,035	129,545	135,107
Bad Debts	176,660	(46,716)	96,024	135,831	-	(15,100)
Regulatory Expenses	136,952	(50,226)	58,387	18,949	-	78,429
Reduction in expenses Account 5020		(100,139)	(206,305)	-	38,811	
Reduction in Materials of OH Maintenance 5025	(133,175)	(38,195)	(147,190)	-	-	
UG distribution lines Account 5040			(78,800)			
Meter labour and expenses			(148,052)	-	(4,948)	(39,827)
Account 5070 Customer premises			(47,428)	(65,246)	26,170	
Reduction in expenses Account 5120	(352,962)	-	(70,549)	(10,229)	11,328	
Increase/(Reduction) in expenses Account 5125	(148,816)	37,317	124,691	23,539	(10,668)	
Miscellaneous Expenses - Capital tax	-	-	-	43,513	(166,855)	(83,846)
Scrap meters related to previous years	(115,409)	115,409				
Pole Inspections	58,126	-	-	34,769	33,578	75,000
Tree trimming activities Account 5135	(29,670)	22,851	33,340	(66,287)	46,464	
Postage, envelopes and bill forms	-	24,080			49,597	40,000
Computer programming, software & hardware maintenance	(43,621)	16,797	61,995	(139,269)		25,000
Legal fees and outside consultants	86,091	181,175	(405,429)	36,120	9,360	
Office equipment lease and rent			(85,284)	57,555	(56,918)	
Payment to Hydro One by PW load transfer 1999 to 2002 Account 561	124,000					
Writeoff non-incremental Qualifying Transition costs in NF 2005	(123,650)					
Other	83,288	248,662	(89,418)	(115,911)	116,958	(95,645)
Closing Balance	12,552,697	13,221,323	12,792,614	13,070,665	13,701,598	14,295,435

Incremental Cost Drivers

OMERS

OMERS costs have continued to rise each year since 2006, however, the portion that is allocated to OM&A versus Capital fluctuates on a year to year basis depending on the allocation of labour required, and thus incremental OM&A impact may vary from year to year. OMERS costs are also a function of the number of eligible employees. NPEI has increased its number of FTE's from 117 in 2006 to 133 in 2011. Of the 133, only 119 are eligible for OMERS in 2011 compared to 107 in 2006. OMERS rates have steadily increased each year from 2006 as well.

Employee Benefits

Employee Benefits include health, dental, long term disability and life insurance. The premium costs have increased due to an increase in the number of claims, increase in the number of FTE's eligible and increase in premium costs. In 2009, there was a decrease from 2008 in employee benefits due to the harmonization of the benefit plans of the two predecessor utilities resulting from the merger. For the first six months of the year in 2008, both benefit plans were in effect until the union contracts were harmonized.

Post Retirement Benefits

In 2008, there was an increase in Post Retirement Benefits. The former Peninsula West Utilities employees did not have a post retirement plan, as a result of wage harmonization stemming from the merger; these employees were accounted for in the 2008 Actuarial valuation and as a result increased both the liability and expense.

Net new positions

The net increase of 25 FTE's from 2004 is the most significant cost driver. The net FTE changes by department are detailed in Table 4-12. The net FTE changes by year are detailed in Table 4-13 and the net changes by job classification are detailed in Table 4-

14. Detailed explanations of FTE changes from year to year are described in the Employee Compensation section of Exhibit 4.

Two executive positions retired in 2009 and were not replaced.

A Controller, Regulatory Financial and Rate Analyst, Administrative Assistant and Co-op accountant were hired throughout the period from 2008 to 2010, due to the increase in regulatory financial reporting requirements.

The Co-op accountant position will not be filled in 2011.

Two smart meter coordinators were hired for the implementation of smart meters in 2010 and two Business Analysts were hired as part of a succession plan for the two Billing Supervisors who are eligible to retire within the next two to five years. The two smart meter coordinators wages are accounted for in account 1556 and are not included in OM&A expenses in 2010 or 2011.

A GIS Technologist, Engineering Manager, Control Room Operator and two Engineering Technicians were hired throughout the period from 2005 to 2010. NPEI implemented a GIS system and continues to upgrade this system with work outage management being added in 2010.

A Safety Health and Wellness Specialist and Human Resource clerk were hired. Changes in safety regulations, increased necessity for documentation related to safety and training and Bill 168 have been the focus.

An IT Manager and Systems Analyst were hired in 2007 for the implementation of a new billing system in 2008 and the new telephone system in 2009 and 2010 as well as other technologies.

Eleven Apprentice/Lineman employees were hired since 2004 due to an aging workforce and a high volume of retirements in the foreseeable future. NPEI has been rebuilding its complement of apprentices.

In 2008, a management job evaluation program was implemented. The increase related to wage harmonization of management employees is included in the net new positions hired/retired in 2008 figure in the cost driver table above.

Inflationary Payroll Increases

NPEI's employees are represented by a Union and a collective agreement is in place setting the economic increase each unionized employee is to receive. The economic increases, effective April 1 of each year, were 3.0% each year from 2005 to 2010. The current union contract expires on March 31, 2011, however a historical estimate of 3% payroll increase has been budgeted for 2011, 2012 and 2013.

Based on the total labour charged to OM&A in each year less the net hired/retired positions already account for, the following payroll inflationary increases have been estimated as cost drivers:

2006 – $114,446
2007 – $114,317
2008 – $126,721
2009 – $131,035
2010 – $129,545
2011 – $135,107

Bad Debts

As demonstrated in Table 4-3, Bad Debts can vary from year to year; they are strongly dependent on the economic environment. NPEI has increased the number of customer service clerks focusing on bad debt collection in 2009 and 2010.

Regulatory expenses

Regulatory expenses increased in 2011 over 2006 as a result of one-quarter ($77,500) of the regulatory costs related to the preparation of the 2011 COS rate application.

Reduction in Operations & Maintenance Expenses

The following reductions in operations and maintenance expenses occurred in 2006, 2007 and 2008

2006 – Account 5025	(133,175)
- Account 5120	(352,962)
- Account 5125	(148,816)
Total	(653,953)
2007 – Account 5020	(100,139)
- Account 5025	(38,195)
- Account 5125	37,317
Total	(101,017)
2008 – Account 5020	(206,305)
- Account 5025	(147,190)
- Account 5040	(78,800)
- Account 5065	(148,052)
- Account 5070	(47,428)
- Account 5120	(70,549)
- Account 5125	124,691
Total	(573,633)

The former Peninsula West Utilities lineman performed mainly maintenance activities as capital work was outsourced. After the merger in 2008, NPEI has increased the number of construction crews to four and as a result capital work is being performed in-house versus being outsourced. In 2005, 2006, and 2007 51% of all labour charged to OM&A expenses was related to operations and maintenance. In 2008, 2009 and 2010, 48% of all labour charged to OM&A expenses related to operations and maintenance. As more capital work is performed in-house truck and material costs have also shifted from operations and maintenance to capital.

Total labour charged to capital was as follows:

	2006	2007	2008	2009
Niagara Falls Hydro	1,171,567	1,351,444		
Peninsula West Utilities	216,237	308,571		
Niagara Peninsual Energy	1,387,804	1,660,015	1,965,378	2,301,389
$ increase		272,211	305,363	336,011
% increase		20%	18%	17%

Capital Taxes

Due to changes in tax regulation, capital taxes will be reduced in 2010 as they are only calculated for half a year in 2010 and then capital taxes will be nil 2011.

Scrap Meters

In 2006, Niagara Falls Hydro recorded scrap meters related to 2003, 2004 and 2005.

Pole Inspections

NPEI completed 3,875 pole inspections in 2008, 4,332 pole inspections in 2009 and an estimated 5,397 poles in 2010 and planned pole inspections of 7,591 in 2011.

Tree Trimming

Tree trimming work rotates on a cycle, which differs between every three years for the urban areas and every five years for the rural areas. In 2011, an increase in focus in the peninsula west service area will occur which is mainly considered to be rural in nature.

Postage

As a result of converting the Niagara Falls area residents and GS<50 rate class from bi-monthly billing to monthly billing in May 2010, the cost of postage, envelopes and bill forms will increase in both 2010 and 2011 for a full year.

Computer programming, software and hardware maintenance fees

In 2009, computer programming, software and hardware maintenance fees decreased from the prior year as a result of converting from a legacy billing system in 2008 to the Harris billing system for Niagara Falls customers. Conversion of the Advanced billing system to the Harris billing system took place in 2009 for the peninsula west customers. As a result of harmonizing the software and hardware systems, the corresponding hardware and software maintenance fees were reduced in 2009 from 2008.

Legal fees and outside consultants

In 2006 and 2007, both former utilities incurred legal fees and outside consultant fees related to the merger. Subsequent to the merger the legal fees in 2008 reduced from 2007 by $400,000.

Office equipment lease and building rent

The former peninsula west utilities had several leases for its office equipment and rented office space for its administrative, customer service and engineering employees. As of 2009, all of the leases were completed and not renewed. The new service center was opened in the fall of 2009 and the office space rented was no longer required.

Payment to Hydro One

In 2006, the former Peninsula West Utilities made a payment to Hydro One for load transfers related to the period from 1999 to April 2002. This cost driver was only in 2006.

Write off Qualifying Transition Costs

In 2005, the former Niagara Falls Hydro wrote off non-incremental qualifying transition costs related to 2001 and 2002. This cost driver savings was only in 2006.

OM&A Cost per Customer and FTEE

NPEI strives to maintain reliable service and succession planning to replace an aging workforce while keeping its controllable expenses in check.

Controllable expenses per customer and per full time equivalent employee are detailed in Table 4-4 below.

Table 4-4 OM&A Cost per Customer and FTEE – Appendix 2I

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Number of Customers	49,033	49,517	50,062	50,870	51,481	52,100
Total OM&A	$ 12,552,697	$ 13,221,323	$ 12,792,613	$ 13,070,664	$ 13,701,598	$ 14,295,435
OM&A Cost per Customer	$ 256	$ 267	$ 256	$ 257	$ 266	$ 274
Number of FTEEs	117	117	121	127	133	133
FTEEs/Customer	0.0024	0.0024	0.0024	0.0025	0.0026	0.0026
OM&A Cost per FTEE	107,288	113,003	105,724	102,919	103,020	107,484
FTEEs/Customer % Increase from Previous Year		-0.98%	2.29%	3.29%	3.48%	-1.19%
OM&A Cost per FTEE % Increase from Previous Year		5.33%	-6.44%	-2.65%	0.10%	4.33%
OM&A Cost per Customer % Increase from Previous Year		4.30%	-4.30%	0.55%	3.58%	3.09%

OM&A Expense Table

Table 4-5 provides details of NPEI's OM&A expenses for the 2005 Actual, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, the 2010 Bridge Year and the 2011 Test Year including the determination of the variance amount for analysis, in accordance with the Filing Requirements. Note that Table 4-5 below does not include account 6110 - Income Tax Expenses (PILS), nor does it include account 5705 – Amortization Expense.

Table 4-5A details the variances year over year by USoA account.

Table 4-5 Detail Account by Account OM&A Expense Table-Appendix 2F

Distribution Expenses - Operation	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
5005-Operation Supervision and Engineering	617,668	688,793	679,881	595,433	578,370	629,835	648,571
5010-Load Dispatching	32,948	32,118	32,248	31,450	44,478	42,867	43,800
5012-Station Buildings and Fixtures Expense	145,090	145,746	83,621	91,253	125,341	122,347	119,771
5014-Transformer Station Equipment - Operation Labour and Expenses	62,352	9,975	12,995	1,410	6,819	10,889	11,507
5015-Transformer Station - Operation Supplies and Expenses	39,501	105,247	106,068	69,666	65,786	53,279	54,733
5016-Distribution Station Equipment - Operation Labour	51,452	8,718	9,281	-	-	-	-
5017-Distribution Station Equipment - Operation Supplies and Expenses	6,936	9,821	-	-	-	-	-
5020-Overhead Distribution Poles, Towers and Fixtures-Operation Labour and Expens	414,250	448,578	348,440	142,135	154,815	193,626	197,358
5025-Overhead Distribution Lines and Feeders - Operation Labour and Expenses	366,610	215,303	177,108	29,918	21,256	19,954	20,421
5030-Overhead Subtransmission Feeders - Operation	-	-	-	-	-	-	-
5035-Overhead Distribution Transformers - Operation	55,681	53,333	39,711	-	-	-	-
5040-Underground Distribution Conduit - Operation Labour and Expenses	126,576	163,656	117,786	38,985	58,365	71,410	72,606
5045-Underground Distribution Conductors and Devices - Operation Labour and Expen	165,249	172,707	159,100	247,672	243,103	193,121	194,991
5050-Underground Subtransmission Feeders - Operation	-	78	-	-	-	-	-
5055-Underground Distribution Transformers - Operation	19,347	11,925	6,796	-	-	-	-
5060-Street Lighting and Signal System Expense	-	-	-	-	-	-	-
5065-Meter Expense	571,227	492,554	750,758	584,964	403,418	521,545	489,927
5070-Customer Premises - Operation Labour and Expenses	223,812	193,390	169,413	121,985	56,738	94,272	96,423
5075-Customer Premises - Materials and Expenses	17,354	9,212	16,839	-	-	-	-
5085-Misc. Distribution and Engineering Labour and Expenses	706,020	809,586	974,347	1,244,042	1,393,900	1,439,073	1,623,583
5090-Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	16,853	32,792	33,766	-	-	-	-
5096-Other Rent	-	-	-	-	-	-	-
Subtotal Distribution Expenses - Operation	3,638,925	3,603,532	3,718,160	3,198,913	3,152,389	3,392,217	3,573,690

Distribution Expenses - Maintenance	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
5105 Maintenance Supervision and Engineering	317,339	256,633	286,909	407,008	398,759	448,874	462,681
5110 Maintenance of Buildings and Fixtures - Distribution Stations	-	-	-	-	-	-	-
5112 Maintenance of Transformer Station Equipment	-	-	-	-	-	-	-
5114 Maintenance of Distribution Station Equipment	(1,433)	14,824	10,775	3,969	2,867	4,871	4,767
5120 Maintenance of Poles, Towers and Fixtures	559,481	206,519	201,503	130,954	125,297	149,838	151,573
5125 Maintenance of Overhead Conductors and Devices	821,249	672,433	709,751	834,442	896,673	914,451	917,736
5130 Maintenance of Overhead Services	72,171	87,589	123,227	155,633	137,622	148,397	150,393
5135 Overhead Distribution Lines and Feeders - Right of Way	300,688	271,498	333,717	364,037	296,535	347,058	352,301
5145 Maintenance of Underground Conduit	59,714	60,893	30,092	46,304	47,652	43,016	42,841
5150 Maintenance of Underground Conductors and Devices	139,417	148,782	191,837	149,829	245,671	248,613	249,450
5155 Maintenance of Underground Services	58,949	74,452	123,898	80,916	92,502	89,602	91,252
5160 Maintenance of Line Transformers	147,860	143,209	192,418	128,445	133,947	133,749	132,000
5165 Maintenance of Street Lighting and Signal Systems	-	-	-	-	-	-	-
5170 Sentinel Lights - Labour	-	-	-	-	-	-	-
5172 Sentinel Lights - Materials and Expenses	-	-	-	-	-	-	-
5175 Maintenance of Meters	6,662	15,401	27,824	19,432	12,601	14,459	13,426
5178 Customer Installations Expenses - Leased Property	-	-	-	-	-	-	-
5195 Maintenance of Other Installations on Customer Premises	-	-	-	-	-	-	-
Subtotal Distribution Expenses - Maintenance	2,482,098	1,952,232	2,231,951	2,320,969	2,390,126	2,542,929	2,568,416

Table 4-5 Detail Account by Account OM&A Expense Table – Appendix 2F

Billing and Collecting	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
5305 Supervision	315,354	285,450	307,325	512,242	366,304	336,369	490,012
5310 Meter Reading Expense	474,235	487,834	505,371	397,340	438,379	461,855	473,321
5315 Customer Billing	1,562,063	1,630,728	1,699,832	1,872,229	1,710,531	1,928,990	2,080,927
5320 Collecting	478,384	424,633	459,241	462,144	459,698	475,013	483,163
5325 Collecting - Cash Over and Short	2,310	(5,603)	333	495	56	-	-
5330 Collection Charges	-	-	-	-	-	-	-
5335 Bad Debt Expense	65,515	242,175	195,460	291,484	427,315	425,100	410,000
5340 Miscellaneous Customer Accounts Expenses	183,362	167,676	204,178	235,781	228,098	256,895	258,306
Subtotal Billing and Collecting	3,081,223	3,232,894	3,371,741	3,771,715	3,630,381	3,884,221	4,195,729

Community Relations (including sales expenses)	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
5405 Supervision	56,860	53,930	62,424	22,869	14,746	-	-
5410 Community Relations - Sundry	12,059	19,025	12,739	14,008	49,823	79,548	81,464
5415 Energy Conservation	-	-	8,131	-	-	-	-
5420 Community Safety Program	1,065	-	-	-	-	-	-
5425 Miscellaneous Customer Service and Informational Expenses	-	-	-	-	-	-	-
5505 Supervision	-	-	-	-	-	-	-
5510 Demonstrating and Selling Expense	-	-	-	-	-	-	-
5515 Advertising Expense	12,283	-	-	-	-	-	-
5520 Miscellaneous Sales Expense	-	-	-	-	-	-	-
Subtotal Community Relations	82,267	72,955	83,295	36,877	64,569	79,548	81,464

Administrative and General Expenses	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
5605 Executive Salaries and Expenses	337,623	349,122	331,218	312,533	279,924	311,388	323,267
5610 Management Salaries and Expenses	1,033,638	1,088,919	1,095,496	1,472,940	1,602,714	1,743,297	1,818,577
5615 General Administrative Salaries and Expenses	410,947	572,506	554,058	315,333	375,307	400,853	421,595
5620 Office Supplies and Expenses	174,797	174,696	260,525	117,200	133,823	132,496	126,460
5625 Administrative Expense Transferred-Credit	-	-	-	-	-	-	-
5630 Outside Services Employed	217,366	293,227	407,804	51,200	39,600	39,600	39,900
5635 Property Insurance	105,821	112,660	114,158	181,842	204,848	206,367	209,777
5640 Injuries and Damages	72,874	63,482	59,174	480	-	-	-
5645 Employee Pensions and Benefits	-	-	-	-	-	-	-
5650 Franchise Requirements	28,125	-	-	-	-	-	-
5655 Regulatory Expenses	-	165,077	114,851	173,238	192,187	190,000	268,429
5660 General Advertising Expenses	8,688	10,714	7,959	465	-	-	-
5665 Miscellaneous Expenses	217,536	338,144	350,606	286,929	352,023	185,605	103,810
5670 Rent	44,866	46,997	61,102	67,102	56,917	-	-
5675 Maintenance of General Plant	503,040	463,532	446,040	484,877	595,857	593,077	564,320
5680 Electrical Safety Authority Fees	8,824	12,009	12,185	-	-	-	-
5685 Independent Market Operator Fees and Penalties	-	-	1,000	-	-	-	-
5695 OM&A Contra Account	-	-	-	-	-	-	-
6205 Charitable Donations	-	-	-	-	-	-	-
Subtotal Administrative and General Expense	3,164,145	3,691,084	3,816,177	3,464,139	3,833,199	3,802,684	3,876,135

Total OM&A Expenses	12,448,658	12,552,697	13,221,323	12,792,613	13,070,664	13,701,598	14,295,435

Table 4-5A Detail account by account OM&A variance by year

Distribution Expenses - Operation	2005 Actual	2006 Actual	Variance 2006 over 2005	2007 Actual	Variance 2007 over 2006	2008 Actual	Variance 2008 over 2007	2009 Actual	Variance 2009 over 2008	2010 Bridge	Variance 2010 over 2009	2011 Test	Variance 2011 over 2010
5005-Operation Supervision and Engineering	617,668	688,793	71,125	679,881	(8,913)	595,433	(84,448)	578,370	(17,063)	629,835	51,465	648,571	18,737
5010-Load Dispatching	32,948	32,118	(830)	32,248	130	31,450	(798)	44,478	13,028	42,867	(1,611)	43,800	933
5012-Station Buildings and Fixtures Expense	145,090	145,746	656	83,621	(62,124)	91,253	7,632	125,341	34,088	122,347	(2,994)	119,771	(2,576)
5014-Transformer Station Equipment - Operation Labour and Expenses	62,352	9,975	(52,377)	12,995	3,020	1,410	(11,585)	6,819	5,409	10,889	4,070	11,507	618
5015-Transformer Station - Operation Supplies and Expenses	39,501	105,247	65,746	106,068	821	69,666	(36,402)	65,786	(3,880)	53,279	(12,507)	54,733	1,454
5016-Distribution Station Equipment - Operation Labour	51,452	8,718	(42,734)	9,281	563	-	(9,281)	-	-	-	-	-	-
5017-Distribution Station Equipment - Operation Supplies and Expenses	6,936	9,821	2,885	-	(9,821)	-	-	-	-	-	-	-	-
5020-Overhead Distribution Poles, Towers and Fixtures-Operation Labour and Expenses	414,250	448,578	34,329	348,440	(100,138)	142,135	(206,305)	154,815	12,680	193,626	38,811	197,358	3,732
5025-Overhead Distribution Lines and Feeders - Operation Labour and Expenses	366,610	215,303	(151,307)	177,108	(38,195)	29,918	(147,190)	21,256	(8,662)	19,954	(1,302)	20,421	468
5030-Overhead Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-	-	-
5035-Overhead Distribution Transformers - Operation	55,681	53,333	(2,348)	39,711	(13,622)	-	(39,711)	-	-	-	-	-	-
5040-Underground Distribution Conduit - Operation Labour and Expenses	126,576	163,656	37,081	117,786	(45,871)	38,985	(78,801)	58,365	19,380	71,410	13,045	72,606	1,196
5045-Underground Distribution Conductors and Devices - Operation Labour and Expenses	165,249	172,707	7,458	159,100	(13,607)	247,672	88,572	243,103	(4,569)	193,121	(49,982)	194,991	1,870
5050-Underground Subtransmission Feeders - Operation	-	78	78	-	(78)	-	-	-	-	-	-	-	-
5055-Underground Distribution Transformers - Operation	19,347	11,925	(7,421)	6,796	(5,130)	-	(6,796)	-	-	-	-	-	-
5060-Street Lighting and Signal System Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
5065-Meter Expense	571,227	492,554	(78,673)	750,758	258,204	584,964	(165,794)	403,418	(181,546)	521,545	118,127	489,927	(31,618)
5070-Customer Premises - Operation Labour and Expenses	223,812	193,390	(30,422)	169,413	(23,977)	121,985	(47,428)	56,738	(65,247)	94,272	37,534	96,423	2,151
5075-Customer Premises - Materials and Expenses	17,354	9,212	(8,142)	16,839	7,628	-	(16,839)	-	-	-	-	-	-
5085-Misc. Distribution and Engineering Labour and Expenses	706,020	809,586	103,565	974,347	164,762	1,244,042	269,695	1,393,900	149,858	1,439,073	45,173	1,623,583	184,509
5090-Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-	-	-	-	-	-	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	16,853	32,792	15,938	33,766	975	-	(33,766)	-	-	-	-	-	-
5096-Other Rent	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Distribution Expenses - Operation	3,638,925	3,603,532	(35,393)	3,718,160	114,628	3,198,913	(519,247)	3,152,389	(46,524)	3,392,217	239,828	3,573,690	181,473

Table 4-5A Detail account by account OM&A variance year over year

Distribution Expenses - Maintenance	2005 Actual	2006 Actual	Variance 2006 over 2005	2007 Actual	Variance 2007 over 2006	2008 Actual	Variance 2008 over 2007	2009 Actual	Variance 2009 over 2008	2010 Bridge	Variance 2010 over 2009	2011 Test	Variance 2011 over 2010
5105 Maintenance Supervision and Engineering	317,339	256,633	(60,707)	286,909	30,276	407,008	120,099	398,759	(8,249)	448,874	50,115	462,681	13,807
5110 Maintenance of Buildings and Fixtures - Distribution Stations	-	-	-	-	-	-	-	-	-	-	-	-	-
5112 Maintenance of Transformer Station Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
5114 Maintenance of Distribution Station Equipment	(1,433)	14,824	16,257	10,775	(4,049)	3,969	(6,806)	2,867	(1,102)	4,871	2,004	4,767	(104)
5120 Maintenance of Poles, Towers and Fixtures	559,481	206,519	(352,962)	201,503	(5,016)	130,954	(70,549)	125,297	(5,657)	149,838	24,541	151,573	1,735
5125 Maintenance of Overhead Conductors and Devices	821,249	672,433	(148,816)	709,751	37,318	834,442	124,691	896,673	62,231	914,451	17,778	917,736	3,285
5130 Maintenance of Overhead Services	72,171	87,589	15,418	123,227	35,638	155,633	32,406	137,622	(18,011)	148,397	10,775	150,393	1,996
5135 Overhead Distribution Lines and Feeders - Right of Way	300,688	271,498	(29,190)	333,717	62,220	364,037	30,320	296,535	(67,502)	347,058	50,523	352,301	5,243
5145 Maintenance of Underground Conduit	59,714	60,893	1,179	30,092	(30,801)	46,304	16,212	47,652	1,348	43,016	(4,636)	42,841	(176)
5150 Maintenance of Underground Conductors and Devices	139,417	148,782	9,365	191,837	43,055	149,829	(42,008)	245,671	95,842	248,613	2,942	249,450	836
5155 Maintenance of Underground Services	58,949	74,452	15,503	123,898	49,446	80,916	(42,982)	92,502	11,586	89,602	(2,900)	91,252	1,650
5160 Maintenance of Line Transformers	147,860	143,209	(4,651)	192,418	49,208	128,445	(63,973)	133,947	5,502	133,749	(198)	132,000	(1,750)
5165 Maintenance of Street Lighting and Signal Systems	-	-	-	-	-	-	-	-	-	-	-	-	-
5170 Sentinel Lights - Labour	-	-	-	-	-	-	-	-	-	-	-	-	-
5172 Sentinel Lights - Materials and Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
5175 Maintenance of Meters	6,662	15,401	8,739	27,824	12,423	19,432	(8,392)	12,601	(6,831)	14,459	1,858	13,426	(1,033)
5178 Customer Installations Expenses - Leased Property	-	-	-	-	-	-	-	-	-	-	-	-	-
5195 Maintenance of Other Installations on Customer Premises	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Distribution Expenses - Maintenance	2,482,098	1,952,232	(529,866)	2,231,951	279,718	2,320,969	89,018	2,390,126	69,157	2,542,929	152,803	2,568,416	25,488

Table 4-5A Detail account by account OM&A variance year over year

Billing and Collecting	2005 Actual	2006 Actual	Variance 2006 over 2005	2007 Actual	Variance 2007 over 2006	2008 Actual	Variance 2008 over 2007	2009 Actual	Variance 2009 over 2008	2010 Bridge	Variance 2010 over 2009	2011 Test	Variance 2011 over 2010
5305 Supervision	315,354	285,450	(29,903)	307,325	21,875	512,242	204,917	366,304	(145,938)	336,369	(29,935)	490,012	153,644
5310 Meter Reading Expense	474,235	487,834	13,599	505,371	17,537	397,340	(108,031)	438,379	41,039	461,855	23,476	473,321	11,466
5315 Customer Billing	1,562,063	1,630,728	68,664	1,699,832	69,105	1,872,229	172,397	1,710,531	(161,698)	1,928,990	218,459	2,080,927	151,937
5320 Collecting	478,384	424,633	(53,751)	459,241	34,608	462,144	2,903	459,698	(2,446)	475,013	15,315	483,163	8,151
5325 Collecting - Cash Over and Short	2,310	(5,603)	(7,913)	333	5,936	495	162	56	(439)	-	(56)	-	-
5330 Collection Charges	-	-	-	-	-	-	-	-	-	-	-	-	-
5335 Bad Debt Expense	65,515	242,175	176,660	195,460	(46,716)	291,484	96,024	427,315	135,831	425,100	(2,215)	410,000	(15,100)
5340 Miscellaneous Customer Accounts Expenses	183,362	167,676	(15,685)	204,178	36,502	235,781	31,603	228,098	(7,683)	256,895	28,797	258,306	1,411
Subtotal Billing and Collecting	3,081,223	3,232,894	151,671	3,371,741	138,847	3,771,715	399,974	3,630,381	(141,334)	3,884,221	253,840	4,195,729	311,509

Community Relations (including sales expenses)	2005 Actual	2006 Actual	Variance 2006 over 2005	2007 Actual	Variance 2007 over 2006	2008 Actual	Variance 2008 over 2007	2009 Actual	Variance 2009 over 2008	2010 Bridge	Variance 2010 over 2009	2011 Test	Variance 2011 over 2010
5405 Supervision	56,860	53,930	(2,930)	62,424	8,494	22,869	(39,555)	14,746	(8,123)	-	(14,746)	-	-
5410 Community Relations - Sundry	12,059	19,025	6,966	12,739	(6,285)	14,008	1,269	49,823	35,815	79,548	29,725	81,464	1,916
5415 Energy Conservation	-	-	-	8,131	8,131	-	(8,131)	-	-	-	-	-	-
5420 Community Safety Program	1,065	-	(1,065)	-	-	-	-	-	-	-	-	-	-
5425 Miscellaneous Customer Service and Informational Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
5505 Supervision	-	-	-	-	-	-	-	-	-	-	-	-	-
5510 Demonstrating and Selling Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
5515 Advertising Expense	12,283	-	(12,283)	-	-	-	-	-	-	-	-	-	-
5520 Miscellaneous Sales Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Community Relations	82,267	72,955	(9,312)	83,295	10,340	36,877	(46,418)	64,569	27,692	79,548	14,979	81,464	1,916

Table 4-5A Detail account by account OM&A variance year over year

Administrative and General Expenses	2005 Actual	2006 Actual	Variance 2006 over 2005	2007 Actual	Variance 2007 over 2006	2008 Actual	Variance 2008 over 2007	2009 Actual	Variance 2009 over 2008	2010 Bridge	Variance 2010 over 2009	2011 Test	Variance 2011 over 2010
5605 Executive Salaries and Expenses	337,623	349,122	11,499	331,218	(17,903)	312,533	(18,685)	279,924	(32,610)	311,388	31,464	323,267	11,879
5610 Management Salaries and Expenses	1,033,638	1,088,919	55,281	1,095,496	6,577	1,472,940	377,444	1,602,714	129,774	1,743,297	140,583	1,818,577	75,280
5615 General Administrative Salaries and Expenses	410,947	572,506	161,559	554,058	(18,448)	315,333	(238,725)	375,307	59,974	400,853	25,546	421,595	20,742
5620 Office Supplies and Expenses	174,797	174,696	(101)	260,525	85,830	117,200	(143,325)	133,823	16,623	132,496	(1,327)	126,460	(6,036)
5625 Administrative Expense Transferred-Credit	-	-	-	-	-	-	-	-	-	-	-	-	-
5630 Outside Services Employed	217,366	293,227	75,861	407,804	114,578	51,200	(356,604)	39,600	(11,600)	39,600	-	39,900	300
5635 Property Insurance	105,821	112,660	6,839	114,158	1,498	181,842	67,684	204,848	23,006	206,367	1,519	209,777	3,410
5640 Injuries and Damages	72,874	63,482	(9,392)	59,174	(4,308)	480	(58,694)	-	(480)	-	-	-	-
5645 Employee Pensions and Benefits	-	-	-	-	-	-	-	-	-	-	-	-	-
5650 Franchise Requirements	28,125	-	(28,125)	-	-	-	-	-	-	-	-	-	-
5655 Regulatory Expenses	-	165,077	165,077	114,851	(50,226)	173,238	58,387	192,187	18,949	190,000	(2,187)	268,429	78,429
5660 General Advertising Expenses	8,688	10,714	2,026	7,959	(2,755)	465	(7,494)	-	(465)	-	-	-	-
5665 Miscellaneous Expenses	217,536	338,144	120,608	350,606	12,462	286,929	(63,677)	352,023	65,094	185,605	(166,417)	103,810	(81,795)
5670 Rent	44,866	46,997	2,131	61,102	14,106	67,102	6,000	56,917	(10,185)	-	(56,917)	-	-
5675 Maintenance of General Plant	503,040	463,532	(39,509)	446,040	(17,492)	484,877	38,837	595,857	110,980	593,077	(2,780)	564,320	(28,757)
5680 Electrical Safety Authority Fees	8,824	12,009	3,185	12,185	176	-	(12,185)	-	-	-	-	-	-
5685 Independent Market Operator Fees and Penalties	-	-	-	1,000	1,000	-	(1,000)	-	-	-	-	-	-
5695 OM&A Contra Account	-	-	-	-	-	-	-	-	-	-	-	-	-
6205 Charitable Donations	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Administrative and General Expense	3,164,145	3,691,084	526,939	3,816,177	125,093	3,464,139	(352,038)	3,833,199	369,060	3,802,684	(30,516)	3,876,135	73,452
Total OM&A Expenses	12,448,658	12,552,697	104,039	13,221,323	668,626	12,792,613	(428,710)	13,070,664	278,051	13,701,598	630,934	14,295,435	593,837

Variance Analysis on OM&A Costs

NPEI has provided a detailed OM&A cost table covering the periods 2005 Actual, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Bridge Year and 2011 Test Year including the variances year over year in Exhibit 4, Table 4-5A, above.

Variance Analysis:

As mentioned above, the variance that triggers the required analysis is $151,178 according to the Filing Requirements. NPEI has explained any variances that exceed $75,000 in order to produce a better analysis. NPEI has reviewed the variance of each OEB USoA account to determine where explanations are necessary.

The variances have been highlighted in Exhibit 4 Table 4-6A and 4-6B, and an explanation of each variance is presented in the following section.

Table 4-6A below highlights the variance from the 2006 Actual to the 2011 Test Year.

Table 4-6B highlights the variances from 2009 Actual to the 2011 Test year.

Explanations of these variances are included in the synopsis below:

Table 4-6A Variance Analysis 2011 Test Year vs. 2006 Actual-Appendix 2J

Distribution Expenses - Operation	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5005-Operation Supervision and Engineering	688,793	648,571	(40,222)	-6%
5010-Load Dispatching	32,118	43,800	11,682	36%
5012-Station Buildings and Fixtures Expense	145,746	119,771	(25,974)	-18%
5014-Transformer Station Equipment - Operation Labour and Expenses	9,975	11,507	1,532	15%
5015-Transformer Station - Operation Supplies and Expenses	105,247	54,733	(50,514)	-48%
5016-Distribution Station Equipment - Operation Labour	8,718	-	(8,718)	-100%
5017-Distribution Station Equipment - Operation Supplies and Expenses	9,821	-	(9,821)	-100%
5020-Overhead Distribution Poles, Towers and Fixtures-Operation Labour and Expens	448,578	197,358	(251,220)	-56%
5025-Overhead Distribution Lines and Feeders - Operation Labour and Expenses	215,303	20,421	(194,882)	-91%
5030-Overhead Subtransmission Feeders - Operation	-	-	-	0%
5035-Overhead Distribution Transformers - Operation	53,333	-	(53,333)	-100%
5040-Underground Distribution Conduit - Operation Labour and Expenses	163,656	72,606	(91,051)	-56%
5045-Underground Distribution Conductors and Devices - Operation Labour and Expen	172,707	194,991	22,284	13%
5050-Underground Subtransmission Feeders - Operation	78	-	(78)	-100%
5055-Underground Distribution Transformers - Operation	11,925	-	(11,925)	-100%
5060-Street Lighting and Signal System Expense	-	-	-	0%
5065-Meter Expense	492,554	489,927	(2,627)	-1%
5070-Customer Premises - Operation Labour and Expenses	193,390	96,423	(96,967)	-50%
5075-Customer Premises - Materials and Expenses	9,212	-	(9,212)	-100%
5085-Misc. Distribution and Engineering Labour and Expenses	809,586	1,623,583	813,997	101%
5090-Underground Distribution Lines and Feeders - Rental Paid	-	-	-	0%
5095-Overhead Distribution Lines and Feeders - Rental Paid	32,792	-	(32,792)	-100%
5096-Other Rent	-	-	-	0%
Subtotal Distribution Expenses - Operation	3,603,532	3,573,690	(29,841)	-1%

Distribution Expenses - Maintenance	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5105-Maintenance Supervision and Engineering	256,633	462,681	206,048	80%
5110-Maintenance of Structures	-	-	-	0%
5112-Maintenance of Transformer Station Equipment	-	-	-	0%
5114-Maintenance Dist Stn Equip	14,824	4,767	(10,057)	-68%
5120-Maintenance of Poles, Towers and Fixtures	206,519	151,573	(54,946)	-27%
5125-Maintenance of Overhead Conductors and Devices	672,433	917,736	245,302	36%
5130-Maintenance of Overhead Services	87,589	150,393	62,804	72%
5135-Overhead Distribution Lines and Feeders - Right of Way	271,498	352,301	80,803	30%
5145-Maintenance of Underground Conduit	60,893	42,841	(18,052)	-30%
5150-Maintenance of Underground Conductors and Devices	148,782	249,450	100,667	68%
5155-Maintenance of Underground Services	74,452	91,252	16,800	23%
5160-Maintenance of Line Transformers	143,209	132,000	(11,210)	-8%
5165-Maintenance of Street Lighting and Signal Systems	-	-	-	0%
5170-Sentinel Lights - Labour	-	-	-	0%
5172-Sentinel Lights - Materials and Expenses	-	-	-	0%
5175-Maintenance of Meters	15,401	13,426	(1,975)	-13%
5178-Customer Installations Expenses - Leased Property	-	-	-	0%
5195-Maintenance of Other Installations on Customer Premises	-	-	-	0%
Subtotal Distribution Expenses - Maintenance	1,952,232	2,568,416	616,184	32%

Table 4-6A Variance Analysis 2011 Test Year vs. 2006 Actual Year

Billing and Collecting	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5305 Supervision	285,450	490,012	204,562	72%
5310 Meter Reading Expense	487,834	473,321	(14,514)	-3%
5315 Customer Billing	1,630,728	2,080,927	450,199	28%
5320 Collecting	424,633	483,163	58,530	14%
5325 Collecting - Cash Over and Short	(5,603)	-	5,603	-100%
5330 Collection Charges	-	-	-	0%
5335 Bad Debt Expense	242,175	410,000	167,825	69%
5340 Miscellaneous Customer Accounts Expenses	167,676	258,306	90,630	54%
Subtotal Billing and Collecting	3,232,894	4,195,729	962,835	30%

Community Relations (including sales expenses)	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5405 Supervision	53,930	-	(53,930)	-100%
5410 Community Relations - Sundry	19,025	81,464	62,439	328%
5415 Energy Conservation	-	-	-	0%
5420 Community Safety Program	-	-	-	0%
5425 Miscellaneous Customer Service and Informational Expenses	-	-	-	0%
5505 Supervision	-	-	-	0%
5510 Demonstrating and Selling Expense	-	-	-	0%
5515 Advertising Expense	-	-	-	0%
5520 Miscellaneous Sales Expense	-	-	-	0%
Subtotal Community Relations	72,955	81,464	8,509	12%

Administrative and General Expenses	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5605 Executive Salaries and Expenses	349,122	323,267	(25,855)	-7%
5610 Management Salaries and Expenses	1,088,919	1,818,577	729,658	67%
5615 General Administrative Salaries and Expenses	572,506	421,595	(150,911)	-26%
5620 Office Supplies and Expenses	174,696	126,460	(48,236)	-28%
5625 Administrative Expense Transferred-Credit	-	-	-	0%
5630 Outside Services Employed	293,227	39,900	(253,327)	-86%
5635 Property Insurance	112,660	209,777	97,116	86%
5640 Injuries and Damages	63,482	-	(63,482)	-100%
5645 Employee Pensions and Benefits	-	-	-	0%
5650 Franchise Requirements	-	-	-	0%
5655 Regulatory Expenses	165,077	268,429	103,352	63%
5660 General Advertising Expenses	10,714	-	(10,714)	-100%
5665 Miscellaneous Expenses	338,144	103,810	(234,334)	-69%
5670 Rent	46,997	-	(46,997)	-100%
5675 Maintenance of General Plant	463,532	564,320	100,789	22%
5680 Electrical Safety Authority Fees	12,009	-	(12,009)	-100%
5685 Independent Market Operator Fees and Penalties	-	-	-	0%
5695 OM&A Contra Account	-	-	-	0%
6205 Charitable Donations	-	-	-	0%
Subtotal Administrative and General Expense	3,691,084	3,876,135	185,051	5%

Total OM&A Expenses	12,552,697	14,295,435	1,742,738	14%

Table 4-6B Variance Analysis 2011 Test Year vs. 2009 Actual-Appendix 2J

5005 Operation Supervision and Engineering	578,370	648,571	70,201	12%
5010 Load Dispatching	44,478	43,800	(678)	-2%
5012 Station Buildings and Fixtures Expense	125,341	119,771	(5,570)	-4%
5014 Transformer Station Equipment - Operation Labour	6,819	11,507	4,688	69%
5015 Transformer Station Equipment - Operation Supplies and Expenses	65,786	54,733	(11,053)	-17%
5016 Distribution Station Equipment - Operation Labour	-	-	-	0%
5017 Distribution Station Equipment - Operation Supplies and Expenses	-	-	-	0%
5020 Overhead Distribution Lines and Feeders - Operation Labour	154,815	197,358	42,543	27%
5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	21,256	20,421	(835)	-4%
5030 Overhead Subtransmission Feeders - Operation	-	-	-	0%
5035 Overhead Distribution Transformers - Operation	-	-	-	0%
5040 Underground Distribution Lines and Feeders - Operation Labour	58,365	72,606	14,241	24%
5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses	243,103	194,991	(48,112)	-20%
5050 Underground Subtransmission Feeders - Operation	-	-	-	0%
5055 Underground Distribution Transformers - Operation	-	-	-	0%
5060 Street Lighting and Signal System Expense	-	-	-	0%
5065 Meter Expense	403,418	489,927	86,509	21%
5070 Customer Premises - Operation Labour	56,738	96,423	39,685	70%
5075 Customer Premises - Materials and Expenses	-	-	-	0%
5085 Miscellaneous Distribution Expense	1,393,900	1,623,583	229,683	16%
5090 Underground Distribution Lines and Feeders - Rental Paid	-	-	-	0%
5095 Overhead Distribution Lines and Feeders - Rental Paid	-	-	-	0%
5096 Other Rent	-	-	-	0%
Subtotal Distribution Expenses - Operation	3,152,389	3,573,690	421,301	13%

Distribution Expenses - Maintenance	2009 Actual	2011 Test	Variance ($)	Percent Change (%)
5105 Maintenance Supervision and Engineering	398,759	462,681	63,922	16%
5110 Maintenance of Buildings and Fixtures - Distribution Stations	-	-	-	0%
5112 Maintenance of Transformer Station Equipment	-	-	-	0%
5114 Maintenance of Distribution Station Equipment	2,867	4,767	1,900	66%
5120 Maintenance of Poles, Towers and Fixtures	125,297	151,573	26,276	21%
5125 Maintenance of Overhead Conductors and Devices	896,673	917,736	21,063	2%
5130 Maintenance of Overhead Services	137,622	150,393	12,771	9%
5135 Overhead Distribution Lines and Feeders - Right of Way	296,535	352,301	55,766	19%
5145 Maintenance of Underground Conduit	47,652	42,841	(4,811)	-10%
5150 Maintenance of Underground Conductors and Devices	245,671	249,450	3,779	2%
5155 Maintenance of Underground Services	92,502	91,252	(1,250)	-1%
5160 Maintenance of Line Transformers	133,947	132,000	(1,947)	-1%
5165 Maintenance of Street Lighting and Signal Systems	-	-	-	0%
5170 Sentinel Lights - Labour	-	-	-	0%
5172 Sentinel Lights - Materials and Expenses	-	-	-	0%
5175 Maintenance of Meters	12,601	13,426	825	7%
5178 Customer Installations Expenses - Leased Property	-	-	-	0%
5195 Maintenance of Other Installations on Customer Premises	-	-	-	0%
Subtotal Distribution Expenses - Maintenance	2,390,126	2,568,416	178,290	7%

1 **Table 4-6B Variance Analysis 2011 Test Year vs. 2009 Actual**

Billing and Collecting	2009 Actual	2011 Test	Variance ($)	Percent Change (%)
5305 Supervision	366,304	490,012	123,708	34%
5310 Meter Reading Expense	438,379	473,321	34,942	8%
5315 Customer Billing	1,710,531	2,080,927	370,396	22%
5320 Collecting	459,698	483,163	23,465	5%
5325 Collecting - Cash Over and Short	56	-	(56)	-100%
5330 Collection Charges	-	-	-	0%
5335 Bad Debt Expense	427,315	410,000	(17,315)	-4%
5340 Miscellaneous Customer Accounts Expenses	228,098	258,306	30,208	13%
Subtotal Billing and Collecting	3,630,381	4,195,729	565,348	16%

Community Relations (including sales expenses)	2009 Actual	2011 Test	Variance ($)	Percent Change (%)
5405 Supervision	14,746	-	(14,746)	-100%
5410 Community Relations - Sundry	49,823	81,464	31,641	64%
5415 Energy Conservation	-	-	-	0%
5420 Community Safety Program	-	-	-	0%
5425 Miscellaneous Customer Service and Informational Expenses	-	-	-	0%
5505 Supervision	-	-	-	0%
5510 Demonstrating and Selling Expense	-	-	-	0%
5515 Advertising Expense	-	-	-	0%
5520 Miscellaneous Sales Expense	-	-	-	0%
Subtotal Community Relations	64,569	81,464	16,895	26%

Administrative and General Expenses	2009 Actual	2011 Test	Variance ($)	Percent Change (%)
5605 Executive Salaries and Expenses	279,924	323,267	43,344	15%
5610 Management Salaries and Expenses	1,602,714	1,818,577	215,863	13%
5615 General Administrative Salaries and Expenses	375,307	421,595	46,288	12%
5620 Office Supplies and Expenses	133,823	126,460	(7,363)	-6%
5625 Administrative Expense Transferred-Credit	-	-	-	0%
5630 Outside Services Employed	39,600	39,900	300	1%
5635 Property Insurance	204,848	209,777	4,929	2%
5640 Injuries and Damages	-	-	-	0%
5645 Employee Pensions and Benefits	-	-	-	0%
5650 Franchise Requirements	-	-	-	0%
5655 Regulatory Expenses	192,187	268,429	76,242	40%
5660 General Advertising Expenses	-	-	-	0%
5665 Miscellaneous Expenses	352,023	103,810	(248,213)	-71%
5670 Rent	56,917	-	(56,917)	-100%
5675 Maintenance of General Plant	595,857	564,320	(31,537)	-5%
5680 Electrical Safety Authority Fees	-	-	-	0%
5685 Independent Market Operator Fees and Penalties	-	-	-	0%
5695 OM&A Contra Account	-	-	-	0%
6205 Charitable Donations	-	-	-	0%
Subtotal Administrative and General Expense	3,833,199	3,876,135	42,936	1%

2

Total OM&A Expenses	13,070,664	14,295,435	1,224,771	9%

2011 Test Year vs. 2006 Board Approved

Table 4-6A is presented by combining the Niagara Falls Hydro and Peninsula West Utilities Trial Balances as they were submitted to the OEB. The two utilities grouped various costs differently for presentation on the RRR Trial Balance.

In order to compare to 2011, eight accounts in the 2006 Trial Balance have been reclassified and restated as per the table below.

Account 5620 was reduced by $72,320 for CDM activities and has been grouped with Account 5315 which is where these costs are presented in 2011.

Account 5620 also included Bank Charges from PWU in the amount of $42,114 which has been grouped with Account 5610 in order to compare to 2011.

Account 5630 was reduced by $203,671 for consulting and legal fees and has been restated in Account 5610.

Account 5640 was combined with Account 5635 for Insurance expenses.

The OEB assessment costs of $38,860 from PWU were regrouped with Account 5655 from Account 5665.

PWU presented its computer software maintenance fees in account 5675 in the amount of $126,455. These fees have been regrouped with Account 5315 in order to compare to 2011.

Restated 2006 presentation of RRR Trial Balance for comparative purposes

Restated 2006 presentation of Trial Balance	2006 Actual	Adjustment	2006 Restated	2011 Test	Adjusted Variance ($)	Percent Change (%)
5315 Customer Billing	1,630,728	198,775	1,829,503	2,080,927	251,424	14%
5610 Management Salaries and Expenses	1,088,919	245,784	1,334,703	1,818,577	483,874	36%
5620 Office Supplies and Expenses	174,695.65	(114,434)	60,262	126,460	66,198	110%
5630 Outside Services Employed	293,226.70	(203,671)	89,556	39,900	(49,656)	-55%
5635 Property Insurance	112,660.40	63,483	176,143	209,777	33,634	19%
5640 Injuries and Damages	63,482.00	(63,482)	-	-	-	#DIV/0!
5655 Regulatory Expenses	165,077.00	38,860	203,937	268,429	64,492	32%
5665 Miscellaneous Expenses	338,144.06	(38,860)	299,284	103,810	(195,474)	-65%
5675 Maintence of General Plant	463,531.59	(126,456)	337,076	564,320	227,244	67%
	4,330,464	(0)	4,330,464	5,212,199	881,735	20%

The Adjusted Variance column will be explained below.

5020-Overhead Distribution Poles, Tower and Fixtures – Labour and Expenses

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5020-Overhead Distribution Poles, Towers and Fixtures-Operation Labour and Expenses	448,578	197,358	(251,220)	-56%

In 2006, Niagara Falls Hydro aided CNP during an October snow storm. Labour was recorded in Account 5020 and the recovery billing to CNP was recorded in Account 4235 as Other Revenue. The total labour including overtime was $111,488.

PWU lineman performed mainly operations and maintenance work in 2006. Most of PWU's capital work was performed by outside contractors. As a result the lineman charged more of their time to operations and maintenance in 2006.

In 2011, more capital projects are constructed by NPEI's linemen and labour has shifted from outside contractors to in-house and from operations and maintenance to capital.

5025- Overhead Distribution Lines and Feeders – Labour and Expenses

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5025-Overhead Distribution Lines and Feeders - Operation Labour and Expenses	215,303	20,421	(194,882)	-91%

In 2006, PWU charged pole inspections to this account in the amount of $58,126. These costs are presented in Account 5085 in 2011.

PWU had material supplies and outside purchases of $104,047 charged to Account 5025 in 2006.

5040- Underground Distribution Conduit

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5040-Underground Distribution Conduit - Operation Labour and Expenses	163,656	72,606	(91,051)	-56%

In 2006, PWU recorded $81,000 of labour and $21,000 of truck time to this account. In 2011, it is anticipated that less time will be charged to the operations of underground conduit.

5070 - Customer Premises

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5070-Customer Premises - Operation Labour and Expenses	193,390	96,423	(96,967)	-50%

This account collects costs associated with the location of underground services on customer premises. There was a greater volume of underground locates requested in the PW service area in 2006 than is anticipated for 2011.

5085 – Distribution and Engineering Labour and Expenses

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5085-Misc. Distribution and Engineering Labour and Expenses	809,586	1,623,583	813,997	101%

Since 2006 the following new positions were added to this department; GIS Technologist, two Engineering Technicians and a Control Room Operator. Total payroll and benefits related to these four positions accounts for $414,000 of the total increase. A wage increase of 3% in each year from 2007 to 2011 accounts for $61,000 of the increase.

Pole inspections for PWU were charged to Account 5025 in 2006 in the amount of $58,126. In 2011 pole inspections are presented in Account 5085. It is anticipated 7,591 poles will be inspected in 2011 and this accounts for $200,000 of the variance from 2011 to 2006.

The increase in number of licenses and modules required for the GIS system and the implementation of the work outage management system accounts for an increase of $75,000 in engineering software maintenance expenses from 2006 to 2011.

5105 – Maintenance Supervision and Engineering

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5105-Maintenance Supervision and Engineering	256,633	462,681	206,048	80%

In 2000, NFH hired an Engineering Manager; this employee implemented the GIS system at NFH. In 2005, this employee left the organization and went to work for the vendor of the GIS system and he later returned in 2007 as the Engineering Manager. During the time from May 2005 to October 2007 this position was vacant and as a result the wages were nil for this position in 2006. This new position accounts for the majority of the variance. The Line Superintendent and three operations supervisors charge half of their time to Account 5105 and the other half to Account 5005. Wage progressions stemming from the management job evaluation plan that was implemented in 2008 as well as cost of living increases of 3% per year since 2006 account for the remainder of the variance.

5125 - Maintenance of Overhead Conductors and Devices

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5125-Maintenance of Overhead Conductors and Devices	672,433	917,736	245,302	36%

The variance is comprised of an increase in payroll and truck time of $71,449, due mainly to cost of living increases of $57,000 since 2006. An increase in materials of $82,419 and an increase in outside purchases of $$91,434 account for the remainder of the variance. Account 5125 includes lineman tools and supplies as well as lineman training. The number of apprentices and increased focus on safety has increased training expenses from 2006. Training expenditures were included as part of the overhead burden. Beginning in 2009, training is charged directly to OM&A accounts.

5135 - Overhead Distribution Lines and Feeders – Right of Way

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5135-Overhead Distribution Lines and Feeders - Right of Way	271,498	352,301	80,803	30%

In 2011, tree trimming activities will be expanded in the peninsula west service area. In previous years the majority of tree trimming activity was concentrated in the Niagara Falls service area. Tree trimming is a significant part of NPEI’s preventative maintenance plan.

5150 - Maintenance of Underground Conductors and Devices

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5150-Maintenance of Underground Conductors and Devices	148,782	249,450	100,667	68%

During the investigation of variances it was discovered that repairs to underground cable faults in 2006 were being capitalized and should have been charged to maintenance. The issue was discovered in 2009 and proper treatment is reflected in 2009 through to 2011. The majority of underground cable faults are repaired by an outside contractor.

5305 - Supervision

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5305 Supervision	285,450	490,012	204,562	72%

In 2010, two Business Analysts were hired as part of NPEI's succession planning. Both Billing Supervisors are eligible to retire within the next two to five years. The upcoming changes required by the government related to time-of-use billing, web presentment of e-bills, change in deposit and collection policies have increased the need for these two positions. The two Business Analysts account for $115,000 of the variance from 2006.

Wage progressions stemming from the job evaluation plan that was implemented in 2008 and a 3% cost of living increase each year from 2006 to 2011 accounts for $67,000 of the variance.

5315 – Customer Billing

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5315 Customer Billing	1,630,728	2,080,927	450,199	28%

	Restated			
5315 Customer Billing	1,829,503	2,080,927	251,424	14%
Adjustment	198,775	-	(198,775)	-100%

The Adjustment to 2006 Actual of $198,775 includes PWU's CDM activities in the amount of $72,320 plus PWU computer software maintenance fees in the amount of $126,455. The variance of $251,424 will be explained.

In 2006, Niagara Falls residential and GS<50 customers were billed on a bi-monthly basis. In May of 2010, as a step to harmonizing the billing of these rate classes between the two service areas the Niagara Falls customers were converted to monthly billing. Costs associated with this conversion include increased postage, bill forms and envelopes.

In 2006, the two utilities combined had 30 FTE's charged to 5315. In 2011, NPEI will have 32 non supervisory FTE's in this department. The increase comes from one additional collections clerk and one additional customer service clerk. The addition of two FTE's increases the variance by $92,000 from 2011 over 2006. The annual wage increases of 3% per year since 2006 accounts for $235,000 of the variance. A pay equity program was implemented in 2010 as a result of the merger. Pay equity resulted in an average increase of $0.915 per hour for customer service and billing clerks and represents an increase of $35,000 per year.

The harmonization of the billing and financial software systems as well as the conversion from a legacy system at NFH to the Harris billing system has resulted in reduced software and hardware maintenance and programming expenses since 2006. The variance is a reduction in billing expenditures from 2006.

5335 – Bad Debt Expense

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5335 Bad Debt Expense	242,175	410,000	167,825	69%

Bad Debts can vary from year to year; they are strongly dependent on the economic environment. In 2008 and 2009, NPEI experienced an increase in bad debts due to the downturn in the economy and an increase in bankruptcies. NPEI allocated an additional customer service clerk to collections in 2009 due to an increase in requests from customers for payment arrangements. Bad debts in 2011 are estimated to decrease from the 2009 level as a result of changing Niagara Falls residents from bi-monthly billing to monthly billing in May of 2010.

5610 – Management Salaries and Expenses

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5610 Management Salaries and Expenses	1,088,919	1,818,577	729,658	67%

	Restated			
5610 Management Salaries and Expenses	1,334,703	1,818,577	483,874	36%
Adjustment	245,784	-	(245,784)	-100%

Legal fees, consulting fees and bank charges in the amount of $245,784 from PWU have been reclassified to 5610 in 2006 for comparative purposes. The variance of $483,874 will be explained.

Payroll has increased $578,000, telephone maintenance fees have increased $70,000 and legal and consulting fees have decreased $200,000.

The increase in payroll is due to the following net positions being added since 2006; IT Manager, Systems Analyst, Controller, Regulatory and Financial Rate Analyst, and an Administrative Assistant offset by the retirement of the VP of Corporate Services for a total of $438,000 including the labour overhead burden. Wage progressions and annual 3% cost of living increases from 2006 to 2011 account for $140,000 of the variance from 2006 to 2011.

The first module of the new IVR telephone system was implemented in 2008 at the NF administrative building. The same telephone system was implemented at the new service center located in Smithville at the end of 2009.

In 2006, PWU utilized an outside consultant and legal firm for the preparation of their 2006 EDR rate application. NPEI is preparing the 2011 COS rate application internally, any legal fees related to an oral hearing are accounted for in Account 5655 in 2011 see Table 4-9. Also, in 2006 NFH and PWU had increased legal and consulting fees related to the merger of the two companies.

5615 - General Administrative Salaries and Expenses

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5615 General Administrative Salaries and Expenses	572,506	421,595	(150,911)	-26%

In 2006, PWU recorded a payment to Hydro One in the amount of $124,000 for load transfer charges in account 5615. These load transfer charges related to the period from 1999 to April 2002. Load transfer charges are included in the cost of power variance account in 2011.

5630 - Outside Services Employed

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5630 Outside Services Employed	293,227	39,900	(253,327)	-86%

	Restated			
5630 Outside Services Employed	89,556	39,900	(49,656)	-55%
Adjustment	(203,671)	-	203,671	-100%

After restatement of consulting fees and legal fees from Account 5630 to Account 5610, outside services employed has decreased by $49,656 from 2006 to 2011. Prior to the merger two external audits were incurred and as a result audit fees are a cost savings from the merger.

5635 - Property Insurance

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5635 Property Insurance	112,660	209,777	97,116	86%

	Restated			
5635 Property Insurance	176,143	209,777	33,634	19%
Adjustment	63,483	-	(63,483)	-100%

After restatement of Account 5640 with Account 5635, total insurance expenses have increased $33,634 from 2006 to 2011 and this variance is below the materiality threshold for variance explanation.

5640 – Injuries and Damages

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5640 Injuries and Damages	63,482	-	(63,482)	(1.00)

	Restated			
5640 Injuries and Damages	0	-	-	0
Adjustment	(63,482)	-	63,482	-100%

The insurance expenses for injuries and damages have been combined with Account 5635 in order to compare to 2011. The variance from 2006 to 2011 is nil after restatement.

5655 – Regulatory Expenses

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5655 Regulatory Expenses	165,077	268,429	103,352	63%

	Restated			
5655 Regulatory Expenses	203,937	268,429	64,492	32%
Adjustment	38,860	-	(38,860)	-100%

The increase in regulatory costs from 2006 to 2011 after restatement of $38,860 from Account 5665 is $64,492. One quarter of the total regulatory costs per Table 4-9 relates to the preparation of the 2011 COS rate application and has been included in this account for 2011.

5665 – Miscellaneous General Expenses

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5665 Miscellaneous Expenses	338,144	103,810	(234,334)	-69%

	Restated			
5665 Miscellaneous Expenses	299,284	103,810	(195,474)	-65%
Adjustment	(38,860)	-	38,860	-100%

After restatement of regulatory costs in the amount of $38,860 from Account 5665 to Account 5655, this account has decreased by $195,474 in 2011 from 2006. In 2006, capital taxes were accounted for as part of Account 5665 on the RRR trial balance. Total capital taxes in 2006 were $269,835. Due to changes in tax legislation, capital taxes are calculated to be nil.

5675 – Maintenance of General Plant

	2006 Actual	2011 Test	Variance ($)	Percent Change (%)
5675 Maintenance of General Plant	463,532	564,320	100,789	22%

	Restated			
5675 Maintenance of General Plant	337,076	564,320	227,244	67%
Adjustment	(126,456)	-	126,456	-100%

After restatement of computer software maintenance fees totaling $126,456 in 2006 from Account 5675 to Account 5315, the variance from 2006 to 2011 is $227,244.

In 2006, Niagara Falls Hydro owned one administration building and PWU rented office space for its administrative staff and owned a building which housed its stores and operations departments. In 2008, the building owned by PWU was excluded from the merger and transferred to Peninsula West Power which was PWU's parent company. A service center commenced construction and the Niagara Falls administrative building underwent a major renovation to accommodate the employees of the former PWU. The new service center houses a stores warehouse, operations department, engineering department, customer service and billing clerks that serve the peninsula west service area. As of result of these changes, utility, landscaping, snow removal, cleaning, building inspection costs and maintenance supplies have increased from 2006.

2011 Test Year vs. 2009 Actual

5065 - Meter Expense

	2009 Actual	2011 Test	Variance ($)	Percent Change (%)
5065 Meter Expense	403,418	489,927	86,509	21%

Wage progressions and cost of living increases of 3% in both 2010 and 2011 account for $23,000 of the variance from 2009 to 2011. As a result of the implementation of smart meters in 2010, more time will be allocated to the maintenance of non-smart meters in 2011.

5085 - Miscellaneous Distribution Expenses

	2009 Actual	2011 Test	Variance ($)	Percent Change (%)
5085 Miscellaneous Distribution Expense	1,393,900	1,623,583	229,683	16%

The variance consists of payroll and benefit increases in the amount of $165,000, This includes a new engineering supervisor located at the Niagara Falls location as well as 3% cost of living increases in both 2010 and 2011.

Pole inspections totaled 4,332 in 2009 and will increase to 7,591 in 2011. This increase represents $55,000 of the variance. The computer software maintenance fees related to the implementation of work outage management will increase expenses by $15,000.

5305 - Supervision Billing and Customer Service

	2009 Actual	2011 Test	Variance ($)	Percent Change (%)
5305 Supervision	366,304	490,012	123,708	34%

In 2010, two Business Analysts were hired on contract in August resulting in 5 months labour being expensed to Account 5305. In 2011, these two analysts will be expensed for a full year representing $67,100 of the variance. Wage progressions and a historical 3% cost of living increase in 2010 and 2011 accounts for $38,300 of the increase from 2009. The VP of Corporate Services retired in January of 2009 and one month of payroll reduction is also accounted for in the variance.

5315 - Customer Billing

	2009 Actual	2011 Test	Variance ($)	Percent Change (%)
5315 Customer Billing	1,710,531	2,080,927	370,396	22%

In 2009, Niagara Falls residential and GS<50 customers were billed on a bi-monthly basis. In May of 2010, as a step to harmonizing the billing of these rate classes between the two service areas the Niagara Falls customers were converted to monthly billing. Costs associated with this conversion include increased postage, bill forms and envelopes.

In 2009, there were 27 FTE's charged to account 5315. Two customer service clerks were promoted to Executive Assistant and Administrative Assistant in September 2009 and February 2010 respectively. These two customer service clerks along with three additional contract customer service/billing clerks were replaced/hired throughout 2010. As a result 32 FTE's are charged to account 5315 in 2010 with no change expected to occur in 2011. The additional 5 customer service/billing clerks account for approximately $160,000.

Historical wage increases of 3% in both 2010 and 2011 account for $74,000 of the increase over 2009.

The pay equity program resulted in an average increase of $0.915 per hour for customer service and billing clerks and represents an increase of $35,000 per year.

5610 - Management Salaries and Expenses

	2009 Actual	2011 Test	Variance ($)	Percent Change (%)
5610 Management Salaries and Expenses	1,602,714	1,818,577	215,863	13%

In March 2009, NPEI hired a Regulatory & Financial rate Analyst representing 9 months labour expensed. In 2011, this position has been included for one year including a wage progression and 3% cost of living increase in both 2010 and 2011 representing $27,000 of the above variance.

Historical wage progressions and a 3% cost of living increase in both 2010 and 2011 for other positions charged to Account 5610 represent $48,600 of the increase.

In February 2010, NPEI promoted a customer service clerk to a new position of Administrative Assistant. This new position including the overhead burden accounts for $80,000 of the variance.

The new telephone system was implemented in phases starting in 2008 as well as a new telephone system implemented at the end of 2009 at the new service centre located in Smithville. As a result the telephone expenses have increased $20,000 from 2009.

5655 - Regulatory Expenses

	2009 Actual	2011 Test	Variance ($)	Percent Change (%)
5655 Regulatory Expenses	192,187	268,429	76,242	40%

The increase in regulatory costs from 2009 to 2011 is $76,242. One quarter of the total regulatory costs per Table 4-9 in the amount of $77,500 relates to the preparation of the 2011 COS rate application and has been included in this account for 2011.

5665 - Miscellaneous Expenses

	2009 Actual	2011 Test	Variance ($)	Percent Change (%)
5665 Miscellaneous Expenses	352,023	103,810	(248,213)	-71%

In 2009, NPEI accounted for its capital taxes as part of Account 5665 on the RRR trial balance. Total capital taxes in 2009 were $251,917. Due to changes in tax legislation, capital taxes are calculated to be nil.

Shared Services/Corporate Cost Allocation

NPEI allocates a portion of its accounting, insurance and administrative expenses as detailed in Table 4-7 below, to its shareholders; Niagara Falls Hydro Holding Corporation (NFHCC) and Peninsula West Power Inc (PWP).

The former Peninsula West Utilities allocated a management fee to its' parent company Peninsula West Power Inc.

Peninsula West Services (PWS) performs streetlight maintenance to the Town of Lincoln, Township of West Lincoln and the Town of Pelham. PWS also provides rental services for water heaters and sentinel lights.

The former PWU and now NPEI perform the accounting and billing functions for PWS.

Table 4-7 Shares Services/Corporate Cost Allocation- Appendix 2L

Date	Name of Company		Service Offered	Pricing Methodology	Price for the Service
	From	To			
2006	PWU	PWP	Management fee	Cost Based	$ 45,745
	PWU	PWS	Management fee	Cost Based	$ 26,752
2007	NFH	NFHHC	Bookkeeping/Insurance	Cost Based	$ 7,961
	PWU	PWP	Management fee	Cost Based	$ 41,004
	PWU	PWS	Management fee	Cost Based	$ 28,732
2008	NPEI	NFHHC	Bookkeeping/Insurance	Cost Based	$ 16,925
	NPEI	PWP	Bookkeeping/Insurance	Cost Based	$ 2,725
	NPEI	PWS	Bookkeeping	Cost Based	$ 16,726
2009	NPEI	NFHHC	Bookkeeping/Insurance	Cost Based	$ 19,020
	NPEI	PWP	Bookkeeping/Insurance	Cost Based	$ 2,700
	NPEI	PWS	Bookkeeping	Cost Based	$ 17,636
2010	NPEI	NFHHC	Bookkeeping/Insurance	Cost Based	$ 20,000
	NPEI	PWP	Bookkeeping/Insurance	Cost Based	$ 2,700
	NPEI	PWS	Bookkeeping	Cost Based	$ 26,897
2011	NPEI	NFHHC	Bookkeeping/Insurance	Cost Based	$ 20,000
	NPEI	PWP	Bookkeeping/Insurance	Cost Based	$ 2,700
	NPEI	PWS	Bookkeeping	Cost Based	$ 27,502

NFHHC = Niagara Falls Hydro Holding Corporation

PWP = Peninsula West Power

PWS = Peninsula West Services

The insurance cost charged from NPEI to NFHHC is based on an actual premium for a building that was transferred from the former Niagara Falls Hydro Inc. to NFHHC prior to the merger. NPEI also allocated directors liability insurance to NFHHC and PWP based on actual premiums included on the invoice from the insurance vendor. Since these costs are paid for by NPEI and charged back to the shareholders they have been included as shared services. All bookkeeping costs are based on actual time recorded. The former Niagara Falls Hydro did not allocate any costs to NFHCC in 2006.

Charges to Affiliates for Services Provided

A summary of charges to affiliates for services provided in 2006, 2007, 2008 and 2009 together with the projections for the 2010 Bridge Year and 2011 Test Year are shown in the following Table 4-8.

NPEI currently performs water and sewer billing for the customers only of the City of Niagara Falls at a market rate by the number of customers. The market rate was researched by polling other LDC's that bill for water and adjusted in order to obtain a profit margin between 10% and 15%. Water and sewer billing for the City of Niagara Falls customers includes supervision, billing, customer service, cashiering, collection, accounting and finance wages and benefits based on actual weekly time recorded. Meter reading costs are provided by an outside third party and are clearly identified on invoices between electric and water services. Billing costs such as postage, envelopes, printed forms, office supplies, software and hardware maintenance are charged to the affiliate based on a fixed cost ($4.20) per water only bill. A fixed asset depreciation fee is charged monthly for the use of various fixed assets. The allocated Water Administrative charges are recorded in Account 4215 and the allocated depreciation is recorded in Account 4235 Miscellaneous Service Revenues.

In 2007, the former Niagara Falls Hydro charged the former Peninsula West Utility for wages and benefits of an Operational Supervisor. These charges were removed from the Niagara Falls Hydro utility company expenses and recorded in the Niagara Falls Hydro Services company. These costs were incurred prior to the merger and Peninsula West Utility was not an affiliate at that time.

Table 4-8 Charges to Affiliates for Services Provided

Name of Company				2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test		2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
From	To	Components of Service	Pricing Methodology	Price for the service ($)							Cost for the service ($)					
NFH/NPEI	City of Niagara Falls	Labour	Cost based								$ 239,143	$ 264,251	$ 305,992	$ 402,756	$ 425,823	$ 435,404
		Meter Reading	# of reads								76,820	78,709	82,328	83,320	82,241	82,241
		Depreciation	Cost based								21,247	18,112	18,112	18,112	18,112	18,112
		Allocated expenses	Fixed rate/water only bills								243,941	302,455	299,664	297,561	295,997	295,000
		Revenue-Water Billing	Market Rate X # of Customers	581,151	663,527	706,096	801,749	822,173	830,757							
		Revenue Late Penalties	# of Late Penalties	114,943	117,400	122,304	147,718	140,943	141,000							
Total Water Billing				696,094	780,927	828,400	949,467	963,116	971,757		581,151	663,527	706,096	801,749	822,173	830,757

Regulatory Costs

Regulatory costs as indicated in the variance analysis are presented in Table 4-9. Regulatory costs for the 2011 rate application amounting to $310,000 have been considered over a four year period in our OM&A costs and the costs that have been included are detailed below:

Table 4-9 Regulatory Costs – Appendix 2H

=

Regulatory Cost Category (A)	USoA Account (B)	USoA Account Balance (C)	Ongoing or One Time Cost? (D)	Last Rebasing Year 2006 (E)	Last Year of Actuals 2009 (F)	Bridge Year 2010 (G)	% Change (H) = [(G) - (F)]/(F)	Test Year Forecast 2011 (I)	% Change (J) = [(I) - (G)]/(G)
1. OEB Annual Assessment	5655		Ongoing	167,389	179,875	183,754	2%	187,429	2%
2. OEB Hearing Assessments (applicant initiated)							0%		0%
3. OEB Section 30 Costs (OEB initiated)	5655		Ongoing		12,312	3,238	-74%	3,500	8%
4. Expert Witness cost for regulatory matters							0%		0%
5. Legal costs for regulatory matters	5655		One-Time	105,074			0%	50,000	0%
6. Consultants' costs for regulatory matters	5655		One-Time				0%	20,000	0%
7. Operating expenses associated with staff resources allocated to regulatory matters							0%		0%
8. Operating expenses associated with other resources allocated to regulatory matters (1)							0%		0%
9. Other regulatory agency fees or assessments							0%		0%
10. Any other costs for regulatory matters (please define)							0%		0%
11. Intervenor Costs	5655		One-time				0%	7,500	0%
12. Sub-total - Ongoing Costs (3)							0%	190,929	0%
13. Sub-total - One time costs (4)							0%	77,500	0%
14. Total (5)				-	-	-	0%	268,429	0%

Legal fees account for $200,000, the Asset Management Plan being prepared by Kinetrics accounts for $75,000 and a Smart Meter special Audit prepared by NPEI's auditors accounts for $5,000 and an estimate of $30,000 for Intervener costs accounts for the balance of the $310,000.

International Financial Reporting Standards (IFRS)

Introduction

Canada will move to IFRS, the same accounting standards as are used by publically accountable enterprises in many other countries around the world. IFRS is anticipated to provide shareholder and regulators with financial information that has enhanced comparability and transparency. The transition to IFRS; however, will not be easy and will require significant effort by NPEI and its staff to comply with the standard. The original implementation date was January 1, 2011 and required NPEI to have the 2010 year-end financial statements in IFRS format. The Canadian Accounting Standards Board (AcSB) has issued an Exposure Draft proposing to extend the implementation date for rate regulated entities by two years to January 1, 2013.

NPEI has proposed in Exhibit 9, Deferral and Variances to defer requesting disposition of the Deferral Account 1508 - Other Regulatory Assets – IFRS, given the uncertainties of the implementation date and, thus, the timing and amount of costs. NPEI has not included any IFRS costs in its distribution expenses in this application. NPEI will continue to record any costs in the Deferral Account and seek disposition in a future filing.

NPEI is receiving assistance from its auditor, for its IFRS implementation project and software modifications from the software vendor and/or contractors.

Employee Compensation, Pension Expense and Post Retirement Benefits

Overview

NPEI is facing the same challenges as other LDC's throughout the electricity distribution sector. In the next five years, 21% of NPEI's employees will be eligible for retirement, and 46% will be eligible within 10 years. NPEI's total employee average age is 43.19 years.

The challenge NPEI faces is effectively bridging the gap in maintaining sufficient talent to meet the current needs of the utility while planning for the "new" future. Table's 4-10 and Table 4-11 illustrate the average age and average years of service for the unionized staff as well as management at NPEI.

Effective workforce planning will be a significant initiative. NPEI recognizes the need to develop a strategy to replace its aging workforce. As a result of the minimum four to five year training program for trades and technical staff, apprentice positions were introduced in 2007.

Table 4-10 Unionized Workforce Average Age & Service

Department	Avg. Age	Avg.Length of Service
Accounting	39.8	5.0
Billing	46.9	13.2
Customer Service	43.4	9.6
Engineering	42.9	11.8
Metering	41.3	12.5
General Maintenance	46.0	17.5
Operation Services	39.9	11.4
Stores	61.5	20.0
Vehicle Maintenance	50.3	19.3
Average	**43.0**	**11.8**

Table 4-11 Management Workforce Average Age & Service

Department	Avg. Age	Avg.Length of Service
Executive	47.2	17.8
Mgrs/Supv/Supt	46.2	19.1
General & Admin	38.8	6.1
Average	**43.8**	**14.2**

Staffing

As of the end of 2009, NPEI had 127 employees. As of the end of 2010, NPEI expects to have 133 employees and 133 employees at the end of 2011. The number of employees by major department as of 2010 is presented in Table 4-12.

There is one union representing the employees of NPEI. The unionized staff is represented by the International Brotherhood of Electrical Workers Union (IBEW) Local 636. The collective agreement expires March 31, 2011. For purposes of this rate application historical wage increases of 3.0% per year was used.

Table 4-12 2010 Number of Employees by Department

Department	2010 Number	2004 Number	Change
Executive	5	7	-2
Finance(General Admin, Accounting & Regulatory)	10	6	4
Customer Service (Customer Service & Billing & Collection)	36	32	4
Engineering	18	13	5
Operations & Maintenance	55	44	11
Purchasing/Stores	3	4	-1
Health Safety and HR	3	1	2
Information Technology	3	1	2
Total Employees by Major Department	**133**	**108**	25

Change in Workforce Year over Year

Table 4-13 and Table 4-14 illustrate NPEI's FTE headcount from 2004 to 2011. NPEI considers an FTE to be equivalent to one employee. Data for the years 2006 and 2007 are combined information from Peninsula West Utilities and Niagara Falls Hydro.

2006 Board Approved (2004) vs. 2006 Actual

As per the 2006 Board Approved rate application for Peninsula West Utilities, the total FTE count was 28, three executive, three management, eleven non-union and eleven union employees. Niagara Falls Hydro had a total of 80 FTE's, four executive, fifteen management FTE's, ten non-union and fifty one union employees. The combined total of FTE's in 2004 was 108 for both utilities.

The net change in FTE's for 2005 was an increase of 3.

Peninsula West Utilities hired most of their employees on a contract basis. In 2005, PWU hired a junior accounting clerk and a billing clerk and one contract lineman left the organization. Peninsula West Utilities contracted out the majority of their capital distribution system work. The lineman employed mainly performed maintenance activities on the distribution assets.

Niagara Falls Hydro hired 3 linemen apprentices in 2005. Niagara Falls Hydro began the implementation of a new GIS system in 2004 and as a result a GIS Technologist was hired in 2005.

The Purchasing Supervisor at NFH retired and was replaced with the Junior Buyer in 2005. The Junior Buyer position was not replaced.

At NFH the Customer Service Supervisor left and was replaced by the Executive Assistant at that time, the EA position remained vacant until 2006.

2006 Actual

A total decrease of three FTE's occurred in 2006. The Engineering Manager at PWU left the organization. In June of 2006, PWU General Manager passed away and was later replaced with the Office Manager as Acting President. And at Niagara Falls Hydro, the Director of Engineering retired in August.

A total increase of nine FTE's occurred in 2006 for a net FTE increase of 6 combined between PWU and NFH.

A Director of Engineering was hired at PWU in February 2006 replacing the Engineering Manager.

In 2005 the Customer Service Supervisor at NFH left to pursue a different career, This position was replaced by the Executive Assistant in November of 2005. The Executive Assistant was then replaced at Niagara Falls Hydro in October 2006.

Two lineman apprentices were hired at PWU. One Administrative/customer service Assistant, one Junior Accountant and one Engineering Technician were hired on contract at PWU.

One Engineering Technician and one Control Room Operator were hired at Niagara Falls Hydro to reduce the amount of work being outsourced.

2007 Actual vs. 2006 Actual

The net change in FTE's was nil in 2007. In August of 2007, the Director of Engineering at PWU left the organization to pursue other opportunities. The Operations Manager at PWU retired in March of 2007.

At Niagara Falls Hydro, the Billing Supervisor retired in December and was later replaced internally in May of 2008.

A lead hand at NFH left the organization in January to pursue an opportunity at a neighboring utility and a billing clerk retired in June 2007. Total combined decrease in FTE's was 5 in 2007.

Niagara Falls Hydro began preparation for conversion to a new billing system in early 2006. NFH went live on the new Harris billing system on January 1, 2008, the same day as the new merged company NPEI. In December 2007, NFH hired an IT Manager and a Systems Analyst to manage the operations of the new billing system. The management of the previous legacy billing system was outsourced.

In 2000, NFH hired an Engineering Manager; this employee implemented the GIS system at NFH commencing in 2004. In 2005, this employee left the organization and went to work for the vendor of the GIS system, he later returned in 2007 as the Engineering Manager. During the time from May 2005 to October 2007 this position was vacant.

Two lineman apprentices were also hired in 2007 at NFH.

Finally, five contract positions at PWU were made full-time prior to the merger.

2008 Actual vs. 2007 Actual

On January 1, 2008 Niagara Falls Hydro and Peninsula West Utilities formed the new company Niagara Peninsula Energy Inc. All employees from the two predecessor utilities joined the new organization.

There was a net increase of 4 FTE's during the 2008 year.

The new company's structure was one President and six Vice Presidents. One Engineering Manager was promoted to VP of Operations and one Engineering Manager was promoted to VP of Engineering. The Director of Administration from the former NFH was promoted to VP of Business Development; the Director of Finance was promoted to VP of Finance. The Manager of Customer Service and Billing was promoted to VP of Customer Service, Billing and IT and the Acting General Manager of the former PWU was promoted to VP of Corporate Services.

The Billing Supervisor who retired at the end of 2007 from the former NFH was replaced internally in May of 2008. This in turn created a vacancy in the billing clerk job classification which was also filled internally. The ultimate replacement was filled by a cashier.

The new merged company commenced with five junior accounting clerks, two of these clerks retired in 2008 and only one was replaced internally by a customer service clerk. Two customer service clerks were filled internally to back fill the movement to accounting and increase the number of collection clerks from two to three. Due to the internal movement to customer service, two additional cashiers were hired on a contract basis to replace vacancies created by these internal postings.

One customer service clerk was also promoted to Health and Wellness Specialist in 2008.

A new position of Metering Supervisor was filled internally by the lead hand of the meter shop. The lead hand meter position was not replaced; however, one of the former PWU engineering techs was reallocated to the meter department.

In January 2008 a former lead hand at NFH was promoted to Operations Supervisor to replace the PWU Operations Manager who retired in 2007. This position was back filled internally and ultimately replaced with an apprentice lineman.

In 2008, one Engineering Tech was promoted to Engineering Supervisor of the PW service area.

In June 2008, a Controller was hired to assume duties and responsibilities of the VP of Finance on a daily and monthly basis.

In September of 2008, 2 apprentices from the Cambrian College, Power line Technicians program were hired as apprentices.

Also in 2008 3 union contracts were harmonized resulting in a three year collective agreement which expires March 31, 2011. The former Peninsula West utilities employees' wages were harmonized with those employees of the former NFH utility. Vacations and other benefits were also harmonized.

2009 Actual vs. 2008 Actual

There was a net increase of 6 FTE's during the 2009 year.

In January 2009, the VP of Corporate Services retired and in August 2009 the VP of Business Development retired. These duties were combined and a new position Manager of CDM and Public Relations was created. This position was filled internally by the Executive Assistant in August 2009.

The Executive Assistant was back filled internally in September 2009 by a customer service clerk. The customer service clerk was then back filled externally in 2010.

An Assistant to the EA position was created in October 2009 and was filled on by a customer service clerk on a contract basis. This position was then hired full time in February 2010. The customer service vacancy was filled in 2010.

In February 2009 a lineman retired. Two apprentice linemen were hired full time as lineman in 2009.

In March 2009 a Regulatory Financial and Rate Analyst was hired to assist with the regulatory financial reporting requirements and rate application preparation.

In May 2009, NPEI hired three additional apprentice linemen from the Cambrian College Power line Technician program.

In June 2009 a Smart Meter Coordinator was hired on a contract basis to help with the implementation of smart meters. NPEI commenced installing smart meters in December 2009 and will complete its installation in September of 2010. The Smart Meter Coordinator's wages are recorded in account 1556.

An HR clerk was hired in 2009 to assist with health and safety initiatives and requirements stemming from a WSIB audit as well as prepare documentation and training for Bill 168.

A receptionist was hired on a contract basis in October 2009 and the outsourcing for this service ceased.

2010 Bridge Year vs. 2009 Actual

There was a net increase of 6 FTE's in 2010.

One customer service clerk and one billing clerk retired in 2010.

Two contract customer service clerks were hired in 2010, one replacing the retirement and one replacing the vacancy created by the filling of the Executive Assistant in 2009.

A co-op accountant was hired from one of the colleges to assist in the accounting and cashiering departments. This co-op position will end at the end of 2010 and will not be filled in 2011.

A second smart meter coordinator was hired in August of 2010 on a contract basis to assist with the implementation of smart meters and billing. This second smart meter coordinators wages are recorded in Account 1556.

Two business analysts were hired on contract basis to prepare documentation of work flow, testing of the billing system, preparation of the web for e-billing and ultimately as part of a succession plan for the two billing supervisors. Both billing supervisors are eligible to retire within the next 2 to 5 years.

Two apprentices from the Cambrian College Power line Technician program started their work term in September 2010.

2011 Test vs. 2010 Bridge

In 2011 NPEI has budgeted for the hiring of an additional Engineering Supervisor. The additional supervisor will assume the daily activities currently being performed by the Engineering Manager in the Niagara Falls location. The Engineering Manager will assume the duties and responsibilities related to the new FIT, microFIT and smart grid programs coming on board in the future.

The Co-Op Accountant position will end in 2010 and will not be replaced in 2011.

The overall increase in FTE's since 2004 is illustrated in Table 4-14 regardless of the internal movement of employees.

Net Increase in FTE employees

Table 4-13 outlines the increase in employees since the 2006 Board Approved EDR (2004) combined Pen West Utilities and Niagara Falls Hydro rate applications. Table 4-14 summarizes the increase in FTE's since 2004 by job classification.

Table 4-13 Net Increase in FTE Employees

Year	Department	Change
2004	FTE 2006 Board Approved (2004 Actual)	108
2005	Lineman hired NF May 2005	3
2005	GIS technologist hired NF August 2005	1
2005	Purchase supervisor retired replace w jr buyer	0
2005	Junior buyer promoted (junior buyer not replaced)	-1
2005	Junior accountant hired PW	1
2005	Billing clerk hired PW	1
2005	CS supervisor left NF-replaced by Exec assist	-1
2005	Contract operations PW left	-1
2006	Director of Engineering PW hired	1
2006	Executive Assistant NF replace vacancy 2005	1
2006	2 Engineering Techs 1 PW, 1 NF hired	2
2006	2 Contract Lineman PW hired	2
2006	Controll room operator hired NF	1
2006	1 Contract Admin/CS PW hired	1
2006	1 Contract Accounting PW hired	1
2006	Director of Engineering NF retired	-1
2006	GM PW deceased	-1
2006	Engineering Manager PW left	-1
2007	Engineering Manager NF hired	1
2007	IT Manager NF hired	1
2007	Systems Analysit NF hired	1
2007	Director of Engineering PW left	-1
2007	Operations Manager PW retired	-1
2007	Operations Lead hand NF left	-1
2007	Billing Supervisor NF retired	-1
2007	Billing Clerk NF retired	-1
2007	2 Apprentices NF hired	2
		117

Net Increase in FTE Employees NPEI

2008	Opening balance NPEI merged company	117
2008	VP of Engineering promoted within mgmt	1
2008	VP of Operations promoted within mgmt	1
2008	VP of Customer Service with Manager of CS	1
2008	Manager of CS not replaced	-1
2008	2 Engineering Managers promoted	-2
2008	2 Accountants retired replaced one with CS clerk	-2
2008	Billing Supervisor replaced with Billing clerk	1
2008	Customer Service clerks replaced	1
2008	Customer Service clerk promoted to Health & Well	1
2008	Controller hired	1
2008	Metering Supervisor promoted with Meter Tech	1
2008	Replace meter tech with PW operations tech	-1
2008	2 Apprentices hired	2
2008	Promote Engineer tech to Engineer supervisor	1
2008	Engineer tech not replaced till 2011	-1
2009	Regulatory & Financial Analyst hired	1
2009	VP Corporate Service Retired Jan 2009	-1
2009	VP Business Development Retired August 2009	-1
2009	EA promoted to Manager CDM	1
2009	Assistant EA promoted from customer service	1
2009	Customer service vacancy filled in 2010	-1
2009	Lineman retired Jan 2009	-1
2009	3 Apprentices hired	3
2009	2 Apprentices hired as lineman full time	2
2009	HR clerk hired	1
2009	Contract smart meter position hired	1
2010	2 Customer Services union retired	-2
2010	Contract 2 Business Analysts hired	2
2010	Contract smart meter position hired	1
2010	2 Lineman Apprentices hired	2
2010	Contract Customer Service/Billing replaced	2
2010	Co-op accounting position hired	1
2011	Engineering Supervisor engineer tech vacancy 2008	1
2011	Co-op accounting position not replaced	-1
	FTE 2011 Test Year	**133**

Table 4-14 Summary Net Increase in FTE by Job Classification

Year	New Positions since 2004	Number
2005	GIS Technologist	1
2005	Lineman Apprentices	1
2005	Junior buyer not replaced	-1
2006	Control Room Operator	1
2006	Engineering Tech	1
2006	Lineman Apprentices	1
2007	Engineering Manager	1
2007	IT Manager	1
2007	System Analyst	1
2008 & 2011	Engineering supervisor	2
2008	Controller	1
2008	Health & Wellness Co-ordinator	1
2008	HR clerk	1
2008	Office Administrator	-2
2008	Lineman Apprentices	3
2009	Regulatory Analyst	1
2009	EA Assistant	1
2009	Lineman Apprentices	4
2010	Business Analysts	2
2010	Co-op Accountant	1
2010	Lineman Apprentices	2
2009 & 2010	Smart Meter analysts	2
2011	Co-op Accountant	-1
	Total increment	25

NPEI's Compensation System

Executive/Management

In 2008, NPEI implemented a new Management Compensation Plan for all salaried employees. The plan was developed by the assistance of an outside consulting firm, Cyr & Associates. Finalized job descriptions were evaluated using a proprietary Plan similar to the Hay Evaluation Plan and placed in pay bands ensuring internal equity. Pay market data was collected from Ontario's LDCs. NPEI uses a pay grid that includes 19 pay grades within the management group with each grade paying more as the level of responsibility increases. Each grade allows for five possible progression steps. Management employees and supervisors are not paid overtime. This pay grid was developed from the available information and approved by the Board of Directors of the new merged NPEI Company.

Individual job performance is aligned with NPEI's vision, mission, goals and strategic plan. All salary performance appraisals are completed at the end of each year and cost of living increases similar to the union contract are implemented on January 1st based on performance meeting expectations. Pay progression may be withheld as needed for performance that is below acceptable levels. There are no incentive compensation plans in place at NPEI.

Union

The former Niagara Falls Hydro Inc. unionized staff and the office workers of the former Peninsula West Utilities Limited were represented by the IBEW Local 636. The linemen and engineering departments of the former Peninsula West Utilities were represented by the Construction Workers Union Local 303. Upon commencement of the merger on January 1, 2008, there were three union contracts in place. A formal set of contract negotiations was conducted and resulted in a harmonized three year collective agreement effective April 1, 2008. All NPEI unionized staff are now represented by the International Brotherhood of Electrical Workers Union (IBEW) Local 636. The settlement included annual wage increases of 3% per year and improvements to the benefits package as well as wage and benefit harmonization of all job classifications. All union increases in the 2011 budget are based on historical estimates as the current union contract expires March 31, 2011. NPEI's pay rates are competitive with other like-sized LDCs in the Niagara Region.

As a result of the merger the pay equity plan was updated with the assistance of an outside consulting company in 2009. The unionized female dominated job classifications were evaluated with updated job descriptions. The result of the pay equity review was an increase in pay for two job classifications; billing clerk and customer service clerk. The payment was made in June 2010 and represented the period from November 1, 2008 to June 30, 2010. The total pay equity adjustment was $49,000 or $29,400 per year.

Non-Union

Non-Union employees at NPEI are employees who are on contract. These employees are not enrolled in OMERS, and are not eligible for extended health benefits or post retirement benefits. Typically, the non-union contracts are for six months to a year depending on the circumstances, i.e. maternity leave, sick leave, or a new project for example smart meters. The contracts are reviewed and reassessed on a regular basis for determination of need to terminate the contract, renew the contract or hire as either full time management or full time union.

Employee Compensation and Benefits

NPEI's employee complement, compensation and benefits are set out in Table 4-15, which is in the Board's Appendix 2-K format as shown in the Board's Minimum Filing Requirements. Table 4-15 reports the actual wages and salaries paid, rather than the general ledger balances and does not include members of the Board (Directors), temporary employees or students.

The "Salaries and Wages" amounts include all Salaries and Wages paid inclusive of vacations, statutory holidays, floater holidays, sick leave, bereavement leave and other miscellaneous paid leave (i.e. jury duty), which may be considered as benefits; however, they are not considered benefits for the purpose of this analysis.

A comprehensive and competitive benefits package exists which includes medical insurance, life insurance, vacation and sick time and post retirement benefits. The plans are designed to address the health and welfare needs of the employee population with similar plans for both union and management employees. Table 4-16 summarizes only the employee benefits of medical, LTD and life insurance for 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Bridge year and 2011 Test Year.

The "Benefits" amounts include the employer's cost to provided Extended Health Care, Dental, Long-Term Disability and Life Insurance to its employees.

NPEI notes that for the 2006 and 2007 years the two former utilities data were combined for purposes of comparison.

Table 4-15 Employee Costs – Appendix 2K

	Last Rebasing Year	Historical Year (Bridge Year -1)	Bridge Year	Test Year
Number of Employees (FTEs including Part-Time)	2004	2009	2010	2011
Executive	7	5	5	5
Management	18	23	23	24
Non-Union	21	12	18	14
Union	62	87	87	90
Total	108	127	133	133
Number of Part-Time Employees				
Executive	0	0	0	0
Management	0	0	0	0
Non-Union	0	0	0	0
Union	0	0	0	0
Total	0	0	0	0
Total Salary and Wages				
Executive	699,287	769,649	684,519	713,623
Management	1,027,908	1,623,272	1,700,261	2,010,974
Non-Union	676,107	223,027	445,195	620,448
Union	3,643,487	5,252,203	5,526,873	5,886,295
Total	6,046,789	7,868,152	8,356,848	9,231,340
Current Benefits				
Executive	44,827	46,521	39,879	40,942
Management	131,171	184,487	191,517	196,359
Non-Union	-	-	-	-
Union	525,186	564,156	624,359	634,194
Total	701,184	795,164	855,755	871,495
Accrued Pension & Post Retirement Benefits				
Executive	72,231	96,820	96,972	99,630
Management	134,890	211,490	213,977	219,326
Non-Union	-	-	-	-
Union	390,940	481,223	539,901	554,160
Total	598,061	789,532	850,850	873,117
Total Benefits (Current + Accrued)				
Executive	117,058	143,341	136,850	140,572
Management	266,061	395,977	405,494	415,685
Non-Union	-	-	-	-
Union	916,126	1,045,379	1,164,261	1,188,354
Total	1,299,245	1,584,696	1,706,605	1,744,612
Total Compensation (Salary, Wages, & Benefits)				
Executive	816,345	912,990	821,369	854,195
Management	1,293,969	2,019,249	2,105,755	2,426,660
Non-Union	676,107	223,027	445,195	620,448
Union	4,559,613	6,297,582	6,691,133	7,074,649
Total	7,346,034	9,452,848	10,063,452	10,975,952
Compensation - Average Yearly Base Wages				
Executive	99,898	153,930	136,904	142,725
Management	54,538	70,539	73,924	83,791
Non-Union	32,196	18,586	24,733	44,318
Union	52,961	57,142	60,040	61,959
Total	52,627	61,954	62,833	69,409
Compensation - Average Yearly Overtime				
Executive	0	0	0	0
Management	389	0	0	0
Non-Union	1619	0	0	0
Union	2,386	3,228	3,487	3,444
Total	1,435	2,218	2,714	2,338
Compensation - Average Yearly Incentive Pay				
Executive	0	0	0	0
Management	0	0	0	0
Non-Union	0	0	0	0
Union	0	0	0	0
Total	0	0	0	0
Compensation - Average Yearly Benefits				
Executive	16,723	28,668	27,370	28,114
Management	14,781	17,216	17,630	17,320
Non-Union	-	-	-	-
Union	14,776	12,016	13,382	13,204
Total	12,030	12,478	12,832	13,117
Total Compensation	7,346,034	9,452,848	10,063,452	10,975,952
Total Compensation Charged to OM&A	5,992,518	7,151,459	7,076,667	7,564,187
Total Compensation Capitalized	1,353,516	2,301,389	2,986,785	3,411,765

Employee Benefits

Premiums paid for 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Bridge Year, and 2011 Test Year, are shown in Table 4-16.

Table 4-16 Summary of Employee Benefits

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Annual Benefit Cost	700,984	744,495	783,220	795,164	855,755	871,495
$ Increase per Year		43,511	38,725	11,944	60,591	15,740
% Increase per Year		6.21%	5.20%	1.52%	7.62%	1.84%
% Average Increase 2006-2011						4.05%

OMERS Pension Expense and Post Retiree Benefits

OMERS Pension Expense

NPEI's employees are members of the Ontario Municipal Employees Retirement System ("OMERS"). Accordingly, NPEI has provided the OMERS pension premium information for 2006 Actual, 2007 Actual, 2008 Actual, 2010 Bridge Year, and the 2011 Test Year in Table 4-17 below.

The amounts paid by NPEI to OMERS continues to increase each year; however these costs are primarily driven by mandated OMER's premium rates and are thus uncontrollable by NPEI. NPEI estimates its OMERS expense by estimating the number of employees within each category (management, union, etc) and their salaries and wages, upon which OMERS contributions are based. The OMERS contributions are then calculated by applying the estimated tiered rates of 6.4% (up to the YMPE) and 9.7% (over the YMPE) for the year 2011. Actual rates of 6.4% and 9.7% were used for the year 2010.

Table 4-17 OMERS Pension Premium Information

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Pension Expense	457,530	500,816	548,845	573,090	621,059	636,585
$ Increase/(Decrease) per Year		43,286	48,029	24,245	47,969	15,526
% Increase/(Decrease) per Year		9%	10%	4%	8%	2.5%

Post-Retirement Benefits - Liability

NPEI has provided post-retirement benefits accounting information as required and has included the change in Post-Retirement expense for 2006 Actual, 2007 Actual, 2008 Actual, 2010 Bridge Year, and 2011 Test Year, in Table 4-18 below.

Post-Retirement Benefits - Premiums

NPEI pays certain health, dental, and life insurance benefits on behalf of its retired employees. Actual premiums paid for 2006 Actual, 2007 Actual, 2010 Bridge Year, and 2011 Test Year, are shown in Table 4-18 below.

Table 4-18 Post-Retirement Benefit Information

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Premiums Paid	134,053	136,215	160,049	175,725	185,644	
Change in Liability Account	6,425	13,162	47,638	40,717	44,147	
Post-Retirement Benefit Expense	**140,478**	**149,377**	**207,687**	**216,442**	**229,791**	**237,000**

A copy of the NPEI's employee's handbook is attached in Appendix E.

Depreciation, Amortization & Depletion

Amortization on capital assets is calculated as follows:

- NPEI uses the pooling of assets for all fixed assets with the exception of the following:
  - o 1915 Furniture & Equipment
  - o 1920 Computer Equipment
  - o 1925 Computer Software,
  - o 1930 Transportation Equipment
  - o 1935 Stores Equipment
  - o 1940 Tools, Shop & Garage Equipment
  - o 1945 Measurement Equipment
  - o 1955 Communication Equipment
  - o 1960 Miscellaneous Equipment
  - o 1980 Supervisory System Equipment,

Amortization is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year; plus:

- Prior to 2010 a full year's amortization was taken on capital additions during the current year. For 2010 and for this rate application NPEI is using the half year rule for calculating depreciation expense for the 2011 Test Year.
- Depreciation rates are in line with rates set out in the APH. As discussed in the OM&A Manager's Summary above, this application has been filed in accordance with CGAAP, thus, NPEI has filed this application under the same depreciation rates

as NPEI files its Audited CGAAP Financial Statements. NPEI has not applied any of the provisions of the Board's Depreciation Study (EB-2010-0178), as this study specifically relates to the transition to IFRS, as evidenced by the subject line of the Board's April 30, 2010 letter "Depreciation Study for Electricity Distributors (EB-2010-0178) – Transition to International Financial Reporting Standards ("IFRS"). A summary of the depreciation rates are as follows in Table 4-19:A summary of those rates are as follows:

Table 4-19 Depreciation Rates

USoA	Description	Rate
1805	Land	N/A
1806	Land Rights	4.00%
1815	Transformer Station Equipment > 50kV	2.50%
1820	Distribution Station Equipment < 50kV	4.00%
1830	Poles, Towers & Fixtures	4.00%
1835	Overhead Conductors & Devices	4.00%
1840	Underground Conduit	4.00%
1845	Underground Conductors & Devices	4.00%
1850	Line Transformers	4.00%
1855	Services	4.00%
1860	Metering	4.00%
1908	Buildings	2.00%
1910	Leasehold improvements	33.33%
1915	Furniture & Equipment	10.00%
1920	Computer Hardware	20.00%
1925	Computer Software	100%
1930	Transportation equipment - large vehicle, trailers	12.50%
1930	Transportation equipment - small vehicles	12.50%
1935	Stores equipment	10.00%
1940	Tools, Shop and Garage Equipment	10.00%
1945	Measurement and Testing Equipment	20.00%
1955	Communication Equipment	25.00%
1960	Miscellaneous Equipment	20.00%
1980	System Supervisory Equipment	7.00%
1995	Contributed Capital	4.00%

All of NPEI's amortization expense runs through account 5705-Amortization Expense – Property, Plant and equipment. Details of NPEI's depreciation by account number are provided in the Fixed Asset Continuity Schedules in Exhibit 2.

NPEI's depreciation expense does match the accumulated amortization because NPEI does not expense depreciation for overhead calculation for vehicles, stores, tools, measurement, and communication equipment. NPEI has a stand alone fixed asset software system for accounts 1915 to 1980. This system calculates depreciation in the first month following the asset being put into use. The pooling method of depreciation is not used for these assets.

Table 4-20 Amortization expense

USoA	Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test Year
5705	Depreciation Expense-Property Plant & Equipment	6,667,024	6,896,734	6,571,652	6,642,438	7,000,940	7,143,688

NPEI has provided in Board Appendix 2-M Format the Depreciation and Amortization Expense Schedules for 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Bridge and 2011 Test Years.

Table 4-21 2006 Depreciation and Amortization Expense

Account	Description	Openning Balance	Less Fully Depreciated	Net for Depreciation	Disposal	Additions	Closing Balance 2006	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense	Adjustments	Total Depreciation
		(a)	(b)	© =(a) - (b)	(c1)	(d)		(e)= (©-c1)+1.0x(d)	(f)	(g)=1/(f)	(h)=(e)/(f)	(i)	(j)=(h)+(i)
1805	Land	508,596	0	508,596		0	508,596	508,596			0	0	0
1806	Land Rights	1,478,155	0	1,478,155		89,984	1,568,139	1,568,139	25	0.04	62,726	(9,032)	53,694
1808	Buildings and Fixtures	410,595	0	410,595		10,204	420,799	420,799	25	0.04	16,832	(7,902)	8,930
1810	Leasehold Improvements	0	0	0		0	0	0			0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	6,777,264	0	6,777,264		(218,750)	6,558,514	6,558,514	40	0.03	163,963	(22,866)	141,097
1820	Distribution Station Equipment - Normally Primary below 50 kV	4,202,787	747,992	3,454,795		28,197	4,230,984	3,482,992	25	0.04	139,320	(6,845)	132,475
1825	Storage Battery Equipment	0	0	0		0	0	0			0	0	0
1830	Poles, Towers and Fixtures	20,285,351	262,328	20,023,023		1,639,570	21,924,921	21,662,593	25	0.04	866,504	123,479	989,983
1835	Overhead Conductors and Devices	22,454,127	608,256	21,845,871		1,487,310	23,941,437	23,333,181	25	0.04	933,327	341,785	1,275,112
1840	Underground Conduit	7,657,174	0	7,657,174		928,142	8,585,316	8,585,316	25	0.04	343,413	(76,607)	266,806
1845	Underground Conductors and Devices	46,186,316	0	46,186,316		2,293,204	48,479,520	48,479,520	25	0.04	1,939,181	(49,014)	1,890,167
1850	Line Transformers	26,007,695	2,757,791	23,249,904	82,666	1,378,952	27,303,981	24,546,190	25	0.04	981,848	(49,634)	932,214
1855	Services	1,522,853	0	1,522,853		567,794	2,090,647	2,090,647	25	0.04	83,626	(17,776)	65,850
1860	Meters	6,340,652	1,283,530	5,057,122	153,776	352,242	6,539,118	5,255,588	25	0.04	210,224	(4,650)	205,573
1865	Other Installations on Customer's Premises	440	0	440		0	440	440	25	0.04	18	(18)	0
1905	Land	287,879	0	287,879		0	287,879	287,879			0	0	0
1906	Land Rights	0	0	0		0	0	0			0	0	0
1908	Buildings and Fixtures	5,708,011	0	5,708,011		45,388	5,753,399	5,753,399	60	0.02	95,890	9,912	105,802
1910	Leasehold Improvements	120,252	116,981	3,271		0	120,252	3,271	3	0.33	1,090	1,296	2,386
1915	Office Furniture and Equipment	783,637	533,070	250,567		73,858	857,495	324,425	10	0.10	32,442	16,248	48,690
1920	Computer Equipment - Hardware	1,693,129	1,205,809	487,320		119,227	1,812,356	606,547	5	0.20	121,309	52,478	173,787
1925	Computer Software	1,792,984	1,203,312	589,672		213,418	2,006,402	803,090	1	1.00	803,090	(300,047)	503,043
1930	Transportation Equipment	3,697,374	2,724,009	973,365	40,995	515,857	4,172,236	1,448,227	8	0.13	181,028	46,004	227,032
1935	Stores Equipment	182,171	175,424	6,747		0	182,171	6,747	10	0.10	675	1,041	1,716
1940	Tools, Shop and Garage Equipment	1,369,906	927,832	442,074		48,599	1,418,505	490,674	10	0.10	49,067	34,838	83,905
1945	Measurement and Testing Equipment	93,036	39,535	53,501		71,867	164,903	125,367	5	0.20	25,073	(13,132)	11,942
1950	Power Operated Equipment	0	0	0		0	0	0			0	0	0
1955	Communication Equipment	117,971	75,355	42,616		0	117,971	42,616	4	0.25	10,654	(4,403)	6,251
1960	Miscellaneous Equipment	38,089	38,089	0		0	38,089	0	5	0.20	0	0	0
1970	Load Management Controls - Customer Premises	0	0	0		0	0	0			0	0	0
1975	Load Management Controls - Utility Premises	0	0	0		0	0	0			0	0	0
1980	System Supervisory Equipment	128,961	103,169	25,792		0	128,961	25,792	15	0.07	1,719	6,877	8,596
1985	Sentinel Lighting Rentals	0	0	0		0	0	0			0	0	0
1990	Other Tangible Property	0	0	0		0	0	0			0	0	0
1995	Contributions and Grants	(10,372,198)	0	(10,372,198)		(1,354,458)	(11,726,656)	(11,726,656)	25	0.04	(469,066)	1,038	(468,028)
2005	Property under Capital Lease	143,036	143,036	0		0	143,036	0	25	0.04	0	0	0
	Total before Work in Process	**149,616,243**	**12,945,519**	**136,670,724**	**277,437**	**8,290,606**	**157,629,412**	**144,683,893**			**6,593,952**	**73,072**	**6,667,024**
	Work in Process												
	Total after Work in Process	**149,616,243**	**12,945,519**	**136,670,724**	**277,437**	**8,290,606**	**157,629,412**	**144,683,893**			**6,593,952**	**73,072**	**6,667,024**

Table 4-22 2007 Depreciation and Amortization Expense

Account	Description	Openning Balance (a)	Less Fully Depreciated (b)	Net for Depreciation © =(a) - (b)	Disposal (c1)	Additions (d)	Closing Balance 2006	Total for Depreciation (e)= (©-c1)+1.0x(d)	Years (f)	Depreciation Rate (g)=1/(f)	Depreciation Expense (h)=(e)/(f)	Adjustments (i)	Total Depreciation (j)=(h)+(i)
1805	Land	508,596	0	508,596	1,322	0	507,274	507,274			0	0	0
1806	Land Rights	1,568,139	0	1,568,139		30,031	1,598,170	1,598,170	25	0.04	63,927	(8,115)	55,811
1808	Buildings and Fixtures	420,799	0	420,799	327,457	18,296	111,638	111,638	25	0.04	4,466	59,780	64,246
1810	Leasehold Improvements	0	0	0		0	0	0			0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	6,558,514	0	6,558,514		0	6,558,514	6,558,514	40	0.03	163,963	(14,179)	149,784
1820	Distribution Station Equipment - Normally Primary below 50 kV	4,230,984	747,992	3,482,992		0	4,230,984	3,482,992	25	0.04	139,320	(6,845)	132,474
1825	Storage Battery Equipment	0	0	0		0	0	0			0	0	0
1830	Poles, Towers and Fixtures	21,924,921	312,328	21,612,593		2,901,140	24,826,061	24,513,733	25	0.04	980,549	424,442	1,404,991
1835	Overhead Conductors and Devices	23,941,437	825,143	23,116,294		2,527,454	26,468,891	25,643,748	25	0.04	1,025,750	44,811	1,070,561
1840	Underground Conduit	8,585,316	0	8,585,316		660,180	9,245,495	9,245,495	25	0.04	369,820	27,495	397,315
1845	Underground Conductors and Devices	48,479,520	0	48,479,520		1,978,131	50,457,651	50,457,651	25	0.04	2,018,306	(139,036)	1,879,270
1850	Line Transformers	27,303,981	2,757,791	24,546,190	105,800	2,048,116	29,246,297	26,488,506	25	0.04	1,059,540	(40,834)	1,018,706
1855	Services	2,090,647	0	2,090,647		701,366	2,792,013	2,792,013	25	0.04	111,681	(31,857)	79,824
1860	Meters	6,539,118	1,340,931	5,198,187	48,681	334,706	6,825,143	5,484,212	25	0.04	219,368	(3,638)	215,730
1865	Other Installations on Customer's Premises	440	0	440		0	440	440	25	0.04	18	(18)	0
1905	Land	287,879	0	287,879	58,415	0	229,465	229,465			0	0	0
1906	Land Rights	0	0	0		0	0	0			0	0	0
1908	Buildings and Fixtures	5,753,399	0	5,753,399	324,974	430,422	5,858,847	5,858,847	60	0.02	97,647	15,682	113,329
1910	Leasehold Improvements	120,252	119,367	885		0	120,252	885	3	0.33	295	590	885
1915	Office Furniture and Equipment	857,495	581,761	275,734		18,181	875,676	293,915	10	0.10	29,392	40,233	69,624
1920	Computer Equipment - Hardware	1,812,356	1,379,596	432,760		101,762	1,914,118	534,521	5	0.20	106,904	61,271	168,175
1925	Computer Software	2,006,402	1,706,355	300,047		62,326	2,068,728	362,373	1	1.00	362,373	(145,708)	216,665
1930	Transportation Equipment	4,172,236	2,879,750	1,292,486	30,345	227,707	4,369,598	1,489,848	8	0.13	186,231	82,072	268,303
1935	Stores Equipment	182,171	177,140	5,031		0	182,171	5,031	10	0.10	503	1,214	1,717
1940	Tools, Shop and Garage Equipment	1,418,505	1,011,737	406,768		60,052	1,478,557	466,820	10	0.10	46,682	42,846	89,528
1945	Measurement and Testing Equipment	164,903	51,477	113,426		0	164,903	113,426	5	0.20	22,685	(8,554)	14,131
1950	Power Operated Equipment	0	0	0		0	0	0			0	0	0
1955	Communication Equipment	117,971	81,606	36,365		1,866	119,837	38,231	4	0.25	9,558	(7,616)	1,942
1960	Miscellaneous Equipment	38,089	38,089	0		0	38,089	0	5	0.20	0	0	0
1970	Load Management Controls - Customer Premises	0	0	0		0	0	0			0	0	0
1975	Load Management Controls - Utility Premises	0	0	0		0	0	0			0	0	0
1980	System Supervisory Equipment	128,961	111,765	17,196		0	128,961	17,196	15	0.07	1,146	7,452	8,598
1985	Sentinel Lighting Rentals	0	0	0		0	0	0			0	0	0
1990	Other Tangible Property	0	0	0		0	0	0			0	0	0
1995	Contributions and Grants	(11,726,656)	0	(11,726,656)		(1,683,128)	(13,409,784)	(13,409,784)	25	0.04	(536,391)	11,514	(524,878)
2005	Property under Capital Lease	143,036	143,036	0		0	143,036	0	25	0.04	0	0	0
	Total before Work in Process	**157,629,412**	**14,265,865**	**143,363,547**	**896,994**	**10,418,607**	**167,151,025**	**152,885,160**			**6,483,732**	**413,002**	**6,896,734**
	Work in Process												
	Total after Work in Process	**157,629,412**	**14,265,865**	**143,363,547**	**896,994**	**10,418,607**	**167,151,025**	**152,885,160**			**6,483,732**	**413,002**	**6,896,734**

Table 4-23 2008 Depreciation and Amortization Expense

Account	Description	Openning Balance (a)	Less Fully Depreciated (b)	Net for Depreciation © =(a) - (b)	Disposal (c1)	Additions (d)	Closing Balance 2006	Total for Depreciation (e)= (©-c1)+1.0x(d)	Years (f)	Depreciation Rate (g)=1/(f)	Depreciation Expense (h)=(e)/(f)	Adjustments (i)	Total Depreciation (j)=(h)+(i)
1805	Land	507,274	0	507,274		0	507,274	507,274			0	0	0
1806	Land Rights	1,598,170	0	1,598,170		0	1,598,170	1,598,170	25	0.04	63,927	(7,077)	56,850
1808	Buildings and Fixtures	111,638	0	111,638		0	111,638	111,638	25	0.04	4,466	5,195	9,661
1810	Leasehold Improvements	0	0	0		0	0	0			0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	6,558,514	0	6,558,514		0	6,558,514	6,558,514	40	0.03	163,963	(18,610)	145,353
1820	Distribution Station Equipment - Normally Primary below 50 kV	4,230,984	747,992	3,482,992		0	4,230,984	3,482,992	25	0.04	139,320	(15,678)	123,642
1825	Storage Battery Equipment	0	0	0		0	0	0			0	0	0
1830	Poles, Towers and Fixtures	24,826,061	3,251,313	21,574,748		1,856,704	26,682,765	23,431,452	25	0.04	937,258	162,153	1,099,411
1835	Overhead Conductors and Devices	26,468,891	1,136,330	25,332,561		2,865,321	29,334,212	28,197,882	25	0.04	1,127,915	(245,605)	882,310
1840	Underground Conduit	9,245,495	0	9,245,495		650,997	9,896,492	9,896,492	25	0.04	395,860	(265,743)	130,117
1845	Underground Conductors and Devices	50,457,651	175,388	50,282,263		1,738,623	52,196,274	52,020,886	25	0.04	2,080,835	55,207	2,136,042
1850	Line Transformers	29,246,297	3,250,103	25,996,194	311,755	1,189,608	30,124,150	26,874,047	25	0.04	1,074,962	(17,045)	1,057,917
1855	Services	2,792,013	0	2,792,013		342,962	3,134,975	3,134,975	25	0.04	125,399	55,694	181,093
1860	Meters	6,825,143	1,340,931	5,484,212		200,905	7,026,048	5,685,117	25	0.04	227,405	(5,525)	221,880
1865	Other Installations on Customer's Premises	440	0	440		0	440	440	25	0.04	18	(18)	0
1905	Land	229,465	0	229,465		0	229,465	229,465			0	0	0
1906	Land Rights	0	0	0		0	0	0			0	0	0
1908	Buildings and Fixtures	5,858,847	0	5,858,847		4,146,632	10,005,479	10,005,479	60	0.02	166,758	2,542	169,300
1910	Leasehold Improvements	120,252	120,252	(0)		0	120,252	(0)	3	0.33	(0)	0	0
1915	Office Furniture and Equipment	875,676	546,426	329,250	104,959	174,930	945,647	399,221	10	0.10	39,922	10,698	50,620
1920	Computer Equipment - Hardware	1,914,118	1,547,771	366,346		525,453	2,439,571	891,799	5	0.20	178,360	10,860	189,220
1925	Computer Software	2,068,728	1,196,587	872,141	726,433	208,496	1,550,791	354,204	1	1.00	354,204	(77,222)	276,982
1930	Transportation Equipment	4,369,598	3,148,054	1,221,544		576,543	4,946,141	1,798,087	8	0.13	224,761	55,390	280,151
1935	Stores Equipment	182,171	178,857	3,314		0	182,171	3,314	10	0.10	331	1,386	1,717
1940	Tools, Shop and Garage Equipment	1,478,557	1,101,265	377,292		38,218	1,516,775	415,510	10	0.10	41,551	45,811	87,362
1945	Measurement and Testing Equipment	164,903	65,608	99,295		6,083	170,986	105,378	5	0.20	21,076	19,587	40,663
1950	Power Operated Equipment	0	0	0		0	0	0			0	0	0
1955	Communication Equipment	119,837	49,047	70,790	34,501	28,326	113,662	64,615	4	0.25	16,154	(15,009)	1,145
1960	Miscellaneous Equipment	38,089	38,089	0		24,228	62,317	24,228	5	0.20	4,846	(1,192)	3,654
1970	Load Management Controls - Customer Premises	0	0	0		0	0	0			0	0	0
1975	Load Management Controls - Utility Premises	0	0	0		0	0	0			0	0	0
1980	System Supervisory Equipment	128,961	120,363	8,598		0	128,961	8,598	15	0.07	573	8,025	8,598
1985	Sentinel Lighting Rentals	0	0	0		0	0	0			0	0	0
1990	Other Tangible Property	0	0	0		0	0	0			0	0	0
1995	Contributions and Grants	(13,409,784)	0	(13,409,784)		(1,712,904)	(15,122,688)	(15,122,688)	25	0.04	(604,908)	22,872	(582,036)
2005	Property under Capital Lease	143,036	143,036	0		0	143,036	0	25	0.04	0	0	0
	Total before Work in Process	**167,151,025**	**18,157,413**	**148,993,612**	**1,177,648**	**12,861,125**	**178,834,502**	**160,677,089**			**6,784,954**	**(213,302)**	**6,571,652**
	Work in Process												
	Total after Work in Process	**167,151,025**	**18,157,413**	**148,993,612**	**1,177,648**	**12,861,125**	**178,834,502**	**160,677,089**			**6,784,954**	**(213,302)**	**6,571,652**

Table 4-24 2009 Depreciation and Amortization Expense

Account	Description	Openning Balance (a)	Less Fully Depreciated (b)	Net for Depreciation © =(a) - (b)	Disposal (c1)	Additions (d)	Closing Balance 2006	Total for Depreciation (e)= (©-c1)+1.0x(d)	Years (f)	Depreciation Rate (g)=1/(f)	Depreciation Expense (h)=(e)/(f)	Adjustments (i)	Total Depreciation (j)=(h)+(i)
1805	Land	507,274	0	507,274		0	507,274	507,274			0		0
1806	Land Rights	1,598,170	0	1,598,170		0	1,598,170	1,598,170	25	0.04	63,927	(7,077)	56,850
1808	Buildings and Fixtures	111,638	0	111,638		0	111,638	111,638	25	0.04	4,466	5,195	9,661
1810	Leasehold Improvements	0	0	0		0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	6,558,514	0	6,558,514		0	6,558,514	6,558,514	40	0.03	163,963	(18,985)	144,978
1820	Distribution Station Equipment - Normally Primary below 50 kV	4,230,984	924,634	3,306,350		276,481	4,507,465	3,582,831	25	0.04	143,313	(17,443)	125,870
1825	Storage Battery Equipment	0	0	0		0	0	0			0	0	0
1830	Poles, Towers and Fixtures	26,682,765	6,349,258	20,333,507		1,982,247	28,665,012	22,315,754	25	0.04	892,630	(580,386)	312,244
1835	Overhead Conductors and Devices	29,334,212	1,155,369	28,178,843		2,060,811	31,395,023	30,239,654	25	0.04	1,209,586	437,285	1,646,871
1840	Underground Conduit	9,896,492	0	9,896,492		471,148	10,367,640	10,367,640	25	0.04	414,706	(265,743)	148,963
1845	Underground Conductors and Devices	52,196,274	223,320	51,972,954		2,200,580	54,396,854	54,173,534	25	0.04	2,166,941	110,738	2,277,679
1850	Line Transformers	30,124,150	3,366,951	26,757,199	242,762	1,222,298	31,103,686	27,736,735	25	0.04	1,109,469	(12,380)	1,097,089
1855	Services	3,134,975	0	3,134,975		324,654	3,459,629	3,459,629	25	0.04	138,385	(2)	138,383
1860	Meters	7,026,048	1,514,529	5,511,519	607,139	258,429	6,677,338	5,162,809	25	0.04	206,512	1,211	207,723
1865	Other Installations on Customer's Premises	440	0	440		0	440	440	25	0.04	18	(18)	0
1905	Land	229,465	0	229,465		279,505	508,970	508,970			0	0	0
1906	Land Rights	0	0	0		0	0	0			0	0	0
1908	Buildings and Fixtures	10,005,479	0	10,005,479		2,385,705	12,391,184	12,391,184	60	0.02	206,520	(84,646)	121,874
1910	Leasehold Improvements	120,252	120,252	(0)		0	120,252	(0)	3	0.33	(0)	0	0
1915	Office Furniture and Equipment	945,647	562,545	383,102		161,652	1,107,299	544,754	10	0.10	54,475	11,644	66,119
1920	Computer Equipment - Hardware	2,439,571	1,736,991	702,579		185,269	2,624,840	887,848	5	0.20	177,570	38,937	216,507
1925	Computer Software	1,550,791	1,473,569	77,222		369,215	1,920,006	446,437	1	1.00	446,437	(184,616)	261,821
1930	Transportation Equipment	4,946,141	3,428,205	1,517,936	50,706	589,462	5,484,897	2,056,692	8	0.13	257,087	72,048	329,135
1935	Stores Equipment	182,171	180,574	1,597		18,090	200,261	19,687	10	0.10	1,969	117	2,086
1940	Tools, Shop and Garage Equipment	1,516,775	1,188,627	328,148		49,335	1,566,110	377,483	10	0.10	37,748	30,851	68,599
1945	Measurement and Testing Equipment	170,986	106,271	64,715		12,160	183,146	76,875	5	0.20	15,375	11,775	27,150
1950	Power Operated Equipment	0	0	0		0	0	0			0	0	0
1955	Communication Equipment	113,662	84,693	28,969		45,272	158,934	74,241	4	0.25	18,560	(10,874)	7,686
1960	Miscellaneous Equipment	62,317	41,743	20,574		5,586	67,903	26,160	5	0.20	5,232	(332)	4,900
1970	Load Management Controls - Customer Premises	0	0	0		0	0	0			0	0	0
1975	Load Management Controls - Utility Premises	0	0	0		0	0	0			0	0	0
1980	System Supervisory Equipment	128,961	128,961	0		0	128,961	0	15	0.07	0	0	0
1985	Sentinel Lighting Rentals	0	0	0		0	0	0			0	0	0
1990	Other Tangible Property	0	0	0		0	0	0			0	0	0
1995	Contributions and Grants	(15,122,688)	0	(15,122,688)		(1,197,961)	(16,320,649)	(16,320,649)	25	0.04	(652,826)	23,076	(629,750)
2005	Property under Capital Lease	143,036	0	143,036		0	143,036	143,036	25	0.04	5,721	(5,721)	0
	Total before Work in Process	**178,834,502**	**22,586,493**	**156,248,009**	**900,607**	**11,699,938**	**189,633,833**	**167,047,340**			**7,087,784**	**(445,346)**	**6,642,438**
	Work in Process												
	Total after Work in Process	**178,834,502**	**22,586,493**	**156,248,009**	**900,607**	**11,699,938**	**189,633,833**	**167,047,340**			**7,087,784**	**(445,346)**	**6,642,438**

Table 4-25 2010 Depreciation and Amortization Expense

Account	Description	Openning Balance (a)	Less Fully Depreciated (b)	Net for Depreciation © =(a) - (b)	Disposal (c1)	Additions (d)	Closing Balance 2006	Total for Depreciation (e)= (©-c1)+.50x(d)	Years (f)	Depreciation Rate (g)=1/(f)	Depreciation Expense (h)=(e)/(f)	Adjustments (i)	Total Depreciation (j)=(h)+(i)
1805	Land	507,274	0	507,274		0	507,274	507,274			0	0	0
1806	Land Rights	1,598,170	0	1,598,170		0	1,598,170	1,598,170	25	0.04	63,927	(7,077)	56,850
1808	Buildings and Fixtures	111,638	0	111,638		0	111,638	111,638	25	0.04	4,466	5,196	9,661
1810	Leasehold Improvements	0	0	0		0	0	0			0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	6,558,514	0	6,558,514		0	6,558,514	6,558,514	40	0.03	163,963	(18,985)	144,978
1820	Distribution Station Equipment - Normally Primary below 50 kV	4,507,465	924,634	3,582,831		185,185	4,692,651	3,675,424	25	0.04	147,017	(17,443)	129,574
1825	Storage Battery Equipment	0	0	0		0	0	0			0	0	0
1830	Poles, Towers and Fixtures	28,665,012	8,329,566	20,335,446		2,860,613	31,525,625	21,765,752	25	0.04	870,630	(38,060)	832,570
1835	Overhead Conductors and Devices	31,395,023	2,048,498	29,346,525		1,231,327	32,626,350	29,962,188	25	0.04	1,198,488	(30,602)	1,167,885
1840	Underground Conduit	10,367,640	0	10,367,640		1,175,040	11,542,680	10,955,160	25	0.04	438,206	(265,743)	172,464
1845	Underground Conductors and Devices	54,396,854	321,277	54,075,577		1,723,794	56,120,648	54,937,474	25	0.04	2,197,499	110,123	2,307,622
1850	Line Transformers	31,103,686	3,366,951	27,736,735		1,384,010	32,487,696	28,428,740	25	0.04	1,137,150	(13,656)	1,123,494
1855	Services	3,459,629	0	3,459,629		486,923	3,946,552	3,703,090	25	0.04	148,124	(2)	148,121
1860	Meters	6,677,338	1,340,931	5,336,407	3,163,008	4,369,541	7,883,872	4,358,170	25	0.04	174,327	57,536	231,863
1865	Other Installations on Customer's Premises	440	0	440		0	440	440	25	0.04	18	(18)	0
1905	Land	508,970	0	508,970		0	508,970	508,970			0	0	0
1906	Land Rights	0	0	0		0	0	0			0	0	0
1908	Buildings and Fixtures	12,391,184	1,817,234	10,573,950		188,557	12,579,740	10,668,228	60	0.02	177,804	32,829	210,633
1910	Leasehold Improvements	120,252	120,252	(0)		0	120,252	(0)	3	0.33	(0)	0	0
1915	Office Furniture and Equipment	1,107,299	628,664	478,635		70,564	1,177,863	513,917	10	0.10	51,392	23,133	74,524
1920	Computer Equipment - Hardware	2,624,840	1,953,498	671,341		273,500	2,898,340	808,091	5	0.20	161,618	85,739	247,358
1925	Computer Software	1,920,006	1,735,390	184,616		278,954	2,198,960	324,093	1	1.00	324,093	(44,810)	279,283
1930	Transportation Equipment	5,484,897	3,706,634	1,778,263		824,149	6,309,047	2,190,338	8	0.13	273,792	124,602	398,395
1935	Stores Equipment	200,261	182,660	17,601		18,900	219,161	27,051	10	0.10	2,705	804	3,509
1940	Tools, Shop and Garage Equipment	1,566,110	1,257,226	308,884		94,342	1,660,452	356,055	10	0.10	35,605	26,969	62,574
1945	Measurement and Testing Equipment	183,146	133,421	49,725		4,690	187,835	52,070	5	0.20	10,414	17,601	28,015
1950	Power Operated Equipment	0	0	0		0	0	0			0	0	0
1955	Communication Equipment	158,934	92,379	66,555		2,843	161,777	67,977	4	0.25	16,994	1,872	18,866
1960	Miscellaneous Equipment	67,903	46,643	21,260		5,049	72,952	23,785	5	0.20	4,757	1,691	6,448
1970	Load Management Controls - Customer Premises	0	0	0		0	0	0			0	0	0
1975	Load Management Controls - Utility Premises	0	0	0		0	0	0			0	0	0
1980	System Supervisory Equipment	128,961	128,961	0		0	128,961	0	15	0.07	0	0	0
1985	Sentinel Lighting Rentals	0	0	0		0	0	0			0	0	0
1990	Other Tangible Property	0	0	0		0	0	0			0	0	0
1995	Contributions and Grants	(16,320,649)	0	(16,320,649)		(1,200,000)	(17,520,649)	(16,920,649)	25	0.04	(676,826)	23,080	(653,746)
2005	Property under Capital Lease	143,036	143,036	0		0	143,036	0	25	0.04	0	0	0
	Total before Work in Process	**189,633,833**	**28,277,856**	**161,355,977**	**3,163,008**	**13,977,982**	**200,448,806**	**165,181,960**			**6,926,161**	**74,779**	**7,000,940**
	Work in Process												
	Total after Work in Process	**189,633,833**	**28,277,856**	**161,355,977**	**3,163,008**	**13,977,982**	**200,448,806**	**165,181,960**			**6,926,161**	**74,779**	**7,000,940**

Table 4-26 2011 Depreciation and Amortization Expense

Account	Description	Openning Balance (a)	Less Fully Depreciated (b)	Net for Depreciation © =(a) - (b)	Disposal (c1)	Additions (d)	Closing Balance 2006	Total for Depreciation (e)= (©-c1)+.5x(d)	Years (f)	Depreciation Rate (g)=1/(f)	Depreciation Expense (h)=(e)/(f)	Adjustments (i)	Total Depreciation (j)=(h)+(i)
1805	Land	507,274	0	507,274		0	507,274	507,274			0	0	0
1806	Land Rights	1,598,170	0	1,598,170		0	1,598,170	1,598,170	25	0.04	63,927	(7,077)	56,850
1808	Buildings and Fixtures	111,638	0	111,638		0	111,638	111,638	25	0.04	4,466	(355)	4,111
1810	Leasehold Improvements	0	0	0		0	0	0			0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	6,558,514	0	6,558,514		0	6,558,514	6,558,514	40	0.03	163,963	(18,985)	144,978
1820	Distribution Station Equipment - Normally Primary below 50 kV	4,692,651	943,634	3,749,017		462,963	5,155,614	3,980,498	25	0.04	159,220	(18,583)	140,637
1825	Storage Battery Equipment	0	0	0		0	0	0			0	0	0
1830	Poles, Towers and Fixtures	31,525,625	8,349,258	23,176,367		2,482,838	34,008,462	24,417,785	25	0.04	976,711	(39,312)	937,399
1835	Overhead Conductors and Devices	32,626,350	2,924,147	29,702,203		972,176	33,598,526	30,188,291	25	0.04	1,207,532	(5,837)	1,201,695
1840	Underground Conduit	11,542,680	0	11,542,680		1,369,289	12,911,969	12,227,325	25	0.04	489,093	(265,743)	223,350
1845	Underground Conductors and Devices	56,120,648	321,277	55,799,371		1,572,596	57,693,245	56,585,670	25	0.04	2,263,427	78,125	2,341,552
1850	Line Transformers	32,487,696	3,357,753	29,129,943		1,284,894	33,772,589	29,772,390	25	0.04	1,190,896	(15,251)	1,175,644
1855	Services	3,946,552	0	3,946,552		499,935	4,446,487	4,196,519	25	0.04	167,861	(20,000)	147,861
1860	Meters	7,883,872	1,487,006	6,396,866		185,185	8,069,057	6,489,458	25	0.04	259,578	(5,933)	253,645
1865	Other Installations on Customer's Premises	440	0	440		0	440	440	25	0.04	18	(18)	0
1905	Land	508,970	0	508,970		0	508,970	508,970			0	0	0
1906	Land Rights	0	0	0		0	0	0			0	0	0
1908	Buildings and Fixtures	12,579,740	0	12,579,740		0	12,579,740	12,579,740	60	0.02	209,662	2,542	212,204
1910	Leasehold Improvements	120,252	120,252	(0)		0	120,252	(0)	3	0.33	(0)	0	0
1915	Office Furniture and Equipment	1,177,863	703,188	474,675		92,593	1,270,456	520,971	10	0.10	52,097	27,057	79,154
1920	Computer Equipment - Hardware	2,898,340	2,200,856	697,484		291,898	3,190,238	843,433	5	0.20	168,687	107,861	276,548
1925	Computer Software	2,198,960	2,198,960	0		182,870	2,381,831	91,436	1	1.00	91,436	(0)	91,435
1930	Transportation Equipment	6,309,047	4,105,028	2,204,018		462,963	6,772,010	2,435,500	8	0.13	304,437	122,892	427,330
1935	Stores Equipment	219,161	186,169	32,992		0	219,161	32,992	10	0.10	3,299	210	3,509
1940	Tools, Shop and Garage Equipment	1,660,452	1,319,800	340,652		92,593	1,753,044	386,948	10	0.10	38,695	28,509	67,204
1945	Measurement and Testing Equipment	187,835	161,436	26,400		0	187,835	26,400	5	0.20	5,280	22,735	28,015
1950	Power Operated Equipment	0	0	0		0	0	0			0	0	0
1955	Communication Equipment	161,777	111,245	50,532		0	161,777	50,532	4	0.25	12,633	6,233	18,866
1960	Miscellaneous Equipment	72,952	53,091	19,861		0	72,952	19,861	5	0.20	3,972	2,475	6,448
1970	Load Management Controls - Customer Premises	0	0	0		0	0	0			0	0	0
1975	Load Management Controls - Utility Premises	0	0	0		0	0	0			0	0	0
1980	System Supervisory Equipment	128,961	128,961	0		0	128,961	0	15	0.07	0	0	0
1985	Sentinel Lighting Rentals	0	0	0		0	0	0			0	0	0
1990	Other Tangible Property	0	0	0		0	0	0			0	0	0
1995	Contributions and Grants	(17,520,649)	0	(17,520,649)		(850,000)	(18,370,649)	(17,945,649)	25	0.04	(717,826)	23,080	(694,746)
2005	Property under Capital Lease	143,036	143,036	0		0	143,036	0	25	0.04	0	0	0
	Total before Work in Process	**200,448,806**	**28,815,098**	**171,633,708**	**0**	**9,102,793**	**209,551,599**	**176,185,105**			**7,119,062**	**24,626**	**7,143,688**
	Work in Process												
	Total after Work in Process	**200,448,806**	**28,815,098**	**171,633,708**	**0**	**9,102,793**	**209,551,599**	**176,185,105**			**7,119,062**	**24,626**	**7,143,688**

Allocated Overhead Functions

NPEI's general ledger accounting system is project driven. For all work that is to be completed, projects are created through NPEI's project accounting system. Most projects are created for a specific purpose or job when needed. Some projects are "standard", which means that they continue from year to year. All projects are created using cost categories, where each cost category represents the OEB account where costs can be charged to. Costs are charged by function of labour, equipment, material or outside purchases to each project.

Further, NPEI has two departments that are considered to be "overhead" departments (balances are cleared or allocated to other business units). The costs from each of these "overhead" departments are allocated to capital, operating, maintenance, administrative and recoverable units based on a management-approved methodology. Most often, but not always, the costs related to these departments are allocated based on charges to each general ledger account.

In addition to the allocated functions below, payroll burden costs or expenses are also allocated.

Payroll burden expenses are outlined in the Employee Compensation section of this Exhibit. An outline of the procedure used by NPEI to allocate overhead costs is attached as Appendix A.

Effectively, based on the allocations calculated each year, the resulting split has historically averaged 60% operating and 40% capital for allocated costs, although it may vary from year to year.

Costs for each of the allocated departments are as follows:

Truck Operation and Maintenance

Truck Operation and Maintenance is responsible for the maintenance of NPEI's fleet of trucks and power operated equipment. NPEI performs many of its own onsite repairs and maintenance, having two full-time mechanics and one assistant vehicle technician in its vehicle garage. The former Peninsula West Utilities outsourced all repairs to its vehicles and equipment as they did not operate their own garage.

USoA	Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test Year
9070	Garage operation & maintenance	1,079,423	1,010,285	1,026,072	1,034,927	1,055,626	1,066,182

The vehicle count is as follows:

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test Year
# of Vehicles	48	51	53	55	58	59
# of Trailers	11	11	12	12	12	12

All expenses to own and operate the fleet (including labour, fuel, repairs and maintenance and garage supplies) are captured within this department. NPEI attempts to control its fleet operating costs by replacing or overhauling vehicles as they reach the end of their useful lives. On a yearly basis, replacement priorities are set at budget time based on a number of conditions including age of the vehicle, hours in use, condition, maintenance records, increasing maintenance expenses or increasing down time.

The increase in 2008 was primarily due to an increase in fuel costs and outside services. A decrease in outside services and the impact of HST on truck tools and supplies is expected in 2010.

Allocation - All vehicle costs are charged to projects based on vehicle usage via daily equipment logs in NPEI's project accounting system. Total accumulated vehicle overhead is charged out through hourly trucking rates (rate depends on the size of the vehicle) directly to the project, thus, the actual use of the vehicle is reflected in each project and general ledger account. The allocation via the project is to operating, capital or recoverable depending on the actual work activity.

Purchasing/Stores Department

USoA	Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test Year
9040	Stores operation	292,538	321,173	266,359	308,277	272,225	279,031

The purchasing department consists of one purchasing manager, two stores keepers and one assistant store keeper for half of the day. The Purchasing Manager's time is allocated to stores, operations, billing, and general administration. The stores keepers time is recorded directly to Account 9040.

The Purchasing/Stores department is responsible for all of the purchasing activities at NPEI as well as the care and control of all inventoried items.

There are two stores warehouses, one located in Smithville and one in Niagara Falls. A number of inventoried items are also stored outside in a fenced yard.

The increase in 2009 was for operational expenses for the set up of the new warehouse located in the new Service Centre which opened in 2009. 2010 expenses are back to 2008 levels with reasonable increases for wage and benefit increases as well as inflation.

Allocation – Costs for this department are allocated based on inventory issues. For all inventory items issued from inventory a 10% to 15% material overhead is charged and the offset is credited against this cost center. The allocation of this cost center will be charged to operating & maintenance, capital and recoverable, depending on the actual work activity.

Building Maintenance, Engineering and General Administration

NPEI does not allocate any costs related to building maintenance, engineering or general administration to operations and maintenance, capital or recoverable projects.

Payments-in-lieu of Income Taxes (PILS)

NPEI is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. Table 4-27 below provides a summary of 2006 OEB Approved, 2006, 2007, 2008 and 2009 income taxes included in audited statements, 2010 Bridge Year estimate using current rates, and 2011 Test Year income taxes based on revised rates. For 2006 Board Approved, 2006 Actual and 2007 Actual the income taxes for the two former utilities Niagara Falls Hydro and Peninsula West Utilities have been combined. A copy of NPEI's 2009 Federal T2 and Ontario C23 tax return has been provided in Exhibit 4, Appendix C.

Table 4-27- Summary of Income Taxes

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Income Taxes	2,056,062	1,107,685	1,546,732	856,225	2,464,188	893,733	1,725,276
Large Corporation Tax	0	0	0	0	0	0	0
Ontario Capital Tax	248,958	269,835	223,184	253,906	251,917	83,846	0
Total Taxes	2,305,020	1,377,520	1,769,916	1,110,131	2,716,105	977,579	1,725,276

Table 4-28 Corporate Tax Rates

Corporate Tax Rates for Tax Year:	2010 Bridge	2011 Test
OCT Exemption	15,000,000	0
Federal Income Tax	18.00%	16.50%
Ontario Income Tax	13.00%	11.75%
Combined Income Tax	31.00%	28.25%
Ontario Capital Tax Rate(0.15% up to June 30 2010)	0.075%	0.000%
Large Corporation Tax Rate	0	0

Tax Calculations

NPEI's detailed tax calculations using the most recent tax rates are provided in the following Table 4-29.

Capital Taxes

NPEI provides details of the calculation of Ontario Capital Taxes in Table 4-29 for the years 2006 Board Approved, 2009 Actual, 2010 Bridge Year and 2011 Test Year. The amounts for Ontario Capital Tax are $83,846 for 2010 and $Nil for 2011. This amount decreases from year to year due to decreasing Ontario Capital Tax rates and NPEI has reflected the cessation of the capital tax rate effective July 1, 2010.

Table 4-29 Tax Calculations

Description	2006 Board Approved	2009 Actual	2010 Bridge	2011 Test
Income before PILs/Taxes	**4,028,459**	**4,146,197**	**2,954,243**	**6,419,587**
Additions:		0	0	0
Interest and penalties on taxes	25,463	8,655	1,039	0
Amortization of tangible assets	5,973,204	7,754,076	7,000,940	7,143,688
Reserves from financial statements- balance at end of year	7,504,880	11,241,890	11,713,874	11,946,671
Non-deductible meals and entertainment expenses	9,532			
Other Additions		0	0	0
Interest Expensed on Capital Leases	6,939	2,065	0	0
Realized Income from Deferred Credit Accounts	14,228			
Previous years apprentice tax credit claimed and Prior Year Apprentice tax credit	0	45,937	39,937	40,000
Total Additions	**13,534,246**	**19,052,623**	**18,755,790**	**19,130,359**
Deductions:				
Capital cost allowance from Schedule 8	4,542,231	6,870,909	7,329,316	7,463,388
Cumulative eligible capital deduction from Schedule 10		98,256	91,378	84,982
Reserves from financial statements - balance at beginning of year	7,156,389	8,531,419	11,241,890	11,713,874
Interest capitalized for accounting deducted for tax	21,642			
Capital Lease Payments	11,840	49,242	0	0
Non-taxable imputed interest income on deferral and variance accounts	138,295			
Apprenticeship and co-op credits included in F/S income		27,284	0	0
Total Deductions	11,870,397	15,577,110	18,662,584	19,262,243
Regulatory Taxable Income	**5,692,308**	**7,621,710**	**3,047,450**	**6,287,703**
Federal Corporate Income Tax Rate	22.12%	19.00%	18.00%	16.50%
Provincial Corporate Income Tax Rate	14.00%	14.00%	13.00%	11.75%
Subtotal	2,056,062	2,515,164	944,709	1,776,276
Less: ATTC, Co-operative Tax Credits and ITC	0	(50,977)	(50,976)	(51,000)
Regulatory Income Tax	2,056,062	2,464,187	893,733	1,725,276
Calculation of Utility Income Taxes				
Income Taxes	2,056,062	2,464,187	893,733	1,725,276
Large Corporation Tax	0	0	0	0
Ontario Capital Tax	208,564	251,917	83,846	0
Total Taxes	2,264,626	2,716,105	977,579	1,725,276
Calculation of Ontario Capital Tax				
Total Rate Base (2006 Taxable Capital Calculated)	89,521,305	126,794,683	126,794,683	119,144,943
Less: Exemption	(20,000,000)	(14,831,406)	(15,000,000)	0
Taxable Capital/Deemed Taxable Capital	69,521,305	111,963,277	111,794,683	119,144,943
OCT Rate	0.30%	0.225%	0.075%	0.00%
Ontario Capital Tax	**208,564**	**251,917**	**83,846**	**0**

Adjustments to Accounting Income

NPEI's adjustments to accounting income include the removal of accounting amortization, addition of capital cost allowance (CCA), the adjustment of reserves, and the addition of the Ontario Apprenticeship and Co-operative Tax Credits. The 2010 adjustments to accounting income are in Table 4-30 and 2011 adjustments to accounting income are in Table 4-31. Reserves from Financial Statements include the Other Employee Future Benefits and Regulatory Liabilities balances.

Table 4-30 Adjustments to Accounting Income for 2010

Line Item	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Utility Amount
Additions:				
Interest and penalties on taxes	103	1,039	0	1,039
Amortization of tangible assets	104	7,000,940	0	7,000,940
Reserves from financial statements- balance at end of year	126	11,713,874	0	11,713,874
Other Additions (Apprenticeship Tax Credits)	295	39,937	0	39,937
Total Additions		**18,755,790**	**0**	**18,755,790**
Deductions:				
Capital cost allowance from Schedule 8	403	7,329,316	0	7,329,316
Cumulative eligible capital deduction from Schedule 10	405	91,378	0	91,378
Reserves from financial statements - balance at beginning of year	414	11,241,890	0	11,241,890
Total Deductions		**18,662,584**	**0**	**18,662,584**
Tax Adjustments to Accounting Income		**93,207**	**0**	**93,207**

Table 4-31 Adjustments to Accounting Income for 2011

Line Item	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Utility Amount
Additions:				
Amortization of tangible assets	104	7,143,688	0	7,143,688
Reserves from financial statements- balance at end of year	126	11,946,671	0	11,946,671
Other Additions (Apprenticeship Tax Credits)	295	40,000	0	40,000
Total Additions		**19,130,359**	**0**	**19,130,359**
Deductions:				
Capital cost allowance from Schedule 8	403	7,463,388	0	7,463,388
Cumulative eligible capital deduction from Schedule 10	405	84,982	0	84,982
Reserves from financial statements - balance at beginning of year	414	11,713,874	0	11,713,874
Total Deductions		**19,262,243**	**0**	**19,262,243**
Tax Adjustments to Accounting Income		**(131,884)**	**0**	**(131,884)**

Apprenticeship tax credits for 2010 and 2011 have been estimated at the same level as 2009 Actual.

Capital Cost Allowance

NPEI is providing Capital Cost Allowance continuity schedules for the 2010 Bridge Year in Table 4-32 and the 2011 Test Year in Table 4-33.

NPEI has Cumulative Eligible Capital and is providing continuity schedules for the 2010 Bridge Year in Table 4-34 and 2011 Test Year in Table 4-35.

Table 4-32 2010 Bridge Year Capital Cost Allowance

CCA Continuity Schedule (2010)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	66,238,417	0	0	66,238,417	0	0	66,238,417	0	66,238,417	0.04	2,649,537	63,588,880
2	Distribution System - pre 1988	4,653,597	0	0	4,653,597	0	0	4,653,597	0	4,653,597	0.06	279,216	4,374,381
6	Buildings (No footings below ground)	0	0	0	0	0	0	0	0	0	0.10	0	0
8	General Office/Stores Equip	1,296,021	0	0	1,296,021	196,388	0	1,492,409	98,194	1,394,215	0.20	278,843	1,213,566
10	Computer Hardware/ Vehicles	1,373,437	0	0	1,373,437	1,097,650	0	2,471,087	548,825	1,922,262	0.30	576,679	1,894,408
10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	0.30	0	0
12	Computer Software	184,608	0	0	184,608	278,954	0	463,562	139,477	324,085	1.00	324,085	139,477
3		1,565,705	0	0	1,565,705	0	0	1,565,705	0	1,565,705	0.05	78,285	1,487,420
1b	Buildings > 18-03-07	6,150,760	0	0	6,150,760	0	0	6,150,760	0	6,150,760	0.06	369,046	5,781,714
13 3	Lease # 3	0	0	0	0	0	0	0	0	0		0	0
13 4	Lease # 4	0	0	0	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	394,209	0	0	394,209	0	0	394,209	0	394,209	0.08	31,537	362,672
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	0	0	0	0.30	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	30,955	0	0	30,955	0	0	30,955	0	30,955	0.45	13,930	17,025
50	Computers & Systems Hardware acq'd post Mar 19/07	180,020	0	0	180,020	0	0	180,020	0	180,020	0.55	99,011	81,009
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	0	0	0	0.30	0	0
47	Distribution System - post 22-Feb-2005	26,661,856			26,661,856	12,404,990	3,163,008	35,903,838	3,039,487	32,864,351	0.08	2,629,148	33,274,690
	SUB-TOTAL - UCC	**108,729,585**	**0**	**0**	**108,729,585**	**13,977,982**	**3,163,008**	**119,544,559**	**3,825,983**	**115,718,576**		**7,329,316**	**112,215,243**

Table 4-33 2011 Test Year Capital Cost Allowance

CCA Continuity Schedule (2011)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	63,588,880	0	0	63,588,880	0	0	63,588,880	0	63,588,880	4%	2,543,555	61,045,325
2	Distribution System - pre 1988	4,374,381	0	0	4,374,381	0	0	4,374,381	0	4,374,381	6%	262,463	4,111,918
6	Buildings (No footings below ground)	0	0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	1,213,566	0	0	1,213,566	185,185	0	1,398,751	92,593	1,306,158	20%	261,232	1,137,519
10	Computer Hardware/ Vehicles	1,894,408	0	0	1,894,408	754,861	0	2,649,269	377,431	2,271,839	30%	681,552	1,967,718
10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	139,477	0	0	139,477	182,870	0	322,347	91,435	230,912	100%	230,912	91,435
3		1,487,420	0	0	1,487,420	0	0	1,487,420	0	1,487,420	5%	74,371	1,413,049
		5,781,714	0	0	5,781,714	0	0	5,781,714	0	5,781,714	6%	346,903	5,434,812
13 3	Lease # 3	0	0	0	0	0	0	0	0	0		0	0
13 4	Lease # 4	0	0	0	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	362,672	0	0	362,672	0	0	362,672	0	362,672	8%	29,014	333,658
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	17,025	0	0	17,025	0	0	17,025	0	17,025	45%	7,661	9,364
50	Computers & Systems Hardware acq'd post Mar 19/07	81,009	0	0	81,009	0	0	81,009	0	81,009	55%	44,555	36,454
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	33,274,690			33,274,690	7,979,876	0	41,254,566	3,989,938	37,264,628	8%	2,981,170	38,273,396
	SUB-TOTAL - UCC	**112,215,243**	**0**	**0**	**112,215,243**	**9,102,793**	**0**	**121,318,036**	**4,551,396**	**116,766,639**		**7,463,388**	**113,854,648**

Table 4-34 2010 Bridge Year Cumulative Eligible Capital

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				1,305,401
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	1,305,401
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				1,305,401
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	1,305,401
Cumulative Eligible Capital Balance				1,305,401
CEC Deduction	7%			91,378
Cumulative Eligible Capital - Closing Balance				1,214,023

Table 4-35 2011 Test Year Cumulative Eligible Capital

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				1,214,023
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	1,214,023
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				1,214,023
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	1,214,023
Cumulative Eligible Capital Balance				1,214,023
CEC Deduction	7%			84,982
Cumulative Eligible Capital - Closing Balance				1,129,041

Purchase of Products and Services from Non-Affiliates

Like other distributors, NPEI purchases many services and products from third parties. The tables below illustrate NPEI's expenditures on purchased products and services. The four tables below contain information on the purchases of non-affiliate services for 2006 (Table 4-36), 2007 (Table 4-37), 2008 (Table 4-38) and 2009 (Table 4-39) by NFH and PWU combined and NPEI. The total costs are the costs paid to Suppliers each year. Suppliers have been included in the list if the total purchases exceed $100,000 per year. Payroll remittances (benefits, Government remittances, etc.), payments to the IESO, OEFC, energy retailers, government organizations, distributors and affiliate transactions are excluded.

Like other distributors, NPEI purchases many services and products from third parties. To ensure that the Corporation receives the value for its money, NPEI has developed a Purchasing Policy which outlines the procedures to be followed by all employees. The Purchasing Policy is attached as Appendix B of this Exhibit 4.

Beside each supplier reference in Tables 4-36 through 4-39 below, is an indication of the type(s) of procurement methodology employed.

Table 4-36 Non-Affiliate Purchases > $100,000 – 2006

Non-Affiliate Purchases > $100,000 in 2006

Supplier	Service/Product	Procurement method	$
AB Data Solutions	Billing system program and maintenance	Sole source	182,482.15
ANIXTER CANADA INC.	Wire	Quote	241,333.37
Bel Volt Sales Limited	Construction materials	Quote/As required	111,423.05
Borden Ladner Gervais LLP	Legal fees	Quote	149,338.65
Canada Power Products Corp	Construction materials	Quote	240,567.10
Canadian Electrical Services	Transformers	Quote	331,877.57
COLLECTIVE UTILITY SERV. INC.	Meter reading service	Annual pricing	147,690.33
DUNDAS POWER LINE LTD	Construction services	Quote	128,638.14
Electrical Cable Supply Ltd	Wire	Quote/As required	244,604.98
Endura Construction	Construction services	Quote	323,369.20
ENERconnect	Meter reading service	Annual pricing	131,556.80
G-A-M-S	Construction services	Quote	330,938.99
General Cable Company	Wire	Quote	471,410.77
Grafton Utility Supply Ltd	Construction materials	Quote	351,136.52
K-LINE MAINTENANCE & CONSTRUCTION	Construction services	Quote	542,346.96
LUCAS TREE EXPERTS	Tree trimming	Annual pricing	161,443.96
Manulife Financial	Employee benefits	Annual pricing	593,259.28
Mearie Management Inc.	Insurance/training seminars	Annual pricing/As required	243,697.36
Moloney Electric	Transformers	Quote	376,511.20
Niagara Meter Services Inc.	Meter reading service	Annual pricing	273,352.76
Postage By Phone System	Postage	Sole source	191,700.00
SOUTHWEST POWER CORP.	Construction services	Quote	423,098.10
Timberland Equipment Limited	Line Truck and Equipment	Quote	155,321.75
Vanwoudenberg Trenching & Excavating Inc.	Trenching & Excavating	Quote	108,483.54
WAJAX INDUSTRIES LIMITED	Line Truck and Equipment	Quote	347,835.44
Westburne Ruddy Electric	Construction materials	Quote/As required	346,358.91
Wiens Underground	Construction services	Quote/As required	189,098.37

Table 4-37 Non-Affiliate Purchases > $100,000 – 2007

Non-Affiliate Purchases > $100,000 in 2007

Supplier	Service/Product	Procurement method	$
AB Data Solutions	Billing system program and maintenance	Sole source	154,590.40
ABB Inc.	Transfomers	Quote	112,668.84
Allan Fyfe Equipment Ltd	Line Truck and Equipment	Quote	118,158.44
ANIXTER CANADA INC.	Wire	Quote	485,831.26
BEL VOLT SALES LTD.	Construction materials	Quote/As required	147,893.21
Bell Canada	Telephone system	Sole source	122,558.16
BLACK & MCDONALD LTD.	Construction services	Quote	577,390.53
CANADA POST	Postage	Sole source	108,239.35
CANADIAN ELECTRICAL SERVICES	Transfomers	Quote	175,717.32
COLLECTIVE UTILITY SERV. INC.	Meter reading	Annual pricing	173,865.66
DUNDAS POWER LINE LTD	Construction services	Quote	820,395.49
Electrical Cable Supply Ltd	Wire	Quote/As required	235,718.20
Endura Construction	Construction services	Quote	395,885.03
ENERconnect	Meter reading	Annual pricing	193,996.46
Engineering Concepts Niagara	Engineering/Project Management	Quote	277,076.00
G-A-M-S	Construction services	Quote	886,824.58
General Cable Company	Wire	Quote	213,636.77
Grafton Utility Supply Ltd	Construction materials	Quote/As required	302,432.86
Guelph Utility Pole Co. Ltd	Construction materials	Quote/As required	532,392.54
H D Supply Utilities	Construction materials	Quote/As required	253,853.69
Harris Computer Systems	Billing system program and maintenance	Tender	315,125.48
ITRON	Meters	Quote	127,094.71
Kelly Services (Canada) Ltd	Temporary labour	Quote	108,297.58
K-LINE MAINTENANCE & CONSTRUCTION	Construction services	Quote	801,826.25
Loud Advertising Inc.	Creative work for communications	Annual pricing	190,011.28
Manulife Financial	Employee Benefits	Annual pricing	649,925.92
Mearie Management Inc.	Insurance/Training & Seminars	Annual pricing	440,172.38
Moloney Electric	Transfomers	Quote	1,057,989.54
Niagara Meter Services Inc.	Metering	Annual pricing	307,782.41
Peninsula Video & Sound Inc.	Locates	Annual pricing	118,679.14
Pineridge Tree Service	Tree trimming	Annual pricing	313,263.99
Postage By Phone System	Postage	Sole source	212,000.00
Prysmian Power Cables & Systems Canada Ltd	Wire	Quote	274,639.73
SOUTHWEST POWER CORP.	Construction services	Quote	325,892.62
VANWOUDENBERG TRENCHING & EXCAVATING	Trenching & Excavating	Quote	190,024.40
Westburne Ruddy Electric	Construction materials	Quote/As required	259,645.71
Wright Fuels (Niagara) Ltd	Fuel	Sole source	101,648.31

Table 4-38 Non-Affiliate Purchases > $100,000 – 2008

Non-Affiliate purchases > $100,000 in 2008

Supplier	Service/Product	Procurement method	$
Anixter Canada Inc	Wire	Quote	280,118.20
Bel Volt Sales Limited	Construction materials	Quote/As required	115,771.00
Bell Canada	Telephone system	Quote	168,820.29
Black & McDonald	Construction services	Quote	588,620.20
Brouwer Construction Ltd.	Renovation/Construction	Tender	973,487.95
COLLECTIVE UTILITY SERV. INC.	Meter reading	Annual pricing	169,686.12
DL HANNON INC	Construction services	Quote	365,767.50
Done-Rite Paving Co.	Paving	Quote	159,593.30
DUNDAS POWER LINE LTD	Construction service	Quote	137,258.85
Electrical Cable Supply Ltd	Wire	Quote	114,590.97
Endura Construction	Construction services	Quote/As required	460,237.61
ENERconnect	Meter reading	Annual pricing	231,116.24
Engineering Concepts Niagara	Engineering/Project Management	Quote	415,435.09
G-A-M-S	Construction services	Quote	580,293.67
GoodCents International, ULC	CDM program	Sole source	126,308.97
Guelph Utility Pole Co. Ltd	Construction materials	Quote	242,481.05
H D Supply Utilities	Construction materials	Quote/As required	314,552.09
Intergraph Canada Ltd.	GIS system	Tender	116,380.96
K-Line Maint. & Construction Ltd	Construction services	Quote	445,489.60
Lakeport Power Ltd	Transformers	Quote	273,629.80
Loud Advertising Inc.	Creative for communications	Annual pricing	157,623.01
Manulife Financial	Employee Benefits	Annual pricing	803,049.10
Mearie Management Inc.	Insurance/Training & Seminars	Annual pricing	292,938.66
Moloney Electric	Transformers	Quote	633,490.43
Nexans	Wire	Quote	231,999.55
Nextec SMS	Computer Equipment	Quote	185,073.66
Niagara Meter Services Inc.	Meter reading	Annual pricing	280,204.22
Norjohn Contracting and Paving Ltd.	Paving	Quote	114,038.21
Peninsula Video & Sound Inc.	Locates	Annual pricing	144,791.06
Pineridge Tree Service	Tree trimming	Annual pricing	173,018.48
Posi-Plus Ontario Inc	Line Trucks & Equipment	Quote	229,136.57
Postage By Phone System	Postage	Sole source	157,416.08
SOUTHWEST POWER CORP.	Construction services	Quote	120,560.02
T.R. Hinan Contractors Inc.	Construction Service Centre	Tender	1,765,035.57
VANWOUDENBERG TRENCHING & EXCAVATING	Trenching & Excavating		101,153.56
Westburne Ruddy Electric	Construction materials	Quote/As required	260,110.13
Wiens Underground	Construction services	Quote	147,047.62
Wright Fuels (Niagara) Ltd	Fuel	Sole source	128,405.90

Table 4-39 Non-Affiliate Purchases > $100,000 – 2009

Non-Affiliate purchases > $100,000 in 2009

Supplier	Service/Product	Procurement method	$
Anixter Canada Inc	Wire	Quote	402,100.77
Bel Volt Sales Limited	Construction material	Quote/As required	171,933.13
Bell Canada	Telephone system	Quote	410,851.54
Broderick & Partners	Legal fees	As required	317,376.36
Brouwer Construction Ltd.	Renovation/Construction	Tender	201,523.91
Canada Power Products Corp	Construction material	Quote	141,839.86
Canadian Electrical Services	Transformers	Quote	303,249.06
Carte International Inc.	Transformers	Quote	164,391.27
CDW Canada Inc.	Computer software	Quote	143,419.10
COLLECTIVE UTILITY SERV. INC.	Meter reading	Annual pricing	158,323.31
DAVEY TREE EXPERT CO OF CANADA	Tree trimming	Annual pricing	292,090.70
DL HANNON INC	Construction services	Quote	126,992.25
Endura Construction	Construction services	Quote/As required	466,278.20
Engineering Concepts Niagara	Engineering/Project Management	Quote	146,336.67
G A M S	Construction services	Quote/As required	1,045,693.54
Greely Construction	Construction services	Quote	144,431.70
Guelph Utility Pole Co. Ltd	Construction material	Quote	370,112.29
H D Supply Utilities	Construction material	Quote/As required	455,327.56
Intergraph Canada Ltd.	GIS system	Tender	277,040.95
KTI Limited	Smart meters	Tender	990,183.15
Lakeport Power Ltd	Transformers	Quote	161,420.97
Lippert & Wright Fuels	Fuel	Sole source	123,386.81
Loud Advertising Inc.	Creative for communications/printing	Annual pricing	137,311.62
M3 & W Inc.	CDM program	Sole source	422,226.04
Manulife Financial	Employee Benefits	Annual pricing	885,363.00
Mearie Management Inc.	Insurance/Training & Seminars	Annual pricing	133,204.32
Moe & Mike Montgomery	Landscaping	Quote	101,454.50
Moloney Electric	Transformers	Quote	285,866.27
Nexans	Wire	Quote	191,508.36
Niagara Meter Services Inc.	Meter reading	Annual pricing	322,773.05

One time Costs

NPEI has included one-time costs in its 2011 distribution rate application for the cost of this application. NPEI has estimated $310,000 to prepare this application and has included one-quarter of this amount, $77,500, in the test year.

NPEI has not included any costs for low income consumer programs in this application as the government has recently allowed the Board to re-commence its proceeding with regards to low-income consumers. NPEI will update this application, prior to the finalization of its rates, with any applicable charges at the time of Board issued instructions.

Special Purpose Charges related to the Green Energy Act

SPECIAL PURPOSE CHARGES RELATED TO THE GREEN ENERGY AND GREEN ECONOMY ACT, 2009:

NPEI completed Smart Meter installations in 2010 in accordance with the Minister's directive. In addition, NPEI plans to continue with the delivery of standard OPA and CDM programs; and has not budgeted for any distribution system costs to connect renewable generation facilities under the FIT program or other renewable generation facilities. NPEI is proposing that if any qualifying expenditure is required in the future, that it would be recorded in the Board approved Deferral Accounts.

There are currently 2 FIT Applications with the OPA in NPEI's service area, however, and one contract has been recently awarded. NPEI has not filed a Distribution System Plan in accordance with EB-2009-0397, in which filing of this plan is optional for 2011 cost of service applications. As NPEI is not requesting funds for recovery for connection of renewable generation facilities, NPEI has not submitted a plan.

NPEI has not included any costs related to the Green Energy Act in the 2011 Test Year distribution expenses.

Appendix A Overhead Recovery Process – Year 2009

Overhead Type	Recovery Basis	From Department	To	Job Type
Allocation of Material Overheads	10 to 15% applied to cost of materials issued from inventory	Purchasing & Stores Burden	Projects	Capital, maintenance, operating, burden accounts and billable
Allocation of Labour Overheads	37% applied to direct labour dollars	Payroll Burden	Projects & Salary G/L accounts	Capital, maintenance, operating, burden accounts and billable
Allocation of Vehicle Overheads	Trucking hourly rate charged directly to projects of G/L account as used - Rates vary from $8-$95 including vehicles and equipment	Vehicle Burden	Projects	Capital, maintenance, operating, burden accounts and billable

Appendix B - NPEI's Purchasing Policy

PURCHASING
NPE-F-200

Niagara
Peninsula
Energy

Purchasing: Equipment, Replacement Parts, Hazardous Materials

Document #: NPE-F-200
Revision #: 3
Effective Date: November 13, 2008

Table of Contents

Niagara Peninsula Energy

Purchasing: Equipment, Replacement Parts, Hazardous Materials

Purpose
To ensure that purchased products and services conform to specified requirements.
Scope Purchased goods, materials and services that have an impact on product quality or heath & safety.
Responsibility: Purchasing Department representatives or departmental purchasing authorities.
Requirements
ISO 9001:2000, Clause 7.4 Purchasing
Reference
NPE-F-201 Records Management
NPE-HS-215 Purchasing, Replacement Parts, Hazardous Materials
NPE-OP-201 Corrective/Preventive Action and Continual Improvement
Procedure
It is the policy of Niagara Peninsula Energy Inc. to ensure that:
Specifications are available and identified prior to a purchase being made;
Purchase orders and purchase order changes are processed by the Purchasing Department or departmental purchasing authority;
Purchase orders are awarded only to pre-approved suppliers;
Purchases conform to specified requirements.
1.0 Requirement Assessment
Prior to purchase, product/service requirements are determined and specified on the ***Purchase Requisition.*** Requisitioners assess requirements with consideration to the following:
Product reliability;
Longevity;
Past history of product/service (as indicated by previous performance, noncompliance's or feedback from users or other corporations);
Price;
Quality;

Inherent safety features;
Data or information provided by their supervisor and/or a health & safety representative regarding product/service health & safety concerns or requirements;
Product replacement parts should be equivalent or superior in quality to those of the OEM (Original Equipment Manufacturer).

CSA Standards

Niagara Peninsula Energy adheres to the standards set forth by the CSA in reference to any and all materials that we, as a company, purchase and issue for use and protection in our electrical distribution system.

Personal Protective Equipment (PPE) and Certified Equipment

Niagara Peninsula Energy is dedicated to providing maximum protection for our employees in the working environment. Our company purchases, and will only purchase, certified safety equipment that meets the standards of our governing authority. Suppliers are required to submit CSA or equivalent standard codes, or related information on each product that assures they meet the requirements set forth by our governing authority. Products and/or equipment that DO NOT meet, or are in question, are immediately quarantined for either disposal, or decision from our governing authority if use can be continued.

2.0 Evaluation and Selection of Suppliers

Suppliers are evaluated and selected by one or more of the criteria described below. Product and/or service applications often dictate that multiple selection criteria be met by the potential supplier.
Circumstances and individual department requirements may apply additional selection criteria as indicated in applicable departmental manuals.
The organization controls any suppliers procured for outsourcing by imposing on them the same requirements that the organization itself must fulfill.
Supplier evaluation results and subsequent actions are documented. Records of assessment are created prior to addition of the supplier to the Approved Supplier Inventory and prior to placing an order.

2.1 Performance Based

Suppliers of products and services may be approved on the basis of their previous delivery and quality performance.

2.2 Supplier Audits

The Purchasing Department representatives or departmental purchasing authorities may audit suppliers.

The audit's purpose is to ensure that the supplier's manufacturing, quality and health & safety practices satisfy the organization's requirements.

Survey audit reports are prepared and retained on file.

2.3 Review of Supplier Data

The organization may approve a supplier based upon a review of the supplier product technical data, contract terms and conditions, published information, or through discussions with customer references provided by the supplier.

2.4 Client-Specified Supplier Requirements

The organization may use suppliers specified by their clients as long as the products do not contravene statutory or regulatory requirements.

Departmental purchasing authorities or Purchasing Department representatives normally perform the assessment of suppliers. Input from other organizational personnel is obtained as required. Records of the assessments are produced. Individual departments maintain records of supplier assessment along with other supplier performance information.

3.0 Approved Supplier Inventory

An Approved Supplier Inventory is maintained by the Purchasing Department for use in purchasing products and services for the organization.

3.1 New Suppliers

The addition of new suppliers, and removal of existing suppliers, is authorized by the departmental purchasing authority with input provided by the Purchasing Department representatives. When consulting and auditing organizations are being assessed, the Management Representative participates and has the final authority for the approval. Applicable purchasing departmental authorities notify the Purchasing Department of additions to the Approved Supplier Inventory.

3.2 Inventory Review

The Approved Supplier Inventory is reviewed and updated annually as a minimum.

Each department notifies the Purchasing Department of any additions or modifications to the Inventory in order to maintain its master list of approved suppliers

With input from each department, the Purchasing Department and/or the Quality Assurance
Representative monitors supplier nonconformances and limitations, and as necessary, initiates appropriate action with identified suppliers.
Suppliers failing to provide acceptable product or services are removed from the Approved Suppliers Inventory.

4.0 Nonconforming Products

Each department monitors its nonconformance's on a regular basis and nonconformance's or limitations (particularly numerous ones) related to purchased product or service are communicated to Purchasing through the CPI process in accordance with *Corrective/Preventive Action and Continual Improvement*, NPE-OP-201.
Following evaluation of this data, the Approved Supplier's Inventory is reviewed and updated as necessary.

5.0 Spending Limits

Authority
• The purchasing manager has signing authority for budgeted items up to $50,000. Budgeted items are defined as described in the capital budget, usual or common inventory and service items.
• Items/Services $50,000 and higher and all non-budgeted items requires approval by VP.
Exceptions – Payment remittances to government entities including Revenue Canada, Debt retirement Fund, GST, Workers' Compensation, and EHT, can be signed by the CEO and designate.
< $1000 Discretion will be used by the Purchasing Manager or Management to obtain optimal value for a product or service.
$1000 to $10,000 Attempt to obtain a minimum of 3 quoted prices. Normally, the lowest price will be accepted. In the event that the item/service is selected based on other than price, the appropriate department manager must be consulted.
$10,000 to $49,999 Obtain a minimum of 3 written prices (where possible) for items/services that meet a prepared specification. Approval of the department manager is required for the purchase. In the event that a vendor is selected not based on lowest price but on delivery or comparative quality etc., a written record shall be filed with the purchasing documents.

75% of inventoried items are purchased through a yearly co-operative tender. The tender is sent out to all bidding suppliers, and the lowest price is taken in all cases where goods are equal. This tender is good for one calendar year.

6.0 Purchasing Process

Purchasing activities are conducted in accordance with purchasing practices established by the organization. Departmental Manuals may have extra requirements to meet their specific needs.

The purchasing process includes the following phases and inputs as identified in figure 1 below.

- Identify
- Requirements
- Create
- Requisition
- (including
- specifications)
- Obtain Quotes
- or Tenders
- Award Purchase
- Order Receive Material
- Approved
- Supplier
- Inventory
- Nonconforming
- Product
- Evaluate
- Responses

Figure 1, Purchasing Process

Departmental authorities identify their purchasing needs. Purchases may be conducted by the requisitioning department or through Purchasing.

6.1 Processed by Requisitioning Department

In addition to their own purchasing authority status, the department manager/supervisor selects additional departmental purchasing authorities as necessary for the purpose of approving purchases for use within the department. The departmental purchasing authority identified has the expertise necessary to make informed purchases for the department.

A ***Purchase Requisition*** identifying requirements and specifications is developed as necessary and forwarded to the departmental purchasing authority for approval. The departmental purchasing authority may allow verbal requisitions for routine purchases such as those identified under a blanket purchase order. Verbal orders to the supplier are identified and recorded through the use of a ***Purchase Requisition***, ***Stock Requirements*** form or by equivalent means.

For higher value purchases, the departmental purchasing authority obtains quotations or tenders from approved suppliers as necessary. The departmental purchasing authority reviews the responses, decides on the purchases to be made, and selects the supplier.

The departmental purchasing authority obtains purchase order numbers or blanket purchase orders from the Purchasing Department and processes the requisitions as appropriate.

The departmental purchasing authority is responsible for ensuring that approval of the supplier and product are obtained prior to making the purchase.

Copies of records created or obtained by the department such as ***Purchase Requisitions*** or receiving documentation such as packing slips and Bills of Lading are approved by department management and forwarded to the Purchasing Department.

6.2 Processed by Purchasing Department

Where purchasing limitations are beyond the authority of the department, a ***Purchase Requisition*** identifying requirements is completed and issued to the Purchasing Department. Technical specifications for the required products or materials, applicable quality standards to be applied, specific contract requirements, etc. are identified and accompany the ***Purchase Requisition***.

The Purchasing Department representatives obtain quotations or tenders from approved suppliers. The requisitioner, with input from the Purchasing Department, reviews the responses, decides on the purchases to be made, ensures that selected purchasing options are identified and selects the supplier.

Approval of the ***Purchase Requisition*** is obtained from the appropriate approval authority. The CEO, with consent from the Board of VP has final approval for high value purchases. The Purchasing Department representatives issue purchase orders as appropriate and provide a copy of the purchase order to the departmental purchasing authority as appropriate.

Departmental purchasing authorities ensure that selected purchasing options are identified to the Purchasing Department for inclusion on the purchase order or referenced documents. Approval of the ***Purchase Requisition*** is obtained from the appropriate departmental approval authority. The Purchasing Department places the contract award and provides a copy of the purchase order to the departmental purchasing authority.

Notes: The organization does not normally perform product verification at their supplier's premises.

Product verification is conducted at the Receiving Inspection stage as defined in applicable departmental Inspection Procedures, Receiving Inspection Lists and Quality Plans. Where product verification is required to be performed at the supplier's premises, the verification will be identified on the purchase order.

Customer verification of subcontracted product will be permitted only where contracted. Verification of product by the customer shall not absolve the organization of the responsibility to provide acceptable product, nor shall it preclude subsequent rejection by the customer.

7.0 Review and Approval of Purchase Orders

A Purchasing Department representative and departmental purchasing authority reviews all purchase orders and amendments. The orders and amendments are signed or initialed before being issued to the supplier.

The Purchasing Department and departmental purchasing authority are provided with a hardcopy of the purchase order, ***Purchase Requisition*** or amendment.

8.0 Purchase Order Modifications

8.1 Initiated by the Organization

A Purchasing Department representative and departmental purchasing authority notifies the supplier of the required change, amends the existing purchase order/***Purchase Requisition*** or cancels the order and issues a new purchase order. The Purchasing Department and departmental purchasing authority are provided with copies of the amended order information.

8.2 Initiated by the Supplier

A Purchasing Department representative or departmental purchasing authority reviews the status of the modification against initial requirements and determines a course of action. The Purchasing Department representative or departmental purchasing authority notifies the supplier and processes the appropriate purchase order change. The Purchasing Department and departmental purchasing authority are provided with copies of the amended order information.

9.0 Purchasing Hazardous Materials

9.1 ***Ordering Procedure***

Make a note of supervisor requesting product and location(s) in the plant where product will be used.

Check the M.S.D.S. binders to see if product is presently on-site. If product is on-site and there is a current M.S.D.S (within the last 3 years) available - Go to Purchasing Procedure 9.2.

If product IS NOT on-site presently:

- Contact the supplier and ask if the product is a WHMIS controlled substance.
- If the product is WHMIS controlled ask the supplier to tell you which WHMIS classifications the product is controlled under.
- Request that the supplier provide a copy of the M.S.D.S.
- Produce copies of the M.S.D.S. for the order originating supervisor, supervisors in other locations where product will be used and for the receiving supervisor. These copies will be employed by the supervisors to make their employees aware of the products hazard before it arrives on-site.

• Specific Personal Protective Equipment to suit the products hazards will be ordered and received on-site before the arrival of the product.

9.2 ***Purchasing Procedure***

When placing an order for a product presently on-site:
Notify the supplier that the product will be returned if it is not labeled according to WHMIS legislation.
When placing an order for a controlled product which is not presently on-site:
Request that the supplier forward a current M.S.D.S. with the shipment.
Notify the supplier that the product will be returned if it is not labeled according to WHMIS legislation.
Upon receipt of the M.S.D.S. and the product, purchasing will produce copies of the Data Sheet and distribute them for inclusion in the appropriate M.S.D.S. binders.

9.3 ***Receiving Procedure***

Supervisor will review with all appropriate receiving personnel, the M.S.D.S., which arrived electronically from the supplier.
Receiving personnel will check all products entering the site, to ensure that WHMIS labels are affixed and that a M.S.D.S. has arrived with the order.
Receiving personnel will return unlabelled products and products not accompanied by a M.S.D.S. to the supplier.
Receiving will be responsible for affixing WHMIS labels to controlled products they accept, which are not labeled properly from the supplier.

9.4 ***Training Procedure***

The order originating supervisor will review the products hazards with their employees, using the supplied M.S.D.S. as a guide, before the product arrives on-site.
Other supervisors, who will have the product in their areas, will review the supplied M.S.D.S. with their personnel, before the product enters the area.
The receiving supervisor will review the M.S.D.S. with his personnel before the product arrives on-site and before his employees make initial contact with the product.

10 Personal Protective Equipment (PPE) Procedure

10.1 Personal Protective Equipment requirements for hazardous materials will be developed jointly by
Purchasing and the Joint Health & Safety Committee.
10.2 Specific personal protective equipment for each hazardous material will be ordered by Purchasing and received and distributed by Receiving before the product(s) arrive on-site.
10.3 Employees who will be working in proximity to a hazardous material, will be trained, by their respective supervisor in the use, care and cleaning of Personal Protective Equipment required in their workplace.

11 Receiving Inspection

Products are received and inspected by Stores or personnel within the requisitioning department.
Receiving inspection activities are conducted as defined in applicable departmental Monitoring and Measurement procedures.
Copies of records obtained by the department during receiving are signed by department management and forwarded to the Purchasing Department.
Records created or received during the activities of this process are filed and maintained in accordance with *Records Managemen*t, NPE-F-201.

Records/Forms
i) ***Purchase Requisition***
ii) ***Stock Requirements*** form
iii) Quotes/Tenders
iv) Correspondence
v) Purchase Orders and Order Changes

Appendix C NPEI 2009 Corporate Income Tax Return

3n03D09.209
2010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

200

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

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, paragraphs, and subparagraphs 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 87196 9127 RC0001

Corporation's name
002 NIAGARA PENINSULA ENERGY 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 7447 PIN OAK DRIVE
012

City	Province, territory, or state
015 NIAGARA FALLS	016 ON
Country (other than Canada)	Postal code/Zip code
017	018 L2E 6S9

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 [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 7447 PIN OAK DRIVE
032

City	Province,territory, or state
035 NIAGARA FALLS	036 ON
Country (other than Canada)	Postal code/Zip code
037	038 L2E 6S9

040 Type of corporation at the end of the tax year

1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] 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 060 2009-01-01 YYYY MM DD
Tax year-end 061 2009-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . 065 ____ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

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 [ ] 2 No [X]
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					

PLEASE KEEP FOR REFERENCE

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	X	9
Is the corporation an associated CCPC?	160	X	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		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	X	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	X	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	X	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	X	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	X	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

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		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 [X]

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	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

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		7,621,710	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")			7,621,710	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		7,621,710	
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)			7,621,710	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** 7,621,710 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** 7,621,710 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 365 = ... 1

500,000 x Number of days in the tax year after 2008 365 / Number of days in the tax year 365 = ... 500,000 2

Add amounts at lines 1 and 2 500,000 4

Business limit (see notes 1 and 2 below) .... **410** 500,000 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 500,000 x **415** *** 264,961 D / 11,250 = ... 11,776,044 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 365 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 365 / Number of days in the tax year 365 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			7,621,710	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")			7,621,710	H

Amount H	7,621,710	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 365	x	7 %	=	I
Amount H	7,621,710	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	J
Amount H	7,621,710	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	365 / 365	x	9 %	= 685,954	K
Amount H	7,621,710	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 365	x	10 %	=	L
Amount H	7,621,710	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	L1
Amount H	7,621,710	x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	L2

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L2 . . . 685,954 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)				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")				S

Amount S		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 365	x	7 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	365 / 365	x	9 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 365	x	10 %	=	W
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	W1
Amount S		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	W2

General tax reduction – Total of amounts T to W2 . . . 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		7,621,710		
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 =			
		7,621,710		
		x 26 2 / 3 % =	2,032,456	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)		1,437,086		
Deduct: Corporate surtax from line 600				
Net amount		1,437,086	1,437,086	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	1,690		
Deduct: Dividend refund for the previous tax year	465	1,690		
				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	500,000	x 1 / 3	166,667	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	2,896,250 A

Corporate surtax calculation

Base amount from line A above	2,896,250	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	762,171	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	6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)		c	

Total of lines 2 to 6	762,171	7
Net amount (line 1 **minus** line 7)	2,134,079	8

Corporate surtax*

Line 8 2,134,079 x Number of days in the tax year before January 1, 2008 ____ / Number of days in the tax year 365 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	7,621,710		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	7,621,710 ▶	7,621,710	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) 2,896,250 E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	608	762,171	
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	685,954	
General tax reduction from amount X	639		
Federal logging tax credit from Schedule 21	640		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652	11,039	
	Subtotal	1,459,164 ▶	1,459,164 F

Part I tax payable – Line E **minus** line F . . . 1,437,086 G
Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	1,437,086
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		1,437,086

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	1,279,019	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		1,279,019 ▶	1,279,019
Total tax payable	770		2,716,105 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	2,450,000	
Total credits	890	2,450,000 ▶	2,450,000 B

Refund code 894 ____ Overpayment ____ ◀ Balance (line A **minus** line B) 266,105

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 266,105

Enclosed payment 898 266,105

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 WILSON (Last name in block letters) 951 SUZANNE (First name in block letters) 954 VICE PRESIDENT FINANCE (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 2010-06-23 Date (yyyy/mm/dd) ____ Signature of the authorized signing officer of the corporation 956 (905) 356-2681 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 ____ Name in block letters 959 ____ 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
	Instalment	2,450,000
	Instalment	
	Instalment	
	Instalment	
	Instalment	
	Instalment	
	Instalment	
	Instalment	
	Instalment	
	Instalment	
	Instalment	
	Instalment	
	Instalment	
	Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	2,450,000 A
	Total instalments credited to the taxation year per T9	2,450,000 B

Transfer

Account number	Taxation year end	Amount	Effective interest date	Description
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				

3n03D09.209
2010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

SCHEDULE 100

Canada Revenue Agency / Agence du revenu du Canada

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	152,135,738	149,275,582
	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	=	152,135,738	149,275,582
	Liabilities				
	Total current liabilities	3139	+	74,497,464	73,809,932
	Total long-term liabilities	3450	+		
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	74,497,464	73,809,932
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	77,638,274	75,465,650
	Total liabilities and shareholder equity	3640	=	152,135,738	149,275,582
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	20,933,185	18,760,561

* Generic item

Gn03D09.209
2010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

Income statement information

Description	GIFI	
Operating name	0001	NIAGARA FALLS HYDRO INC.
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	+	121,398,708	121,263,893
	Cost of sales	8518	–	95,684,413	95,532,348
	Gross profit/loss	8519	=	25,714,295	25,731,545
	Cost of sales	8518	+	95,684,413	95,532,348
	Total operating expenses	9367	+	23,868,172	23,625,846
	Total expenses (mandatory field)	9368	=	119,552,585	119,158,194
	Total revenue (mandatory field)	8299	+	123,698,782	123,223,917
	Total expenses (mandatory field)	9368	–	119,552,585	119,158,194
	Net non-farming income	9369	=	4,146,197	4,065,723
	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	=	4,146,197	4,065,723
	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	–	2,509,116	2,090,933
	Deferred income tax provision	9995	–	-1,035,543	-618,152
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	2,672,624	2,592,942

n03D09.209 2009-12-31 NIAGARA PENINSULA ENERGY INC.
)10-06-23 16:16 87196 9127 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- 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 [X] 2 No [ ]

If **yes**, complete lines 102 to 107 below:

- Are any values presented at other than cost? .... 102 1 Yes [ ] 2 No [X]
- Has there been a change in accounting policies since the last return? .... 103 1 Yes [ ] 2 No [X]
- Are subsequent events mentioned in the notes? .... 104 1 Yes [ ] 2 No [X]
- Is re-evaluation of asset information mentioned in the notes? .... 105 1 Yes [ ] 2 No [X]
- Is contingent liability information mentioned in the notes? .... 106 1 Yes [X] 2 No [ ]
- Is information regarding commitments mentioned in the notes? .... 107 1 Yes [X] 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 [ ]

3n03D09.209
2010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- 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				2,672,624 A
Add:				
Provision for income taxes – current		101	2,509,116	
Provision for income taxes – deferred		102	-1,035,543	
Interest and penalties on taxes		103	8,655	
Amortization of tangible assets		104	7,754,076	
Subtotal of additions			9,236,304 ▶	9,236,304
Other additions:				
Miscellaneous other additions:				
600 Change in Employee Future Benefits		290	41,717	
601 Previous years apprentice tax credit claimed		291	6,000	
602 Regulatory Asset Variances		292	2,668,754	
OITC/ORDTC/BCRDTC/ABRDTC from prior year - 12(1)(x)	39,937			
Total	39,937	293	39,937	
604				
Interest on capital lease	2,065			
Total	2,065	294	2,065	
Subtotal of other additions		199	2,758,473 ▶	2,758,473
Total additions		500	11,994,777 ▶	11,994,777
Deduct:				
Capital cost allowance from Schedule 8		403	6,870,909	
Cumulative eligible capital deduction from Schedule 10		405	98,256	
Subtotal of deductions			6,969,165 ▶	6,969,165
Other deductions:				
Miscellaneous other deductions:				
700 Apprenticeship and Co-op credits included in F/S income		390	27,284	
704 Total Capital lease payments	49,242			
Total	49,242	394	49,242	
Subtotal of other deductions		499	76,526 ▶	76,526
Total deductions		510	7,045,691 ▶	7,045,691
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				7,621,710

* For reference purposes only

T2 SCH 1 E (09)

Canada

Gn03D09.209
2010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency | Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return.*
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide.*
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "1" under column B if the payer corporation is connected.
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

Name of payer corporation (Use only one line per corporation, abreviating its name if necessary) 200	A	B 205	C Business Number 210	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYY/MM/DD 220	E Non-taxable dividend under section 83 230
		Complete if payer corporation is connected			
1		2			
				Total	

Note: If your corporation's taxation year end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d) 240	F1 Eligible dividends (included in column F)	F2	G Total taxable dividends paid by connected payer corporation 250	H Dividend refund of the connected payer corporation 260	I Part IV tax before deductions F x 1 / 3 * 270
			If payer corporation is not connected, leave these columns blank.		
1					
Total (enter amount of column F on line 320 of the T2 return)					J

For dividends received from connected corporations: Part IV tax equals: $\frac{\text{Column F x Column H}}{\text{Column G}}$

* Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Gri03D09.209
2010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)			
Deduct:			
Part IV.I tax payable on dividends subject to Part IV tax		320	
		Subtotal	
Deduct:			
Current-year non-capital loss claimed to reduce Part IV tax	330		
Non-capital losses from previous years claimed to reduce Part IV tax	335		
Current-year farm loss claimed to reduce Part IV tax	340		
Farm losses from previous years claimed to reduce Part IV tax	345		
Total losses applied against Part IV tax		x 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)		360	

Part 3 – Taxable dividends paid in the taxation year for purposes of a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation 400	Business Number 410	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430	Eligible dividends (included in column D)
1	NIAGARA FALLS HYDRO HOLDING CORPORATION	86750 8830 RC0001	2009-12-31	372,500	
2	PENINSULA WEST POWER INC.	89108 9419 RC0001	2009-12-31	127,500	
3					

Note

If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total		500,000
Total taxable dividends paid in the taxation year to other than connected corporations	450	
Eligible dividends (included in line 450)	450a	
Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450)	460	500,000

Part 4 – Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (from above)			500,000
Other dividends paid in the taxation year (total of 510 to 540)			
Total dividends paid in the taxation year		500	500,000
Deduct:			
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
Subtotal		▶	
Total taxable dividends paid in the taxation year for purposes of a dividend refund			500,000

T2 SCH 3 E (05)

Canadä

n03D09.209 2009-12-31 NIAGARA PENINSULA ENERGY INC.
)10-06-23 16:16 87196 9127 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- 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 [X]	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 centre; 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 calculating 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.

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
7,621,710		7,621,710	1,024,539

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	1,067,039			
Deduct: Ontario small business deduction (from schedule 500)	402	42,500			
Subtotal (if negative, enter "0")		1,024,539	▶	1,024,539	A6
Add:					
Surtax re Ontario small business deduction (from Schedule 500)	272	42,500			
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		42,500	▶	42,500	B6
Subtotal (amount A6 **plus** amount B6)				1,067,039	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")				1,067,039	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")				1,067,039	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")				1,067,039	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282	251,917			
Subtotal		251,917	▶	251,917	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				1,318,956	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	39,937			
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		39,937	▶	39,937	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	1,279,019	K6

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** 1,279,019

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.

Gn03D09.209
2010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

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 [X]

	1 Class number (See Note)	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year)	3 Cost of acquisitions during the year (new property must be available for use)*	4 Net adjustments**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***	7 Reduced undepreciated capital cost	8 CCA rate %	9 Recapture of capital cost allowance (line 107 of Schedule 1)	10 Terminal loss (line 404 of Schedule 1)	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)****	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11)
	200		201	203	205	207	211		212	213	215	217	220
1.	1		68,998,351			0		68,998,351	4	0	0	2,759,934	66,238,417
2.	2		4,950,635			0		4,950,635	6	0	0	297,038	4,653,597
3.	3		1,648,111			0		1,648,111	5	0	0	82,406	1,565,705
4.	8		1,342,350	246,823		0	123,412	1,465,761	20	0	0	293,152	1,296,021
5.	10		1,246,278	589,461		0	294,731	1,541,008	30	0	0	462,302	1,373,437
6.	12	COMPUTER SOFTWARE	104,249	369,215		0	184,608	288,856	100	0	0	288,856	184,608
7.	17		381,248	45,272		0	22,636	403,884	8	0	0	32,311	394,209
8.	47		21,267,546	7,391,368		0	3,695,684	24,963,230	8	0	0	1,997,058	26,661,856
9.	45	COMPUTERS	56,281			0		56,281	45	0	0	25,326	30,955
10.	50	COMPUTERS > 3/18/07	400,044			0		400,044	55	0	0	220,024	180,020
11.	1b	Buildings > 18-03-07	1,196,452	5,181,541		0	2,590,771	3,787,222	6	0	0	227,233	6,150,760
12.	52	computers Jan 27 09 to Feb 1, 2		185,269		0		185,269	100	0	0	185,269	
		Total	101,591,545	14,008,949			6,911,842	108,688,652				6,870,909	108,729,585

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.

n03D09.209
)10-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

This schedule is to be completed by a corporation having one or more of the following:
– related corporation(s)
– associated corporations(s)

	Name	Country of residence (if other than Canada)	Business Number (Canadian corporation only) (see note 1)	Relationship code (see note 2)	Number of common shares owned	% of common shares owned	Number of preferred shares owned	% of preferred shares owned	Book value of capital stock
	100	200	300	400	500	550	600	650	700
1.	NIAGARA FALLS HYDRO SERVICES		87146 8120 RC0001	3					
2.	NIAGARA FALLS HOLDING CORPOR		86750 8830 RC0001	1	1,000	100.000			25,605,089

Note 1: Enter "NR" if a corporation is not registered.
Note 2: Enter the code number of the relationship that applies from the following order: 1 – Parent 2 – Subsidiary 3 – Associated 4 – Related, but not associated.

T2 SCH 9(99)

Canada

;n03D09.209
010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- 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** 1,403,657 A

Add: Cost of eligible capital property acquired during the taxation year . . . . **222** ______

Other adjustments . . . . **226** ______

Subtotal (line 222 plus line 226) ______ x 3 / 4 = ______ 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") ______ ▶ ______ D

Amount transferred on amalgamation or wind-up of subsidiary . . . . **224** ______ E

Subtotal (add amounts A, D, and E) **230** 1,403,657 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) . . . . 1,403,657 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 1,403,657

less amount from line 249 ______

Current year deduction . . . . 1,403,657 x 7.00 % = **250** 98,256 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 98,256 ▶ 98,256 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 1,305,401 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.

T2 SCH 10 (04)

Canada

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			× 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")					R
Amount R			× 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	

Gn03D09.209
2010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . 025 Year Month Day

Enter the calendar year to which the agreement applies . . . . 050 Year 2009

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . 075 1 Yes [ ] 2 No [X]

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Association code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	1	500,000	100.0000	500,000
2	NIAGARA FALLS HYDRO SERVICES	87146 8120 RC0001	1	500,000		
3	NIAGARA FALLS HOLDING CORPORAT	86750 8830 RC0001	1	500,000		
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

T2 SCH 23 (09)

Canada

ı03D09.209
10-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations.* References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward for credits earned in tax years that end after 1997 and did not expire before 2008 and a ten-year carryforward for credits earned in tax years that end before 1998. The apprenticeship job creation tax credit can only be carried back to tax years that end after May 1, 2006.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151 (**consolidated**), *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada* and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim.*

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. For more information, see Interpretation Bulletin IT-151. Special rules apply to specified and limited partners.
6. For SR&ED expenditures, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC that incurred qualified expenditures for SR&ED in any area in Canada	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . **101** 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its qualifying income limit for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;
b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or
c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . **102** 1 Yes ☐ 2 No ☒

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations.* Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125

*CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5 ______

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year . . . . . . ______

Deduct:

Credit deemed as a remittance of co-op corporations . . . . . . 210 ______

Credit expired* . . . . . . 215 ______

Subtotal ______ ▶ ______

ITC at the beginning of the tax year . . . . . . 220 ______

Add:

Credit transferred on amalgamation or wind-up of subsidiary . . . . . . 230 ______

ITC from repayment of assistance . . . . . . 235 ______

Total current-year credit: total of column 125 ______ x 10 % = 240 ______

Credit allocated from a partnership . . . . . . 250 ______

Subtotal ______ ▶ ______

Total credit available . . . . . . ______

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) . . . . . . 260 ______

Credit carried back to the previous year(s) (from Part 6) . . . . . . ______ A

Credit transferred to offset Part VII tax liability . . . . . . 280 ______

Subtotal ______ ▶ ______

Credit balance before refund . . . . . . ______ B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) . . . . . . 310 ______

ITC closing balance of investments from qualified property . . . . . . 320 ______

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and did not expire before 2008 and 10 tax years if it was earned in a tax year ending before 1998.

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day			
1st previous tax year				Credit to be applied	901	______
2nd previous tax year				Credit to be applied	902	______
3rd previous tax year				Credit to be applied	903	______

Total (enter on line A in Part 5) ______

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) . . . . . . ______ C

Credit balance before refund (amount B from Part 5) . . . . . . ______ D

Refund (40 % of amount C or D, whichever is less) . . . . . . ______ E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

SR&ED

Part 8 – Qualified expenditures for SR&ED

Current expenditures

Current expenditures (from line 557 on Form T661) . . . .

Add:

Contributions to agricultural organizations for SR&ED under paragraph 37(1)(a)* . . . .

Deduct:

Government and non-government assistance* . . . .

Contributions to agricultural organizations for SR&ED* . . . .

Current expenditures (including contributions to agricultural organizations for SR&ED)*	350	
Capital expenditures (from line 558 on Form T661)	360	
Repayments made in the year (from line 560 on Form T661)	370	
Total (this must equal the amount from line 570 on Form T661)*	380	

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . **385** 1 Yes ☐ 2 No ☒

Complete lines 390, 395 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

a) Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied).		390	6,267,920
b) Enter your reduced business limit** for the current tax year* (this amount cannot be more than the amount at line 4 on page 4 of the T2 return).		395	
c) Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million.	126,900,731	398	40,000,000

* If either of the tax years referred to at line 390 or 395 is less than 51 weeks, multiply the taxable income or the business limit by the following result: 365 divided by the number of days in these tax years. For details on the expression "Reduced business limit," see line 652 of the *T2 Corporation – Income Tax Guide*.

** If the corporation is claiming only a portion of the business limit from line 4 on page 4 of the T2 return because of its association with other corporations, calculate your reduced business limit as if the corporation was not associated in the current tax year. Enter the result at line 395.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC

For stand-alone corporations:

Calculation 1: Tax year ends before February 26, 2008.
[($6,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x ((line 395 from Part 9) **divided by** line 4 on page 4 of the T2 return)] . . . . ________

Calculation 2: Tax year starts after February 26, 2008 and ends before January 1, 2010.
[($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ________

Calculation 3: Tax year includes February 26, 2008.
AA + [(BB **minus** AA) x (CC **divided by** DD)] where,

- **AA =** [($6,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x ((line 395 from Part 9) **divided by** line 4 on page 4 of the T2 return)];
- **BB =** [($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];
- **CC =** number of days in the tax year after February 25, 2008;
- **DD =** number of days in the tax year. . . . . ________

Calculation 4: Tax year starts after December 31, 2009.
[($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ________

Calculation 5: Tax year includes January 1, 2010.
EE + [(FF **minus** EE) x (GG **divided by** HH)] where,

- **EE =** [($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];
- **FF =** [($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];
- **GG =** number of days in the tax year after December 31, 2009;
- **HH =** number of days in the tax year. . . . . ________

Enter the amount from Calculation 1, 2, 3, 4 or 5, whichever is applicable ________ *G

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . **400** ________ *H

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H ________ x Number of days in the tax year / 365 = 365 = ... ________ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . **410** ________

* Amount G or H cannot be more than $3,000,000 ($2,000,000 if tax year ending before February 26, 2008).

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x 35 % =		J
Line 350 minus line 410 (if negative, enter "0")	430		x 20 % =		K
Line 410 minus line 350 (if negative, enter "0")			L		
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x 35 % =		M
Line 360 minus line L (if negative, enter "0")	450		x 20 % =		N

Repayments (amount from line 370 in Part 8) . . . . ______

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x 35 % =			
480		x 20 % =			
		Total		▶	O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) . . . . ______

* For corporations that are not CCPCs, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	510			
Credit expired*	515			
Subtotal			▶	
ITC at the beginning of the tax year			520	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	530			
Total current-year credit	540			
Credit allocated from a partnership	550			
Subtotal			▶	
Total credit available				
Deduct:				
Credit deducted from Part I tax (enter on line B2 in Part 30)	560			
Credit carried back to the previous year(s) (from Part 13)		P		
Credit transferred to offset Part VII tax liability	580			
Subtotal			▶	
Credit balance before refund				Q
Deduct:				
Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)			610	
ITC closing balance on SR&ED			620	

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and did not expire before 2008 and 10 tax years if it was earned in a tax year ending before 1998.

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? 650 1 Yes [ ] 2 No [X]

Credit balance before refund (amount Q from Part 12)		R		
Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11)		S		
Refundable credits (amount R or S, whichever is less)*				T
Amount J from Part 11		U		
Subtract: Amount T or U, whichever is less				V
Net amount (if negative, enter "0")				W
Amount W	x 40 %			X
Add: Amount V				Y
Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12)				Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12)				AA
Amount J from Part 11		BB		
Subtract: Amount AA or BB, whichever is less				CC
Net amount (if negative, enter "0")				DD
Amount M from Part 11				EE
Amount DD or EE, whichever is less	x 40 %			FF
Add : Amount CC above				GG
Refund of ITC (amounts FF **plus** GG)				HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997, or in any of the 10 previous tax years, if the credit was earned in a tax year ending before 1998;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ______ II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

A Rate percentage that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED (continued)

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

D Amount determined by the formula **(A x B) - C**	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less

Subtotal (enter this amount on line MM in Part 17) ______ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) **760** ______ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16 . . . . ______ LL

Recaptured ITC for calculation 2 from line JJ in Part 16 above . . . . ______ MM

Recaptured ITC for calculation 3 from line KK in Part 16 above . . . . ______ NN

Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN . . . . ______ OO
Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

List of minerals 800

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

Project name 805	Mineral title 806	Mining division 807

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts at column 826 ▶			VV
Total pre-production mining expenditures (add amounts PP to VV)	830		
Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 minus line 832) (if negative, enter "0")			WW
Add: Repayments of government and non-government assistance	835		XX
Pre-production mining expenditures (amount WW plus amount XX)			YY

* A pre-production mining expenditure is defined under subsection 127(9) and does not include an amount renounced under subsection 66(12.6).

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations **841**

Credit expired* **845**

Subtotal ▶

ITC at the beginning of the tax year **850**

Add:

Credit transferred on amalgamation or wind-up of subsidiary **860**

Expenditures from line YY in Part 18 **870** x 10 % = **880**

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) **885**

Credit carried back to the previous year(s) (from Part 20) CCC

Subtotal ▶

ITC closing balance from pre-production mining expenditures **890**

* The credit is eligible for a 20 year carryforward effective for credits earned in 2003 and later tax years.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	**921**
2nd previous tax year				Credit to be applied	**922**
3rd previous tax year				Credit to be applied	**923**

Total (enter on line CCC in Part 19)

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred after March 18, 2007, to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation is not a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year **715** ______ EEE

Add: Specified child care start-up expenditures from the current tax year . . . . **705** ______ FFF

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . ______ GGG

Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG) . . . . **725** ______ HHH

Excess (amount GGG **minus** amount HHH) (if negative, enter "0") ______ III

Add: Repayments of government and non-government assistance . . . . **735** ______ JJJ

Total eligible expenditures for child care spaces (amount III **plus** amount JJJ) . . . . **745** ______

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred after March 18, 2007, to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)			x 25 % =		KKK
Number of child care spaces	755		x $ 10,000 =		LLL
ITC from child care spaces expenditures (amount KKK or LLL, whichever is less)					MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal			▶	
ITC at the beginning of the tax year			775	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	777			
Total current-year credit (amount MMM above)	780			
Credit allocated from a partnership	782			
Subtotal			▶	
Total credit available				
Deduct:				
Credit deducted from Part I tax (enter on line B5 in Part 30)	785			
Credit carried back to the previous year(s) (from Part 27)			NNN	
Subtotal			▶	
ITC closing balance from child care spaces expenditures			790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2008-12-31	Credit to be applied	941	
2nd previous tax year	2007-12-31	Credit to be applied	942	
3rd previous tax year	2006-12-31	Credit to be applied	943	
		Total (enter on line NNN in Part 26)		

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . **792** ______ ZZZ

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . **797** ______

Amount from line 795 or line 797, whichever is less . . . . ______ OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC **799** ______ PPP

Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP
Enter amount QQQ on line A2 in Part 29. . . . . ______ QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17		A1
Recaptured child care spaces ITC from line QQQ in Part 28 above		A2
Total recapture of investment tax credit – Add lines A1 and A2 Enter amount A3 on line 602 of the T2 return.		A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		B1
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)		B2
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		B3
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	11,039	B4
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		B5
Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) Enter amount B6 at line 652 of the T2 return.	11,039	B6

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
11,039	11,039			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				
2001-09-30				
2000-12-31				*
1999-12-31				
1998-12-31				
1997-12-31				
1996-12-31				
1995-12-31				
1994-12-31				
1993-12-31				
1992-12-31				
1991-12-31				
1990-12-31				*
Total				

B+C+D+G **Total ITC utilized** 11,039

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

n03D09.209
)10-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 33

TAXABLE CAPITAL EMPLOYED IN CANADA – LARGE CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution," "long-term debt," and "reserves."
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If you are filing a provincial capital tax return with your *T2 Corporation Income Tax Return*, also file a completed Schedule 33 with the return no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of publishing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 – Capital

Add the following amounts at the end of the year:

Reserves that have not been deducted in computing income for the year under Part I	101	3,811,634	
Capital stock (or members' contributions if incorporated without share capital)	103	31,245,882	
Retained earnings	104	20,933,185	
Contributed surplus	105	25,459,207	
Any other surpluses	106		
Deferred unrealized foreign exchange gains	107		
All loans and advances to the corporation	108	47,706,212	
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109		
Any dividends declared but not paid by the corporation before the end of the year	110		
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111		
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112		
	Subtotal	129,156,120 ▶	129,156,120 A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121	2,331,369	
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123		
The amount of deferred unrealized foreign exchange losses at the end of the year	124		
	Subtotal	2,331,369 ▶	2,331,369 B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")		190	126,824,751

Note: Lines 101, 107, 108, 109, 111, and 112 are determined as follows:
- If the partnership is a member of another partnership (tiered partnerships), include the amounts of the partnership and tiered partnerships.
- Amounts for the partnership and tiered partnerships are those that would be determined for lines 101, 107, 108, 109, 111, and 112 as if they apply in the same way that they apply to corporations.
- Do not include amounts owing to the member or to other corporations that are members of the partnership.
- Amounts are determined at the end of the last fiscal period of the partnership ending in the year of the corporation.
- The proportion of the total amounts is determined by the corporation's share of the partnership's income or loss for the fiscal period of the partnership.

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	30,068
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership (see note 1 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	30,068

Notes:
1. Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
   – the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
   – the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's tax year; and
   – the carrying value of a partnership member's interest at the end of the year is its specified proportion [as defined in subsection 248(1)] of the partnership's investment allowance.
2. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)].
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, according to subsection 181.2(6).

Part 3 – Taxable capital

Capital for the year (line 190)		126,824,751	C
Deduct: Investment allowance for the year (line 490)		30,068	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	126,794,683	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 126,794,683 x (Taxable income earned in Canada **610** 7,621,710 / Taxable income 7,621,710) = **Taxable capital employed in Canada** **690** 126,794,683

Notes: 1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	701		
Deduct the following amounts:			
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711		
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712		
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713		
Total deductions (add lines 711, 712, and 713)		►	E
Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0")	790		

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)		F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.00225)		I

Enter this amount at line 415 of the T2 return

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	NIAGARA FALLS HYDRO HOLDING CORPORATION	86750 8830 RC0001			74.500	
2	PENINSULA WEST POWER INC.	89108 9419 RC0001			25.500	
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

On: 2009-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 — 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			**100**	15,194,220 A
Taxable income for the year (DICs enter "0") *	**110**	7,621,710 B		
Income for the credit union deduction * (amount E in Part 3 of Schedule 17) **120**				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less * **130**				
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income * **140**				
Subtotal (**add** lines 120, 130, and 140)	▶	C		
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")	**150**	7,621,710		
After-tax income (line 150 x general rate factor for the tax year ** 0.68)			**190**	5,182,763 D
Eligible dividends received in the tax year	**200**			
Dividends deductible under section 113 received in the tax year	**210**			
Subtotal (**add** lines 200 and 210)			▶	E
GRIP addition:				
Becoming a CCPC (line PP from Part 4)	**220**			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	**230**			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	**240**			
Subtotal (**add** lines 220, 230, and 240)			▶ **290**	F
Subtotal (**add** lines A, D, E, and F)				20,376,983 G
Eligible dividends paid in the previous tax year	**300**			
Excessive eligible dividend designations made in the previous tax year	**310**			
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.				
Subtotal (line 300 **minus** line 310)			▶	H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)			**490**	20,376,983
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			**560**	
GRIP at the end of the tax year (line 490 **minus** line 560) Enter this amount on line 160 of Schedule 55.			**590**	20,376,983

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year		6,267,920 J1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (**add** lines K1, L1, and M1)	▶	N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")		6,267,920 ▶	6,267,920 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . ______ S1

Subtotal (**add** lines Q1, R1, and S1) ______ ▶ ______ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ______ ▶ ______ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ______ V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.68) . . . . **500** ______

Second previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year 5,216,257 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) 6,337 M2

Subtotal (**add** lines K2, L2, and M2) 6,337 ▶ 6,337 N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 5,209,920 ▶ 5,209,920 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . ______ S2

Subtotal (**add** lines Q2, R2, and S2) ______ ▶ ______ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ______ ▶ ______ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ______ V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.68) . . . . **520** ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year . . . 5,644,226 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . ______ M3

Subtotal (**add** lines K3, L3, and M3) ______ ▶ ______ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 5,644,226 ▶ 5,644,226 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ▶ ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ▶ ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ______ V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied by** the general rate factor for the tax year 0.68) . . . . **540** ______

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . ______ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ▶ ______ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . ______ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . ______ GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . . ______
Net capital losses . . . . ______
Farm losses . . . . ______
Restricted farm losses . . . . ______
Limited partnership losses . . . . ______

Subtotal ______ ▶ ______ HH

Subtotal (**add** lines FF, GG, and HH) ______ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . ______ JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . ______ KK

All the corporation's reserves deducted in its previous/last tax year . . . . ______ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . ______ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . ______ NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ______ ▶ ______ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") . . . . ______ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year. Calculate your results to four decimal places.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	365 / 365	.... =	0.6800	QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	/ 365	.... =		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	/ 365	.... =		SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	.... =		TT

General rate factor for the tax year (total of lines QQ to TT) .... 0.6800 UU

Gn03D09.209
2010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation,* or Schedule 54, *Low Rate Income Pool Calculation (LRIP)*; whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- Parts, subsections, and paragraphs mentioned in this schedule refer to the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3		500,000			
Total taxable dividends paid in the tax year	100	500,000			
Total eligible dividends paid in the tax year			150		
GRIP at the end of the year (line 590 on Schedule 53) (if negative, enter "0")			160	20,376,983	
Excessive eligible dividend designation (line 150 **minus** line 160)					A
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (line A **multiplied** by 20%)		x 20 %	190		

Enter the amount from line 190 at line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3					
Total taxable dividends paid in the tax year	200				
Total excessive eligible dividend designations in the tax year (line A of Schedule 54)					B
Part III.1 tax on excessive eligible dividend designations – Other corporations (line B **multiplied** by 20%)		x 20 %	290		

Enter the amount from line 290 at line 710 of the T2 return.

Gn03D09.209
2010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- 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 rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	365 / 365	x	14.00 %	=	14.00000 %	A1
Number of days in the tax year after June 30, 2010 and before July 1, 2011 / Number of days in the tax year	/ 365	x	12.00 %	=	%	A2
Number of days in the tax year after June 30, 2011 and before July 1, 2012 / Number of days in the tax year	/ 365	x	11.50 %	=	%	A3
Number of days in the tax year after June 30, 2012 and before July 1, 2013 / Number of days in the tax year	/ 365	x	11.00 %	=	%	A4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	10.00 %	=	%	A5

Ontario basic rate of tax for the year (total of rates A1 to A5) 14.00000 ▶ 14.00000 % A6

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 7,621,710 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A6 from Part 1) . . . . 1,067,039 C

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 C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations.* Otherwise, enter it on line 760 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 of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – 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)					7,621,710	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)					7,621,710	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	500,000	x	500,000 / 500,000 (line 4 on page 4 of the T2 return)	=	500,000	3
Enter the least of amounts 1, 2, and 3					500,000	D
Ontario domestic factor: Ontario taxable income * / taxable income earned in all provinces and territories **			7,621,710.00 / 7,621,710	=	1.00000	E
Ontario small business income (amount D **multiplied** by amount E)					500,000	F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	365 / 365	x	8.50 %	=	8.50000 %	G1
Number of days in the tax year after June 30, 2010 and before July 1, 2011 / Number of days in the tax year	/ 365	x	7.50 %	=	%	G2
Number of days in the tax year after June 30, 2011 and before July 1, 2012 / Number of days in the tax year	/ 365	x	7.00 %	=	%	G3
Number of days in the tax year after June 30, 2012 and before July 1, 2013 / Number of days in the tax year	/ 365	x	6.50 %	=	%	G4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	5.50 %	=	%	G5

OSBD rate for the year (total of rates G1 to G5) . . . 8.50000 % G6

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G6) . . . 42,500 H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia, and Newfoundland and Labrador.

Part 4 – 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*.

Note: You do not need to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income *	7,621,710	I		
Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501)		J		
Aggregate adjusted taxable income (amount I **plus** amount J)	7,621,710	▶	7,621,710	K
Deduct:				
Ontario business limit			500,000	
Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P)			7,121,710	L

Small business surtax rate for the year:

Number of days in the tax year before July 1, 2010 / Number of days in the tax year: 365 / 365 x 4.25 % = 4.25 % M

Note: For days in the tax year after June 30, 2010, the small business surtax rate is reduced to 0%.

Multiply: Amount L x % on line M =		302,673	N
Amount N x Ontario small business income (amount F from Part 3) / 500,000	500,000 / 500,000 =	302,673	O
Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H in Part 3)		42,500	P

Enter amount P 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 5 – 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 D in Part 3		500,000	Q
Surtax payable (amount P from Part 4) / Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3) 8.50000 %	42,500 / 0.08500 =	500,000	R

Note: Enter "0" on line R for tax years beginning after June 30, 2010

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") ____ S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – 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			T
Deduct:			
Ontario adjusted small business income (amount S from Part 5)			U
Subtotal (amount T **minus** amount U) (if negative, enter "0")			V
OSBD rate for the year (rate G6 from Part 3)	8.50000 %		
Amount V **multiplied** by the OSBD rate for the year			W
Ontario domestic factor (amount E from Part 3)		1.00000	X
Ontario credit union tax reduction (amount W **multiplied** by amount X)			Y

Enter amount Y on line 410 on Schedule 5.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 501

ONTARIO ADJUSTED TAXABLE INCOME OF ASSOCIATED CORPORATIONS TO DETERMINE SURTAX RE ONTARIO SMALL BUSINESS DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- For use by Canadian-controlled private corporations (CCPCs) to report the adjusted taxable income of all corporations (Canadian and foreign) with which the filing corporation was associated at any time during the tax year.
- Include the adjusted taxable income for the tax year of the associated corporation that ends at or before the date of the filing corporation's tax year-end.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations* 100	Business number of associated corporations** 200	Tax year-end 300	Adjusted taxable income *** (if loss, enter "0") 400
1	NIAGARA FALLS HYDRO SERVICES	87146 8120 RC0001	2009-12-31	
2	NIAGARA FALLS HOLDING CORPORAT	86750 8830 RC0001	2009-12-31	
			Total 500	

Enter the total adjusted taxable income from line 500 on line J in Part 4 of Schedule 500, *Ontario Corporation Tax Calculation.*

* Subsection 256(2) of the federal *Income Tax Act* may deem the filing corporation to be associated with another corporation, because both corporations are associated with a third corporation. If so, do not list the other corporation, nor the third corporation if it is not a CCPC or has elected under subsection 256(2) of the federal Act not to be associated for purposes of section 125 of the federal Act.

** Enter "NR" if a corporation is not registered.

*** **Rules for adjusted taxable income:**

- If the associated corporation's tax year ends after December 31, 2008, its adjusted taxable income is equal to its taxable income or taxable income earned in Canada **plus** its adjusted Crown royalties **minus** its notional resource allowance for the year.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's adjusted taxable income by 365 and **divide** by the number of days in the associated corporation's tax year.
- If the associated corporation has two or more tax years ending in the filing corporation's tax year, enter the last tax year-end date on line 300 and, for the entry on line 400, **multiply** the sum of the adjusted taxable income for each of those tax years by 365, and **divide** by the total number of days in all of those tax years.

T2 SCH 501 (10)

Canadä

in03D09.209
010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency — Agence du revenu du Canada

SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- 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	152,135,738
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	110,349,644
Total assets (total of lines 112 to 116)		262,485,382
Total revenue of the corporation for the tax year **	142	123,698,782
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	1,822,045
Total revenue (total of lines 142 to 146)		125,520,827

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 are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $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 are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $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 SAT payable in the year.

* **Rules for total assets**
– Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Do not include 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	2,672,624
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	2,509,116		
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 deducted as interest expense on financial statements (subsection 57(2) of the *Taxation Act, 2007* (Ontario)), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	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		2,509,116 ▶		2,509,116 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	1,035,543		
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		1,035,543 ▶		1,035,543 B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	4,146,197

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

In accordance with *Ontario Regulation 37/09*, in calculating net income for CMT purposes, accounting income should be adjusted to remove unrealized gains and losses on mark-to-market property, as well as foreign currency gains and losses on assets, that are included in income for accounting purposes but not in income for income tax purposes. In later years, accounting income is adjusted in arriving at net income for CMT purposes by including these gains or losses when they are realized.

These realized gains and losses apply to the disposition of mark-to-market property:

– that is not capital property in the year;

– that is capital property and realized in the year or the preceding tax year that ends after March 22, 2007.

The mark-to-market rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **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 were a corporation and the tax year of the partnership or joint venture were 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	4,146,197	
Deduct:			
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	4,146,197	

Amount from line 520 4,146,197 × (Number of days in the tax year before July 1, 2010 365 / Number of days in the tax year 365) × 4 % = 165,848 1

Amount from line 520 4,146,197 × (Number of days in the tax year after June 30, 2010 ____ / Number of days in the tax year 365) × 2.7 % = ____ 2

Subtotal (amount 1 **plus** amount 2) 165,848 3

Gross CMT: amount on line 3 above x OAF **	540	165,848	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		165,848	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		1,067,039	
Net CMT payable (if negative, enter "0")			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)				
SAT payable (amount O from Part 6 of Schedule 512)				
Subtotal		▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)		670		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)		1,067,039	1	
For a corporation that is not a life insurance corporation:				
CMT after foreign tax credit deduction (amount D from Part 3)	165,848	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:		165,848	6	
Subtotal (if negative, enter "0")		901,191 ▶	901,191	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		1,067,039		
Deduct:				
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)		39,937		
Subtotal (if negative, enter "0")		1,027,102 ▶	1,027,102	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:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

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:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 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 23, 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 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

3n03D09.209
2010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	NIAGARA FALLS HYDRO SERVICES	87146 8120 RC0001	13,329,868	821,492
2	NIAGARA FALLS HOLDING CORPORAT	86750 8830 RC0001	97,019,776	1,000,553
		Total	450 110,349,644	550 1,822,045

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter "NR" if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** 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 associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated 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.

T2 SCH 511

Canada

Gn03D09.209 2010-06-23 16:16 | 2009-12-31 | NIAGARA PENINSULA ENERGY INC. 87196 9127 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 515

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- 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

	Line	Amount		
Amount A from Part 1 of Schedule 33	100	129,156,120		
Add:				
Accumulated other comprehensive income at the end of the year	105			
Subtotal		129,156,120	129,156,120	A
Deduct:				
Amount B from Part 1 of Schedule 33	110	2,331,369		
Amount on line 490 from Part 2 of Schedule 33	115	30,068		
Subtotal		2,361,437	2,361,437	B
Taxable capital (amount A **minus** amount 8) (if negative, enter "0")	120		126,794,683	

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) **200** 126,794,683
÷
Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year * **210** 128,236,004

x 15,000,000 $ = **Capital deduction** **220** 14,831,406

* 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) **300** ______
÷
Ontario allocation factor (OAF) (amount I in Part 3)

= **Capital deduction** **305** ______

Gn03D09.209
2010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 515

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- 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

	Line	Amount		Total	
Amount A from Part 1 of Schedule 33	100	129,156,120			
Add:					
Accumulated other comprehensive income at the end of the year	105				
Subtotal		129,156,120	▶	129,156,120	A
Deduct:					
Amount B from Part 1 of Schedule 33	110	2,331,369			
Amount on line 490 from Part 2 of Schedule 33	115	30,068			
Subtotal		2,361,437	▶	2,361,437	B
Taxable capital (amount A **minus** amount 8) (if negative, enter "0")	120			126,794,683	

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.

	Line	Amount				
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)	200	126,794,683	x 15,000,000 $ =	**Capital deduction**	220	14,831,406
Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year *	210	128,236,004				

* 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).

	Line	Amount				
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** 126,794,683

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) . . . . 14,831,406 B

Net amount (line 320 **minus** amount B) (if negative, enter "0") . . . . 111,963,277 C

Amount C 111,963,277 x (Number of days in the tax year before January 1, 2010 / Number of days in the tax year) 365 / 365 x 0.00225 = 251,917 D

Amount C 111,963,277 x (Number of days in the tax year after December 31, 2009 and before July 1, 2010 / Number of days in the tax year) ____ / 365 x 0.00150 = ____ E

Subtotal (amount D **plus** amount E) 251,917 F

Amount F 251,917 x OAF (amount on line I) 1.00000 = ... 251,917 G

Amount G 251,917 x (Number of days in the tax year * / 365) 365 / 365 = ... 251,917 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** 251,917

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* **405** / Total Ontario labour cost** **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 251,917 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
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- 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).
- [X] 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)

3n03D09.209
2010-06-23 16:16

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA PENINSULA ENERGY INC.	87196 9127 RC0001	2009-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009* or the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information	**120** Telephone number including area code
SUZANNE WILSON	(905) 356-2681

Is the claim filed for an ATTC earned through a partnership? * . . . . **150** 1 Yes [ ] 2 No [X]

If **yes** to the question at line 150, what is the name of the partnership? . . . . **160** ____________

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 8,001,679

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\ \% - \left[5\ \% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\ \% - \left[10\ \% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code **400**	B Apprenticeship program/ trade name **405**	C Name of apprentice **410**
1.	434a	Lineworker	Jeremy Manders
2.	434a	Lineworker	Joe Piroski
3.	434a	Lineworker	Aaron Lowden
4.	434a	Lineworker	Blair Thompson
5.	434a	Lineworker	Troy Sider
6.	434a	Lineworker	Robert Denton
7.	434a	Lineworker	Scott Norton
8.	434a	Lineworker	Paul Stanley
9.	434a	Lineworker	Jacob Crowe
10.			

	D Original contract or training agreement number **420**	E Original registration date of apprenticeship contract or training agreement (see note 1 below) **425**	F Start date of employment as an apprentice in the tax year (see note 2 below) **430**	G End date of employment as an apprentice in the tax year (see note 3 below) **435**
1.	A83069	2006-04-21	2009-01-01	2009-04-20
2.	D10686	2007-09-05	2009-01-01	2009-09-04
3.	A83249	2007-01-22	2009-01-01	2009-01-31
4.	PA6256	2007-04-11	2009-01-01	2009-12-31
5.	PA4119	2007-09-05	2009-01-01	2009-12-31
6.	PA9035	2008-02-07	2009-01-01	2009-12-31
7.	PA8735	2008-11-04	2009-01-01	2009-12-31
8.	PA8737	2008-11-04	2009-01-01	2009-12-31
9.	PA9030	2008-02-07	2009-09-01	2009-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
10.				

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.	85	25	110	1,849
2.	85	162	247	5,602
3.	31		31	425
4.	85	280	365	8,835
5.	85	280	365	8,835
6.	85	280	365	8,835
7.	85	280	365	8,835
8.	85	280	365	8,835
9.		122	122	3,342
10.				

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.	14,552	4,280	18,832	5,136
2.	14,808	28,223	43,031	13,580
3.	6,036		6,036	1,509
4.	6,419	21,147	27,566	9,006
5.	6,600	21,744	28,344	9,260
6.	2,605	8,580	11,185	3,654
7.	2,803	9,236	12,039	3,934
8.	2,467	8,125	10,592	3,461
9.		10,527	10,527	3,684
10.				

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	1,849		1,849
2.	5,602		5,602
3.	425		425
4.	8,835		8,835
5.	8,835		8,835
6.	3,654		3,654
7.	3,934		3,934
8.	3,461		3,461
9.	3,342		3,342
10.			
Ontario apprenticeship training tax credit (total of amounts in column N) 500			39,937 O

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ________________ x percentage on line 170 in Part 1 ________ % = ... ________________________ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.

For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = (\$5,000 x H1/365*) + (\$10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.

For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

3n03D09 Exempt.209
:010-06-23 16:40

2009-12-31

NIAGARA PENINSULA ENERGY INC.
87196 9127 RC0001

Canada Revenue Agency — Agence du revenu du Canada

INFORMATION RETURN FOR CORPORATIONS FILING ELECTRONICALLY

- You have to complete this return to allow your transmitter to electronically file your corporation income tax return to us at the Canada Revenue Agency. You have to complete this return for each taxation year.
- By completing Part B and signing Part C, you acknowledge that, under the *Income Tax Act*, you have to keep all records used to prepare your corporation income tax return, and provide this information to us on request.
- Part D must be completed by either you or the preparer of your corporation income tax return.
- You have to give the signed original of this return to the transmitter and keep a copy for yourself.
- We are responsible for ensuring the confidentiality of your electronically filed tax information only after we have accepted it.

Part A – Identification

Name of corporation			
NIAGARA PENINSULA ENERGY INC.			
Business Number 87196 9127 RC0001	Taxation year: ▶	From Y M D 2009-01-01	To Y M D 2009-12-31

Part B – Declaration

Enter the following amounts, if applicable, from your corporation income tax return for the taxation year noted above:

Net income or (loss) for income tax purposes from Schedule 1, financial statements or GIFI (line 300)	4,146,197
Part I tax payable (line 700)	
Part I.3 tax payable (line 704)	
Part II surtax payable (line 708)	
Part III.1 tax payable (line 710)	
Part IV tax payable (line 712)	
Part IV.1 tax payable (line 716)	
Part VI tax payable (line 720)	
Part VI.1 tax payable (line 724)	
Part XIV tax payable (line 728)	
Net provincial and territorial tax payable (line 760)	
Provincial tax on large corporations (line 765)	

Part C – Certification and authorization

I certify that the amounts in Part B above are correct and complete, and fully disclose the corporation's income tax payable. These amounts also reflect the information given on the corporation's income tax return.

I authorize the transmitter identified in Part D to electronically file the corporation income tax return identified in Part A. The transmitter can also modify the information originally filed in response to any errors Canada Revenue Agency identifies. This authorization expires when the Minister of National Revenue accepts the electronic return as filed.

Signature of an authorized signing officer of the corporation — Date

Part D – Transmitter identification

The following person or firm has electronically filed the tax return of the corporation identified in Part A.

Name of person or firm: Crawford Smith and Swallow

Address: 4741 Queen Street
Niagara Falls ON L2E 2M2

This return is for your records. Do not send it to us unless we ask for it.

PLEASE KEEP FOR REFERENCE

T183 CORP (07)

Canada

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2010-12-31

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
2010-01-31	219,088			219,088
2010-02-28	219,088			219,088
2010-03-31	219,088			219,088
2010-04-30	219,088			219,088
2010-05-31	219,088			219,088
2010-06-30	219,088			219,088
2010-07-31	219,088			219,088
2010-08-31	219,088			219,088
2010-09-30	219,088			219,088
2010-10-31	219,088			219,088
2010-11-30	219,088			219,088
2010-12-31	219,080			219,080
Total	2,629,048			2,629,048

Appendix D – Notice of Assessments

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Assessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2009/01/01 to 2009/12/31

	Account No.	Assessment Date (year, month, day)	Page
NIAGARA PENINSULA ENERGY INC.	1800406	2010/07/27	1 of 1

ASSESSMENT NO. 36

Tax: Federal and Provincial PIL		2,716,105.00
Assessment Interest		1,039.04
Total Assessment Liability		2,717,144.04

SUMMARY OF 2009/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	2,716,105.00CR	
Sub-Total		2,716,105.00CR
TAXATION YEAR BALANCE DUE **		1,039.04

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Total tax assessed as per company estimate

NEW AMALGAMATION: Instalments based on grossed up/aggregate of predecessor companies.

**Remember to include additional interest due with your payment. Interest on the balance is compounded daily from the date of this Notice/Statement until payment is received by the Ontario Electricity Financial Corporation (OEFC) The current interest rate is 0.0136986%.

OEFC001 . 800-6035-00-00 1,039.04

V# 28746 posted Aug 5/10

PX5003 004

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Assessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2008/01/01 to 2008/12/31

NIAGARA PENINSULA ENERGY INC.

Account No.	Assessment Date (year, month, day)	Page
1800406	2009/07/21	1 of 1

ASSESSMENT NO. 19

Tax: Federal and Provincial PIL		2,324,686.00
Assessment Interest		8,655.47
Total Assessment Liability		2,333,341.47

SUMMARY OF 2008/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	2,776,083.00CR	
Sub-Total		2,776,083.00CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		442,741.53CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Total tax assessed as per company estimate

NEW AMALGAMATION: Instalments based on grossed up/aggregate of predecessor companies.

Installment $ 200,000

PXS003 D04

Tax (Re)Assessment Enquiries: • 1 866 ONT-TAXS (1 866 668-8297) ext. 21113 • FAX 416 218-3276 • TTY 1 800 263-7776 • ontario.ca/revenue

Account Billing Enquiries & Change of Address Information: • 1 866 ONT-TAXS (1 866 668-8297) • FAX 905 433-5197

0000002

SUPPLIER INVOICE CODING

VENDOR # OEFC001

Account #	Amount
2290-2	
1305-05-00	200000.00
Total Invoice	200000.00

Approved by

Ontario

Ministry of Revenue
Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Account No.
1800141

35
PX5005

NIAGARA FALLS HYDRO INC.
C/O SUZANNE WILSON
7447 PIN OAK DR
PO BOX 120
NIAGARA FALLS ON
L2E 6S9

Taxation Year End: (YYYYMMDD)	
Payment Amount:	$
Taxation Year End: (YYYYMMDD)	2 0 0 7 1 2 3 1
Payment Amount:	$
Total Payment Enclosed:	$

Ontario

Ministry of Revenue
Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Reassessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2007/01/01 **to** 2007/12/31

	Account No.	Reassessment Date (year, month, day)	Page
NIAGARA FALLS HYDRO INC.	**1800141**	2008/11/26	1 of 1

REASSESSMENT NO. 180 REPLACING ASSESSMENT DATED: 2008/07/09

Tax: Federal and Provincial PIL		2,019,167.00
Assessment Interest		5,753.56CR
Total Reassessment Liability		2,013,413.44

SUMMARY OF 2007/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	2,228,424.00CR	
Refunds	173,577.67	
Sub-Total		2,054,846.33CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		41,432.89CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Adjustment to the computation of Capital Tax.

Tax (Re)Assessment Enquiries:
• Toronto 416 218-3283 • FAX 416 730-5593

Account Billing Enquiries & Change of Address Information:
• Toll-Free 1 800 262-0784 ext. 3036 • FAX 905 433-5197

Detach and return this REMITTANCE FORM with your payment.

Ontario

Ministry of Revenue
Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Account No.
1800141
35
PX5003

Taxation Year End: (YYYYMMDD)
Payment Amount: $

NIAGARA FALLS HYDRO INC.
C/O SUZANNE WILSON
7447 PIN OAK DR
PO BOX 120
NIAGARA FALLS ON
L2E 6S9

Taxation Year End: (YYYYMMDD) 2 0 0 7 1 2 3 1
Payment Amount: $
Total Payment Enclosed: $

Ontario

Ministry of Revenue
Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Assessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2007/01/01 to 2007/12/31

Account No.	Assessment Date (year, month, day)	Page
1800141	2008/07/09	1 of 1

NIAGARA FALLS HYDRO INC.

ASSESSMENT NO. 175

Tax: Federal and Provincial PIL	2,059,853.00
Assessment Interest	4,826.06CR
Total Assessment Liability	2,055,026.94

SUMMARY OF 2007/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	2,228,424.00CR	
Sub-Total		2,228,424.00CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		173,397.06CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Total tax assessed as per company estimate

PX5003 003

Tax (Re)Assessment Enquiries:
• Toronto 416 218-3283 • FAX 416 730-5593

Account Billing Enquiries & Change of Address Information:
• Toll-Free 1 800 262-0784 ext. 3036 • FAX 905 433-5197

0000001

Ontario
Ministry of Revenue
Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Corporations Tax Act, R.S.O. 1990

Account No.
1800166

35
PX5005

PENINSULA WEST UTILITIES LIMITED
C/O KAREN BUBISH
2-4548 ONTARIO ST

BEAMSVILLE ON
L0R 1B5

Taxation Year End: (YYYYMMDD)	
Payment Amount:	$
Taxation Year End: (YYYYMMDD)	2 0 0 7 1 2 3 1
Payment Amount:	$
Total Payment Enclosed:	$

Ontario
Ministry of Revenue
Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Reassessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990

from 2007/01/01 to 2007/12/31

	Account No.	Reassessment Date (year, month, day)	Page
PENINSULA WEST UTILITIES LIMITED	1800166	2008/10/29	1 of 1

REASSESSMENT NO. 119 REPLACING ASSESSMENT DATED: 2008/07/16

Tax: Federal and Provincial PIL		2,180,790.00
Assessment Interest		22,235.48
Total Reassessment Liability		2,203,025.48

SUMMARY OF 2007/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	2,679,400.00CR	
Refunds	468,161.20	
Sub-Total		2,211,238.80CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		8,213.32CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Capital Tax adjusted due to rate reduction as per 2008 Budget changes

Tax (Re)Assessment Enquiries:
• Toronto 416 218-3283 • FAX 416 730-5593

Account Billing Enquiries & Change of Address Information:
• Toll-Free 1 800 262-0784 ext. 3036 • FAX 905 433-5197

0000010

Detach and return this REMITTANCE FORM with your payment.

Ontario

Ministry of Finance
Corporations Tax Branch - Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Account No.
1800141

35
PX5003

NIAGARA FALLS HYDRO INC.
C/O SUZANNE WILSON
7447 PIN OAK DR
PO BOX 120
NIAGARA FALLS ON
L2E 6S9

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Taxation Year End: (YYYYMMDD)

Payment Amount: $

Taxation Year End: (YYYYMMDD) 2 0 0 6 1 2 3 1

Payment Amount: $

Total Payment Enclosed: $

Ontario

Ministry of Finance
Corporations Tax Branch - Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Assessment

Electricity Act, 1998 • *Corporations Tax Act, R.S.O. 1990*
from 2006/01/01 to 2006/12/31

	Account No.	Assessment Date (year, month, day)	Page
NIAGARA FALLS HYDRO INC.	1800141	2007/08/28	1 of 1

ASSESSMENT NO. 160

Tax: Federal and Provincial PIL		2,228,413.00
Assessment Interest		18,754.74CR
Total Assessment Liability		2,209,658.26

SUMMARY OF 2006/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	2,229,460.34CR	
Sub-Total		2,229,460.34CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		19,802.08CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Total tax assessed as per company estimate

Tax (Re)Assessment Enquiries:
- Toronto (416) 730-5585
- FAX (416) 730-5593

Account Billing Enquiries & Change of Address Information:
- Oshawa and Local (905) 433-6708
- Toronto (416) 920-9048 ext. 3036
- Toll-Free 1-800-262-0784 ext. 3036
- FAX (905) 433-5197

0000002

002 PX5003

Detach and return this **REMITTANCE FORM** with your payment.

Ontario

Ministry of Finance
Corporations Tax Branch - Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Account No.
1800166

35
PX5003

PENINSULA WEST UTILITIES LIMITED
C/O KAREN BUBISH, DIR OF ADM
2-4548 ONTARIO ST

BEAMSVILLE ON
L0R 1B5

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Taxation Year End: (YYYYMMDD)

Payment Amount: $

Taxation Year End: (YYYYMMDD) 2 0 0 6 1 2 3 1

Payment Amount: $

Total Payment Enclosed: $

Ontario

Ministry of Finance
Corporations Tax Branch - Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Assessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2006/01/01 **to** 2006/12/31

	Account No.	Assessment Date (year, month, day)	Page
PENINSULA WEST UTILITIES LIMITED	**1800166**	2007/08/14	1 of 1

ASSESSMENT NO. 102

Tax: Federal and Provincial PIL		906,384.00
Assessment Interest		4,024.34
Total Assessment Liability		910,408.34

SUMMARY OF 2006/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	950,668.00CR	
Sub-Total		950,668.00CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		40,259.66CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Total tax assessed as per company estimate

Tax (Re)Assessment Enquiries:
- Toronto (416) 730-5585
- FAX (416) 730-5593

Account Billing Enquiries & Change of Address Information:
- Oshawa and Local (905) 433-6708
- Toronto (416) 920-9048 ext. 3036
- Toll-Free 1-800-262-0784 ext. 3036
- FAX (905) 433-5197

002 PX5003

Appendix E – NPEI's Actuarial Valuation 2008

Dion Durrell
Actuaries and Consultants

Dion, Durrell + Associates Inc.
250 Yonge Street, Suite 2900
Toronto, Ontario, Canada M5B 2L7
dion-durrell.com

T 416 408 2626
F 416 408 3721

NIAGARA PENINSULA ENERGY INC.

REPORT ON THE ACTUARIAL VALUATION OF POST-RETIREMENT NON-PENSION BENEFITS

As At January 1, 2008

FINAL—January 6, 2009

Dion Durrell

TABLE OF CONTENTS

mearie\mearie actuarial service\utilities\niagara peninsula energy inc\valuations\jan 1, 2008\post ret&emp val'n at jan 1 08_niagara peninsula energy inc_final.doc

Dion Durrell

EXECUTIVE SUMMARY

PURPOSE

Effective Jan. 1, 2008, the former Niagara Falls Hydro Inc. ("Niagara Falls") merged with Peninsula West Utilities Limited ("PenWest") to form Niagara Peninsula Energy Inc. (the "Corporation").

MEARIE Actuarial Services and Dion, Durrell + Associates Inc. were engaged by the Corporation to perform an actuarial valuation of the post-retirement non-pension benefits sponsored by the Corporation and to determine the accounting results for those benefits for the fiscal period ending December 31, 2008.

As it relates to the aforementioned merger, the following key details were communicated in writing by the Corporation and thus formed the basis of our valuation of the Corporation's benefits:

- Post-retirement non-pension benefits provided on and after January 1, 2008 for the Corporation are identical for both former Niagara Falls Hydro employees and former PenWest employees and are defined benefit in nature.
- PenWest did not provide any post-retirement non-pension benefits to its employees meaning that there are no related financial statement entries to be "carried forward".
- The recognition of PenWest past service (i.e. service prior to January 1, 2008) for benefit eligibility purposes and thus valuation purposes results in a past service liability.

This report is prepared in accordance with The Canadian Institute of Chartered Accountants (the "CICA") guidelines outlined in Employee Future Benefits, Section 3461 of the CICA Handbook-Accounting ("CICA Section 3461"). CICA Section 3461 was first applied to Niagara Falls with effect from January 1, 2001.

The most recent full valuation in respect of Niagara Falls Hydro was prepared as at January 1, 2006 based on the then appropriate assumptions. There is no prior valuation for PenWest because, as noted above, there were no post-retirement non-pension benefits.

The purpose of this valuation is threefold:

i) to determine the Corporation's liabilities in respect of post-retirement non-pension benefits at January 1, 2008;

ii) to determine the Corporation's benefit expense for fiscal year 2008; and

iii) to provide all other pertinent information necessary for compliance with CICA Section 3461.

The intended users of this report include the Corporation and their auditors. This report is not intended for use by the plan beneficiaries or for use in determining any funding of the benefit obligations.

Dion Durrell

SUMMARY OF KEY RESULTS

The key results of this actuarial valuation as at January 1, 2008 with comparative results from the previous valuation as at January 1, 2006 (for Niagara Falls) are shown below:

	January 1, 2006 (000s)	January 1, 2008 (000s)
Accrued Benefit Obligation (ABO)		
a) People In Receipt Of Benefits	$ 1,256	$ 1,169
b) Fully Eligible Actives	$ 134	$ 344
c) Not Fully Eligible Actives	$ 956	$ 1,065
Total ABO	**$ 2,346**	**$ 2,578**
Current Service Cost *for following 12 months*	$ 78	$ 96
Benefit Expense *for following 12 months*	$ 113	$ 170
Prepaid Benefit Liability *at January 1*		$ 3,525

The Corporation results for the period from January 1, 2008 to December 31, 2008 include a past service liability in the amount of $240,599 in respect of the former PenWest employees as a result of their previously noted past service recognition (i.e. from date of hire to January 1, 2008). Pursuant to CICA Section 3461, the past service liability in respect of the former PenWest employees as at January 1, 2008 will be amortized on a straight-line basis over the Expected Average Remaining Service Lifetime (hereinafter referred to as the "E.A.R.S.L.") of active employees. The January 1, 2008 Prepaid Benefit Liability is based on the projections provided with our January 1, 2006 valuation report for Niagara Falls.

Dion Durrell

ACTUARIAL CERTIFICATION

An actuarial valuation has been performed on the post-retirement non-pension benefit plans sponsored by Niagara Peninsula Energy Inc. as at January 1, 2008, for the purposes described in this report.

In accordance with the Canadian Institute of Actuaries Consolidated Standards of Practice General Standards, we hereby certify that, in our opinion, for the purposes stated in the Executive Summary:

1. The data on which the valuation is based is sufficient and reliable;
2. The assumptions employed, as outlined in this report, have been selected by the Corporation as management's best estimate assumptions (no provision for adverse deviations) and are in accordance with accepted actuarial practice;
3. The actuarial methods employed, as outlined in Section C, are appropriate for the purpose and consistent with sound actuarial principles;
4. All known substantive commitments with respect to the post-retirement non-pension benefits sponsored by and identified by the Corporation are included in the calculations; and
5. The valuation conforms to the standards set out in the Canadian Institute of Chartered Accountants Accounting Handbook Section 3461.

We are not aware of any subsequent events from January 1, 2008 up to the date of this report that would have a significant effect on our valuation.

The latest date on which the next actuarial valuation should be performed is January 1, 2011. If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,

DION, DURRELL + ASSOCIATES INC.

Stanley Caravaggio

Stanley Caravaggio FSA, FCIA

Patrick G. Kavanagh

Patrick G. Kavanagh
Actuarial Analyst

Toronto, Ontario
January 6, 2009

Dion Durrell

SECTION A
VALUATION RESULTS

Table A - 1 shows the key valuation results for the prior valuation (for Niagara Falls) and the current valuation.

Table A - 2 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown a change to the assumed retirement age from age 60 to 58, and an increase/decrease in the health and dental claims cost trend rates by 1% per annum.

Table A - 3 presents the determination of the actuarial gain/(loss) from the previous valuation at January 1, 2006 (for Niagara Falls). There is no prior valuation in respect of either the Corporation or PenWest.

Dion Durrell

Table A.1—Valuation Results
(in thousands of dollars)

	January 1, 2006	January 1, 2008
1. Accrued Benefit Obligation		
a) People in receipt of benefits	$ 1,256	$ 1,169
b) Fully eligible actives	$ 134	$ 344
b) Not fully eligible actives	$ 956	$ 1,065
Total ABO	**$ 2,346**	**$ 2,578**
2. Benefit Expense		
a) Current Service Cost	$ 78	$ 96
b) Interest Cost	$ 119	$ 131
c) Expected Return on Assets	$ -	$ -
d) Amortization of Transition Amount	$ -	$ -
e) Amortization of Past Service Cost	$ -	$ 20
f) Amortization of (Gains)/Losses	$ (84)	$ (77)
Total Benefit Expense *for following 12 months*	$ **113**	$ **170**
3. Expected Benefit Payments *for following 12 months*	$ 107	$ 122

Dion Durrell

Table A.2—Sensitivity Analysis
(in thousands of dollars)

	January 1, 2008			
	Valuation Results	*Retirement Age 58*	*1% Higher Trend*	*1% Lower Trend*
1. ABO				
a) People in receipt of benefits	$1,169	$ 1,169	$1,192	$1,149
b) Fully eligible actives	$ 344	$ 390	$ 354	$ 334
b) Not fully eligible actives	$1,065	$ 1,392	$1,218	$ 937
Total ABO	**$2,578**	**$ 2,951**	**$2,764**	**$2,420**
2. Current Service Cost *for following 12 months*	$ 96	$ 123	$ 113	$ 83
3. Interest Cost *for following 12 months*	$ 131	$ 150	$ 141	$ 122
4. Average Working Lifetime of the *current active employees (years)*	12	12	12	12

Dion Durrell

DEVELOPMENT OF NET GAINS OR LOSSES

**Table A.3—Development of Net Gains or Losses
(in thousands of dollars)**

	2006	2007
ABO at January 1	$ 2,346	$ 2,437
Current Service Cost	$ 78	$ 82
Interest Cost	$ 119	$ 123
Expected Benefit Payments	$ (106)	$ (108)
Expected ABO at December 31	$ 2,437	$ 2,534
Unamortized Past Service Cost at January 1, 2008		$ 240
Actual ABO at December 31, 2007 per Financial Statement		$ 2,578
Actuarial Loss/(Gain)		$ (196)
Amortization of Unamortized actuarial loss		
Unamortized Net Actuarial Loss (Gain) at December 31, 2007		$ (991)
Actuarial Loss (Gain) for Current Year at January 1, 2008		$ (196)
Total Loss (Gain) at January 1, 2008		$(1,187)
Less: Actual Amortization for 2008		$ (77)
Expected Unamortized Actuarial Loss (Gain) at December 31, 2008		$(1,110)

Dion Durrell

Please note that the actual ABO at January 1, 2008 for the Corporation is approximately $196,000 lower than the expected ABO at December 31, 2007. This is due to a combination of the following factors:

- Difference between the actual and the expected benefit premium rates (a decrease of approximately $126,000)
- Changes in claims cost trend rates and salary increase rate assumptions (a decrease of approximately $103,000)
- Deviations from the expected demographic changes of the valued group and other miscellaneous factors (an increase of approximately $33,000 in the total ABO)

CICA Section 3461 requires entities to adopt a systematic method for recognizing actuarial gains and losses in income. Furthermore, once adopted, CICA Section 3461 requires that the method of recognizing actuarial gain/(loss) be applied consistently from year to year. The required minimum amortization is equal to the amount of any gain or loss in excess of 10% of the ABO divided by the E.A.R.S.L. For clarity, there is no requirement to recognize any actuarial gain/(loss) amount below 10% of the ABO. The E.A.R.S.L. of the Corporation's current active group is 12 years as at January 1, 2008. In prior valuations, Niagara Falls Hydro has previously recognized the minimum actuarial gain or loss. This practice has been continued for the Corporation in 2008 and therefore, the actual amount of the gain recognized in the year 2008 is approximately $77,000.

AMORTIZATION OF UNAMORTIZED PAST SERVICE COST

Unamortized Past Service Costs at January 1, 2008	$	240
Less: Actual Amortization for year 2008	$	(20)
Unamortized Past Service Costs at December 31, 2008	$	220

The recognition of past service (i.e. service from date of hire to January 1, 2008) in respect of former PenWest active employees for benefit eligibility purposes and thus valuation purposes results in a past service liability as of January 1, 2008 of $240,599.

CICA Section 3461 states that an entity should amortize past service costs by assigning an equal amount to each remaining service period up to the full eligibility date of each employee active who was net yet fully eligible for benefits at the date of measurement of the past service liability. In addition, to reduce complexity, CICA Section 3461 also allows for an alternative amortization approach that amortizes past service costs more rapidly, however once chosen the alternative amortization approach is to be used consistently from year to year. Pursuant to CICA Section 3461, the PenWest past service liability is amortized on a straight-line basis over the average remaining service period of active employees expected to receive Benefits up to the full eligibility date. The average remaining service period to full eligibility of the active employees of the Corporation at January 1, 2008 is 12 years. Therefore, the actual amortization for the year 2008 is approximately $20,000 (see accounting worksheet).

Dion Durrell

SECTION B
PLAN PARTICIPANTS

Table B – 1 sets out the summary information with respect to the plan participants valued in the report, along with comparisons to the participants in the previous valuation at January 1, 2006 (for Niagara Falls).

Table B – 2 reconciles the number of participants in the prior valuation for Niagara Falls to the number of participants in the current valuation for the Corporation.

Dion Durrell

PARTICIPANT DATE

Table B.1—Participant Data

Membership data as at January 1, 2008 was received from the Corporation in respect of both former Niagara Falls and former PenWest via e-mail and included information such as name, sex, date of birth, date of hire, current salary, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

We have reviewed the data and compared it to the data used in the prior valuation for consistency and reliability for use in this valuation. The main tests of sufficiency and reliability that were conducted on the membership data are as follows:

- Date of birth prior to date of hire
- Salaries less than $20,000 per year, or greater than $250,000 per year
- Ages under 18 or over 100
- Abnormal levels of benefits and/or premiums
- Duplicate records

In addition, the following tests were performed:

- A reconciliation of statuses from the prior valuation to the current valuation;
- A review of the consistency of individual data items and statistical summaries between the current and prior valuations; and
- A review of the reasonableness of changes in such information since the prior valuation.

Active Employees

As of January 1	2006*			2008		
	Male	**Female**	**Total**	**Male**	**Female**	**Total**
Number of Employees	45	28	73	65	44	109
Average Length of Service	13.8	10.2	12.4	11.9	9.2	10.8

** includes former Niagara Falls employees only*

Dion Durrell

As of January 1, 2008	Current Age					
	Active Lives – not fully eligible			Active Lives – fully eligible		
	Count			Count		
Age Band	Male	Female	Total	Male	Female	Total
Less than 30	9	2	11	-	-	-
30-35	15	8	23	-	-	-
36-40	4	6	10	-	-	-
41-45	13	11	24	-	-	-
46-50	11	5	16	-	-	-
51-55	5	5	10	-	-	-
56-60	-	-	-	3	1	4
61-65	-	-	-	4	5	9
66-70	-	-	-	1	1	2
71-75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
Total	**57**	**37**	**94**	**8**	**7**	**15**

As of January 1, 2008	Average Service					
	Active Lives – not fully eligible			Active Lives – fully eligible		
	Service			Service		
Age Band	Male	Female	Total	Male	Female	Total
Less than 30	3.73	3.08	3.61	-	-	-
30-35	4.57	5.66	4.95	-	-	-
36-40	8.50	8.76	8.66	-	-	-
41-45	14.30	8.50	11.64	-	-	-
46-50	19.86	21.47	20.36	-	-	-
51-55	14.98	7.87	11.43	-	-	-
56-60	-	-	-	17.92	2.33	14.02
61-65	-	-	-	20.85	9.38	14.48
66-70	-	-	-	22.17	11.75	16.96
71-75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
Total	**10.80**	**9.30**	**10.21**	**19.92**	**8.71**	**14.69**

Dion Durrell

People in Receipt of Benefits (including LTD)

As of January 1	2006* Male	2006* Female	2006* Total	2008 Male	2008 Female	2008 Total
Number of Members	30	6	36	29	8	37

* *Includes former Niagara Falls employees only*

As of January 1, 2008

Expected Annual Benefit Payments

Age Band	Male	Female	Total
Less than 30	$ -	$ -	$ -
30-35	$ -	$ -	$ -
36-40	$ -	$ -	$ -
41-45	$ -	$ -	$ -
46-50	$ -	$ -	$ -
51-55	$ -	$ -	$ -
56-60	$ -	$13,001	$ 13,001
61-65	$ 26,322	$ 5,564	$ 31,886
66-70	$ -	$ 3,200	$ 3,200
71-75	$ 3,643	$ 426	$ 4,069
Greater than 75	$ 7,328	$ 789	$ 8,117
	$ 42,080	$ -	$ 42,080
Total	**$ 79,373**	**$22,980**	**$102,353**

RECONCILIATION OF DATA

Table B.2—Reconciliation Data

	Actives	Dependents	Disabled	Retirees
As at January 1, 2006*	**73**	**1**	**0**	**35**
New Entrants	9	-	-	-
Disabled	(1)	-	1	-
Terminated without benefits	(1)	-	-	-
Deceased	-	-	-	-
Retired	(2)	-	-	(2)
As at January 1, 2008 (Niagara Falls)	**78**	**1**	**1**	2
Former PenWest Employees**	31	-	-	**35**
As at January 1, 2008 (Corporation)	**109**	**1**	**1**	-
				35

* *Data as at January 1, 2006 from the prior valuation for Niagara Falls excludes Former PenWest employees.*
** *Effective Jan. 1, 2008, Niagara Falls merged with PenWest to form Niagara Peninsula Energy Inc.*

Dion Durrell

SECTION C
SUMMARY OF ACTUARIAL METHOD AND ASSUMPTIONS

ACTUARIAL METHOD

The aim of an actuarial valuation of post-retirement non-pension benefits is to provide a reasonable and systematic allocation of the cost of these future benefits to the years in which the related employees' services are rendered. To accomplish this, it is necessary to:

- make assumptions as to the discount rates, salary rate increases, mortality and other decrements;
- use these assumptions to calculate the present value of the expected future benefits; and
- adopt an actuarial cost method to allocate the present value of expected future benefits to the specific years of employment.

The ABO and Current Service Cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by CICA Section 3461 when future salary levels or cost escalation affect the amount of the employee's future benefits. Under this method, the projected post-retirement benefits are deemed to be earned on a pro-rata basis over the years of service in the attribution period. CICA Section 3461 stipulates that the attribution period commences at the employee's hire date and ends at the earliest age at which the employee could retire and qualify for the post-retirement non-pension benefits valued herein.

For each employee not yet fully eligible for benefits, the ABO is equal to the present value of expected future benefits multiplied by the ratio of the years of service to the valuation date to the total years of service in the attribution period. The Current Service Cost is equal to the present value of expected future benefits multiplied by the ratio of the year (or part) of service in the fiscal year to total years of service in the attribution period.

For health and dental benefits, we have used the current premium rates charged to retirees as an estimate of the claims to be incurred. The total monthly premium rates used are as follows:

Health Care		*Dental Care*	
Single Coverage	Family Coverage	Single Coverage	Family Coverage
$162.37	$372.02	$66.70	$162.31

These premium rates were provided by the Corporation and represent the rates effective January 1, 2008.

The ABO at January 1, 2008 is based on membership data at January 1, 2008 and management's best-estimate assumptions at January 1, 2008.

ACCOUNTING POLICIES

The Corporation amortizes the amount of any gain or loss in excess of 10% of the ABO divided by the expected average remaining service lifetime of the active members of the group.

Dion Durrell

Pursuant to CICA Section 3461, the past service cost is amortized on a straight-line basis over the average remaining service period to full eligibility of active employees at the measurement date.

MANAGEMENT'S BEST ESTIMATE ASSUMPTIONS

The following are management's best estimate economic and demographic assumptions as at January 1, 2008.

ECONOMIC ASSUMPTIONS

Consumer Price Index

The consumer price index is assumed to be 2.30% per annum.

Discount Rate

The rate used to discount future benefits is assumed to be 5.00% per annum. This rate reflects the assumed long term yield on high quality bonds.

The assumption used in the previous valuation for Niagara Falls was 5.00% per annum.

Salary Increase Rate

The rate used to increase salaries is assumed to be 3.80% per annum. This rate reflects the expected Consumer Price Index adjusted for productivity, merit and promotion.

The assumption used in the previous valuation for Niagara Falls was 3.30% per annum.

Claims Cost Trend Rate

The rates used to project benefits costs into the future are as follows:

	Current Valuation		Previous Valuation*	
End of Year	***Health***	***Dental***	***Health***	***Dental***
2008	10.00%	5.00%	8.00%	5.00%
2009	9.00%	5.00%	7.00%	5.00%
2010	8.00%	5.00%	7.00%	5.00%
2011	7.00%	5.00%	7.00%	5.00%
2012	6.00%	5.00%	7.00%	5.00%
2013 and Thereafter	5.00%	5.00%	7.00%	5.00%

** Valuation as at January 1, 2006 for Niagara Falls*

Dion Durrell

DEMOGRAPHIC ASSUMPTIONS

Mortality table

Mortality is assumed to be in accordance with the 1994 Uninsured Pensioner Mortality (UP-94) table, with a projection of mortality improvements to the year 2015 based upon Projection Scale AA. The use of these rates seems reasonable given this is the mortality table to be used in accordance with the Canadian Institute of Actuaries' Standard of Practice for Determining Pension Commuted Values, effective February 1, 2005.

Mortality rates are applied on a sex-distinct basis.

This is the same assumption that was used in the previous valuation for Niagara Falls.

Rates of Withdrawal

Termination of employment prior to age 55 was assumed to be equal to 2.0% per annum.

This is the same assumption used in the prior valuation for Niagara Falls.

Retirement Age

All active employees are assumed to retire at age 60, or immediately if currently over age 60.

This assumption remains unchanged from the previous valuation for Niagara Falls.

Disablity

No provision was made for future disability. It is assumed that individuals currently receiving long-term disability benefits will remain disabled until retirement at age 65.

This assumption remains unchanged from the previous valuation for Niagara Falls.

Family/Single Coverage

It is assumed that the current coverage type will remain into retirement.

This assumption remains unchanged from the previous valuation for Niagara Falls.

Expenses and Taxes

We have assumed 10% of benefits are required for taxes and the cost of sponsoring the program for life insurance.

We have assumed taxes and expenses are included in the premium rates for health and dental benefits.

This is the same assumption that was used in the previous valuation for Niagara Falls.

Dion Durrell

SECTION D
SUMMARY OF POST-RETIREMENT BENEFITS

The following is a summary of the plan provisions that are pertinent to this valuation.

GOVERNING DOCUMENTS

The program is governed by the collective agreement between Niagara Peninsula Energy Inc. and Local Union No. 636 of the International Brotherhood of Electrical Workers (A.F. of L. C.I.O. C.L.C) in effect until March 31, 2011.

What follows is only a summary of the post retirement non-pension benefit program. For a complete description, please refer to the above-noted documents.

ELIGIBILITY

All employees hired prior to January 1, 2007 are eligible for post-retirement life insurance coverage. All employees hired after January 1, 2007 are not eligible for post-retirement life insurance coverage.

All employees who leave from the Corporation from age 55 to age 65 with a minimum of 20 years of active service at the time they leave are eligible for the post-retirement health and dental benefits.

PARTICIPANT CONTRIBUTIONS

For employees hired prior to January 1, 2007, the Corporation shall pay 100% of the cost of the post-retirement life, health and dental benefits for the eligible retirees.

For employees hired after January 1, 2007, the Corporation shall pay 55% of the cost of the post-retirement health and dental benefits for the eligible retirees.

PAST SERVICE

Past Service is defined as continuous service prior to joining the plan if the participant was employed with PenWest prior to joining the Corporation.

LENGTH OF SERVICE

Length of service is defined as continuous service from the date of hire to the valuation date, measured in years and months.

Dion Durrell

SUMMARY OF BENEFITS

Post-Retirement Life Insurance

All eligible employees who retire from the Corporation are entitled to lifetime post-retirement life insurance, as per the MEARIE plan administered by Great West Life, based upon the following table:

Plan Option	Amount of Coverage	Eligibility
1	Flat $2,000.	If employee retires with less than 10 years of service in the Plan.
2	50% of final annual earnings reducing by 2.5% of final annual earnings each year thereafter for 10 years, to a final benefit equal to 25.0% of final annual earnings. Reduction occurs on anniversary date of retirement.	If employee was ever insured under Employee Plan options 2, 3 or 4, **or** if employee retires with 10 or more years of service in Plan but was never in superseded plan.
3	50% of final annual earnings	If employee was insured under superseded plan and was hired on or after May 1, 1967 and elected coverage under Option 1 only.
4	70% of the final amount insured for under the life plan immediately prior to retirement.	If employee was insured under the superseded plan and was hired before May 1, 1967 and elected coverage under Option 1 only.
5	Amount of retirement insurance coverage in force under superseded plan grandfathered.	Frozen group of insured whose retirement occurred under superseded plan prior to transfer to Great West Life (formerly Canada Life).

Post-Retirement Health and Dental Benefits

All eligible employees are entitled for extended health and dental benefits until age 65. This includes dependents of employees and/or retirees covered by this clause upon their death, regardless of years of service until the employee's normal retirement date or the spouse remarries.

A detailed description of the health and dental benefits covered under the post-retirement non-pension benefits can be found in the above-noted collective agreement.

Long Term Disability Benefits

The Corporation will continue to pay for existing employee's benefits while the employee is on LTD up to a maximum of 24 months.

SECTION E
EMPLOYER CERTIFICATION

Post-Retirement Non-Pension Benefit Plan
of Niagara Peninsula Energy Inc.
Actuarial Valuation as at January 1, 2008

I hereby confirm as an authorized signing officer of the administrator of the Post-Retirement Non-Pension Benefit Plan of Niagara Peninsula Energy Inc. that, to the best of my knowledge and belief, for the purposes of the valuation:

i) the assumptions upon which this report is based as summarized in Section C are management best estimate assumptions and are adequate and appropriate for the purposes of this valuation;

ii) the membership data summarized in Section B is accurate and complete; and

iii) the summary of Plan Provisions in Section D is an accurate and complete summary of the terms of the Plan in effect on January 1, 2008.

NIAGARA PENINSULA ENERGY INC.

Dec 10/08 — Date

S Wilson — Signature

Suzanne Wilson — Name

VP Finance — Title

1/6/2009

Niagara Peninsula Energy Inc.
ESTIMATED BENEFIT EXPENSE (CICA 3461)
Final

	Calendar Year 2008	Projected Calendar Year 2009	Projected Calendar Year 2010
Discount Rate	5.00%	5.00%	5.00%
Withdrawal Rate	2.00%	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*	expected*

A. Determination of Benefit Expense

	Calendar Year 2008	Projected Calendar Year 2009	Projected Calendar Year 2010
Current Service Cost	96,396	101,216	106,277
Interest on Benefits	130,669	135,741	140,734
Expected Interest on Assets	-	-	-
Past Service Cost	20,050	20,050	20,050
Transitional Obligation/(Asset)	-	-	-
Actuarial (Gain)/Loss	(77,444)	(77,444)	(77,444)
Benefit Expense	169,670	179,563	189,616

B. Reconciliation of Prepaid Benefit Asset (Liability)

	Calendar Year 2008	Projected Calendar Year 2009	Projected Calendar Year 2010
Accrued Benefit Obligation (ABO) as at December 31	2,683,024	2,781,134	2,882,675
Assets as at December 31	-	-	-
Unfunded ABO	(2,683,024)	(2,781,134)	(2,882,675)
Unrecognized Loss/(Gain)	(1,109,686)	(1,032,242)	(954,798)
Unrecognized Past Service Cost	220,550	200,500	180,450
Unrecognized Transition	-	-	-
Prepaid Benefit Asset (Liability)	(3,572,160)	(3,612,877)	(3,657,023)
Prepaid Benefit/(Liability) as at January 1	(3,524,523)	(3,572,160)	(3,612,877)
Benefit Income/(Expense)	(169,670)	(179,563)	(189,616)
Contributions/Benefit Payments by the Employer	122,033	138,846	145,470
Prepaid Benefit Asset (Liability)	(3,572,160)	(3,612,877)	(3,657,023)

* based on estimated employer benefit payments for those expected to be eligible for benefits.

Projected calendar year 2009 and 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2008 and December 31, 2009, respectively.

1/6/2009

Niagara Peninsula Energy Inc.
ESTIMATED BENEFIT EXPENSE (CICA 3461)
Final

C. Calculation of Component Items

	Calendar Year 2008	Projected Calendar Year 2009	Projected Calendar Year 2010
Calculation of the Service Cost			
- Current service cost	96,396	101,216	106,277
Interest on Benefits			
- ABO at January 1	2,577,992	2,683,024	2,781,134
- Current service cost	96,396	101,216	106,277
- Benefit payments	(61,017)	(69,423)	(72,735)
- Accrued benefits	2,613,372	2,714,817	2,814,676
- Interest	130,669	135,741	140,734
Expected Interest on Assets			
- Assets at January 1	-	-	-
- Funding	61,017	69,423	72,735
- Benefit payments	(61,017)	(69,423)	(72,735)
- Expected assets	-	-	-
- Interest	-	-	-
Expected ABO as at December 31			
- ABO at January 1	2,577,992	2,683,024	2,781,134
- Current service cost	96,396	101,216	106,277
- Interest on benefits	130,669	135,741	140,734
- Benefit payments	(122,033)	(138,846)	(145,470)
- Expected ABO at December 31	2,683,024	2,781,134	2,882,675
Expected Assets as at December 31			
- Assets at January 1	-	-	-
- Funding	122,033	138,846	145,470
- Interest on assets	-	-	-
- Benefit payments	(122,033)	(138,846)	(145,470)
- Expected Assets at December 31	-	-	-

Projected calendar year 2009 and 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2008 and December 31, 2009, respectively.

1/6/2009

Niagara Peninsula Energy Inc.
ESTIMATED BENEFIT EXPENSE (CICA 3461)
Final

	Calendar Year 2008	Projected Calendar Year 2009	Projected Calendar Year 2010
D. Actuarial (Gain)/Loss			
(Gain)/Loss on ABO as at January 1			
- Prepaid Benefit/(Liability)	3,524,523	3,572,160	3,612,877
- Unamortized (Gain)/Loss From Prior Year	(990,820)	(1,109,686)	(1,032,242)
- Expected ABO	2,533,703	2,462,474	2,580,635
- Unamortized Past Service Cost	240,599	220,550	200,500
- Actual ABO	2,577,992	2,683,024	2,781,134
- (Gain)/Loss on ABO	(196,310)	-	-
(Gain)/Loss on assets as at January 1			
- Expected assets	-	-	-
- Actual assets	-	-	-
- (Gain)/Loss on assets	-	-	-
Total (Gain)/Loss as at January 1	(1,187,130)	(1,109,686)	(1,032,242)
10% of ABO as at January 1	257,799	268,302	278,113
Total (Gain)/Loss in excess of 10%	(929,331)	(841,384)	(754,128)
Expected average remaining service life (years)	12	11	10
Minimum Amortization for current year	(77,444)	(76,489)	(75,413)
Actual Amortization for current year	(77,444)	(77,444)	(77,444)
Unamortized (Gain)/Loss	(1,109,686)	(1,032,242)	(954,798)
E. Amortization of Past Service Costs			
Unamortized past service costs as at beginning of period	240,599	220,550	200,500
Period over which past service costs are to be amortized (years)	12	11	10
Actual Amortization for current period	20,050	20,050	20,050
Unamortized past service costs as at the end of period	220,550	200,500	180,450

Projected calendar year 2009 and 2010 results are provided for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2008 and December 31, 2009, respectively.

Appendix F – Employee Benefit Handbook

YOUR GROUP BENEFITS

THE EMPLOYEES OF
NIAGARA PENINSULA ENERGY INC.
GROUP CONTRACT NUMBER: 15212
EFFECTIVE DATE: REFER TO MASTER CONTRACT
ELIGIBILITY PERIOD: the day immediately following completion of the waiting period stipulated by the Employer.

You can contact Manulife Financial at
1-866-769-5556
or visit our web site at:
www.manulife.ca/groupbenefits/secureserve

IMPORTANT INFORMATION:

This material summarizes the important features of your group benefit plan. This booklet is prepared as information only, and does not, in itself, constitute a contract. The exact terms and conditions of your group benefits are described in the Contract held by your Employer.

The information contained in this booklet is important and should be kept in a safe place.

For Employees hired on or before December 31, 2006:

The Employer agrees to pay 100% of the premiums for early retirees who are age 55 and older but under age 65, and who have a minimum of 20 years service with the Employer for the health care plans that shall be the same as a regular employee. This will include dependents of employees and/or retirees covered by this clause upon their death, regardless of years service until the employee's normal retirement date or the spouse remarries.

For Employees hired after January 1, 2007:

The Employer agrees to pay 55% of the premiums for early retirees who are age 55 and older but under age 65 for the above health care plans, with a minimum of 20 years service.

This will include dependents of employees and/or retirees covered by this clause upon their death, regardless of years service until the employee's normal retirement date or the spouse remarries.

SUMMARY OF BENEFITS

Benefits Underwritten By The Manufacturers Life Insurance Company

LONG TERM DISABILITY BENEFIT

Benefits are based on 66.67% of monthly earnings.

Benefits commence on the 181st day in the event of accident or sickness and are payable to age 65.

- maximum issue limit - $3,500.
- claim payments received are taxable benefits.
- benefits cease at the earlier of retirement or age 65.

CRITICAL ILLNESS COVERAGE

Amount: $2,000

Taxability: The taxability of the Critical Illness benefit will be administered on the same basis as that of the Long Term Disability benefit.

Termination: When you reach age 65, retire, or when the Critical Illness Benefit is paid, whichever occurs first.

EXTENDED HEALTH BENEFITS (EHB)

Single Deductible - $10 per calendar year.

Family Deductible - $20 per calendar year.

Prescription Drugs - $.20 per prescription.

100% reimbursement of eligible charges in excess of the deductible amount.

Hospital Accommodation

Deductible - Nil.

100% reimbursement of the charge made by a hospital for semi-private or private room accommodation, which is in excess of the standard ward rate.

Prescription Drugs

Deductible - Nil, except as noted.

100% reimbursement of eligible charges in excess of the prescription drug deductible.

Hearing Aids

Deductible - Nil.

100% reimbursement up to a maximum of a lifetime maximum of $350 per person.

Vision

Deductible - Nil.

100% reimbursement up to a maximum of $400 per 24 consecutive months.

Eye Examination

Deductible - Nil.

100% reimbursement up to a maximum of $70 every 2 calendar years.

Deluxe Travel

Maximum per trip:

Duration 60 days

Coverage $1,000,000 per person

Deductible - Nil

100% reimbursement of eligible charges.

EHB Overall Maximum - Unlimited.

DENTAL BENEFITS

Deluxe Plan

Deductible - Nil.

100% reimbursement of eligible charges, up to the amount specified in the applicable Fee Guide.

Dental Overall Maximum

$2,200 per calendar year, of which up to $500 may be used for Endodontic services.

Fee Guide - Ontario Dental Association Fee Guide for General Practitioners in effect one year prior to the date the services are rendered.

Note:

You are eligible to enroll for benefits if you are working in the required classification as determined by your employer.

Retirement coverage becomes available on the date of retirement.

All health and dental benefits terminate at age 65 or retirement, whichever is earlier.

A calendar year is January 1 to December 31. Eligible charges incurred during the last 3 months of a calendar year may be used to satisfy the deductible for the next following year.

GENERAL PROVISIONS

ELIGIBLE EMPLOYEES

You are eligible to enroll for benefits if you are a full-time, permanent employee actively working a minimum number of hours per week and have completed the waiting period, both of which are shown in the Summary of Benefits.

You may elect coverage by completing an application within 31 days of becoming eligible following the waiting period. Coverage is effective on the later of the date of eligibility or the date that application is made for group benefits, provided you are actively at work on the effective date. If not actively at work when you would normally have become eligible, your coverage will commence when you return to work on a full-time basis.

ELIGIBLE DEPENDENTS

Dependents are defined as your spouse (as described below), and unmarried, unemployed dependent children including natural, legally adopted, stepchildren or foster children.

The term "spouse" is defined as your legally married spouse or, a person of the opposite or same sex who has continuously lived with you for a period of at least one year in a conjugal relationship outside marriage. Only one spouse will be considered as being covered at any time.

Dependent children are eligible for benefits if they are less than 21 years of age, or, if 21 years of age but less than 25 years of age, they must be attending an accredited educational institution on a full-time basis.

Unmarried, unemployed children over 21 years of age qualify if they are dependent upon you by reason of a mental or physical disability and have been continuously so disabled since the age of 21. Unmarried, unemployed children who became totally disabled while attending an accredited educational institution on a full-time basis prior to age 25 and have been continuously so disabled since that time also qualify as a dependent.

Dependent coverage begins for your eligible dependents on the same date as your coverage, or as soon as they become eligible dependents if added later, provided that dependent benefits were applied for within 31 days of their becoming eligible. If coverage is not applied for within this 31 day period, evidence of health on the dependents may have to be submitted and approved before coverage begins.

EVIDENCE OF HEALTH

Proof of good health is not required if application is made within 31 days of first becoming eligible. If coverage is not applied for within this 31 day period, evidence may be requested for you and your dependents, if any, before benefits commence.

Certain other situations may require the submission of evidence of health before coverage will be approved. These could include benefits in excess of the non-evidence limits, as indicated in the Summary of Benefits. The cost of obtaining evidence of health shall be paid by the insurer if you or your dependent apply for coverage within 31 days of becoming eligible.

TERMINATION OF BENEFITS

Subject to any retirement coverage for which you may become eligible, coverage for you and your dependents will cease on the earliest of:

- the last day of the month for which premiums have been paid,
- the date you terminate employment,
- the date you cease to be eligible due to retirement, death, leave of absence, age limitation, change in classification, etc.
- the termination date of the Group Contract.

NOTICE OF CLAIM

Applicable to the Long Term Disability Benefit only

Written notice of claim must be given to Manulife Financial at least 30 days before the end of the Elimination Period or, if later, within six months of the onset of Total Disability.

Within 15 days of receiving written notice of claim, Manulife Financial will send you the forms required for filing proof of claim. If the forms are not received on time you may submit proof of claim using a written statement covering the occurrence, character and extent of the Total Disability.

If the Policy terminates and written notice of claim is not given to Manulife Financial within six months of the onset of the Total Disability, the claim will be invalid.

PROOF OF CLAIM

For Disability and Critical Illness Coverage's

Satisfactory written proof of claim must be given to the insurer within the following time periods:

• 90 days of the end of the Elimination Period, for disability benefits;

• 90 days after the date the Critical Illness was first incurred and diagnosed, for Critical Illness benefits.

Manulife Financial may require additional written proof of the continuance of Total Disability from time to time. Such proof must be submitted within 90 days of the date the proof was requested.

Claims must be sent to the address indicated on the claim form.

For Extended Health, Deluxe Travel and Dental Benefits

For Deluxe Travel Benefits, written proof of claim, satisfactory to Manulife Financial, must be received not later than six months following the date the claim was incurred.

For all other Benefits, written proof of claim satisfactory to Manulife Financial, must be received by Manulife Financial not later than the end of the calendar year following the year in which the claim was incurred.

However, if a Covered Person's coverage terminates for any reason, written proof of claim satisfactory to Manulife Financial must be received by Manulife Financial not later than 90 days following the date of termination.

In addition to written proof of claim, Manulife Financial may require you to submit:

• information from the Covered Person's physician in order to determine whether an Eligible Expense under the Extended Health Care Benefit is medically necessary;

• information from the Covered Person's dentist which Manulife Financial considers necessary to adjudicate a claim, such as a description of the treatment rendered (e.g., an expertise letter) and/or relevant x-rays.

Claims must be sent to the address indicated on the claim form.

PAYMENT OF CLAIMS

For Disability and Critical Illness Coverage's

Subject to the receipt of the required proof of claim, Long Term Disability benefits will be paid monthly in arrears. All other benefits will be paid promptly after the receipt of the required proof of claim.

All benefits will be payable to you. If you die before payment for Critical Illness Coverage is made, the benefit will be payable to your estate. If you die before all other benefits that are payable to you have been paid, or if expenses are incurred after your death, benefits will be made payable to any person and/or corporation appearing to Manulife Financial to be entitled to payment, where such payment is permissible under applicable law. Manulife
Financial fully discharges its liability by making such payments.

For Extended Health, Deluxe Travel and Dental Benefits

If written proof of claim satisfactory to Manulife Financial is provided, claim payments will be made directly to the provider of the care, service or supply if that provider has an agreement with Manulife Financial or a written request has been received from you to pay the provider directly. Any other claim payments will be made to you.

A Covered Person must submit a pre-authorization form completed by the attending physician for any Eligible Expense which requires the prior approval of Manulife Financial, before a claim will be considered.

A claim for an eligible dental expense or an eligible dental accident expense will be considered incurred on the date of completion of the care or services. All other Eligible
Expenses will be considered incurred as of the date the service or supply is received or, if earlier, the date the Covered Person incurred an obligation with the provider for the service or supply. However, no benefit will be payable before the date the Covered Person receives the service or supply.

If you die before receiving payment for incurred Eligible Expenses, payment will be made to any person and/or corporation appearing to Manulife Financial to be entitled to payment, where such payment is permissible under applicable law. Manulife Financial fully discharges its liability by making such payments.

CO-ORDINATING COVERAGE GUIDELINES FOR

OUT-OF-COUNTRY/PROVINCE HEALTH CARE EXPENSES

Applicable to Extended Health and Deluxe Travel Benefits

If a person who is covered under this group benefit plan is also covered under another Plan which provides similar coverage (such as employment-related group contracts, individual or group travel or health care contracts, credit card coverages or any other private insurance sources), any claim for Eligible Expenses incurred outside the province of residence or outside Canada will be co-ordinated with the other Plan(s) in accordance with the Coordinating

Coverage Guidelines for Out-of-Country/Province Health Care Expenses as outlined by the Canadian Life and Health Insurance Association Inc. Any information that is required by Manulife Financial to co-ordinate coverage in accordance with these guidelines must be supplied by the Covered Person upon request.

Manulife Financial may obtain from or release to any person or corporation, any information considered necessary to satisfy the intent of this provision and facilitate payment of benefits under this group benefit plan.

COORDINATION OF BENEFITS

Applicable to Extended Health, Deluxe Travel and Dental Benefits

Your Manulife Financial plan includes a Coordination of Benefits provision. If you have similar benefits through any other insurer, the amount payable through this plan shall be coordinated as follows, so that payment from all benefit plans does not exceed 100 percent of the eligible expense. Where both spouses of a family have coverage through their own employer benefit plans, the first payer of each spouse's claims is their own employer's plan.

Any amount not paid by the first payer can then be submitted for consideration to the other spouse's benefit plan (the second payer).

Claims for dependent children should be submitted first to the benefit plan of the spouse who has the earlier birthday in a calendar year, and second to the other spouse's benefit plan.

When submitting a claim to a second payer, be sure to include payment details provided by the first payer.

CONVERSION

Applicable to Extended Health and Dental Benefits only

When you or your dependent leaves the group, application may be made for conversion to an individual plan. Application for conversion to an individual plan must be made within 60 days of leaving the group.

LONG TERM DISABILITY BENEFIT

Long Term Disability (LTD) plans are designed to provide a monthly income to those employees confronted with loss of income during a lengthy or permanent disability.

If you become totally disabled while covered for this benefit and are under the continuous active care and treatment of a physician who is a duly qualified specialist, then subject to the terms and provisions of this coverage, a monthly benefit will be paid for as long as you remain totally disabled and are under age 65.

TOTAL DISABILITY (24 month own occupation plan)

You will be considered totally disabled during the elimination period shown in the Summary of Benefits and the next 24 months if, as a result of sickness or bodily injury, you are unable to perform the essential and material duties of your regular occupation and are not working for wage or profit except as part of a rehabilitation program.

Thereafter, you will be considered totally disabled if, as a result of sickness or bodily injury, you are unable to perform the essential and material duties of any occupation for which you are reasonably fitted, or could so become, by education, training or experience and are not working for wage or profit except as part of a rehabilitation program. (The availability of occupations with your employer or any other employer will not be considered when determining whether you are considered totally disabled.)

"Essential and material duties" are duties which are required in your performance of an occupation and which cannot be reasonably modified or omitted, as determined by Manulife Financial.

The amount of benefit is shown in the Summary of Benefits and is subject to the Integration of Benefits provision.

ELIMINATION PERIOD

The elimination period, shown in the Summary of Benefits, is the period of time which you must wait from the onset of the disability before you receive Long Term Disability benefits.

When the disability is not continuous, the days you are totally disabled may be accumulated to satisfy the elimination period, provided that no interruption is longer than two weeks and the two periods of disability are due to the same or a related cause.

RECURRENT DISABILITY

Separate periods of total disability occurring after LTD benefits have become payable and resulting from the same or related causes, will be considered one period of disability unless they are separated by a period of six consecutive months or more during which you had returned to work on a full-time basis.

Separate periods of total disability occurring after LTD benefits have become payable and resulting from unrelated causes; will be considered one period of disability unless they are separated by a period of at least one day during which you had returned to work on a fulltime basis.

INTEGRATION OF BENEFITS

Monthly benefits are coordinated with income payments to which you become entitled as a result of the current disability. The benefit coordination is applied as follows:

A. The amount of monthly benefit from the LTD plan is reduced by any disability benefits available from the Canada or Quebec Pension Plan (employee benefits only), any worker's compensation act or similar legislation and "income from all other sources".

"Income from all other sources" includes:

- disability benefits available under any other government program, excluding dependent benefits payable to you under the Canada or Quebec Pension Plan,
- retirement benefits provided by any employer or government program,
- income or benefits payable under any group program provided by or through the employer,
- income or benefits payable under a plan sponsored by an association, union or fraternal organization of which you are a member,
- income replacement benefits payable under any plan of automobile insurance, where such reduction is not prohibited by law, and
- wages or remuneration payable from any employer but excluding 50% of earnings received under an approved rehabilitation program.

B. The amount determined in A. above is further reduced if necessary, so that the amount of monthly benefit, together with all amounts of income described in A. above plus dependent benefits payable to you under the Canada or Quebec Pension

Plan, does not exceed 85% of gross earnings on taxable plans, or 85% of net earnings on non-taxable plans, except as provided under a rehabilitation program.

During the period of an approved rehabilitation program, the amount of monthly benefit as defined above will be further reduced if necessary, so that the amount of monthly benefit together with all amounts of income described in paragraph A. above, including 100% of earnings received from a rehabilitation program and dependent benefits payable to you under the Canada or Quebec Pension Plan, does not exceed 100% of gross earnings on taxable plans, or 100% of net earnings on nontaxable plans.

Canada/Quebec Pension Plan Freeze

Once the initial CPP/QPP offset has been established on a Long Term Disability claim, it will not be changed due to cost of living adjustments to the CPP/QPP payments.

REHABILITATION PROGRAM

Manulife Financial may at any time require you, if totally disabled, to join a program of rehabilitative employment which is appropriate for your circumstances. Participation in a program of rehabilitative employment will not disqualify you for Long Term Disability benefits while the rehabilitative employment continues and while you continue to be otherwise eligible for benefits.

Refusal to enter and participate in a rehabilitation program considered appropriate by Manulife Financial will result in termination of benefit payments.

PRE-EXISTING CONDITIONS

A pre-existing condition is a sickness or bodily injury for which you have consulted a physician, received medical treatment, care or services (including diagnostic measures), or been prescribed medication during the three months prior to the effective date of your Long Term Disability coverage.

Long Term Disability benefits are not payable for any disability which is due to a pre-existing condition and which begins within 12 months after the effective date of your Long Term Disability coverage.

DRUG AND ALCOHOL PROVISION

Long Term Disability benefits are not payable for any disability caused by the use of drugs or alcohol unless you are engaged in, and complete, a recognized rehabilitation program specifically for the treatment of substance abuse. Such treatment must begin during the elimination period. This exclusion will not apply if the total disability is due to a related organic disease.

EXCLUSIONS AND LIMITATIONS

Long Term Disability benefits are not payable for any of the following:

1. Any period during which you are not under the continuous active care and treatment of a physician who is a duly qualified specialist;
2. Any period during which you are imprisoned;
3. Any period during which you are not residing in Canada;
4. Any disability due to or resulting from self-inflicted injury or sickness;
5. Any disability due to or resulting from insurrection, war (declared or not) or the hostile actions of the armed forces of any country, service in the armed forces or participation in any riot, civil commotion or other act of aggression;
6. Any disability due to or resulting directly or indirectly from committing or attempting to commit a criminal offense; or
7. Any disability during the period:

- Of formal maternity leave taken by you pursuant to provincial or federal law, or pursuant to mutual agreement between you and the employer, or
- In which Employment Insurance maternity benefits are being paid or would be paid if you were eligible, whichever is the longer.

WAIVER OF PREMIUM

During the period that benefits are being received, you will not be required to submit premium payments.

TERMINATION OF BENEFIT PAYMENTS

Long Term Disability payments will terminate if:

1. You are no longer totally disabled as described above;
2. You have received Long Term Disability benefits for the maximum period of time indicated in the Summary of Benefits or have attained age 65, whichever is earlier;
3. You fail to provide satisfactory proof of the continuance of disability, or fail to undergo an examination requested by Manulife Financial;

4. You are not receiving continuing medical supervision and treatment considered appropriate by a physician designated by Manulife Financial;

5. You refuse to enter and participate in a rehabilitation program which is considered appropriate by Manulife Financial and which would facilitate a return to your own occupation or another occupation;

6. You retire; or

7. You die.

CRITICAL ILLNESS COVERAGE

DEFINITIONS

Critical Illness Coverage applies only to those sicknesses or disorders defined below. Any sickness or disorder not specifically defined below is not covered under this Critical Illness

Coverage and no benefit will be payable.

Heart Attack means the death of a portion of the heart muscle as a result of inadequate blood supply as evidenced by both new electrocardiographic (ECG) changes indicative of myocardial infarction and the elevation of cardiac biochemical markers to a level considered diagnostic for acute infarction. Heart attack during coronary angioplasty is covered provided that there are diagnostic changes of new Q wave infarction on the ECG in addition to elevation of cardiac markers.

Heart attack does not include:

- An incidental finding of ECG changes suggesting a prior myocardial infarction, in the absence of a corroborating event; or
- Elevation of cardiac markers due to coronary angioplasty, unless there are diagnostic changes of new Q wave infarction on the ECG.

Life Threatening Cancer means a tumor characterized by the uncontrolled growth and spread of malignant cells and the invasion of tissue, but excluding:

- carcinoma in situ;
- Stage 1A malignant melanoma (melanoma less than or equal to 1.00 mm in thickness, not ulcerated and without level IV or V invasion);

- Any non-melanoma skin cancer that has not become metastatic (spread to distant organs);
- stage A (T1a or T1b) prostate cancer; and
- Any tumor in the presence of any HIV.

Stroke means a cerebrovascular event producing neurological sequelae lasting more than 30 days and caused by either:

- intracranial thrombosis or hemorrhage; or
- embolism from an extra-cranial source.

There must be evidence of measurable, objective neurological deficit. Transient Ischemic
Attacks are specifically excluded.

BENEFIT

If, while covered for this Coverage, you incur and are diagnosed with a Critical Illness and complete the Survival Period, then subject to the terms of this Coverage, Manulife Financial will pay a lump sum amount of $2,000.

The Survival Period is the minimum number of consecutive days, immediately following the date of diagnosis of a covered condition, which you must survive before a Critical Illness benefit becomes payable. In this Coverage, the Survival Period is 30 days.

If more than one Critical Illness is incurred by and diagnosed for you, payment will be made for only one Critical Illness under this Coverage. Upon payment of this amount for one Critical Illness, your coverage under this Critical Illness Coverage will terminate.

DIAGNOSIS

The diagnosis of any Critical Illness must be made by a Physician in Canada, the United States or any other region that Manulife Financial may approve, whose practice is limited to the particular branch of medicine relating to the Critical Illness. For this Critical Illness Coverage, the Physician may not be a business associate of you or the Covered Person or related to the Covered Person by birth or marriage.

EXCLUSIONS AND LIMITATIONS

Critical Illness benefits are subject to the following limitations:

PRE-EXISTING CONDITIONS LIMITATION

A pre-existing condition is a sickness or bodily injury for which you have received medical treatment, care or services (including diagnostic measures), consulted a Physician or have been prescribed medication during the three months prior to the date you first became covered for this Critical Illness Coverage.

No benefit is payable for a Critical Illness which is due to a pre-existing condition and which is incurred and diagnosed within 12 months after the date you first became covered for this Critical Illness Coverage. This limitation applies without regard to whether or not you knew that you had the condition or had received a diagnosis prior to the date you first became covered for this Critical Illness Coverage.

CANCER LIMITATION

No Critical Illness benefit for cancer will be payable if the earlier of the date of diagnosis of any covered or excluded cancer, or the date of signs and/or symptoms and/or medical consultations or tests that led to the diagnosis of any covered or excluded cancer, is within 90 days after the effective date of coverage or last reinstatement.

Any diagnosis of cancer covered or excluded under this coverage, or signs and/or symptoms leading to a diagnosis of cancer covered or excluded under this coverage, occurring within 90 days after the effective date of coverage or last reinstatement must be reported to Manulife Financial.

In addition, unless a specific request is made to and approved by Manulife Financial, no benefits will be payable under this coverage for any subsequent diagnosis of cancer or for any complications arising from the original cancer.

If any of the events described above occur and Manulife Financial does not approve a specific request for you, your coverage under this Critical Illness Coverage will terminate.

Critical Illness benefits are not payable for a Critical Illness which is due to or results directly or indirectly from any of the following:

- Failure to seek or follow medical advice to the standard of a reasonable person in similar circumstances;
- Intentional self-inflicted injuries, suicide or attempted suicide;
- Misuse of medication or the abuse of drugs or intoxicants;

- committing or attempting to commit a criminal act as defined under legislation in the jurisdiction where the act was attempted or committed;
- insurrection, war (declared or not), or the hostile action of the armed forces of any country, service in the armed forces, or participation in any riot, civil commotion or any other act of aggression;
- Operate a vehicle while impaired by drugs, toxic substances or an alcohol level in excess of the legal limit. (For this exclusion, vehicle means any form of transportation which is drawn, propelled or driven by any means and includes, but is not restricted to, an automobile, truck, motorcycle, moped, bicycle, snowmobile or boat.);
- Travel or flight in, or descent from, any kind of aircraft if you:
- are a member of the aircraft crew,
- have any duties relating to the operation, maintenance, testing or control of the aircraft, or are on the aircraft for the purpose of instruction or training;
- Participation in under water diving, hang gliding, parachuting, skydiving, any form of motorized vehicle racing, including time trials; or
- Cosmetic or elective surgery.

WAIVER OF PREMIUM

While the premium is being waived for the Long Term Disability Benefit because the Employee is Totally Disabled, the Employee's coverage under this Critical Illness Benefit will be continued. However, if this Policy terminates, the Employee's coverage under this Critical Illness Benefit will also terminate

EXTENDED HEALTH BENEFITS

The benefits described below are available to you through Manulife Financial Extended Health Benefit Plan when required as a result of sickness or accidental bodily injury. Refer to the "Summary of Benefits" for information regarding reimbursement of this benefit.

GENERAL INFORMATION

- No medical examination is required.

· Benefits apply anywhere in the world. Reimbursement will be in Canadian funds up to the reasonable and customary charges for the services received, plus the rate of exchange if any, as determined by Manulife Financial from the date of the last service provided.

· Pre-existing conditions are covered from the moment the Agreement takes effect, except for dental care as a result of an accident.

BENEFITS

1. DRUGS - Formulary Two: Drugs, medicines and injected allergy sera, and insulin (needles, syringes and test-tape for use by diabetics) purchased on the prescription of a medical doctor and which are listed in Manulife Financial Formulary Two. Sexual dysfunction drugs are also covered, subject to the prescription drug deductible and reimbursement stated in the Summary of Benefits. No coverage is provided for vitamins or vitamin preparations (unless injected), smoking cessation aids, and drugs not approved for legal sale to the general public in Canada.

2. PRIVATE NURSING: Charges for private nursing services which require, and can only be performed by a Registered Nurse (RN); when such services are provided in the home by a Registered Nurse who is registered in the jurisdiction in which the services are performed and is not a relative of the patient. RN services must be certified medically necessary by the attending physician; and will be reimbursed to a maximum of 90 eight hour shifts per covered person per calendar year. Agency fees, commissions and overtime charges, or any amount in excess of the fee level set by the largest nursing registry in the province of Ontario, are not included.

An "Authorization Form for RN Services" must be completed by the attending physician and submitted to Manulife Financial. When the services are extended for more than 30 days, prior approval must be obtained from Manulife Financial on a monthly basis.

3. DIAGNOSTIC SERVICE: Diagnostic services performed at a hospital.

4. PRIVATE ROOM: Difference in cost between semi-private accommodation and a private room (not a suite) in a public general hospital.

5. CHRONIC CARE: Charges for accommodation in a public chronic hospital, or in a chronic wing facility of a public hospital for semi-private accommodation of up to $3 per day for 120 days during any period of 12 consecutive months.

6. ACCIDENTAL DENTAL: Dental care necessitated by a direct accidental blow to the mouth and not by an object wittingly or unwittingly placed in the mouth. The accident and treatment must occur while coverage is in force. Treatment must begin within 90 days of the accident, and must be completed within one year. Manulife Financial must be notified immediately. Payment will be made up to the fees set out in the Ontario Dental Association suggested Fee Guide for General Practitioners in effect on the date of treatment. Where the patient is less than 18 years of age at the time of the accident, treatment must be completed prior to attainment of age 19.

7. PRIVATE HOSPITAL: Charges up to $10 a day to a maximum of 120 days per person while your coverage is in force for care in a licensed private hospital.

8. PROSTHETIC APPLIANCES: Purchase of the following items when authorized in writing by the patient's attending physician: standard type artificial limb or eye, splints, trusses, casts, cervical collars, braces (excluding dental braces), catheters, urinary kits, external breast prostheses (following mastectomies), ostomy supplies (where a surgical stoma exists), corrective prosthetic lenses and frames (once only for persons who lack an organic lens or after cataract surgery), custom-made boots or shoes or adjustments to stock item footwear, and custom moulded foot orthoses (orthotics), 2 pairs per calendar year, up to the reasonable and customary maximum per pair, as determined by Manulife Financial.

9. DURABLE MEDICAL EQUIPMENT: Purchase or rental of the following items when authorized in writing by the attending physician: hospital bed, crutches, cane, walker, oxygen set, respirator (a device to provide artificial respiration), standard-type wheelchair and wheelchair repairs.

10. MEDICAL SERVICES AND SUPPLIES: Bandages or surgical dressings, blood transfusions, plasma, radium and radioactive isotope treatments when authorized in writing by the patient's attending physician.

11. AMBULANCE: Licensed ground and air ambulance services (the difference between the government agency allowance and the customary charge).

12. PARAMEDICAL SERVICES - services of the following licensed, certified or registered practitioners:

a) **Physiotherapist** (who does not have an agreement with the provincial health plan), up to a maximum of $2,500 per person per calendar year.

b) **Clinical Psychologist**, up to $60 for the initial visit, $40 for each subsequent visit, subject to an overall maximum amount of $420 per calendar year.

c) **Masseur**, when the patient's attending physician authorizes in writing once every 12 months that such treatment is necessary, payment will be made up to $500 per person per calendar year.

d) **Speech Pathologist**, up to $60 for the initial visit, $40 for each subsequent visit, subject to an overall maximum amount of $260 per calendar year.

e) **Chiropractor***, up to a maximum of $550 per person calendar year, plus an allowance of $35 per calendar year for x-rays.

f) **Osteopath**, **Acupuncturist**, **Chiropodist**, **Podiatrist***, **Naturopath**, up to $300 per practitioner, per person in a calendar year.

No payment will be made for completion of reports, assessments, tests or evaluations.

* Benefits are payable only after the annual maximum allowance under your provincial health plan has been paid.

13. HEARING AIDS - this benefit provides payment towards the purchase of a hearing aid for you or an eligible dependent, when prescribed by a physician or hearing specialist.

Eligible charges include the cost of repairs and initial batteries. Refer to the Summary of Benefits for the amount and frequency of payment. Benefits are not payable for ear examinations, tests or replacement batteries.

14. VISION - this benefit provides payment towards the purchase of new or replacement eyeglasses or contact lenses, laser eye surgery performed by a licensed ophthalmologist for you or an eligible dependent, when prescribed by your doctor, ophthalmologist or optometrist. Charges to repair existing frames or lenses are also covered. Refer to the Summary of Benefits for the amount and frequency of payment.

Charges for one eye examination per person every 2 consecutive calendar years, performed by an ophthalmologist or optometrist, are covered up to a maximum of $70 per Covered Person.

Benefits are not payable for the cost of industrial safety glasses.

LIMITATIONS

Extended Health Benefits are not payable for:

· Services covered by any provincial government plan or any workers' compensation board,

· Any care, services or supplies which are not medically necessary, as determined by Manulife Financial,

· Care, services or supplies utilized as treatment of lifestyle choices, as determined by Manulife Financial,

· Services or supplies which are primarily for cosmetic purposes,

· Rest cures, travel for health reasons or examinations for the use of a third party,

· Services or supplies provided in a health spa, psychiatric or chronic care hospital or chronic care unit of a general hospital,

· Services or supplies provided while confined in a nursing home or home for the aged,

· charges for dental care due to an accident which occurred prior to the effective date of coverage,

· Drugs or medicines, services or supplies which have been self prescribed, or prescribed by or for family members,

· drugs, injectables, supplies or appliances which are experimental or which are not approved by the Health Protection Branch of Health & Welfare Canada for use in Canada,

· Charges incurred as a result of conditions arising from war, whether or not war was declared, from participation in any civil commotion, insurrection or riot, or while serving in the armed forces,

· Additional, duplicate or replacement appliances or devices, except where the replacement is required because the existing appliance can no longer be made serviceable due to normal wear and tear, or as the result of a pathological change, unless prior approval in writing is obtained from Manulife Financial,

· Vaporizers,

· Charges incurred as a result of self-inflicted injury or while committing, or attempting to commit, a criminal offence,

· charges for the completion of claim forms or other documentation, or charges incurred for failing to keep a scheduled appointment or for transfer of medical files,

· Expenses incurred for benefits or that part of benefits which cease to be payable under any government program.

DELUXE TRAVEL

The following benefits provide protection when you and/or your eligible dependents are vacationing or travelling outside the province of residence for other than health reasons. Eligible expenses over and above those paid by the provincial government health plan are covered when emergency illness or injuries occur outside the province of residence. Coverage is limited to a maximum of 60 consecutive days per trip, beginning on and including the date of departure. If you are in hospital on the 60th day, coverage will be extended until date of discharge. The total amount payable per trip for all eligible expenses will not exceed $1,000,000 per person.

Any benefit maximums listed are in Canadian funds.

When eligible expenses are incurred for benefits which have a limitation, i.e., accidental dental, balances may be eligible through your Manulife Financial EHB (Extended Health Benefits) plan. Refer to the Summary of Benefits for information regarding reimbursement of the following benefits.

Benefits

1. Hospital Accommodation: Reasonable and customary charges in excess of the provincial health plan allowance for active treatment hospital room accommodation (not a private room or suite). Payment will also be made for outpatient services provided by an active treatment hospital, in excess of the provincial health plan allowance. If coverage expires after admission to hospital, benefits continue until discharge.
2. Doctor Bills: Reasonable and customary charges in excess of the provincial health plan allowance.
3. Private Duty Registered Nurse: Reasonable and customary charges for private duty nursing services which can only be performed by a Registered Nurse (R.N.) when those services are performed during or immediately following hospitalization. Private duty nursing services must be certified in writing as medically necessary by the attending physician and cannot be performed by a relative.
4. Ambulance: Reasonable and customary charges for ground ambulance service from the place of illness or accident to the nearest qualified medical facility.
5. Air Ambulance: The cost of air evacuation between hospitals or for repatriation for hospital admission in your province of residence, when the transfer is approved in advance by Manulife Financial. Any unused portion of your air ticket must be returned to Manulife Financial. (Arrangements must be made through the Assistance Centre.)
6. Paramedical Services: Payment of up to $300 for charges made by a physiotherapist, chiropractor, chiropodist, podiatrist or osteopath (including x-rays), when required for emergency treatment.
7. Diagnostic Services: Reasonable and customary charges for laboratory tests and x-rays when prescribed by the attending physician.
8. Treatments: The cost of whole blood, blood plasma or specialized treatments using radium and radioisotopes are covered, when rendered due to emergency hospitalization.

9. Prescriptions: When required for emergency treatment, reasonable and customary charges for drugs, medicines and injected sera, when purchased on the prescription of a physician or dentist and dispensed by a licensed pharmacist. Benefits are not payable for vitamins, vitamin/mineral preparations, food supplements, general public (G.P.) products or over-the-counter drugs or medicines, whether prescribed or not. Requires original receipt, showing name of prescribing physician, prescription number, name of medication, date, quantity and total cost.

10. Medical Appliances: Cost of splints, casts, crutches, canes, slings, trusses, walkers and/or the temporary rental of a wheelchair prescribed by the attending physician, will be reimbursed when required due to an accident or unexpected illness which occurs, and when devices are obtained, outside your province of residence.

11. Accidental Dental: Up to $2,000 will be reimbursed for treatment by a dentist to natural teeth when necessitated by a direct, external accidental blow to the mouth. Treatment must begin within the period of coverage and be completed within 183 days of the accident. An accident report is required from the dentist or physician, immediately following the accident.

12. Repatriation: When your emergency is such that:

· the attending physician specifies in writing that you should immediately return to your province of residence for immediate medical attention, Manulife Financial will reimburse the extra cost incurred for the purchase of the most economical airfare (available only when you are not holding a valid open-return air ticket), plus the additional most economical airfare, if required, to accommodate a stretcher, to return you by the most direct route to the air terminal nearest the departure point in your province of residence. This benefit also applies to one member of the family who is covered by this plan, and is travelling with the person at the time of illness or injury.

(Arrangements must be made through the Assistance Centre.)

· the attending physician or commercial airline stipulates in writing that you must be accompanied by a qualified medical attendant (not a relative), Manulife Financial will reimburse the reasonable and customary fee charged by a medical attendant registered in the jurisdiction in which treatment is provided, including the most economical airfare and overnight hotel and meal expenses, if required. (Arrangements must be made through the Assistance Centre.)

13. Friend/Family Hospital Visits: The most economical airfare by the most direct route from your province of residence will be reimbursed for any one family member or friend to:

· visit a covered person confined in hospital. Benefit requires the covered person to have been an inpatient for at least 7 days outside the province of residence, plus the written verification of the attending physician that the situation was serious enough to have required the visit.

· identify deceased prior to release of the body, where necessary. (Arrangements must be made through the Assistance Centre.)

14. Automatic Extension of Coverage: Coverage will automatically be extended to the covered person and any accompanying family members for up to 72 hours:

· following discharge date (and including the period of hospitalization) when return to the province of residence is delayed due to hospitalization, where such confinement continues beyond the 60th day following the date of departure from the province of residence;

· beyond the 60th day following the date of departure from the province of residence when return to the province of residence is delayed, by order of the attending physician, due to a covered illness or accidental injury;

· beyond the 60th day following the date of departure from the province of residence when return to the province of residence is delayed, due to the delay of a common carrier (airplane, bus, taxi, train) on which a covered person is a passenger; or the delay is caused by a traffic accident or mechanical failure of a private automobile en route to the departure point. Claims must be supported by documented proof.

15. Return of Deceased: Up to $5000 will be reimbursed towards the cost of preparation and homeward transportation of a deceased covered person to the province of residence

OR up to $2500 for cremation and/or burial at place of death. Benefit excludes the cost of a burial coffin.

16. Meals and Accommodation: Up to $1500 (for you and your dependents combined, limited to a daily maximum of $150) will be reimbursed for the extra cost of commercial accommodation and meals incurred by a covered person remaining with a travelling companion, when return to the province of residence is delayed beyond the planned termination date of the trip due to illness or injury to a travelling companion or a covered person. Claims must be verified by the attending physician and supported with receipts from commercial organizations.

17. Vehicle Services: Up to $1000 will be reimbursed towards the cost of driving your vehicle, either private or rental, to the province of residence or nearest appropriate vehicle rental agency when you are unable to do so due to unexpected illness or physical injury and your travelling companion is unable to do so. Medical certification is required, as well as receipts for costs incurred (i.e., fuel, accommodation, meals, airfares).

If your private vehicle is stolen or rendered inoperable due to an accident, costs will be covered for the most economical airfare to return the covered persons, by most direct route, to point of departure in the province of residence. Requires official police report of the loss or accident.

18. Relief of Dental Pain: Treatment for the emergency relief of dental pain, excluding root canals, is covered to a maximum of $200. Treatment must be rendered at a location at least 200 km from the province of residence.

19. Hospital Expenses: Payment of up to $100 per hospital stay to cover incidental expenses. Paid receipts must be submitted.

Emergency and Payment Assistance:

Hospital/Medical Payment: Many hospitals around the world require a substantial deposit when non-residents are admitted for emergency treatment. And, before the patient is discharged from care, most hospitals and physicians expect payment in full for services provided. The Assistance Centre will arrange and/or coordinate payment in full on your behalf, whenever possible. Be sure to call for assistance.

Emergency Helpline: In the event of an emergency, illness or accident while travelling outside your province of residence, call the Assistance Centre. The toll-free numbers are listed on the back of your benefit card and are available 24 hours a day, seven days a week.

WHEN HOSPITALIZATION OCCURS, THE ASSISTANCE CENTRE MUST BE CONTACTED WITHIN 24 HOURS OF ADMISSION. FAILURE TO CONTACT THE ASSISTANCE CENTRE MAY RESULT IN A DELAY IN THE SETTLEMENT OF YOUR CLAIM.

Note: You must be able to provide your provincial health insurance number to the Assistance Centre before payments can be arranged on your behalf. Be sure to travel with your provincial health insurance number and the number of each member of your family.

Provide the Assistance Centre with your Manulife Financial group policy number, certificate number and the Service Code shown on the back of your benefit card.

If you require general information about your travel benefit, please call Manulife Financial at 1 866-769-5556.

Travel Assistance Benefits:

Assistance Related to Medical Services

- Help you locate a physician, clinic or hospital.
- Confirm coverage to the hospital or physician.
- Arrange payment to the hospital or physician wherever possible.
- Monitor the medical treatment and keep the family informed.
- Arrange the transportation of a family member to the patient's bedside or to identify the deceased.
- Arrange for transportation home of the patient, if medically permissible.

General Assistance

- Provide emergency response in most major languages.
- Assist in contacting your family, business partner or family physician.
- Arrange for local care of dependent children and coordinate their return home, if the covered person is hospitalized.

· Arrange for the transmission of urgent messages to family members or business partners.

· Assist in the event of loss of passports or airline tickets.

· Help you to access legal counsel in the event of a serious accident.

· Coordinate claims processing with your provincial health plan.

To Make A Claim

When major emergencies occur outside Canada and the cost of services provided by a hospital or physician are beyond your immediate ability to pay, call or ask the physician or hospital administration to call the emergency helpline. The Assistance Centre will confirm your coverage and arrange payment on your behalf, whenever possible. You need do nothing more until an authorization and claim form is sent to you for signing. Once this form is signed and returned, benefits will be coordinated on your behalf with the government insurance plan and Manulife Financial.

For eligible expenses which you pay yourself while outside your province of residence, send your claim to the address indicated on the claim form. Claims payment will be payable to you.

Definition

“Travelling companion” is any person who has prepaid accommodation and/or transportation with the covered person. (Maximum four persons, including the covered person)

General Information

1. Coverage is available only to residents of Canada who are covered by a provincial government health plan while they are travelling outside their province of residence.

2. The availability, quality or results of any medical treatment, transport or other services, or the failure of the person to obtain medical treatment or other services will not be the responsibility of Manulife Financial or the Assistance Centre.

3. To be eligible, the hospital or medical benefits covered must have been provided at the nearest eligible facility capable of providing adequate service at the time the illness or injury occurred.

4. Manulife Financial will make benefit payments, based on reasonable and customary charges, after receipt and evaluation of satisfactory claim information. Reimbursement will be made in Canadian funds based on the rate of exchange you would be charged within the country of travel as determined by Manulife Financial in its sole discretion, based upon advice of any Schedule One Canadian bank. No sum payable will carry interest.

5. Where required, benefits listed herein will be payable only on receipt of certification from the attending physician that services have been rendered and were for emergency treatment. Costs for completion of medical certificates or documentation required for the assessment of claims are the responsibility of the covered person.

6. Manulife Financial, in consultation with the attending physician, reserves the right to transfer the covered person to another hospital or return the covered person to his or her province of residence. If any covered person is able to return to the province of residence following the diagnosis of, or the emergency medical treatment for, a medical condition which requires continuing medical care, treatment or surgery and the covered person elects to have the care, treatment or surgery performed outside the province of residence, no benefits will be payable with respect to such continuing care, treatment or surgery. The immediate availability of care, treatment or surgery on return to the province of residence is not the responsibility of Manulife Financial or the Assistance Centre.

7. The coverage provided under this benefit is subject to change by Manulife Financial. If this benefit and/or its provisions are revised by Manulife Financial, coverage for trips commencing on or after the effective date of such revisions will be in accordance with such revised benefits and/or provisions.

Exclusions

Manulife Financial will not pay benefits for expenses incurred:

1. For care, services or supplies which are not medically necessary, as determined by Manulife Financial.

2. For elective (non-emergency) treatment or surgery. This includes treatment or surgery:

- Not required for the immediate relief of acute pain and suffering;
- Which medically could be delayed until the covered person has returned to Canada; or
- Which the covered person elects to have rendered or performed outside Canada following emergency treatment for, or diagnosis of, a medical condition which (on medical evidence) would not prevent the covered person from returning to Canada prior to such treatment or surgery.

3. For hospital accommodation or treatment received in a hospital which is not an active treatment hospital, such as a nursing home, health spa, chronic care hospital or chronic care unit of a public hospital.
4. Outside the province of residence when the covered person could have been returned to the province of residence without risk to the covered person's life or health, even if the treatment available in the province of residence is of lesser quality than that available elsewhere.
5. For a medical condition for which, prior to departure, medical evidence would suggest that treatment or hospitalization could be required while on the trip.
6. By a covered person who is travelling outside the province of residence, with intent or incidentally, to seek medical advice or treatment, even if the trip is on the recommendation of a physician.
7. For hospitalization or services rendered in connection with or in any way associated with:

- general health examinations for check-up purposes;
- ongoing maintenance of an existing medical condition;
- rehabilitation or ongoing care in connection with drug, alcohol or other substance abuse;
- a rest cure or travel for health reasons; or
- cosmetic treatment.

8. In connection with or in any way associated with travel booked or commenced contrary to medical advice or after receipt of a terminal prognosis.
9. For hospital or medical care of either a covered person or a newborn child as a result of, in connection with or in any way associated with:

- full-term birth;

- medical complications after the 26th week of pregnancy; or
- deliberate termination of pregnancy.

10. For services provided by naturopaths or optometrists or for cataract surgery.
11. As a result of, in connection with or in any way associated with driving a Motorized Vehicle while impaired by drugs, alcohol or toxic substances or an alcohol level of more than 80 milligrams in 100 millilitres of blood. (For the purpose of this exclusion, “Motorized Vehicle” means any form of transportation which is propelled or driven by a motor and includes, but is not restricted to, an automobile, truck, motorcycle, moped, snowmobile or boat.)
12. As a result of, in connection with or in any way associated with abuse of medication, toxic substances, alcohol or the use of non-prescribed drugs.
13. As a result of, in connection with or in any way associated with suicide, attempted suicide or self-inflicted injury, whether sane or insane.
14. As a result of, in connection with or in any way associated with committing, or attempting to commit, a criminal act under legislation in the jurisdiction where the act was attempted or committed.
15. As a result of, in connection with or in any way associated with parachuting, hang gliding, bungee jumping, mountaineering, cave exploring, participation in professional sports or any speed contest by a Motorized Vehicle. (For the purpose of this exclusion, “Motorized Vehicle” means any form of transportation which is propelled or driven by a motor and includes, but is not restricted to, an automobile, truck, motorcycle, moped, snowmobile or boat.)
16. As a result of, in connection with or in any way associated with a flight accident unless the covered person is riding as a fare-paying passenger on a commercial airline or charter aircraft with a seating capacity of six people or more.
17. As a result of, in connection with or in any way associated with the radioactive, toxic, explosive or other hazardous properties of nuclear materials or by-products.
18. As a result of, in connection with or in any way associated with any of the following, regardless of any other cause or event contributing concurrently or in any other sequence thereto: war, invasion, acts of foreign enemies, hostilities, warlike operations

(whether war be declared or not), civil war, rebellion, revolution, insurrection, civil commotion assuming the proportions of or amounting to an uprising, military or usurped power, hijacking or any Act of Terrorism or any action taken in controlling, preventing or suppressing any of the foregoing. (For the purpose of this exclusion, “Act of Terrorism” means an act, including but not limited to, the use of force or violence and/or the threat thereof, by any person or groups of persons, whether acting alone or on behalf of or in connection with any organization or government, committed for political, religious, ideological, or similar purposes including the intention to influence any government and/or to put the public, or any section of the public, in fear that has been determined by the appropriate federal authority to have been an act of terrorism.)

1

19. As a result of, in connection with or in any way associated with service in the armed forces.

20. For services or supplies to the extent to which they are available under any government plan, or would be available without charge if this coverage was not in effect.

Manulife Financial will not provide emergency assistance services which relate in any way to expenses which are excluded above.

DENTAL BENEFITS

DELUXE PLAN

The following provides a general description of the benefits available to you and your eligible dependents under this dental plan. A complete list of the specific procedures (and applicable limitations) can be found in the Master Contract held by your Employer.

Payment for eligible benefits will be based on the monetary rates shown in the Dental Association Fee Guide applicable to the group plan.

Refer to the Summary of Benefits for information regarding any deductible, co-payment or maximum benefit amounts.

BENEFITS

Examinations - includes complete oral examinations once every 3 years and recall oral examinations once every 6 months

Consultations - with patient (maximum 2 units every 12 months) or with a member of the profession

Radiographs - includes complete series intra oral films once every 3 years, panoramic films once every 3 years, bitewing films once every 6 months

Diagnostic Services - includes bacteriologic tests, biopsy and cytological tests

Preventive Services - includes polishing (one unit of time every 6 months), scaling, fluoride treatment, oral hygiene instruction and reinstruction once every 6 months, space maintainers, and pit and fissure sealants for permanent molar teeth of children up to and including age 15 (only one replacement sealant per tooth)

Fillings

Endodontic Services - includes root canal therapy, surgical and emergency services

Periodontic Services - includes periodontal surgery, root planing and occlusal equilibration

(8 units of time every 12 months)

Complete and/or Partial Dentures - (once every 5 years)

Major Denture Adjustments

Denture Repairs, Minor Adjustment (after 3 months from insertion)

Relining/Rebasing

Restorative Services - (once every 5 years) includes post/core, crowns (natural teeth only), inlays/onlays

Fixed Prosthodontic Services - (once every 5 years) - includes bridgework (natural teeth only)

Orthodontic Services - includes observation, adjustments, orthodontic appliances and major orthodontic treatment.

Surgical Services - includes extractions, surgical incision/excision and frenectomy

Anaesthesia

In-office and Commercial Laboratory Charges - when applicable to the covered benefits

Orthodontic Treatment

Prior to the commencement of orthodontic treatment, your dentist should prepare a report outlining the details with respect to malocclusion, diagnosis, proposed treatment and applicable fees. This treatment plan should be forwarded to Manulife Financial for review to establish the extent of the payable benefit.

Limitation on Benefits Provided Outside the Province of Residence

When you incur expenses outside your province of residence, Manulife Financial will not pay an amount which is greater than it would pay for such expenses when incurred in your province of residence.

PREDETERMINATION OF BENEFITS AND ALTERNATE BENEFIT PROVISION

Prior to beginning dental treatment which is expected to cost $500 or more, you should obtain from your dentist and submit to Manulife Financial a treatment plan outlining the procedures and charges. Your dentist may be requested to submit any relevant x-rays.

Approval of the treatment plan should be obtained from Manulife Financial prior to commencement of treatment. After reviewing the plan, you will be advised of the amount payable by Manulife Financial. Where a range of fees, individual consideration or laboratory charges are included, Manulife Financial will determine the amount payable. The approved estimate will be honored for a period of twelve months from the date of approval.

There are many ways to treat a particular dental problem or condition and the cost of different procedures, services, courses of treatment and materials may vary considerably.

Manulife Financial may determine that payment for a less expensive procedure which will provide satisfactory results, may be made towards the cost of a procedure selected by you and your dentist. The difference between the amount payable by Manulife Financial and the dentist's charge is your responsibility. If you do not submit a treatment plan, Manulife Financial reserves the right to pay benefits based on the less expensive procedure which will provide satisfactory results.

Note: a treatment plan does not have to be submitted for the following services: basic fillings, root canals or extraction of wisdom teeth.

Benefits are not payable for:

· Services or supplies not listed under Benefits.

· Services or supplies for cosmetic purposes, as determined by Manulife Financial.

· Charges for periodontal splinting.

· Charges for procedures or appliances connected with implants.

· Services or supplies related to Temporomandibular Joint problems.

· Charges incurred as a result of conditions arising from war, whether or not war was declared, from participation in any civil commotion, insurrection or riot, or while serving in the armed forces.

· Charges incurred as a result of self-inflicted injury.

· Charges incurred while committing, or attempting to commit, directly or indirectly, a criminal act under legislation in the jurisdiction where the act was committed.

· Charges for the completion of claim forms or other documentation, or charges incurred for failing to keep a scheduled appointment or for transfer of medical files.

· Charges for procedures in excess of those stated in the Fee Guide for General Practitioners, as shown in the Summary of Benefits.

· Services or supplies covered by any government plan.

· Services completed after termination of coverage.

Table of Contents

EXHIBIT 5 – COST OF CAPITAL AND CAPITAL STRUCTURE

Overview:

The purpose of this evidence is to summarize the method and cost of capital requirements to support NPEI's 2011 proposed rate base.

Capital Structure:

NPEI has a current approved deemed capital structure of 60% debt with a combined return of 7.13% and 40% equity with a return of 9% as approved in the 2010 IRM rate decisions EB2009-0205 and EB2009-0206. The approved debt rate of 7.13% represents the weighted average approved debt rate of the predecessor companies of NPEI.

NPEI has prepared this rate application with a deemed capital structure of 56% Long Term Debt, 4% Short Term Debt, and 40% Equity to comply with the Report of the Board on Cost of Capital for Ontario Regulated Utilities, December 11, 2009 (the "Cost of Capital Report"). NPEI wishes to adopt the Board's guidelines and confirms the cost of capital parameters will be updated in accordance with these guidelines.

Table 5-1 details NPEI's proposed weighted average cost of capital for 2011. Table 5-2 details NPEI's proposed deemed capital structure for 2011 Test year in the Board's Appendix 2-N format as well as the 2006 Board Approved, 2007 deemed, 2008 deemed, 2009 deemed and 2010 Bridge Year.

Cost of Debt:

Long Term Debt

NPEI is requesting a return on long term debt for the 2011 Test Year of 6.36%. The details associated with the requested long term debt rate are provided in the following table 5-1

Table 5-1 2011 Weighted Average Cost of Capital

Table 5-1: 2011 Weighted Average Cost of Capital							
Description	Debt Holder	Affiliated with LDC?	Date of Issuance	Principal Balance at December 31, 2011	Term (Years)	Rate%	Interest Cost Per Amortization Schedule
Long term note payable	City of Niagara Falls	Y	April 1, 2000	$22,000,000	20	7.25%	$1,595,000
Long term note payable	Niagara Falls Hydro Holding Corporation	Y	April 1, 2000	$3,605,090	20	7.25%	$261,369
Long term bank loan	Scotiabank	N	June 1, 2004	$3,398,502	10	6.44%	$192,771
Term loan	TD	N	July 19, 2009	$7,965,243	10	4.58%	$348,793
Term loan smart meters	Scotiabank	N	September 30, 2015	$4,143,643	10	4.97%	$215,605
Total				$41,112,478			$2,613,538
Weighted Average Cost of Long Term Debt						6.36%	

The two long term notes payable to the City of Niagara Falls and to Niagara Falls Hydro Holding Corporation are fixed rate instruments that have a fixed interest rate that was the Board's deemed long-term debt rate at the time of issuance. They are the same long term notes payable approved by the Board in Niagara Falls Hydro 2006 EDR application. Both long term notes either upon demand by the City of Niagara Falls ($22,000,000) or Niagara Falls Hydro Holding Corporation ($3,605,090) respectively have a maturity date of April 1, 2020. Both notes at the option of the debt issuer and on one year's prior written notice may be revised or changed. As a result, it is NPEI's view they should be classified as embedded debt and the fixed rate of 7.25% should be reflected in the calculation of the weighted average cost of long term debt for 2011. Further details on these two debt instruments are provided in Appendix A.

The long term loan payable to Scotiabank in the amount of $3,398,502 as at December 31, 2011, was incurred in 2004 when NPEI constructed a new transformer station in the City of Niagara Falls. The loan was a fixed rate loan in the amount of $8.0 million dollars. The loan amortization period was for ten years commencing in June of 2004 at a fixed interest rate of 6.44%. This loan was also approved by the Board in Niagara Falls Hydro's 2006 EDR application. Principal and interest payments are made monthly.

The long term loan payable to TD Bank in the amount of $7,965,243 as at December 31, 2011, is at a fixed interest rate of 4.58% and an amortization period of ten years commencing in July 2009. The original loan was in the amount of $9.5 million dollars and was refinanced in July of 2009 in the amount of $9.0 million dollars. The loan originated from the former Peninsula West Utilities. The original loan of $9.5 million dollars was approved by the Board in Peninsula West Utility's 2006 EDR application. Principal and interest payments are made monthly commencing in August 2009.

Finally, the smart meter loan payable to Scotiabank in the amount of $4,143,643 as at December 31, 2011, commenced in December 2009 as a revolving term loan required for the installation of smart meters. The maximum loan amount approved by the bank for smart meters was for $10.0 million dollars. At September 30, 2010 NPEI had drawn a total of $4.5 million dollars. In the fall of 2009, NPEI secured $4,500,000 of the maximum loan amount in a non-revolving five year term loan, amortized over ten years at a fixed interest rate of 4.97%. Principal and interest payments are made monthly commencing in January 2011.

Share capital consists of 1,000 common shares, 745 issued to Niagara Falls Hydro Holding Corporation and 255 issued to Peninsula West Power Inc.

Short Term Debt

NPEI is requesting a return on Short Term Debt for the 2011 Test year of 2.07% in accordance with the Cost of Capital Parameter Updates for 2010 Cost of Service Applications issued by the OEB on February 24, 2010. NPEI understands that the OEB will be finalizing the return on short term debt for 2011 rates based on January 2011 market interest rate information. NPEI will adjust the Short Term Debt rate of 2.07% to the revised published rate adopted by the OEB.

Rate Base and Rate of Return

The following Table 5-2 details NPEI's rate base, deemed debt/equity ratios, deemed rate of return for 2006, 2007, 2008, 2009, 2010 Bridge and 2011 Test year.

Table 5-2 2006, 2007, 2008 Deemed Capital Structure

Table 5-2 Capitalization and Cost of Capital

Deemed Capital Structure for 2006

Description	% of Rate Base	$	Cost Rate	Return
Long Term Debt	50%	47,091,527	7.13%	3,357,626
Unfunded Short Term Debt				
Total Debt	50%	47,091,527		3,357,626
Common Share Equity	50%	47,091,527	9.00%	4,238,237
Total equity	50%	47,091,527		4,238,237
Total Rate Base	100%	94,183,053	8.07%	7,595,863

Deemed Capital Structure for 2007

Description	% of Rate Base	$	Cost Rate	Return
Long Term Debt	50%	48,667,643	7.13%	3,470,003
Unfunded Short Term Debt				
Total Debt	50%	48,667,643		3,470,003
Common Share Equity	50%	48,667,643	9.00%	4,380,088
Total equity	50%	48,667,643		4,380,088
Total Rate Base	100%	97,335,286	8.07%	7,850,091

Deemed Capital Structure for 2008

Description	% of Rate Base	$	Cost Rate	Return
Long Term Debt	53%	54,346,985	7.13%	3,874,940
Unfunded Short Term Debt				
Total Debt	53%	54,346,985		3,874,940
Common Share Equity	47%	47,617,339	9.00%	4,285,561
Total equity	47%	47,617,339		4,285,561
Total Rate Base	100%	101,964,324	8.00%	8,160,501

Table 5-2 2009, 2010, 2011 Deemed Capital Structure

Deemed Capital Structure for 2009				
Description	**% of Rate Base**	**$**	**Cost Rate**	**Return**
Long Term Debt	57%	61,369,996	7.13%	4,375,681
Unfunded Short Term Debt				
Total Debt	57%	61,369,996		4,375,681
Common Share Equity	43%	46,866,329	9.00%	4,217,970
Total equity	43%	46,866,329		4,217,970
Total Rate Base	100%	108,236,325	7.94%	8,593,650

Deemed Capital Structure for 2010				
Description	**% of Rate Base**	**$**	**Cost Rate**	**Return**
Long Term Debt	60%	68,702,377	5.97%	4,100,818
Unfunded Short Term Debt	0%		0.00%	0
Total Debt	60%	68,702,377		4,100,818
Common Share Equity	40%	45,801,585	9.00%	4,122,143
Total equity	40%	45,801,585		4,122,143
Total Rate Base	100%	114,503,962	7.18%	8,222,960

Deemed Capital Structure for 2011				
Description	**% of Rate Base**	**$**	**Cost Rate**	**Return**
Long Term Debt	56%	66,721,168	6.36%	4,241,494
Unfunded Short Term Debt	4%	4,765,798	2.07%	98,652
Total Debt	60%	71,486,966		4,340,146
Common Share Equity	40%	47,657,977	9.85%	4,694,311
Total equity	40%	47,657,977		4,694,311
Total Rate Base	100%	119,144,943	7.58%	9,034,456

Table 5-3 Capital Structure Deemed vs. Actual

Table 5-3

Capital Structure Deemed vs Actual

	2006 Board Approved	2006 Actual PWU + NFH	2007 Actual PWU + NFH	2008 Actual NPEI	2009 Actual NPEI
Long Term Debt	46,723,851	41,581,832	40,866,482	40,128,864	39,045,645
Common Equity	46,723,851	53,118,111	52,762,015	75,465,648	77,638,272
Actual Debt/Equity					
Long Term Debt Ratio		44%	44%	35%	33%
Equity Ratio		56%	56%	65%	67%
Deemed Debt/Equity	50% / 50%	50% / 50%	50% / 50%	53.3% / 46.7%	56.7% / 43.3%

PWU = Peninsula West Utilities Limited

NFH = Niagara Falls Hydro Inc.

On January 1, 2008, NPEI resulted in the merger of the former Peninsula West Utilities Limited and Niagara Falls Hydro Inc. As a result of this merger, $18,753,902 of Contributed Surplus arising from the excess of fair value of common shares issued over stated capital increased the equity of the new corporation. The increase in contributed surplus in conjunction with long term debt being repaid has shifted the actual debt to equity ratio to 35:65. NPEI paid dividends in the amount of $500,000 in 2008 and 2009 to the respective shareholders in proportion to their share holdings. NPEI intends to continue to pay a dividend of $500,000 in 2010 and 2011 to its respective shareholders in the same proportion as their share holdings. With respect to the long term debt holdings, NPEI intends to increase the smart meter debt as it completes the installation and implementation of the smart meter program throughout the remainder of 2010 and 2011. Since all the costs are not known at this time, NPEI does not have an amount of what this increase in debt will be. NPEI does not intend to borrow any new long term debt in 2010 or 2011 except for the above noted smart meter debt. NPEI does not intend to have any share offerings in 2010 or 2011.

Return on Equity:

NPEI is requesting a return on equity ("ROE") for the 2011 Test year of 9.85% in accordance with the Cost of Capital Parameter Updates for 2010 Cost of Service Applications issued by the OEB on February 24, 2010. NPEI understands that the OEB will be finalizing the ROE for 2011 rates based on January 2011 market interest rate information. NPEI will adjust the ROE of 9.85% to the revised published rate adopted by the OEB in early 2011.

Table 5-4 illustrates the ROE's for the years 2006 through to 2009. Note that for the Board approved 2006, 2006 Actual and 2007 Actual these numbers are the sum of the former Peninsula West Utilities Limited and former Niagara Falls Hydro Inc. In 2008 and 2009, the ROE is for the merged corporation, NPEI.

Table 5-4 Cost of Capital Deemed vs. Actual

	2006 Board Approved	2006 Actual PWU + NFH	2007 Actual PWU + NFH	2008 Actual NPEI	2009 Actual NPEI
Long Term Debt	46,723,851	41,581,832	40,866,482	40,128,864	39,045,645
Common Equity	46,723,851	53,118,111	52,762,015	75,465,648	77,638,272
Actual Debt/Equity					
Long Term Debt Ratio		44%	44%	35%	33%
Equity Ratio		56%	56%	65%	67%
Deemed Debt/Equity	50% / 50%	50% / 50%	50% / 50%	53.3% / 46.7%	56.7% / 43.3%
Interest on Long Term Debt		2,803,928	2,750,660	2,799,747	2,412,911
Net Income		2,098,189	2,345,915	2,692,941	2,672,624
Actual Long Term Debt Rate		6.74%	6.73%	6.98%	6.18%
Actual Return on Equity		3.95%	4.45%	3.57%	3.44%
Deemed Long Term Debt Rate	7.13%	7.13%	7.13%	7.13%	7.13%
Deemed Return on Equity	9.00%	9.00%	9.00%	9.00%	9.00%
Actual Cost of Capital		5.18%	5.44%	4.75%	4.36%
Deemed Cost of Capital	8.06%	8.06%	8.06%	8.06%	8.06%

Appendix A Promissory Notes

PROMISSORY NOTE

COPY

Due: April 1, 2020

FOR VALUE RECEIVED, Niagara Falls Hydro Inc. ("WiresCo") hereby promises to pay to or to the order of the City of Niagara Falls (the "City") the principal sum of twenty-two million dollars ($22,000,000.00) with interest at the rate specified herein, either upon demand by the City or on April 1, 2020 (the "Maturity Date").

Interest on the principal sum shall accrue from April 1, 2000 and be payable at a rate of seven and one-quarter percent (7¼ %) per annum, based on the interest rate for third party financing which the Ontario Energy Board or its successor may permit regulated distribution corporations to recover for rate making purposes.

Interest at the aforesaid rate shall be payable in quarterly installments, by means of an electronic funds transfer to the City, with the first of such payments commencing on June 30, 2000.

At the option of the City, on one year's prior written notice to WiresCo, the Maturity Date and any of the terms of this Promissory Note may be revised, changed or restated by the City in consultation with WiresCo.

This Promissory Note may, at the option of the City, be converted, as to some or all of the principal sum outstanding, into common shares of WiresCo at a conversion ratio of $100 per share. The foregoing conversion right may be exercised by the City at any time on 90 days prior written notice to WiresCo.

The terms of this Promissory Note are subject to the adjustment provisions of the Transfer By-law passed by the City of Niagara Falls on May 8, 2000 as By-law No.2000-97.

This Promissory Note is not assignable by the City without the consent of WiresCo.

DATED this 26th day of September, 2000.

NIAGARA FALLS HYDRO INC.

Per:

Authorized Signing Officer

Authorized Signing Officer

COPY

::ODMA\PCDOCS\CCT\59298\2

PROMISSORY NOTE

Due: April 1, 2020

FOR VALUE RECEIVED, Niagara Falls Hydro Inc. ("WiresCo") hereby promises to pay to or to the order of the Niagara Falls Hydro Holding Corporation ("HoldCo") the principal sum of Three Million Six Hundred and Five Thousand and Ninety Dollars ($3,605,090.00) with interest at the rate specified herein, either upon demand by HoldCo or on April 1, 2020 (the "Maturity Date").

Interest on the principal sum shall accrue from April 1, 2000 and be payable at a rate of seven and one-quarter percent (7¼ %) per annum, based on the interest rate for third party financing which the Ontario Energy Board or its successor may permit regulated distribution corporations to recover for rate making purposes.

Interest at the aforesaid rate shall be payable in quarterly installments, by means of an electronic funds transfer to HoldCo, with the first of such payments commencing on June 30, 2000.

At the option of HoldCo, on one year's prior written notice to WiresCo, the Maturity Date and any of the terms of this Promissory Note may be revised, changed or restated by HoldCo in consultation with WiresCo.

This Promissory Note may, at the option of HoldCo, be converted, as to some or all of the principal sum outstanding, into common shares of WiresCo at a conversion ratio of $100 per share. The foregoing conversion right may be exercised by HoldCo at any time on 90 days prior written notice to WiresCo.

The terms of this Promissory Note are subject to the adjustment provisions of the Transfer By-law passed by the City of Niagara Falls on May 8, 2000 as By-law No.2000-97.

This Promissory Note is not assignable by HoldCo without the consent of WiresCo.

This Promissory Note replaces a promissory note in the principal amount of $5,000,000.00 previously issued by WiresCo to HoldCo pursuant to the provisions of the said Transfer By-law.

DATED this 24th day of July, 2001.

NIAGARA FALLS HYDRO INC.

per: ______________________
President

per: ______________________
Treasurer

::ODMA\PCDOCS\CCT\59297\3

Table of Contents

EXHIBIT 6 RATE BASE AND REVENUE REQUIREMENT

Rate Base and Revenue Requirement

To continue to provide safe and reliable service to its customers and earn its permitted return on equity (ROE), NPEI requests to increase its Base Revenue Requirement to $30.24M. NPEI's 2006 Board Approved Revenue Requirement was based on 2004 Actual results and there have been significant changes to Distribution Expenses and Rate Base for the past six years as well as a merger of the former Niagara Falls Hydro Inc and Peninsula West Utilities Ltd utilities. Actual Distribution Expenses (including depreciation and amortization) have increased to $19.9M in 2009 from the 2006 Board Approved amount of $18.5M representing 1.5% annual growth from 2004 to 2009. The Rate Base increased to $108.24M in 2009 from the 2006 Board Approved amount of $89.52M, adding almost 4.18% every year.

These increases to both Rate Base and Distribution Expenses will continue into the Bridge Year 2010 and the Test Year 2011.

NPEI proposes for 2011:

1. A Rate Base of $119.09M, which is a 4.7% annualized increase from $89.52M of 2006 Board Approved. NFH ($65.34M) and PWU ($24.18M) to 2011

2. A Base Revenue Requirement of $30.24M, representing a 2.17% annualized increase from $26.25M of 2006 Board Approved. NFH ($17.45M) and PWU ($8.80M) to 2011.

Table 6-1 provides the calculated 2011 Revenue Requirement.

Table 6-2a combines Niagara Falls Hydro (NFH) and Peninsula West Utilities (PWU) 2006 Board Approved Revenue Requirement that is used in Table 6-2.

Table 6-2 demonstrates the steps used to calculate the Revenue Requirement and the details of year over year comparison in the event that NPEI was allowed to rebase every year.

Cost of Capital and PILs in Table 6-2 are the deemed Cost of Capital and PILs in that year.

Table 6-1 2011 Revenue Requirement Calculation

Table 6-1
2011 Revenue Requirement Calculation

	2011 Test Year ($)	Comments
Average Fixed Assets	101,968,654	From Exhibit 2
+		
Working Capital Allowance	17,176,290	From Exhibit 2
=		
Rate Base	119,144,943	
X		
Cost of Capital	7.58%	From Exhibit 5
=		
Return on Ratebase	9,034,456	
+		
Distribution Expenses (including Amortization)	21,661,597	From Exhibit 4
=		
Revenue Requirment before PILS	30,696,054	
+		
PILS	1,725,276	From Exhibit 4
=		
Service Revenue Requirment	32,421,330	
-		
Other Revenue	2,185,747	From Exhibit 3
=		
Base Revenue Requirement	30,235,583	
+		
Transformer Ownership Allowance	392,476	From Exhibit 3
+		
Low Voltage Charges	360,512	From Exhibit 8
=		
Throughput Revenue	30,988,570	

Table 6-2A 2006 Board Approved Niagara Falls + Pen West

Table 6-2A
2006 Board Approved Niagara Falls + PenWest

	2006 Board Approved - NFH	2006 Board Approved - PWU	2006 Board Approved
Average Fixed Assets	56,061,771	19,288,110	75,349,881
+			
Working Capital Allowance	9,276,265	4,895,160	14,171,425
=			
Rate Base	65,338,036	24,183,270	89,521,306
X			
Cost of Capital (Deemed)	8.03%	8.16%	8.06%
=			
Return on Ratebase	5,245,943	1,973,005	7,218,948
+			
Distribution Expenses (including Amortization)	11,497,496	7,003,845	18,501,341
=			
Revenue Requirment before PILS	16,743,439	8,976,850	25,720,289
+			
PILS (Deemed)	2,468,395	1,044,729	3,513,124
=			
Service Revenue Requirment	19,211,834	10,021,579	29,233,413
-			
Other Revenue	1,759,924	1,219,457	2,979,381
=			
Base Revenue Requirement	17,451,910	8,802,122	26,254,032
+			
Transformer Ownership Allowance	322,052	60,024	382,076
+			
Low Voltage Charges	0	776,577	776,577
=			
Throughput Revenue	17,773,962	9,638,723	27,412,685

Table 6-2 Revenue Requirement if Rebased Every Year

	2006 Board Approved - NFH	2006 Board Approved - PWU	2006 Board Approved	2006 Actual	2006 Actual vs 2006 Board Approved	2007 Actual	2007 Actual vs 2006 Actual	2008 Actual	2008 Actual vs. 2007 Actual	2009 Actual	2009 Actual vs. 2008 Actual	2010 Bridge	2010 Bridge vs 2009 Actual	2011 Test	2010 Bridge vs 2011 Test
Average Fixed Assets	56,061,771	19,288,110	75,349,881	79,697,709	4,347,828	82,169,939	2,472,230	86,976,440	4,806,501	92,546,546	5,570,106	97,979,846	5,433,300	101,968,654	3,988,807
+															
Working Capital Allowance	9,276,265	4,895,160	14,171,425	14,485,344	313,919	15,165,347	680,002	14,987,884	(177,463)	15,689,779	701,895	16,524,115	834,337	17,176,290	652,174
=															
Rate Base	65,338,036	24,183,270	89,521,306	94,183,053	4,661,747	97,335,286	3,152,232	101,964,324	4,629,039	108,236,325	6,272,001	114,503,962	6,267,637	119,144,943	4,640,981
X															
Cost of Capital (Deemed)	8.03%	8.16%	8.06%	8.06%		8.06%		8.06%		8.06%		7.18%		7.58%	
=															
Return on Ratebase	5,245,943	1,973,005	7,218,948	7,594,869	375,921	7,849,063	254,194	8,222,346	373,283	8,728,117	505,771	8,222,960	(505,156)	9,034,456	811,496
+															
Distribution Expenses (including Amortization)	11,497,496	7,003,845	18,501,341	19,382,007	880,666	20,319,265	937,258	19,595,536	(723,729)	19,928,356	332,820	20,934,539	1,006,183	21,661,597	727,058
=															
Revenue Requirment before PILS	16,743,439	8,976,850	25,720,289	26,976,876	1,256,587	28,168,328	1,191,452	27,817,882	(350,446)	28,656,473	838,591	29,157,499	501,027	30,696,054	1,538,555
+															
PILS (Deemed)	2,468,395	1,044,729	3,513,124	3,513,124	0	2,529,983	(983,141)	1,552,064	(977,919)	1,363,742	(188,322)	2,418,755	1,055,013	1,725,276	(693,479)
=															
Service Revenue Requirment	19,211,834	10,021,579	29,233,413	30,490,000	1,256,587	30,698,311	208,311	29,369,946	(1,328,365)	30,020,215	650,269	31,576,254	1,556,039	32,421,330	845,076
-															
Other Revenue	1,759,924	1,219,457	2,979,381	2,454,374	(525,007)	2,719,211	264,837	2,182,958	(536,253)	2,507,942	324,984	2,209,583	(298,359)	2,185,747	(23,836)
=															
Base Revenue Requirement	17,451,910	8,802,122	26,254,032	28,035,626	1,781,594	27,979,100	(56,526)	27,186,988	(792,112)	27,512,273	325,285	29,366,671	1,854,398	30,235,583	868,912
+															
Transformer Ownership Allowance	322,052	60,024	382,076	383,322	1,246	400,821	17,499	419,029	18,208	392,476	(26,553)	436,527	44,051	392,476	(44,051)
+															
Low Voltage Charges	0	776,577	776,577	499,276	(277,301)	715,716	216,440	612,662	(103,054)	280,838	(331,824)	339,100	58,262	360,512	21,412
=															
Throughput Revenue	17,773,962	9,638,723	27,412,685	28,918,224	1,505,539	29,095,637	177,413	28,218,679	(876,958)	28,185,587	(33,092)	30,142,298	1,956,711	30,988,570	846,272

Net Utility Income and Return on Rate Base

This evidence is to demonstrate the actual return on Rate Base using actual Operating Revenue, Distribution Expenses, including Interest Expense and PILs, to compare the actual return expected on Rate Base to the deemed return on Rate Base in support of NPEI's Revenue Deficiency calculation.

The combined former Peninsula West Utilities and former Niagara Falls Hydro Inc. 2006 Board Approved return on Rate Base is 8.06%. The actual earned return on actual Rate Base by 2009 was 5.15% due to a growing rate base and increased Distribution Expenses (see Table 6-3 for details). Based on most the recent Board Approved Cost of Capital (2010 Applications), the deemed return on Rate Base should be 7.58% (40% * 9.85% + 4% * 2.07% + 56% * 6.36%). The estimated return on Rate Base for 2011, using NPEI's existing rates, is only 5.53%, as shown in Table 6-5. This return is far below the requested return on Rate Base of 7.58%.

NPEI has determined its 2011 Net Income after Interest Expense to be $4.692M. Table 6-3 provides the detailed Net Income and return on Rate Base calculation.

PILs and Interest Expense presented in Table 6-3 are the actual expense incurred in the year and will be different from deemed PILs and Interest Expenses, with the exception of 2006 Board Approved, the 2010 Bridge Year and the 2011 Test Year.

PILs and Interest Expense for the 2010 Bridge Year and the 2011 Test Year are based on deemed PILs and Interest Expense amounts.

Table 6-3 Return on Rate Base

	2006 Board Approved	2006 Actual	2006 Actual vs 2006 Board Approved	2007 Actual	2007 vs 2006 Actual	2008 Actual	2008 vs. 2007 Actual	2009 Actual	2009 vs. 2008 Actual	2010 Bridge	2010 Bridge vs 2009 Actual	2011 Test	2010 Bridge vs 2011 Test
Total Operating Revenue	29,233,413	26,544,169	(2,689,244)	28,306,209	1,762,040	27,691,568	(614,641)	28,014,368	322,800	27,989,599	(24,769)	32,421,330	4,431,731
-													
Distribution Expenses	18,501,341	19,382,007	880,666	20,319,265	937,258	19,595,536	(723,729)	19,928,356	332,820	20,934,539	1,006,183	21,661,597	727,058
=													
Net Income Before PILS and Interest	10,732,072	7,162,162	(3,569,910)	7,986,944	824,782	8,096,032	109,088	8,086,012	(10,020)	7,055,060	(1,030,952)	10,759,732	3,704,672
-													
PILS	3,513,124	2,587,981	(925,143)	4,189,894	1,601,913	2,090,933	(2,098,961)	2,509,116	418,183	2,418,755	(90,361)	1,725,276	(693,479)
=													
Net Income Before Interest	7,218,948	4,574,181	(2,644,767)	3,797,050	(777,131)	6,005,099	2,208,049	5,576,896	(428,203)	4,636,305	(940,591)	9,034,456	4,398,151
-													
Interest Expense	3,192,371	2,867,534	(324,837)	2,846,060	(21,474)	2,752,846	(93,214)	3,019,825	266,979	4,100,818	1,080,993	4,340,146	239,328
=													
Net Income after Interest	4,026,577	1,706,647	(2,319,930)	950,990	(755,657)	3,252,253	2,301,263	2,557,071	(695,182)	535,488	(2,021,584)	4,694,311	4,158,823
Rate Base	89,521,306	94,183,053	4,661,747	97,335,286	3,152,232	101,964,324	4,629,039	108,236,325	6,272,001	114,503,962	6,267,637	119,144,943	4,640,981
Return on Rate Base	8.06%	4.86%	-3.21%	3.90%	-0.96%	5.89%	1.99%	5.15%	-0.74%	4.05%	-1.10%	7.58%	3.53%

Revenue Deficiency – Overview:

NPEI has provided detailed calculations supporting its 2011 revenue deficiency. NPEI's net revenue deficiency is $2,451,313 and when grossed up for PILs NPEI's revenue deficiency is $3,378,275. Table 6-5 on the following page provides the revenue deficiency calculations for the 2011 Test Year at Existing 2010 OEB-approved rates and the 2011 Test Year Revenue Requirement.

Table 6-4 below provides the Revenue Deficiency calculations for the 2011 Test Year at 2010 Board Approved combined rates for Niagara Falls territory customers and Peninsula West territory customers and the resulting 2011 Test Year Revenue Requirement by rate class.

NPEI notes Table 6-4 includes interest expense and PILS amounts not included in Exhibit 4-Operating Costs, Table 4-1.

The Revenue Deficiency arises from the following major factors:

- An increase in net Average Fixed Assets of $26.62M from $75.35M of combined 2006 Board Approved to $101.97M in 2011

- An increase in Working Capital Allowance of $2.95M from 14.17M of combined 2006 Board Approved to $17.12M in 2011

- A decrease in Cost of Capital of 0.48% from combined 2006 Board Approved 8.06% to 7.58% in 2011

- An increase in Distribution Expenses including depreciation and amortization of $3.16M from combined 2006 Board Approved $18.50M to $21.66M in 2011.

Table 6-4 2011 Throughput Revenue at 2010 Existing Rates

Table 6-4

2011 Throughput Revenue at Existing 2010 rates

	Fixed Rate - Note A	Variable Rate - Note B	Number of Customers	kWh / kW Sales	Fixed Charge $	Variable Charge $	Base Revenue $
Residential	14.21	0.01432717	46,900	459,406,923	7,995,709	6,582,001	14,577,711
GS < 50 kW	34.15	0.012494575	4,352	121,437,543	1,783,761	1,517,310	3,301,071
GS >50	213.09	3.864806312	848	1,806,009	2,169,282	6,979,877	9,149,159
Sentinel Lights	1.04	1.30187433	560	809	7,005	1,053	8,058
Street Lighting	0.38	1.489098819	12,408	20,107	56,525	29,942	86,467
USL	17.65	0.012336364	465	2,335,428	98,507	28,811	127,318
Total 2011 Throughput Revenue- Note 1					12,110,790	15,138,994	**27,249,784**
2011 Throughput Revenue Requirement - Note 2							**30,628,059**
Total 2011 Revenue Deficiency							**(3,378,275)**

Note A
Fixed Rate is a calculated rate for Niagara Falls territory customers and Peninsula West customers as rates are not harmonized in 2010
Total Fixed Charge divided by number of customers.
Note B
Variable Rate is a calculated rate for Niagara Falls territory customers and Peninsula West customers as rates are not harmonized in 2010
Total Variable Charge divided by kWh/kW sales

Note 1 Includes Transformer Allowance
Note 2 2011 Throughput Revenue Requirement

2011 Throughput Revenue per Table 6-2	30,988,570
Less: Low Voltage Charges per Table 6-2	(360,512)
	30,628,059

Table 6-5 Calculation of Revenue Deficiency or Surplus

Table 6-5 Calculation of Revenue Deficiency or Surplus

	2011 Test Year at Existing Rates	2011 Test Proposed Rates
Revenue		
Suff/ Def From Below.		3,378,275
Distribution Revenue	26,857,308	26,857,308
Other Operating Revenue (Net)	2,185,747	2,185,747
Total Revenue	29,043,055	32,421,330
Distribution Costs		
Operation, Maintenance, and Administration	14,295,435	14,295,435
Depreciation & Amortization	7,143,688	7,143,688
Property & Capital Taxes	222,474	222,474
Interest- Deemed Interest	4,340,146	4,340,146
Total Costs and Expenses	26,001,743	26,001,743
Utility Income Before Income Taxes	3,041,312	6,419,587
Net Adjustments per 2009 Pils	(131,884)	(131,884)
Taxable Income	2,909,428	6,287,703
Tax Rate	27.44%	27.44%
Income Tax	798,315	1,725,276
Utility Income	2,242,997	4,694,311
Rate Base	119,144,943	119,144,943
Equity	40.00%	40.00%
Equity Component Rate Base	47,657,977	47,657,977
Income / Equity Rate Base %	4.71%	9.85%
Target Return -Equity on Rate Base	9.85%	9.85%
Indicated Rate of Return	5.53%	7.58%
Requested Rate of Return on Rate Base	7.58%	7.58%
Difference	(2.06%)	0.00%
Return- Equity on Rate Base	4,694,311	4,694,311
Revenue Deficiency	2,451,313	
Revenue Deficiency (Gross-up)	3,378,275	

Summary of Drivers

The various key cost drivers are discussed in detail in Exhibit 4 – Operating Costs. The key cost drivers are as follows:

- Increase in Return on Rate Base due to growth related increases in capital investments.

- Increase of twenty five FTE's since 2004 along with benefit increases

- Increase in Regulatory costs for the preparation of this Application.

- Increase in bad debts expense

- Estimated general union wage increases of 3.0% effective April 1st of each year.

- General management wage increase of 3% along with job performance increases.

Table of Contents

EXHIBIT 7 – COST ALLOCATION

Cost Allocation Overview:

Introduction:

On September 29, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the “Directions”). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors (“the Guidelines”), the Cost Allocation Model (the “Model”) and User Instructions (the “Instructions”) for the Model.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor’s rate classifications. It was felt that this would give an indication of cross-subsidization from one class to another and this information would be useful as a tool in future rate applications.

For the purposes of this Application, NPEI has completed a cost allocation study to reflect 2011 test year costs, customer numbers and demand values. The 2011 demand values are based on the weather normalized load forecast used to design rates. NPEI has also removed the “cost” and "revenue" associated with transformer ownership allowance from the cost allocation study.

NPEI is the result of the amalgamation of the former Niagara Falls Hydro Inc. and the former Peninsula West Utilities Ltd. utilities. The former Peninsula West Utilities Ltd. filed a Cost Allocation Informational Filing on March 15, 2007 (EB-2005-0405) (EB-2007-0002). The former Niagara Falls Hydro Inc. prepared its load profiles for all rates classes and received RUN1 data from Hydro One for its hourly load shapes, however NFH did not file a Cost Allocation Informational Filing in 2007 as they were preparing the merger application and considered it to be more useful, prudent and practical to file a Cost of Service Study at the time of rebasing and harmonizing rates for the new merged company. As a result, there is no comparison to 2007 Cost Allocation data in this Cost of Service rate application for 2011.

Summary of Results and Proposed Changes:

Cost Allocation Study Results

NPEI has completed its Cost Allocation Study according to the Board's Minimum Filing Requirements issued June 28, 2010 for LDC's filing Cost of Service rate applications and includes the revenue- to-cost ratios requested by the Board.

Tables 7-2 through to Table 7-4 are in the format of the Board's Appendix 2-O Cost Allocation tables as found in the Minimum Filing Requirements.

The data used in the cost allocation study is consistent with NPEI's cost data that supports the proposed 2011 revenue requirement outlined in this application. Consistent with the Guidelines, NPEI's assets were broken out into primary and secondary distribution functions using breakout percentages based on current engineering records. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to NPEI from its customer/billing and financial information systems. An Excel version of the updated cost allocation study has been included in the Input and Output Sheet section of Exhibit 7.

Capital contributions, depreciation and accumulated depreciation by USoA are consistent with the information provided in the 2011 continuity statement shown in Exhibit 2. The rate class customer data used in the cost allocation study is consistent with the 2011 customer forecast outlined in Exhibit 3. The load profiles for all rate classes are consistent with the Hydro One data provided to the predecessor companies of NPEI in 2006 for cost allocation purposes but have been combined to reflect the new NPEI company and been scaled to match the 2011 load forecast. The following outlines the scaling factors used by rate class:

Table 7-1 Load Profile Scaling Percentages

Table 7-1: Load Profile Scaling Percentages			
Rate Class	2004 Weather Normal Values (kWh)	2011 Weather Normal Values (KWh)	Scaling Factor
Residential	429,014,461	459,406,923	107.1%
GS < 50	124,214,191	121,437,543	97.8%
General Service 50 to 4999 kW	664,866,113	623,806,670	93.8%
Streetlight	7,464,976	7,467,591	100.0%
Sentinel Lights	361,921	292,817	80.9%
Unmetered Scattered Load	2,567,220	2,335,428	91.0%
Total	**1,228,488,882**	**1,214,746,971**	**98.9%**

The allocated cost by rate class for the 2011 cost allocation study is provided in the following Table 7-2. The results exclude the "cost" and "revenues" of the transformation allowance as outlined in the Board's Minimum Filing Requirements issued June 28, 2010.

Table 7-2 Allocated Cost

Table 7-2: Allocated Cost		
Rate Class	Cost Allocated in the 2011 Study	%
Residential	$21,470,314	66.2%
GS < 50	$3,677,379	11.3%
General Service 50 to 4999 kW	$6,599,352	20.4%
Streetlight	$383,681	1.2%
Sentinel Lights	$146,591	0.5%
Unmetered Scattered Load	$144,014	0.4%
Total	$32,421,330	100.0%

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

On November 28, 2007, the OEB issued its “Report on Application of Cost Allocation for Electricity Distributors” (the “Cost Allocation Report”). In the Cost Allocation Report, the OEB established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 7-3 below. In addition Table 7-3 provides NPEI’s revenue to cost ratios from the 2011 cost allocation study and the proposed 2011 to 2013 ratios.

Table 7-3 Revenue to Cost Ratios

Table 7-3 Revenue to Cost Ratios						
Class	2011 Cost Allocation Study	2011 Proposed Ratios	2012 Proposed Ratios	2013 Proposed Ratios	Board Targets Min to Max	
Residential	82.3%	85.0%	85.0%	85.0%	85.0%	115.0%
GS < 50	108.2%	108.2%	108.2%	108.2%	80.0%	120.0%
General Service 50 to 4999 kW	159.3%	148.6%	147.6%	146.6%	80.0%	180.0%
Streetlight	6.6%	47.9%	58.9%	70.0%	70.0%	120.0%
Sentinel Lights	25.7%	38.3%	54.1%	70.0%	70.0%	120.0%
Unmetered Scattered Load	100.5%	100.5%	100.5%	100.5%	80.0%	120.0%

NPEI is proposing in this application to re-align its revenue to cost ratios by adjusting the allocations of revenue among rate classes in order to reduce some of the cross-subsidization that is occurring. For 2011, the Residential class is proposed to move from 82.3% to the minimum Board target of 85% in 2011. The additional revenue will be assigned to the General Service 50 to 4999 kW class. NPEI also proposes to move the revenue to cost ratios for the Streetlight and Sentinel Lights classes to the bottom of the Board's target range by 2013 as shown above.

The following Table 7-4 provides information on calculated class revenue. The resulting 2011 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this application.

Table 7-4 Calculated Class Revenue

Table 7-4 Calculated Class Revenue				
Class	2011 Base Revenue at Existing Rates	2011 Proposed Base Revenue Allocated at Existing Rates Proportion	2011 Proposed Base Revenue	Miscellaneous Revenue
Residential	$14,577,711	$16,411,383	$16,982,230	$1,267,536
GS < 50	$3,301,071	$3,716,300	$3,716,300	$262,161
General Service 50 to 4999 kW	$8,756,683	$9,858,152	$9,155,837	$652,821
Streetlight	$86,467	$97,344	$182,318	$1,284
Sentinel Lights	$8,058	$9,072	$55,565	$556
Unmetered Scattered Load	$127,318	$143,333	$143,333	$1,389
Total	$26,857,308	$30,235,583	$30,235,583	$2,185,747

Proposed 2011 Cost Allocation Study

2011 Cost Allocation Details of Preparation

NPEI ran the Cost Allocation model based on the Board's Minimum Filing Requirements issued June 28, 2010 and followed the cost allocation policies reflected in the Board's report of November 28, 2007, *Application of Cost Allocation for Electricity Distributors,* (EB-2007-0667).

Details of the preparation of the Cost Allocation study are as follows:

- The preparation of the Cost Allocation study followed the guidelines released by the Ontario Energy Board ("OEB") on September 29, 2006 (RP-2005-0317).

- As part of NPEI's 2011 electricity distribution rate application, this Cost Allocation Study has been prepared on a future test year basis, using the forecasted 2011 Trial Balance.

- NPEI purchased the use of the provincial generic load shape using data generated by the Joint Load Data Research Study in 2006.

- The Hydro One Load Research team conducted the analysis on NFH and PWU's behalf to develop a utility specific load shape for the 2007 Cost Allocation Study.

- This load shape was maintained however the data was repopulated with forecast 2011 consumption data as shown in Table 7-1.

- The total amount of distribution revenue from the 2011 Trial Balance was included in the Cost Allocation Study, with the exception of Low Voltage and Transformer Allowance (revenue and cost).

- Standard weighting factors calculated by the model for meter capital and meter reading costs were used, however, where standard weighting factors were not available, NPEI calculated the relative weighting. For smart meters the cost per meter installed was calculated using the capital costs as at June 30, 2010 that has been included in rate base for 2010 divided by the number of meters received and installed at June 30, 2010.

- The number of customers was obtained from the 2011 Load Forecast. The default weighting factors were used for services and billings. NPEI connects both individually controlled and group controlled streetlights to its secondary distribution system. Individually controlled streetlights consist of a single streetlight fixture connected directly to NPEI's 120/240V secondary distribution circuit. The streetlight fixture is controlled by a photo-eye mounted on top of the light. Group controlled streetlights consist of multiple streetlight fixtures daisy chained together. The group of streetlights is connected to NPEI's secondary distribution system through a single point of disconnect and control using a streetlight conductor. The streetlight conductor, disconnect, and control are owned by the streetlight owner. There are typically 10 to 14 streetlight fixtures supplied by a single streetlight disconnect in this scenario. Approximately 320 streetlights are individually controlled and connect directly to NPEI's secondary distribution system. Approximately 12,088 streetlights are connected indirectly to NPEI's secondary distribution system through 921 streetlight disconnects. Therefore, the total number of streetlight service connections is 1,241. This is based on the limited amount of streetlight data modeled in our GIS. NPEI is currently developing a more accurate streetlight model based on data supplied from the streetlight owners.

- Fixed assets were broken out into primary and secondary distribution functions, as well as >50kV and <50kV.

- The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to NPEI, its engineering records, and its customer and financial information systems.

- NPEI does not have any bulk transmission.

Input and Output Sheets

In accordance with the Minimum Filing Guidelines, NPEI has provided the Cost Allocation Model Sheets I-6, I-8, O-1, O-2 and E-4 below.

Appendix A 2011 NPEI Cost Allocation Study

Sheet 1-6

2011 COST ALLOCATION STUDY
Niagara Peninsula Energy Inc.
EB-2010-0138 EB-2007-0002
Tuesday, November 30, 2010
Sheet I6 Customer Data Worksheet - First Run PUBLIC

Total kWhs	1,214,746,971	1,184,016,140
Total kWs	1,826,926	1,731,737
Total Approved Distribution Revenue ($)	$30,235,583	25,815,527

			1	2	3	7	8	9
Billing Data	ID	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
kWh from load forecasting model	CEN	1,214,746,971	459,406,923	121,437,543	623,806,670	7,467,591	292,817	2,335,428
kW from load forecasting model	CDEM	1,826,926			1,806,009	20,107	809	
kW, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		654,126			654,126			
Optional - kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	1,214,746,971	459,406,923	121,437,543	623,806,670	7,467,591	292,817	2,335,428
kWh - weather normalized amount from load forecast		1,214,746,971	459,406,923	121,437,543	623,806,670	7,467,591	292,817	2,335,428
Proposed Distribution Rev	CREV	$30,235,583	$16,411,383	$3,716,300	$9,858,152	$97,344	$9,072	$143,333
Bad Debt	BDHA	$425,100	$297,570	$123,279	$4,251	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$456,315	$240,396	$69,507	$145,761	$0	$0	$651
Weighting Factor - Services			1.0	2.0	10.0	1.0	1.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	1.0	0.1	1.0
Number of Bills	CNB	625,998	562,798	52,228	10,180	48	624	120
Number of Connections (Unmetered)	CCON	2,263				1,241	563	460
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	CCA	52,166	46,900	4,352	848	4	52	10
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	52,100	46,900	4,352	848			
Line Transformer Customer Base	CCLT	51,998	46,900	4,349	749			
Secondary Customer Base	CCS	52,053	46,900	4,352	801			
Weighted - Services	CWCS	65,881	46,900	8,705	8,013	1,241	563	460
Weighted Meter -Capital	CWMC	7,895,350	4,729,048	1,310,185	1,856,116	-	-	-
Weighted Meter Reading	CWMR	470,144	173,580	88,124	208,440	-	-	-
Weighted Bills	CWNB	738,744	562,798	104,455	71,260	48	62	120
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		30,235,583	16,411,383	3,716,300	9,858,152	97,344	9,072	143,333

Sheet 1-8

2011 COST ALLOCATION STUDY
Niagara Peninsula Energy Inc.
EB-2010-0138 EB-2007-0002
Tuesday, November 30, 2010
Sheet I8 Demand Data Worksheet - First Run PUBLIC

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
			1	2	3	7	8	9
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	224,557	99,785	27,545	97,226	-	-	-
Bulk Delivery CP	BCP1	224,557	99,785	27,545	97,226	-	-	-
Total Sytem CP	DCP1	224,557	99,785	27,545	97,226	-	-	-
4 CP								
Transformation CP	TCP4	856,644	385,484	79,865	391,295	-	-	-
Bulk Delivery CP	BCP4	856,644	385,484	79,865	391,295	-	-	-
Total Sytem CP	DCP4	856,644	385,484	79,865	391,295	-	-	-
12 CP								
Transformation CP	TCP12	2,257,537	976,709	211,121	1,056,224	10,206	370	2,908
Bulk Delivery CP	BCP12	2,257,537	976,709	211,121	1,056,224	10,206	370	2,908
Total Sytem CP	DCP12	2,257,537	976,709	211,121	1,056,224	10,206	370	2,908
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	244,665	102,696	33,596	105,768	1,743	103	759
Primary NCP	PNCP1	244,665	102,696	33,596	105,768	1,743	103	759
Line Transformer NCP	LTNCP1	232,298	102,696	33,573	93,425	1,743	103	759
Secondary NCP	SNCP1	238,805	102,696	33,596	99,908	1,743	103	759
4 NCP								
Classification NCP from Load Data Provider	DNCP4	937,428	397,185	111,164	419,020	6,962	348	2,749
Primary NCP	PNCP4	937,428	397,185	111,164	419,020	6,962	348	2,749
Line Transformer NCP	LTNCP4	888,452	397,185	111,087	370,121	6,962	348	2,749
Secondary NCP	SNCP4	914,213	397,185	111,164	395,805	6,962	348	2,749
12 NCP								
Classification NCP from Load Data Provider	DNCP12	2,442,333	1,048,758	240,526	1,124,851	20,655	841	6,702
Primary NCP	PNCP12	2,442,333	1,048,758	240,526	1,124,851	20,655	841	6,702
Line Transformer NCP	LTNCP12	2,310,898	1,048,758	240,360	993,582	20,655	841	6,702
Secondary NCP	SNCP12	2,380,013	1,048,758	240,526	1,062,532	20,655	841	6,702

Sheet O-1

2011 COST ALLOCATION STUDY
Niagara Peninsula Energy Inc.
EB-2010-0138 EB-2007-0002
Tuesday, November 30, 2010
Sheet O1 Revenue to Cost Summary Worksheet - First Run PUBLIC

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
crev	Distribution Revenue (sale)	$30,235,583	$16,411,383	$3,716,300	$9,858,152	$97,344	$9,072	$143,333
mi	Miscellaneous Revenue (mi)	$2,185,747	$1,267,536	$262,161	$652,821	$1,284	$556	$1,389
	Total Revenue	$32,421,330	$17,678,920	$3,978,461	$10,510,972	$98,628	$9,628	$144,722
	Expenses							
di	Distribution Costs (di)	$5,542,331	$3,678,395	$549,491	$1,161,007	$87,133	$33,743	$32,562
cu	Customer Related Costs (cu)	$4,795,505	$3,369,923	$767,229	$653,305	$2,416	$1,278	$1,353
ad	General and Administration (ad)	$4,180,074	$2,834,027	$521,968	$755,953	$38,559	$14,996	$14,571
dep	Depreciation and Amortization (dep)	$7,143,688	$4,679,675	$727,683	$1,550,002	$106,106	$40,482	$39,740
INPUT	PILs (INPUT)	$1,725,276	$1,107,715	$178,145	$397,510	$23,966	$8,994	$8,945
INT	Interest	$4,340,146	$2,786,593	$448,146	$999,987	$60,291	$22,626	$22,503
	Total Expenses	$27,727,019	$18,456,329	$3,192,663	$5,517,764	$318,471	$122,119	$119,674
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$4,694,311	$3,013,985	$484,716	$1,081,588	$65,210	$24,472	$24,339
	Revenue Requirement (includes NI)	$32,421,330	$21,470,314	$3,677,379	$6,599,352	$383,681	$146,591	$144,014
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$194,017,047	$126,411,058	$19,759,179	$42,845,501	$2,851,523	$1,082,310	$1,067,475
gp	General Plant - Gross	$28,928,804	$18,744,896	$2,984,158	$6,473,629	$414,199	$157,212	$154,711
accum dep	Accumulated Depreciation	($103,031,548)	($67,455,503)	($10,373,548)	($22,484,952)	($1,548,805)	($587,855)	($580,886)
co	Capital Contribution	($17,945,649)	($12,141,543)	($1,842,436)	($3,440,854)	($293,952)	($116,733)	($110,130)
	Total Net Plant	$101,968,654	$65,558,908	$10,527,353	$23,393,324	$1,422,965	$534,934	$531,170
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$99,990,688	$37,815,624	$9,996,010	$51,348,025	$614,687	$24,103	$192,238
	OM&A Expenses	$14,517,910	$9,882,345	$1,838,688	$2,570,265	$128,107	$50,018	$48,486
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	$114,508,597	$47,697,969	$11,834,698	$53,918,290	$742,795	$74,121	$240,725
	Working Capital	$17,176,290	$7,154,695	$1,775,205	$8,087,744	$111,419	$11,118	$36,109
	Total Rate Base	$119,144,944	$72,713,603	$12,302,558	$31,481,068	$1,534,384	$546,052	$567,278
		Rate Base Input equals Output						
	Equity Component of Rate Base	$47,657,977	$29,085,441	$4,921,023	$12,592,427	$613,754	$218,421	$226,911
	Net Income on Allocated Assets	$4,694,311	($777,409)	$785,798	$4,993,208	($219,843)	($112,491)	$25,047
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$4,694,311	($777,409)	$785,798	$4,993,208	($219,843)	($112,491)	$25,047
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	100.00%	82.34%	108.19%	159.27%	25.71%	6.57%	100.49%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($0)	($3,791,394)	$301,082	$3,911,621	($285,053)	($136,963)	$708
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.85%	-2.67%	15.97%	39.65%	-35.82%	-51.50%	11.04%

1 # Sheet O-2

2011 COST ALLOCATION STUDY
Niagara Peninsula Energy Inc.
EB-2010-0138 EB-2007-0002
Tuesday, November 30, 2010
Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - First Run PUBLIC

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9
	Residential	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$4.77	$11.34	$59.26	$0.16	$0.18	$0.09
Customer Unit Cost per month - Directly Related	$6.76	$16.04	$86.97	$0.23	$0.26	$0.18
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$27.09	$39.75	$114.35	$20.01	$21.65	$19.99
Fixed Charge per approved 2006 EDR	$15.96	$47.27	$280.14	$0.32	$1.10	$23.65

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	7	8	9
	Total	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
General Plant - Gross Assets	$28,928,804	$18,744,896	$2,984,158	$6,473,629	$414,199	$157,212	$154,711
General Plant - Accumulated Depreciation	($13,737,923)	($8,901,714)	($1,417,139)	($3,074,244)	($196,698)	($74,658)	($73,470)
General Plant - Net Fixed Assets	$15,190,881	$9,843,182	$1,567,019	$3,399,385	$217,501	$82,554	$81,241
General Plant - Depreciation	$1,103,403	$714,968	$113,822	$246,917	$15,798	$5,996	$5,901
Total Net Fixed Assets Excluding General Plant	$86,777,772	$55,715,726	$8,960,334	$19,993,940	$1,205,464	$452,380	$449,929
Total Administration and General Expense	$4,180,074	$2,834,027	$521,968	$755,953	$38,559	$14,996	$14,571
Total O&M	$10,337,836	$7,048,318	$1,316,720	$1,814,312	$89,549	$35,021	$33,915

2

1 Sheet O-2

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

			1	2	3	7	8	9
USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant							
1860	Meters	$7,976,464	$4,777,633	$1,323,646	$1,875,185	$0	$0	$0
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant - Meters only	($2,132,632)	($1,277,375)	($353,897)	($501,360)	$0	$0	$0
	Meter Net Fixed Assets	**$5,843,832**	**$3,500,258**	**$969,748**	**$1,373,825**	**$0**	**$0**	**$0**
	Misc Revenue							
4082	Retail Services Revenues	($80,748)	($61,516)	($11,417)	($7,789)	($5)	($7)	($13)
4084	Service Transaction Requests (STR) Revenues	($2,970)	($2,263)	($420)	($287)	($0)	($0)	($0)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($518,557)	($273,187)	($78,988)	($165,643)	$0	$0	($739)
	Sub-total	*($602,275)*	*($336,966)*	*($90,826)*	*($173,719)*	*($5)*	*($7)*	*($753)*
	Operation							
5065	Meter Expense	$489,927	$293,450	$81,300	$115,177	$0	$0	$0
5070	Customer Premises - Operation Labour	$96,423	$83,184	$7,720	$1,505	$2,201	$998	$815
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$586,350*	*$376,634*	*$89,020*	*$116,682*	*$2,201*	*$998*	*$815*
	Maintenance							
5175	Maintenance of Meters	$13,426	$8,042	$2,228	$3,156	$0	$0	$0
	Billing and Collection							
5310	Meter Reading Expense	$473,321	$174,752	$88,720	$209,848	$0	$0	$0
5315	Customer Billing	$2,080,927	$1,585,314	$294,235	$200,729	$135	$176	$338
5320	Collecting	$483,163	$368,089	$68,317	$46,607	$31	$41	$78
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
	Sub-total	$3,037,411	$2,128,155	$451,272	$457,184	$167	$217	$417
	Total Operation, Maintenance and Billing	$3,637,186	$2,512,831	$542,520	$577,022	$2,367	$1,215	$1,232
	Amortization Expense - Meters	$231,164	$138,459	$38,360	$54,344	$0	$0	$0
	Allocated PILs	$98,897	$59,142	$16,410	$23,345	$0	$0	$0
	Allocated Debt Return	$248,787	$148,779	$41,282	$58,726	$0	$0	$0
	Allocated Equity Return	$269,089	$160,920	$44,651	$63,519	$0	$0	$0
2	**Total**	**$3,882,848**	**$2,683,166**	**$592,397**	**$603,237**	**$2,362**	**$1,208**	**$479**

Sheet O-2

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
	Distribution Plant							
1860	Meters	$7,976,464	$4,777,633	$1,323,646	$1,875,185	$0	$0	$0
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant - Meters only	($2,132,632)	($1,277,375)	($353,897)	($501,360)	$0	$0	$0
	Meter Net Fixed Assets	$5,843,832	$3,500,258	$969,748	$1,373,825	$0	$0	$0
	Allocated General Plant Net Fixed Assets	$1,021,556	$618,383	$169,593	$233,579	$0	$0	$0
	Meter Net Fixed Assets Including General Plant	$6,865,388	$4,118,642	$1,139,342	$1,607,404	$0	$0	$0
	Misc Revenue							
4082	Retail Services Revenues	($80,748)	($61,516)	($11,417)	($7,789)	($5)	($7)	($13)
4084	Service Transaction Requests (STR) Revenues	($2,970)	($2,263)	($420)	($287)	($0)	($0)	($0)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($518,557)	($273,187)	($78,988)	($165,643)	$0	$0	($739)
	Sub-total	*($602,275)*	*($336,966)*	*($90,826)*	*($173,719)*	*($5)*	*($7)*	*($753)*
	Operation							
5065	Meter Expense	$489,927	$293,450	$81,300	$115,177	$0	$0	$0
5070	Customer Premises - Operation Labour	$96,423	$83,184	$7,720	$1,505	$2,201	$998	$815
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$586,350*	*$376,634*	*$89,020*	*$116,682*	*$2,201*	*$998*	*$815*
	Maintenance							
5175	Maintenance of Meters	$13,426	$8,042	$2,228	$3,156	$0	$0	$0
	Billing and Collection							
5310	Meter Reading Expense	$473,321	$174,752	$88,720	$209,848	$0	$0	$0
5315	Customer Billing	$2,080,927	$1,585,314	$294,235	$200,729	$135	$176	$338
5320	Collecting	$483,163	$368,089	$68,317	$46,607	$31	$41	$78
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$3,037,411*	*$2,128,155*	*$451,272*	*$457,184*	*$167*	*$217*	*$417*
	Total Operation, Maintenance and Billing	$3,637,186	$2,512,831	$542,520	$577,022	$2,367	$1,215	$1,232
	Amortization Expense - Meters	$231,164	$138,459	$38,360	$54,344	$0	$0	$0
	Amortization Expense - General Plant assigned to Meters	*$74,202*	*$44,917*	*$12,319*	*$16,966*	*$0*	*$0*	*$0*
	Admin and General	$1,467,927	$1,010,373	$215,063	$240,422	$1,019	$520	$529
	Allocated PILs	$116,184	$69,591	$19,280	$27,314	$0	$0	$0
	Allocated Debt Return	$292,276	$175,064	$48,501	$68,711	$0	$0	$0
	Allocated Equity Return	$316,127	$189,349	$52,459	$74,318	$0	$0	$0
	Total	**$5,532,791**	**$3,803,618**	**$837,677**	**$885,379**	**$3,381**	**$1,728**	**$1,008**

1 ## Sheet O-2

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
	Distribution Plant							
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$15,393,957	$13,280,460	$1,232,428	$240,220	$351,344	$159,371	$130,133
1830-5	Poles, Towers and Fixtures - Secondary	$4,266,269	$3,683,721	$341,850	$62,940	$97,455	$44,206	$36,096
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$16,927,078	$14,603,094	$1,355,169	$264,144	$386,335	$175,243	$143,094
1835-5	Overhead Conductors and Devices - Secondary	$2,940,384	$2,538,883	$235,609	$43,380	$67,168	$30,468	$24,878
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$3,609,506	$3,113,943	$288,974	$56,326	$82,382	$37,369	$30,513
1840-5	Underground Conduit - Secondary	$3,726,889	$3,217,992	$298,630	$54,983	$85,134	$38,617	$31,533
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$25,608,126	$22,092,286	$2,050,167	$399,611	$584,467	$265,116	$216,479
1845-5	Underground Conductors and Devices - Secondary	$8,536,042	$7,370,468	$683,980	$125,933	$194,991	$88,448	$72,222
1850	Line Transformers	$19,878,086	$17,181,182	$1,593,317	$274,510	$454,540	$206,181	$168,356
1855	Services	$4,196,959	$2,987,763	$554,530	$510,492	$79,043	$35,854	$29,277
1860	Meters	$7,976,464	$4,777,633	$1,323,646	$1,875,185	$0	$0	$0
2	*Sub-total*	*$113,059,761*	*$94,847,424*	*$9,958,299*	*$3,907,725*	*$2,382,860*	*$1,080,873*	*$882,580*

3

Sheet O-2

	<u>**Accumulated Amortization**</u>							
	Accum. Amortization of Electric Utility Plant - Line Transformers, Services and Meters	($63,390,498)	($53,745,278)	($5,400,348)	($1,713,036)	($1,388,075)	($629,635)	($514,125)
	Customer Related Net Fixed Assets	$49,669,263	$41,102,146	$4,557,951	$2,194,688	$994,784	$451,237	$368,455
	Allocated General Plant Net Fixed Assets	$8,760,050	$7,261,431	$797,113	$373,143	$179,488	$82,345	$66,529
	Customer Related NFA Including General Plant	$58,429,313	$48,363,578	$5,355,064	$2,567,831	$1,174,273	$533,583	$434,985
	<u>**Misc Revenue**</u>							
4082	Retail Services Revenues	($80,748)	($61,516)	($11,417)	($7,789)	($5)	($7)	($13)
4084	Service Transaction Requests (STR) Revenues	($2,970)	($2,263)	($420)	($287)	($0)	($0)	($0)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($518,557)	($273,187)	($78,988)	($165,643)	$0	$0	($739)
4235	Miscellaneous Service Revenues	($1,148,451)	($874,925)	($162,386)	($110,781)	($75)	($97)	($187)
	Sub-total	*($1,750,726)*	*($1,211,891)*	*($253,212)*	*($284,500)*	*($80)*	*($104)*	*($940)*
	<u>**Operating and Maintenance**</u>							
5005	Operation Supervision and Engineering	$389,143	$333,545	$31,976	$7,527	$8,824	$4,003	$3,268
5010	Load Dispatching	$26,280	$22,525	$2,159	$508	$596	$270	$221
5020	Overhead Distribution Lines and Feeders - Operation Labour	$118,415	$102,173	$9,482	$1,829	$2,703	$1,226	$1,001
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$12,253	$10,572	$981	$189	$280	$127	$104
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$43,563	$37,592	$3,489	$669	$995	$451	$368
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$116,994	$100,958	$9,369	$1,796	$2,671	$1,212	$989
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0
5065	Meter Expense	$489,927	$293,450	$81,300	$115,177	$0	$0	$0
5070	Customer Premises - Operation Labour	$96,423	$83,184	$7,720	$1,505	$2,201	$998	$815
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0
5085	Miscellaneous Distribution Expense	$974,150	$834,970	$80,045	$18,842	$22,090	$10,020	$8,182
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0

Sheet O-2

5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$277,608	$237,946	$22,811	$5,370	$6,295	$2,855	$2,332
5120	Maintenance of Poles, Towers and Fixtures	$90,944	$78,472	$7,282	$1,402	$2,076	$942	$769
5125	Maintenance of Overhead Conductors and Devices	$550,641	$475,103	$44,090	$8,523	$12,569	$5,701	$4,655
5130	Maintenance of Overhead Services	$150,393	$107,063	$19,871	$18,293	$2,832	$1,285	$1,049
5135	Overhead Distribution Lines and Feeders - Right of Way	$211,380	$182,388	$16,926	$3,266	$4,825	$2,189	$1,787
5145	Maintenance of Underground Conduit	$25,704	$22,185	$2,059	$390	$587	$266	$217
5150	Maintenance of Underground Conductors and Devices	$149,670	$129,149	$11,985	$2,304	$3,417	$1,550	$1,266
5155	Maintenance of Underground Services	$91,252	$64,961	$12,057	$11,099	$1,719	$780	$637
5160	Maintenance of Line Transformers	$79,200	$68,455	$6,348	$1,094	$1,811	$821	$671
5175	Maintenance of Meters	$13,426	$8,042	$2,228	$3,156	$0	$0	$0
	Sub-total	*$3,907,365*	*$3,192,733*	*$372,177*	*$202,939*	*$76,490*	*$34,696*	*$28,331*
	Billing and Collection							
5305	Supervision	$490,012	$373,306	$69,286	$47,267	$32	$41	$80
5310	Meter Reading Expense	$473,321	$174,752	$88,720	$209,848	$0	$0	$0
5315	Customer Billing	$2,080,927	$1,585,314	$294,235	$200,729	$135	$176	$338
5320	Collecting	$483,163	$368,089	$68,317	$46,607	$31	$41	$78
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$410,000	$287,000	$118,900	$4,100	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$258,306	$196,786	$36,523	$24,917	$17	$22	$42
	Sub-total	*$4,195,729*	*$2,985,247*	*$675,981*	*$533,468*	*$215*	*$280*	*$538*
	Sub Total Operating, Maintenance and Biling	*$8,103,095*	*$6,177,980*	*$1,048,158*	*$736,407*	*$76,705*	*$34,976*	*$28,869*
	Amortization Expense - Customer Related	$3,581,025	$3,009,565	$313,666	$119,249	$75,957	$34,454	$28,134
	Amortization Expense - General Plant assigned to Meters	$636,294	$527,440	$57,899	$27,104	$13,037	$5,981	$4,832
	Admin and General	$3,266,822	$2,484,076	$415,506	$306,832	$33,028	$14,977	$12,403
	Allocated PILs	$987,502	$817,174	$90,619	$43,634	$19,778	$8,971	$7,325
	Allocated Debt Return	$2,484,183	$2,055,703	$227,964	$109,766	$49,754	$22,568	$18,428
	Allocated Equity Return	$2,686,897	$2,223,452	$246,566	$118,723	$53,814	$24,410	$19,932
	PLCC Adjustment for Line Transformer	$158,428	$138,371	$12,823	$2,208	$3,668	$0	$1,359
	PLCC Adjustment for Primary Costs	$524,608	$457,289	$42,387	$8,277	$12,153	$0	$4,501
	PLCC Adjustment for Secondary Costs	$270,642	$240,928	$15,962	$2,640	$8,209	$0	$2,903
	Total	$19,041,413	**$15,246,913**	**$2,075,993**	**$1,164,090**	**$297,962**	**$146,234**	**$110,220**

1 # Sheet O-2

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total		Residential		GS <50		GS>50-Regular		Street Light		Sentinel		Unmetered Scattered Load
Distribution Plant													
CWMC	$	7,976,464	$	4,777,633	$	1,323,646	$	1,875,185	$	-	$	-	$ -
Accumulated Amortization													
Accum. Amortization of Electric Utility Plant - Meters only	$	(2,132,632)	$	(1,277,375)	$	(353,897)	$	(501,360)	$	-	$	-	$ -
Meter Net Fixed Assets	$	5,843,832	$	3,500,258	$	969,748	$	1,373,825	$	-	$	-	$ -
Misc Revenue													
CWNB	$	(83,718)	$	(63,779)	$	(11,837)	$	(8,076)	$	(5)	$	(7)	$ (14)
NFA	$	-	$	-	$	-	$	-	$	-	$	-	$ -
LPHA	$	(518,557)	$	(273,187)	$	(78,988)	$	(165,643)	$	-	$	-	$ (739)
Sub-total	$	(602,275)	$	(336,966)	$	(90,826)	$	(173,719)	$	(5)	$	(7)	$ (753)
Operation													
CWMC	$	489,927	$	293,450	$	81,300	$	115,177	$	-	$	-	$ -
CCA	$	96,423	$	83,184	$	7,720	$	1,505	$	2,201	$	998	$ 815
Sub-total	$	586,350	$	376,634	$	89,020	$	116,682	$	2,201	$	998	$ 815
Maintenance													
1860	$	13,426	$	8,042	$	2,228	$	3,156	$	-	$	-	$ -
Billing and Collection													
CWMR	$	473,321	$	174,752	$	88,720	$	209,848	$	-	$	-	$ -
CWNB	$	2,564,090	$	1,953,403	$	362,552	$	247,335	$	167	$	217	$ 417
Sub-total	$	3,037,411	$	2,128,155	$	451,272	$	457,184	$	167	$	217	$ 417
Total Operation, Maintenance and Billing	$	3,637,186	$	2,512,831	$	542,520	$	577,022	$	2,367	$	1,215	$ 1,232
Amortization Expense - Meters	$	231,164	$	138,459	$	38,360	$	54,344	$	-	$	-	$ -
Allocated PILs	$	98,897	$	59,142	$	16,410	$	23,345	$	-	$	-	$ -
Allocated Debt Return	$	248,787	$	148,779	$	41,282	$	58,726	$	-	$	-	$ -
Allocated Equity Return	$	269,089	$	160,920	$	44,651	$	63,519	$	-	$	-	$ -
2 **Total**	**$**	**3,882,848**	**$**	**2,683,166**	**$**	**592,397**	**$**	**603,237**	**$**	**2,362**	**$**	**1,208**	**$ 479**

Sheet O-2

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 7,976,464	$ 4,777,633	$ 1,323,646	$ 1,875,185	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (2,132,632)	$ (1,277,375)	$ (353,897)	$ (501,360)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 5,843,832	$ 3,500,258	$ 969,748	$ 1,373,825	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 1,021,556	$ 618,383	$ 169,593	$ 233,579	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 6,865,388	$ 4,118,642	$ 1,139,342	$ 1,607,404	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (83,718)	$ (63,779)	$ (11,837)	$ (8,076)	$ (5)	$ (7)	$ (14)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (518,557)	$ (273,187)	$ (78,988)	$ (165,643)	$ -	$ -	$ (739)
Sub-total	*$ (602,275)*	*$ (336,966)*	*$ (90,826)*	*$ (173,719)*	*$ (5)*	*$ (7)*	*$ (753)*
Operation							
CWMC	$ 489,927	$ 293,450	$ 81,300	$ 115,177	$ -	$ -	$ -
CCA	$ 96,423	$ 83,184	$ 7,720	$ 1,505	$ 2,201	$ 998	$ 815
Sub-total	*$ 586,350*	*$ 376,634*	*$ 89,020*	*$ 116,682*	*$ 2,201*	*$ 998*	*$ 815*
Maintenance							
1860	$ 13,426	$ 8,042	$ 2,228	$ 3,156	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 473,321	$ 174,752	$ 88,720	$ 209,848	$ -	$ -	$ -
CWNB	$ 2,564,090	$ 1,953,403	$ 362,552	$ 247,335	$ 167	$ 217	$ 417
Sub-total	*$ 3,037,411*	*$ 2,128,155*	*$ 451,272*	*$ 457,184*	*$ 167*	*$ 217*	*$ 417*
Total Operation, Maintenance and Billing	$ 3,637,186	$ 2,512,831	$ 542,520	$ 577,022	$ 2,367	$ 1,215	$ 1,232
Amortization Expense - Meters	$ 231,164	$ 138,459	$ 38,360	$ 54,344	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 74,202	$ 44,917	$ 12,319	$ 16,966	$ -	$ -	$ -
Admin and General	$ 1,467,927	$ 1,010,373	$ 215,063	$ 240,422	$ 1,019	$ 520	$ 529
Allocated PILs	$ 116,184	$ 69,591	$ 19,280	$ 27,314	$ -	$ -	$ -
Allocated Debt Return	$ 292,276	$ 175,064	$ 48,501	$ 68,711	$ -	$ -	$ -
Allocated Equity Return	$ 316,127	$ 189,349	$ 52,459	$ 74,318	$ -	$ -	$ -
Total	**$ 5,532,791**	**$ 3,803,618**	**$ 837,677**	**$ 885,379**	**$ 3,381**	**$ 1,728**	**$ 1,008**

1 # Sheet O-2

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant							
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 61,538,668	$ 53,089,784	$ 4,926,738	$ 960,301	$ 1,404,528	$ 637,098	$ 520,219
	SNCP	$ 19,469,584	$ 16,811,063	$ 1,560,069	$ 287,236	$ 444,749	$ 201,739	$ 164,729
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 19,878,086	$ 17,181,182	$ 1,593,317	$ 274,510	$ 454,540	$ 206,181	$ 168,356
	CWCS	$ 4,196,959	$ 2,987,763	$ 554,530	$ 510,492	$ 79,043	$ 35,854	$ 29,277
	CWMC	$ 7,976,464	$ 4,777,633	$ 1,323,646	$ 1,875,185	$ -	$ -	$ -
	Sub-total	*$ 113,059,761*	*$ 94,847,424*	*$ 9,958,299*	*$ 3,907,725*	*$ 2,382,860*	*$ 1,080,873*	*$ 882,580*
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant - Line Transformers, Services and Meters	$ (63,390,498)	$ (53,745,278)	$ (5,400,348)	$ (1,713,036)	$ (1,388,075)	$ (629,635)	$ (514,125)
	Customer Related Net Fixed Assets	$ 49,669,263	$ 41,102,146	$ 4,557,951	$ 2,194,688	$ 994,784	$ 451,237	$ 368,455
	Allocated General Plant Net Fixed Assets	$ 8,760,050	$ 7,261,431	$ 797,113	$ 373,143	$ 179,488	$ 82,345	$ 66,529
	Customer Related NFA Including General Plant	$ 58,429,313	$ 48,363,578	$ 5,355,064	$ 2,567,831	$ 1,174,273	$ 533,583	$ 434,985
	Misc Revenue							
	CWNB	$ (1,232,169)	$ (938,704)	$ (174,224)	$ (118,857)	$ (80)	$ (104)	$ (200)
	NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LPHA	$ (518,557)	$ (273,187)	$ (78,988)	$ (165,643)	$ -	$ -	$ (739)
	Sub-total	*$ (1,750,726)*	*$ (1,211,891)*	*$ (253,212)*	*$ (284,500)*	*$ (80)*	*$ (104)*	*$ (940)*
	Operating and Maintenance							
	1815-1855	$ 1,667,181	$ 1,428,987	$ 136,992	$ 32,247	$ 37,805	$ 17,148	$ 14,002
	1830 & 1835	$ 342,048	$ 295,133	$ 27,388	$ 5,284	$ 7,808	$ 3,542	$ 2,892
	1850	$ 79,200	$ 68,455	$ 6,348	$ 1,094	$ 1,811	$ 821	$ 671
	1840 & 1845	$ 160,558	$ 138,550	$ 12,857	$ 2,465	$ 3,665	$ 1,663	$ 1,358
	CWMC	$ 489,927	$ 293,450	$ 81,300	$ 115,177	$ -	$ -	$ -
	CCA	$ 96,423	$ 83,184	$ 7,720	$ 1,505	$ 2,201	$ 998	$ 815
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 90,944	$ 78,472	$ 7,282	$ 1,402	$ 2,076	$ 942	$ 769
	1835	$ 550,641	$ 475,103	$ 44,090	$ 8,523	$ 12,569	$ 5,701	$ 4,655
	1855	$ 241,644	$ 172,024	$ 31,928	$ 29,392	$ 4,551	$ 2,064	$ 1,686
	1840	$ 25,704	$ 22,185	$ 2,059	$ 390	$ 587	$ 266	$ 217
	1845	$ 149,670	$ 129,149	$ 11,985	$ 2,304	$ 3,417	$ 1,550	$ 1,266
	1860	$ 13,426	$ 8,042	$ 2,228	$ 3,156	$ -	$ -	$ -
2	*Sub-total*	*$ 3,907,365*	*$ 3,192,733*	*$ 372,177*	*$ 202,939*	*$ 76,490*	*$ 34,696*	*$ 28,331*

Sheet O-2

Billing and Collection							
CWNB	$ 3,312,409	$ 2,523,495	$ 468,361	$ 319,519	$ 215	$ 280	$ 538
CWMR	$ 473,321	$ 174,752	$ 88,720	$ 209,848	$ -	$ -	$ -
BDHA	$ 410,000	$ 287,000	$ 118,900	$ 4,100	$ -	$ -	$ -
Sub-total	*$ 4,195,729*	*$ 2,985,247*	*$ 675,981*	*$ 533,468*	*$ 215*	*$ 280*	*$ 538*
Sub Total Operating, Maintenance and Biling	*$ 8,103,095*	*$ 6,177,980*	*$ 1,048,158*	*$ 736,407*	*$ 76,705*	*$ 34,976*	*$ 28,869*
Amortization Expense - Customer Related	$ 3,581,025	$ 3,009,565	$ 313,666	$ 119,249	$ 75,957	$ 34,454	$ 28,134
Amortization Expense - General Plant assigned to Meters	$ 636,294	$ 527,440	$ 57,899	$ 27,104	$ 13,037	$ 5,981	$ 4,832
Admin and General	$ 3,266,822	$ 2,484,076	$ 415,506	$ 306,832	$ 33,028	$ 14,977	$ 12,403
Allocated PILs	$ 987,502	$ 817,174	$ 90,619	$ 43,634	$ 19,778	$ 8,971	$ 7,325
Allocated Debt Return	$ 2,484,183	$ 2,055,703	$ 227,964	$ 109,766	$ 49,754	$ 22,568	$ 18,428
Allocated Equity Return	$ 2,686,897	$ 2,223,452	$ 246,566	$ 118,723	$ 53,814	$ 24,410	$ 19,932
PLCC Adjustment for Line Transformer	$ 158,428	$ 138,371	$ 12,823	$ 2,208	$ 3,668	$ -	$ 1,359
PLCC Adjustment for Primary Costs	$ 524,608	$ 457,289	$ 42,387	$ 8,277	$ 12,153	$ -	$ 4,501
PLCC Adjustment for Secondary Costs	$ 270,642	$ 240,928	$ 15,962	$ 2,640	$ 8,209	$ -	$ 2,903
Total	**$ 19,041,413**	**$ 15,246,913**	**$ 2,075,993**	**$ 1,164,090**	**$ 297,962**	**$ 146,234**	**$ 110,220**

Sheet E-4

2011 COST ALLOCATION STUDY
Niagara Peninsula Energy Inc.
EB-2010-0138 EB-2007-0002
Tuesday, November 30, 2010
Sheet E4 Trial Balance Allocation Detail Worksheet - First Run PUBLIC

Details:
The worksheet below details how costs are treated, categorized, and grouped.

This sheet shows what accounts are included in the COSS, and how they are grouped into working capital and rate base. It shows how accounts are categorized in the customer and demand related costs. It will then show how the categorized costs are allocated to customer and demand related components. It will also show how Miscellaneous Revenue and General Plant and Administration costs are allocated. Finally, it will show how costs are being grouped together for presentation purposes.

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID
1565	Conservation and Demand Management Expenditures and Recoveries	CDM Expenditures and Recoveries	dp			O&M			O&M		
1608	Franchises and Consents	Other Distribution Assets	gp							NFA ECC	
1805	Land		dp	DDCP							
1805-1	Land Station >50 kV		dp	TCP	TCP12			TCP12			
1805-2	Land Station <50 kV		dp	DCP	DCP12			DCP12			
1806	Land Rights		dp	DDCP							
1806-1	Land Rights Station >50 kV		dp	TCP	TCP12			TCP12			
1806-2	Land Rights Station <50 kV		dp	DCP	DCP12			DCP12			
1808	Buildings and Fixtures		dp	DDCP							
1808-1	Buildings and Fixtures > 50 kV		dp	TCP	TCP12			TCP12			
1808-2	Buildings and Fixtures < 50 KV		dp	DCP	DCP12			DCP12			
1810	Leasehold Improvements		dp	DDCP							
1810-1	Leasehold Improvements >50 kV		dp	TCP	TCP12			TCP12			
1810-2	Leasehold Improvements <50 kV		dp	DCP	DCP12			DCP12			
1815	Transformer Station Equipment - Normally Primary above 50 kV		dp	TCP	TCP12			TCP12			
1820	Distribution Station Equipment - Normally Primary below 50 kV		dp	DCP	DCP12			DCP12			
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		dp	DCP	DCP12			DCP12			
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		dp	PNCP	PNCP4			PNCP4			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		dp			CEN			CEN		
1825	Storage Battery Equipment		dp	DDCP							
1825-1	Storage Battery Equipment > 50 kV		dp	TCP	TCP12			TCP12			

Sheet E-4

1825-2	Storage Battery Equipment <50 kV		dp	DCP	DCP12			DCP12			
1830	Poles, Towers and Fixtures		dp	DDNCP							
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12			
1830-4	Poles, Towers and Fixtures - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP		
1830-5	Poles, Towers and Fixtures - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS		
1835	Overhead Conductors and Devices		dp	DDNCP							
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12			
1835-4	Overhead Conductors and Devices - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP		
1835-5	Overhead Conductors and Devices - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS		
1840	Underground Conduit		dp	DDNCP							
1840-3	Underground Conduit - Bulk Delivery	Land and Buildings	dp	BCP	BCP12			BCP12			
1840-4	Underground Conduit - Primary	Land and Buildings	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP		
1840-5	Underground Conduit - Secondary	Land and Buildings	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS		
1845	Underground Conductors and Devices	Land and Buildings	dp	DDNCP							
1845-3	Underground Conductors and Devices - Bulk Delivery	TS Primary Above 50	dp	BCP	BCP12			BCP12			
1845-4	Underground Conductors and Devices - Primary	DS	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP		
1845-5	Underground Conductors and Devices - Secondary	Other Distribution Assets	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS		
1850	Line Transformers	Poles, Wires	dp	LTNCP	LTNCP4	CCLT	x	LTNCP4	CCLT		
1855	Services	Services and Meters	dp			CWCS			CWCS		
1860	Meters	Services and Meters	dp			CWMC			CWMC		
1905	Land	Land and Buildings	gp							NFA ECC	
1906	Land Rights	Land and Buildings	gp							NFA ECC	
1908	Buildings and Fixtures	General Plant	gp							NFA ECC	
1910	Leasehold Improvements	General Plant	gp							NFA ECC	
1915	Office Furniture and Equipment	Equipment	gp							NFA ECC	
1920	Computer Equipment - Hardware	IT Assets	gp							NFA ECC	
1925	Computer Software	IT Assets	gp							NFA ECC	
1930	Transportation Equipment	Equipment	gp							NFA ECC	
1935	Stores Equipment	Equipment	gp							NFA ECC	
1940	Tools, Shop and Garage Equipment	Equipment	gp							NFA ECC	
1945	Measurement and Testing Equipment	Equipment	gp							NFA ECC	
1950	Power Operated Equipment	Equipment	gp							NFA ECC	
1955	Communication Equipment	Equipment	gp							NFA ECC	
1960	Miscellaneous Equipment	Equipment	gp							NFA ECC	

Sheet E-4

1970	Load Management Controls - Customer Premises	Other Distribution Assets	gp							NFA ECC	
1975	Load Management Controls - Utility Premises	Other Distribution Assets	gp							NFA ECC	
1980	System Supervisory Equipment	Other Distribution Assets	gp							NFA ECC	
1990	Other Tangible Property	Other Distribution Assets	gp							NFA ECC	
1995	Contributions and Grants - Credit	Contributions and Grants	co		Break out	Breakout		Break out	Breakout		
2005	Property Under Capital Leases	Other Distribution Assets	gp							NFA ECC	
2010	Electric Plant Purchased or Sold	Other Distribution Assets	gp							NFA ECC	
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout		
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout		
3046	Balance Transferred From Income	Equity	NI								NFA
4080	Distribution Services Revenue	Distribution Services Revenue	CREV								CREV
4082	Retail Services Revenues	Other Distribution Revenue	mi								CWNB
4084	Service Transaction Requests (STR) Revenues	Other Distribution Revenue	mi								CWNB
4090	Electric Services Incidental to Energy Sales	Other Distribution Revenue	mi								CWNB
4205	Interdepartmental Rents	Other Distribution Revenue	mi								NFA
4210	Rent from Electric Property	Other Distribution Revenue	mi								NFA
4215	Other Utility Operating Income	Other Distribution Revenue	mi								SBMR
4220	Other Electric Revenues	Other Distribution Revenue	mi								NFA
4225	Late Payment Charges	Late Payment Charges	mi								LPHA
4235	Miscellaneous Service Revenues	Specific Service Charges	mi								CWNB
4240	Provision for Rate Refunds	Other Distribution Revenue	mi								NFA
4245	Government Assistance Directly Credited to Income	Other Distribution Revenue	mi								NFA
4305	Regulatory Debits	Other Income & Deductions	mi								NFA
4310	Regulatory Credits	Other Income & Deductions	mi								NFA
4315	Revenues from Electric Plant Leased to Others	Other Income & Deductions	mi								NFA
4320	Expenses of Electric Plant Leased to Others	Other Income & Deductions	mi								NFA

Sheet E-4

4325	Revenues from Merchandise, Jobbing, Etc.	Other Income & Deductions	mi								NFA
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Other Income & Deductions	mi								NFA
4335	Profits and Losses from Financial Instrument Hedges	Other Income & Deductions	mi								NFA
4340	Profits and Losses from Financial Instrument Investments	Other Income & Deductions	mi								NFA
4345	Gains from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA
4350	Losses from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA
4355	Gain on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA
4360	Loss on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA
4365	Gains from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA
4370	Losses from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA
4390	Miscellaneous Non-Operating Income	Other Income & Deductions	mi								NFA
4395	Rate-Payer Benefit Including Interest	Other Income & Deductions	mi								NFA
4398	Foreign Exchange Gains and Losses, Including Amortization	Other Income & Deductions	mi								NFA
4405	Interest and Dividend Income	Other Income & Deductions	mi								NFA
4415	Equity in Earnings of Subsidiary Companies	Other Income & Deductions	mi								NFA
4705	Power Purchased	Power Supply Expenses (Working Capital)	cop							CEN EWMP	
4708	Charges-WMS	Power Supply Expenses (Working Capital)	cop							CEN EWMP	
4710	Cost of Power Adjustments	Power Supply Expenses (Working Capital)	cop							CEN EWMP	
4712	Charges-One-Time	Power Supply Expenses (Working Capital)	cop							CEN EWMP	
4714	Charges-NW	Power Supply Expenses (Working Capital)	cop							CEN	
4715	System Control and Load Dispatching	Other Power Supply Expenses	cop							CEN EWMP	
4716	Charges-CN	Power Supply Expenses (Working Capital)	cop							CEN	
4730	Rural Rate Assistance Expense	Power Supply Expenses (Working Capital)	cop							CEN EWMP	

Sheet E-4

5005	Operation Supervision and Engineering	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C		
5010	Load Dispatching	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C		
5012	Station Buildings and Fixtures Expense	Operation (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C		
5014	Transformer Station Equipment - Operation Labour	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C		
5015	Transformer Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C		
5016	Distribution Station Equipment - Operation Labour	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C		
5017	Distribution Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C		
5020	Overhead Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C		
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C		
5030	Overhead Subtransmission Feeders - Operation	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C		830 & 1835	1830 & 1835 C		
5035	Overhead Distribution Transformers- Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C		
5040	Underground Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845	1840 & 1845 C	x	840 & 1845	1840 & 1845 C		
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845	1840 & 1845 C	x	840 & 1845	1840 & 1845 C		
5050	Underground Subtransmission Feeders - Operation	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845	1840 & 1845 C		840 & 1845	1840 & 1845 C		
5055	Underground Distribution Transformers - Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C		
5065	Meter Expense	Operation (Working Capital)	cu			CWMC			CWMC		
5070	Customer Premises - Operation Labour	Operation (Working Capital)	cu			CCA			CCA		
5075	Customer Premises - Materials and Expenses	Operation (Working Capital)	cu			CCA			CCA		
5085	Miscellaneous Distribution Expense	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C		
5090	Underground Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845	1840 & 1845 C	x	840 & 1845	1840 & 1845 C		
5095	Overhead Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C		
5096	Other Rent	Operation (Working Capital)	di							O&M	

Sheet E-4

5105	Maintenance Supervision and Engineering	Maintenance (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C		
5110	Maintenance of Buildings and Fixtures - Distribution Stations	Maintenance (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C		
5112	Maintenance of Transformer Station Equipment	Maintenance (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C		
5114	Maintenance of Distribution Station Equipment	Maintenance (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C		
5120	Maintenance of Poles, Towers and Fixtures	Maintenance (Working Capital)	di	1830 D	1830 D	1830 C	x	1830 D	1830 C		
5125	Maintenance of Overhead Conductors and Devices	Maintenance (Working Capital)	di	1835 D	1835 D	1835 C	x	1835 D	1835 C		
5130	Maintenance of Overhead Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C		
5135	Overhead Distribution Lines and Feeders - Right of Way	Maintenance (Working Capital)	di	1830 & 1835 D	1830 & 1835	1830 & 1835 C	x	1830 & 1835	1830 & 1835 C		
5145	Maintenance of Underground Conduit	Maintenance (Working Capital)	di	1840 D	1840 D	1840 C	x	1840 D	1840 C		
5150	Maintenance of Underground Conductors and Devices	Maintenance (Working Capital)	di	1845 D	1845 D	1845 C	x	1845 D	1845 C		
5155	Maintenance of Underground Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C		
5160	Maintenance of Line Transformers	Maintenance (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C		
5175	Maintenance of Meters	Maintenance (Working Capital)	cu	1860 D	1860 D	1860 C		1860 D	1860 C		
5305	Supervision	Billing and Collection (Working Capital)	cu			CWNB			CWNB		
5310	Meter Reading Expense	Billing and Collection (Working Capital)	cu			CWMR			CWMR		
5315	Customer Billing	Billing and Collection (Working Capital)	cu			CWNB			CWNB		
5320	Collecting	Billing and Collection (Working Capital)	cu			CWNB			CWNB		
5325	Collecting- Cash Over and Short	Billing and Collection (Working Capital)	cu			CWNB			CWNB		
5330	Collection Charges	Billing and Collection (Working Capital)	cu			CWNB			CWNB		
5335	Bad Debt Expense	Bad Debt Expense (Working Capital)	cu			BDHA			BDHA		
5340	Miscellaneous Customer Accounts Expenses	Billing and Collection (Working Capital)	cu			CWNB			CWNB		

Sheet E-4

5405	Supervision	Community Relations (Working Capital)	ad							O & M	
5410	Community Relations - Sundry	Community Relations (Working Capital)	ad							O & M	
5415	Energy Conservation	Community Relations - CDM (Working Capital)	ad							O & M	
5420	Community Safety Program	Community Relations (Working Capital)	ad							NFA ECC	
5425	Miscellaneous Customer Service and Informational Expenses	Community Relations (Working Capital)	ad							O & M	
5505	Supervision	Other Distribution Expenses	ad							O & M	
5510	Demonstrating and Selling Expense	Other Distribution Expenses	ad							O & M	
5515	Advertising Expense	Advertising Expenses	ad							O & M	
5520	Miscellaneous Sales Expense	Other Distribution Expenses	ad							O & M	
5605	Executive Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O & M	
5610	Management Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O & M	
5615	General Administrative Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O & M	
5620	Office Supplies and Expenses	Administrative and General Expenses (Working Capital)	ad							O & M	
5625	Administrative Expense Transferred Credit	Administrative and General Expenses (Working Capital)	ad							O & M	
5630	Outside Services Employed	Administrative and General Expenses (Working Capital)	ad							O & M	
5635	Property Insurance	Insurance Expense (Working Capital)	ad							NFA ECC	
5640	Injuries and Damages	Administrative and General Expenses (Working Capital)	ad							O & M	
5645	Employee Pensions and Benefits	Administrative and General Expenses (Working Capital)	ad							O & M	
5650	Franchise Requirements	Administrative and General Expenses (Working Capital)	ad							O & M	
5655	Regulatory Expenses	Administrative and General Expenses (Working Capital)	ad							O & M	
5660	General Advertising Expenses	Advertising Expenses	ad							O & M	
5665	Miscellaneous General Expenses	Administrative and General Expenses (Working Capital)	ad							O & M	
5670	Rent	Administrative and General Expenses (Working Capital)	ad							O & M	
5675	Maintenance of General Plant	Administrative and General Expenses (Working Capital)	ad							O & M	
5680	Electrical Safety Authority Fees	Administrative and General Expenses (Working Capital)	ad							O & M	

Sheet E-4

5685	Independent Market Operator Fees and Penalties	Power Supply Expenses (Working Capital)	cop							NFA ECC	
5705	Amortization Expense - Property, Plant, and Equipment	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout		
5710	Amortization of Limited Term Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout		
5715	Amortization of Intangibles and Other Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout		
5720	Amortization of Electric Plant Acquisition Adjustments	Other Amortization - Unclassified	dep	PRORATED	Break out	Breakout			Breakout		
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	Amortization of Assets	dep							O&M	
5735	Amortization of Deferred Development Costs	Amortization of Assets	dep							O&M	
5740	Amortization of Deferred Charges	Amortization of Assets	dep							O&M	
6005	Interest on Long Term Debt	Interest Expense - Unclassifed	INT							NFA	
6105	Taxes Other Than Income Taxes	Other Distribution Expenses	ad							NFA	
6110	Income Taxes	Income Tax Expense - Unclassified	Input							NFA	
6205	Donations	Charitable Contributions	ad							O&M	
6210	Life Insurance	Insurance Expense (Working Capital)	ad							O&M	
6215	Penalties	Other Distribution Expenses	ad							O&M	
6225	Other Deductions	Other Distribution Expenses	ad							O&M	

Conclusion

The results from the cost allocation study Table 7-3 showed that the Residential rate class was below the minimum acceptable range mandated by the Board. As a result NPEI has moved the Residential rate class from 82.3% to the minimum range of 85% in 2011. Street Light and Sentinel rate classes were also extremely below the Board's minimum range percentage and NPEI proposes to move to the Board target over the next 3 years.

Table of Contents

EXHIBIT 8 – RATE DESIGN

Rate Design Overview:

This Exhibit documents the calculation of NPEI's proposed distribution rates by rate class for the 2011 test year, based on the rate design as proposed in this Exhibit.

NPEI has determined its total 2011 service revenue requirement to be $32,421,330. The total revenue offsets in the amount of $2,185,747 reduce NPEI's total service revenue requirement to a base revenue requirement to $30,235,583 which is used to determine the proposed distribution rates. The base revenue requirement is derived from NPEI's 2011 capital and operating forecasts, weather normalized usage, forecasted customer counts, and regulated return on rate base. The revenue requirement is summarized in the table below:

Table 8-1 Calculation of Base Revenue Requirement

Table 8-1 Calculation of Base Revenue Requirement	
Description	**Amount**
OM&A Expenses	$14,517,909
Amortization Expenses	$7,143,688
Regulated Return On Capital	$9,034,456
PILs	$1,725,276
Service Revenue Requirement	$32,421,330
Less: Revenue Offsets	$2,185,747
Base Revenue Requirement	**$30,235,583**

The outstanding base revenue requirement is allocated to the various rate classes using the proposed revenue to cost ratios outlined in Exhibit 7 – Cost Allocation. Table 8-2 shows how the base revenue requirement has been allocated to the rate classes.

Table 8-2 Proposed Apportionment of Base Revenue to Rate Classes

Table 8-2 Proposed Apportionment of Base Revenue to Rate Classes					
Rate Classification	Total Revenue Requirement 2011 Cost Allocation	2011 Proposed Revenue to Cost Ratio	2011 Proposed Service Revenue Requirement	2011 Proposed Misc. Revenue Allocated as per Cost Allocation Model	2011 Proposed Base Revenue Requirement
Residential	$ 21,470,314	85.00%	$ 18,249,767	$ 1,267,536	$16,982,230
GS < 50	$ 3,677,379	108.19%	$ 3,978,461	$ 262,161	$3,716,300
General Service 50 to 4999 kW	$ 6,599,352	148.63%	$ 9,808,658	$ 652,821	$9,155,837
Sentinel Lights	$ 146,591	38.28%	$ 56,121	$ 556	$55,565
Streetlight	$ 383,681	47.85%	$ 183,602	$ 1,284	$182,318
Unmetered Scattered Load	$ 144,014	100.49%	$ 144,722	$ 1,389	$143,333
Total	**$ 32,421,330**		**$ 32,421,330**	**$ 2,185,747**	**$30,235,583**

Fixed/Variable Proportion

Table 8-3 provides a summary of the proposed fixed rate and resulting fixed proportion, based on forecasted customer/connections for the 2011 Test Year.

Table 8-3 Proposed Fixed Rate and Fixed Revenue Portion

Table 8-3 Proposed Fixed Rate and Fixed Revenue Portion				
Rate Classification	2011 Total Base Revenue	Proposed Fixed Distribution Charge	Annualized (Average) 2011 Customers/Connections	2011 Fixed Base Revenue with 2011 Proposed Rates
Residential	$16,982,230	$ 16.55	46,900	$ 9,314,561
GS < 50	$3,716,300	$ 38.45	4,352	$ 2,008,133
General Service 50 to 4999 kW	$9,155,837	$ 222.81	848	$ 2,268,164
Sentinel Lights	$55,565	$ 7.19	560	$ 48,302
Streetlight	$182,318	$ 0.80	12,408	$ 119,185
Unmetered Scattered Load	$143,333	$ 19.87	465	$ 110,898
Total	**$30,235,583**			**$ 13,869,243**

Table 8-4 Proposed Fixed/Variable Proportions

Table 8-4 Proposed Fixed/Variable Proportions					
Rate Classification	2011 Base Revenue with 2011 Proposed Rates	2011 Fixed Base Revenue with 2011 Proposed Rates	2011 Variable Base Revenue with 2011 Proposed Rates	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	$16,982,230	$ 9,314,561	$7,667,669	54.8%	45.2%
GS < 50	$3,716,300	$ 2,008,133	$1,708,167	54.0%	46.0%
General Service 50 to 4999 kW	$9,155,837	$ 2,268,164	$6,887,673	24.8%	75.2%
Sentinel Lights	$55,565	$ 48,302	$7,262	86.9%	13.1%
Streetlight	$182,318	$ 119,185	$63,133	65.4%	34.6%
Unmetered Scattered Load	$143,333	$ 110,898	$32,435	77.4%	22.6%
Total	**$30,235,583**	**$13,869,243**	**$16,366,340**	**45.9%**	**54.1%**

Based on applying the existing approved monthly service charges, excluding the smart meter adder, to the forecasted number of customers for 2011 and applying the existing approved distribution volumetric charge, excluding the adjustment for Low Voltage and transformation allowance, to 2011 forecasted volumes the following Table 8-5 outlines NPEI's combined current split between fixed and variable distribution revenue.

Table 8-5 Current Combined Fixed/Variable Split

Table 8-5 Current Combined Fixed Variable Split					
Rate Classification	2011 Total Base Revenue with 2010 Approved Rates	2011 Fixed Base Revenue with 2010 Approved Rates	2011 Variable Base Revenue with 2010 Approved Rates	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	$14,577,711	$7,995,709	$6,582,001	54.8%	45.2%
GS < 50	$3,301,071	$1,783,761	$1,517,310	54.0%	46.0%
General Service 50 to 4999 kW	$8,756,683	$2,169,282	$6,587,401	24.8%	75.2%
Sentinel Lights	$8,058	$7,005	$1,053	86.9%	13.1%
Streetlight	$86,467	$56,525	$29,942	65.4%	34.6%
Unmetered Scattered Load	$127,318	$98,507	$28,811	77.4%	22.6%
Total	**$26,857,308**	**$12,110,790**	**$14,746,519**	**45.1%**	**54.9%**

The Niagara Falls territory customers currently have the following fixed to variable revenue split in Table 8-5-NF and the Peninsula West territory customers currently have the following fixed to variable revenue split as shown in Table 8-5-PW.

Table 8-5NF Current Fixed/Variable Split

Table 8-5-NF Current Fixed Variable Split					
Rate Classification	2011 Total Base Revenue with 2010 Approved Rates	2011 Fixed Base Revenue with 2010 Approved Rates	2011 Variable Base Revenue with 2010 Approved Rates	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	$10,310,471	$6,226,019	$4,084,452	60.4%	39.6%
GS < 50	$2,407,495	$1,591,719	$815,777	66.1%	33.9%
General Service 50 to 4999 kW	$5,849,325	$2,108,953	$3,740,372	36.1%	63.9%
Sentinel Lights	$657	$265	$392	40.3%	59.7%
Streetlight	$63,439	$37,121	$26,318	58.5%	41.5%
Unmetered Scattered Load	$104,987	$89,107	$15,880	84.9%	15.1%
Total	**$18,736,374**	**$10,053,184**	**$8,683,190**	**53.7%**	**46.3%**

Table 8-5PW Current Fixed/Variable Split

Table 8-5-PW Current Fixed Variable Split					
Rate Classification	2011 Total Base Revenue with 2010 Approved Rates	2011 Fixed Base Revenue with 2010 Approved Rates	2011 Variable Base Revenue with 2010 Approved Rates	Fixed Revenue Proportion	Variable Revenue Proportion
Residential - Urban	$2,576,073	$1,144,356	$1,431,716	44.4%	55.6%
Residential - Suburban	$1,691,167	$625,334	$1,065,833	37.0%	63.0%
GS < 50	$893,576	$192,042	$701,534	21.5%	78.5%
General Service 50 to 4999 kW	$2,907,359	$60,329	$2,847,030	2.1%	97.9%
Sentinel Lights	$7,401	$6,740	$661	91.1%	8.9%
Streetlight	$23,028	$19,404	$3,624	84.3%	15.7%
Unmetered Scattered Load	$22,331	$9,400	$12,931	42.1%	57.9%
Total	**$8,120,934**	**$2,057,605**	**$6,063,329**	**25.3%**	**74.7%**

NPEI submits that it is appropriate for 2011 to maintain the same combined fixed/variable proportions assumed in the current rates to all customer classifications. As a result of rate harmonization, the Peninsula West territory customers are moving to a higher percentage of fixed proportion.

In its November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors, the OEB addressed a number of “Other Rate Matters”, including the treatment of the fixed rate component the Monthly Service Charge, of the bill. At page 12 of the Report, the OEB determined that the floor amount for the monthly service charge should be the avoided costs, as that term is defined in the September 29, 2006 report of the OEB entitled “Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors”. NPEI’s monthly service charges exceed that floor amount by rate class, see Table 8-6. With respect to the upper bound for the monthly service charge, the OEB considered it to be inappropriate to make changes to the monthly service charge ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB’s Rate Review proceeding (EB-2008-0031). The OEB indicated that for the time being, it does not expect distributors to make changes to the monthly service charge that result in a charge that is greater than the ceiling as defined in the Methodology for the monthly service charge; and that distributors that are currently above that value are not required to make changes to their current monthly service charge to bring it to or below that level at this time. In regards to possible monthly service charges and in accordance with the filing requirements the following information has been provided.

Table 8-6 Monthly Service Charge Information from Cost Allocation Model

Table 8-6 NF Monthly Service Charge Information from Cost Allocation Model

Rate Classification	2010 Monthly Service Charge Excluding Smart Meter Adder	Customer Unit Cost per month - Avoided Cost	Customer Unit Cost per month - Minimum System with PLCC Adjustment
Residential	$15.96	$4.77	$27.09
GS < 50	$47.27	$11.34	$39.75
General Service 50 to 4999 kW	$280.14	$59.26	$114.35
Streetlight	$0.32	$0.16	$20.01
Sentinel Lights	$1.10	$0.18	$21.65
Unmetered Scattered Load	$23.65	$0.09	$19.99

Table 8-6 PW Monthly Service Charge Information from Cost Allocation Model

Rate Classification	2010 Monthly Service Charge Excluding Smart Meter Adder	Customer Unit Cost per month - Avoided Cost	Customer Unit Cost per month - Minimum System with PLCC Adjustment
Residential - Urban	$10.04	$4.77	$27.09
Residential - Suburban	$10.65	$4.77	$27.09
GS < 50	$10.65	$11.34	$39.75
General Service 50 to 4999 kW	$22.75	$59.26	$114.35
Streetlight	$0.59	$0.16	$20.01
Sentinel Lights	$1.04	$0.18	$21.65
Unmetered Scattered Load	$5.18	$0.09	$19.99

Consistent with the Board's Decision in Norfolk Power's 2008 EDR CoS Application (EB-2007-0753), NPEI submits that a monthly service charge ceiling has not been established and the fixed/variable split should not be adjusted until Board proceedings, discussed below, relating to distribution rate design are completed.

In 2007, the Board had initiated a distribution rate review proceeding (EB-2007-0031, referred to as the “Rate Review Proceeding”). One of the objectives of the Rate

Review Proceeding was to explore what would be the appropriate fixed/variable split. At the time, Norfolk Power submitted in its 2008 cost of service rate application that it would not be appropriate to adjust the fixed/variable split until this proceeding was completed and the Board accepted this position

The Board decided to defer completion of the Rate Review Proceeding while staff conducted more research and expands the ability to model rate impacts. However, On March 22, 2010, the Board notified stakeholders that it "is initiating a consultation process to examine the revenue adjustment and cost recovery mechanisms that are currently available to electricity and natural gas distributors to address revenue erosion resulting from unforecasted changes in the volume of energy sold. Such mechanisms have now been in place for some time, and the Board has determined that a review is appropriate at this time to enable the Board to confirm whether such remain adequate and sufficient under current conditions." This is referred to as the Board's "Distribution Revenue Decoupling" proceeding (EB-2010-0060).

As noted in the Executive Summary on the Review of Distribution Revenue Decoupling Mechanisms ("the Review"), commissioned by the Board and undertaken by Pacific Economics Group ("PEG") in the Distribution Revenue Decoupling proceeding, "The cost of energy distribution and customer care is driven, in the short run, chiefly by customer growth and is largely fixed with respect to system use." (page 5, paragraph 2).

In this application, NPEI submits that until "Distribution Revenue Decoupling" proceeding (EB-2010-0060) is completed it would not be appropriate to change the fixed/variable split. As a result, changes in monthly service charges are due solely to changes in the total base revenue requirement attributable to each customer class.

The following Table 8-7 provides NPEI's calculations of its proposed monthly fixed distribution charges for the 2011 Test Year assuming the fixed/variable split supporting the current approved rates.

Table 8-7 Proposed Monthly Service Charge

Table 8-7 Proposed Monthly Service Charge				
Rate Classification	Total Base Revenue Requirement	Fixed Revenue Proportion	Annualized Customers / Connections	Proposed Fixed Distribution Charge
Residential	$16,982,230	54.8%	562,798	$16.55
GS < 50	$3,716,300	54.0%	52,228	$38.45
General Service 50 to 4999 kW	$9,155,837	24.8%	10,180	$222.81
Streetlight	$182,318	65.4%	148,892	$0.80
Sentinel Lights	$55,565	86.9%	6,722	$7.19
Unmetered Scattered Load	$143,333	77.4%	5,582	$19.87
Total	**$30,235,583**			

Proposed Volumetric Charges:

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2011 Test Year usage, kWh or kW, as the class charge determinant.

The following Table 8-8 provides NPEI's calculations of its proposed volumetric distribution charges for the 2011 Test Year which maintains the same fixed/variable split used in designing the current approved rates.

Table 8-8 Proposed Volumetric Charge

Table 8-8 Proposed Distribution Volumetric Charge						
Rate Classification	Total Base Revenue Requirement	Fixed Revenue	Variable Revenue	Annualized kWh or kW as required	Unit of Measure	Proposed Variable Distribution Charge before Transformer Allowance
Residential	$16,982,230	$9,314,561	$7,667,669	459,406,923	kWh	$0.0167
GS < 50	$3,716,300	$2,008,133	$1,708,167	121,437,543	kWh	$0.0141
General Service 50 to 4999 kW	$9,155,837	$2,268,164	$6,887,673	1,806,009	kW	$3.8138
Streetlight	$182,318	$119,185	$63,133	20,107	kW	$3.1398
Sentinel Lights	$55,565	$48,302	$7,262	809	kW	$8.9771
Unmetered Scattered Load	$143,333	$110,898	$32,435	2,335,428	kWh	$0.0139
Total	**$30,235,583**	**$13,869,243**	**$16,366,340**			

Proposed Adjustment for Transformer Allowance:

Currently, NPEI provides a Transformer Allowance to those customers that own their transformation facilities. NPEI proposes to maintain the current approved transformer ownership allowance of $0.60 per kW. The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

The amount of Transformer Allowance expected to be provided to those General Service > 50 kW customers that own their transformers has been included in the volumetric charge for this class. This means the General Service > 50 kW volumetric charge of $3.8317 per kW will increase by $0.2107 per kW to a total of $4.0424 per kW to recover the amount of the Transformer Allowance over all kWs in the General Service > 50 class.

Proposed Distribution Rates:

The following Table 8-9 sets out NPEI's proposed 2011 electricity distribution rates based on the foregoing calculations, including adjustments for the recovery of transformer allowance.

Table 8-9 Proposed Distribution Rates

Table 8-9 Proposed Distribution Rates			
Rate Classification	**Proposed Monthly Service Charge Excl Smart Meter Adder**	**Unit of Measure**	**Proposed Volumetric Distribution Charge incl LV and Transformer Allowance Adjustment**
Residential	$16.55	kWh	$0.0167
GS < 50	$38.45	kWh	$0.0141
General Service 50 to 4999 kW	$222.81	kW	$4.0311
Streetlight	$0.80	kW	$3.1398
Sentinel Lights	$7.19	kW	$8.9771
Unmetered Scattered Load	$19.87	kWh	$0.0139
Transformer Discount		kW	($0.60)

Recovery of Low Voltage Costs:

Consistent with the approach in the Board's 2006 EDR model, LV costs of $360,512 have been allocated to each rate class based on the proportion of retail transmission connection revenue collected from each class. The amount of the forecasted Low Voltage costs in 2011 is based on 12 months of actual charge determinants from Hydro One invoices and the most recently approved Hydro One rates for the Sub-Transmission class, which became effective May 1, 2010.

The following Table 8-10 displays the annual charge determinants used by NPEI to calculate the proposed 2011 Low Voltage costs:

The calculation to recover the 2011 LV amount is outlined in the following table:

Table 8-10 Low Voltage Costs

Table 8-10 2011 Low Voltage Costs						
Component	**Charge Determinant per Month**	**Rate**	**2011 Forecast Charge Determinants**	**Monthly/ Yearly**	**Multiplier**	**LV Charge**
Service Charge	$/Delivery Point	$211.47	10	Month	12	$25,376.40
Meter Charge	$/Meter	$252.71	2	Month	12	$6,065.04
Common ST Lines Charge	$/KW	$0.44	228,296	Year	1	$100,906.83
Specific Primary Lines Charge	$/KM	$279.80	-			
LVDS	$/KW	$1.43	54,705	Year	1	$78,064.04
Specific ST Lines Charges	$/KM	$361.05	0	Month	12	$563.24
HVDS Low	$/KW	$2.79	-			
HVDS High	$/KW	$1.03	145,889	Year	1	$149,536.23
				Total		**$360,511.77**

Table 8-11 Low Voltage Charges - Determination of Rates

Table 8-11 Low Voltage Charges - Determination of Rates										
	Retail TX		**Billing Determinants**		**llocation of Low Voltage Charge**			**Low Voltage Charge Rates**		
	Per kWh	**per kW**	**Calculated kWh**	**Calculated kW**	**Retail Tx Con Revenue - Basis for Allocation**	**Allocation Percentages**	**Allocated**	**Volumetric Rate Type**	**Low Voltage Rates/kWh**	**Low Voltage Rates/ kW**
Residential	$0.0045		459,406,923		2,051,621	42.0%	151,495	kWh	$0.0003	
General Service 50 to 4999 kW		$1.5483		1,806,009	2,796,301	57.3%	206,483	kW		$0.1143
Streetlight		$1.1895	=	20,107	23,917	0.5%	1,766	kW		$0.0878
Sentinel Lights		$1.2938	0	809	1,047	0.0%	77	kW		$0.0955
Unmetered Scattered Load	$0.0040		2,335,428	0	9,343	0.2%	690	kWh	$0.0003	
TOTAL			**461,742,351**	**1,826,926**	**4,882,229**	**100.0%**	**$360,512**			

Retail Transmission Service Rates

On July 8, 2010, the Board issued its Revision 2.0 to Guideline G-2008-0001 – Electricity Distribution Retail Transmission Service Rates. This revision outlined the information that the Board requires an electricity distributor to file for approval to adjust its retail transmission service rates and directed that the revised guideline should be used for 2011 rate applications.

For 2011, distributors shall adjust their retail transmission service rates (“RTSRs”) based on a comparison of historical transmission costs adjusted for new UTR levels and revenues generated from existing RTSRs. This approach is expected to minimize variances in USoA Accounts 1584 and 1586.

On August 20, 2010, the Board issued an RTSR Adjustment workform for electricity distributors to incorporate into their applications for 2011 transmission rates. NPEI has utilized this workform, which includes current Uniform Transmission Rates (“UTRs”). NPEI understands that once the January 1, 2011 UTR adjustment is determined, the Board will adjust the RTSR workform to incorporate this change, if any.

The methodology employed in the Board’s model is to begin with the 2009 historical wholesale transmission charges paid by NPEI to the IESO and Hydro One. The historical wholesale amounts are then adjusted to reflect the forecast 2011 UTRs, which gives 2011 forecast wholesale charge dollar amounts for both Network and Connection. Next, NPEI’s actual 2009 billed kW or kWh quantities are multiplied by NPEI’s current approved transmission rates to determine the current proportion of billed dollars by rate class. These proportions are applied to the 2011 anticipated wholesale charges to determine the dollar amount that NPEI needs to bill each customer class for Network and Connection. The proposed transmission rates are then determined by dividing the dollar amounts required from each class by the appropriate billing determinants.

As mentioned above, the RTSR Adjustment model incorporates the current approved RTSR Connection and RTSR Network rates from the 2010 Tariff sheet. For 2010 approved rates, NPEI has separate transmission rates for each service territory, Niagara Falls and Peninsula West. The following Table 8-12 shows the current approved RTSRs:

Table 8-12 Current Approved RTS Rates

Table 8-12 Current Approved Retail Transmission Service Rates			
Niagara Falls 2010 Approved Retail Transmission Service Rates (EB-2009-0205)			
Class	**kW/kWh**	**Network Charge**	**Connection Charge**
Residential	kWh	0.0053	0.0046
General Service < 50 kW	kWh	0.0049	0.0041
General Service > 50 kW	kW	1.9973	1.6277
Sentinel	kW	1.5139	1.2847
Streetlights	kW	1.5063	1.2583
Unmetered Scattered Load	kWh	0.0049	0.0041
Peninsula West 2010 Approved Retail Transmission Service Rates (EB-2009-0206)			
Class	**kW/kWh**	**Network Charge**	**Connection Charge**
Residential	kWh	0.0052	0.0051
General Service < 50 kW	kWh	0.0047	0.0045
General Service > 50 kW	kW	1.9309	1.7693
Sentinel	kW	1.4635	1.3963
Streetlights	kW	1.4562	1.3678
Unmetered Scattered Load	kWh	0.0047	0.0045

As indicated in Exhibit 1, NPEI is proposing to harmonize the retail transmission service rates for the two service territories. Accordingly, where the workform model requires the current approved transmission rates as inputs, the Applicant has actually used a weighted average of the two approved rates, based on the proportion of consumption or load billed to customers of each service territory in 2009. NPEI submits that this weighted average approach is an appropriate method to achieve harmonization of the currently approved rates, which are then adjusted in the workform to produce the 2011 proposed harmonized rates.

The tables below outline the calculation of the weighted average current rates by customer class:

Table 8-13 Weighted Average of Current Network Rates

Table 8-13 Weighted Average of Current Network Rates							
2009 Actual Billing Determinants		**Residential**	**GS<50**	**GS>50**	**Sentinel**	**Streetlights**	**USL**
Niagara Falls	**kWh**	245,617,187	81,798,710				1,242,102
	kW			1,260,497	36	21,808	
Pen West	**kWh**	150,627,448	46,816,745				803,295
	kW			437,187	663	4,948	
Total	**kWh**	396,244,635	128,615,455				2,045,397
	kWh			1,697,684	699	26,756	
Niagara Falls Weight		62.0%	63.6%	74.2%	5.2%	81.5%	60.7%
Pen West Weight		38.0%	36.4%	25.8%	94.8%	18.5%	39.3%
Niagara Falls 2010 Rate	**kWh**	0.0053	0.0049				0.0049
	kW			1.9973	1.5139	1.5063	
Pen West 2010 Rate	**kWh**	0.0052	0.0047				0.0047
	kW			1.9309	1.4635	1.4562	
Harmonized Rate	**kWh**	0.0053	0.0048				0.0048
(Weighted Average)	**kW**			1.9802	1.4661	1.4970	

Table 8-14 Weighted Average of Current Connection Rates

Table 8-14 Weighted Average of Current Connection Rates							
2009 Actual Billing Determinants		**Residential**	**GS<50**	**GS>50**	**Sentinel**	**Streetlights**	**USL**
Niagara Falls	**kWh**	245,617,187	81,798,710				1,242,102
	kW			1,260,497	36	21,808	
Pen West	**kWh**	150,627,448	46,816,745				803,295
	kW			437,187	663	4,948	
Total	**kWh**	396,244,635	128,615,455				2,045,397
	kWh			1,697,684	699	26,756	
Niagara Falls Weight		62.0%	63.6%	74.2%	5.2%	81.5%	60.7%
Pen West Weight		38.0%	36.4%	25.8%	94.8%	18.5%	39.3%
Niagara Falls 2010 Rate	**kWh**	0.0046	0.0041				0.0041
	kW			1.6277	1.2847	1.2583	
Pen West 2010 Rate	**kWh**	0.0051	0.0045				0.0045
	kW			1.7693	1.3963	1.3678	
Harmonized Rate	**kWh**	0.0048	0.0042				0.0043
(Weighted Average)	**kW**			1.6642	1.3906	1.2785	

Beginning with the weighted average rates given above and then utilizing the RTSR Adjustment model issued by the Board, NPEI is proposing the following retail transmission service rates for 2011:

Table 8-15 2011 Proposed Network Rates

Table 8-15 2011 Proposed Network Rates		
Rate Class	**Volume Metric**	**Proposed RTSR - Network**
Residential	kWh	0.0057
General Service Less Than 50 kW	kWh	0.0051
General Service 50 to 4,999 kW	kW	2.1173
Sentinel Lighting	kW	1.5676
Street Lighting	kW	1.6006
Unmetered Scattered Load	kWh	0.0051

Table 8-16 2011 Proposed Connection Rates

Table 8-16 2011 Proposed Connection Rates		
Rate Class	**Volume Metric**	**Proposed RTSR - Connection**
Residential	kWh	0.0045
General Service Less Than 50 kW	kWh	0.0039
General Service 50 to 4,999 kW	kW	1.5483
Sentinel Lighting	kW	1.2938
Street Lighting	kW	1.1895
Unmetered Scattered Load	kWh	0.0040

Table 8-17 Proposed Total RST Rates

Table 8-17 2011 Proposed Total RST Rates		
Rate Class	Volume Metric	Proposed RTSR
Residential	kWh	0.0101
General Service Less Than 50 kW	kWh	0.0090
General Service 50 to 4,999 kW	kW	3.6656
Sentinel Lighting	kW	2.8614
Street Lighting	kW	2.7901
Unmetered Scattered Load	kWh	0.0091

The tables below compare the proposed 2011 harmonized rates to the current approved 2010 rates for each service territory:

Table 8-18 Niagara Falls Impact of Proposed Transmission Rates

Class	Niagara Falls 2010 Rate	Harmonized 2011 Proposed	Change $	Change %
Residential				
Network	0.0053	0.0057	0.0004	6.9%
Connection	0.0046	0.0045	(0.0001)	-2.9%
Total Transmission	0.0099	0.0101	0.0002	2.4%
GS<50				
Network	0.0049	0.0051	0.0002	4.7%
Connection	0.0041	0.0039	(0.0002)	-4.7%
Total Transmission	0.0090	0.0090	0.0000	0.4%
GS>50				
Network	1.9973	2.1173	0.1200	6.0%
Connection	1.6277	1.5483	(0.0794)	-4.9%
Total Transmission	3.6250	3.6656	0.0406	1.1%
Unmetered Scattered Load				
Network	0.0049	0.0051	0.0002	4.7%
Connection	0.0041	0.0040	(0.0001)	-2.4%
Total Transmission	0.0090	0.0091	0.0001	1.5%
Sentinel Lighting				
Network	1.5139	1.5676	0.0537	3.5%
Connection	1.2847	1.2938	0.0091	0.7%
Total Transmission	2.7986	2.8614	0.0628	2.2%
Streetlighting				
Network	1.5063	1.6006	0.0943	6.3%
Connection	1.2583	1.1895	(0.0688)	-5.5%
Total Transmission	2.7646	2.7901	0.0255	0.9%

Table 8-19 Peninsula West Impact of Proposed Transmission Rates

Table 8-19 Peninsula West Impact of Proposed Transmission Rates				
Class	**Pen West 2010 Rate**	**Harmonized 2011 Proposed**	**Change $**	**Change %**
Residential				
Network	0.0052	0.0057	0.0005	9.0%
Connection	0.0051	0.0045	(0.0006)	-12.4%
Total Transmission	0.0103	0.0101	(0.0002)	-1.6%
GS<50				
Network	0.0047	0.0051	0.0004	9.2%
Connection	0.0045	0.0039	(0.0006)	-13.2%
Total Transmission	0.0092	0.0090	(0.0002)	-1.7%
GS>50				
Network	1.9309	2.1173	0.1864	9.7%
Connection	1.7693	1.5483	(0.2210)	-12.5%
Total Transmission	3.7002	3.6656	(0.0346)	-0.9%
Unmetered Scattered Load				
Network	0.0047	0.0051	0.0004	9.2%
Connection	0.0045	0.0040	(0.0005)	-11.1%
Total Transmission	0.0092	0.0091	(0.0001)	-0.7%
Sentinel Lighting				
Network	1.4635	1.5676	0.1041	7.1%
Connection	1.3963	1.2938	(0.1025)	-7.3%
Total Transmission	2.8598	2.8614	0.0016	0.1%
Streetlighting				
Network	1.4562	1.6006	0.1444	9.9%
Connection	1.3678	1.1895	(0.1783)	-13.0%
Total Transmission	2.8240	2.7901	(0.0339)	-1.2%

A copy of NPEI's completed 2011 RTSR Adjustment Workform model is included in Appendix 8 - B.

As per the Filing Requirements, NPEI has examined two years of wholesale costs and retail billings, and the resulting variances in USoA accounts 1584 and 1586. These are shown in the table below:

Table 8-20 Transmission Network and Connection Monthly Variances

Table 8-20 Transmission Network and Connection Monthly Variances						
	Network			Connection		
Month	Cost	Billed	Variance	Cost	Billed	Variance
Jul-08	600,275	(553,769)	46,507	433,690	(466,687)	(32,997)
Aug-08	555,192	(556,231)	(1,039)	439,165	(475,967)	(36,802)
Sep-08	558,719	(593,697)	(34,978)	428,223	(510,973)	(82,750)
Oct-08	410,587	(522,167)	(111,580)	351,931	(454,184)	(102,253)
Nov-08	451,650	(495,323)	(43,672)	390,416	(428,221)	(37,805)
Dec-08	481,704	(473,142)	8,561	410,112	(403,872)	6,240
Jan-09	594,110	(535,403)	58,707	503,096	(459,141)	43,955
Feb-09	470,801	(534,223)	(63,423)	352,068	(459,191)	(107,124)
Mar-09	516,235	(574,477)	(58,242)	410,133	(497,822)	(87,688)
Apr-09	448,466	(477,297)	(28,830)	365,300	(410,168)	(44,869)
May-09	434,769	(515,940)	(81,170)	364,240	(449,790)	(85,550)
Jun-09	594,771	(581,370)	13,402	468,904	(499,627)	(30,723)
Jul-09	612,942	(367,983)	244,959	455,298	(325,781)	129,517
Aug-09	706,608	(489,350)	217,258	420,776	(422,870)	(2,094)
Sep-09	571,681	(556,807)	14,874	425,407	(499,887)	(74,480)
Oct-09	459,024	(637,063)	(178,039)	349,528	(453,560)	(104,032)
Nov-09	509,069	(580,137)	(71,068)	400,891	(416,440)	(15,549)
Dec-09	557,780	(459,864)	97,916	425,647	(418,428)	7,218
Jan-10	613,800	(509,753)	104,047	447,482	(466,322)	(18,841)
Feb-10	579,650	(536,264)	43,385	441,164	(479,020)	(37,857)
Mar-10	527,351	(472,469)	54,882	403,031	(433,604)	(30,573)
Apr-10	522,870	(462,329)	60,541	414,336	(435,231)	(20,895)
May-10	674,752	(479,721)	195,031	457,975	(421,869)	36,106
Jun-10	711,778	(606,274)	105,504	479,488	(474,824)	4,664
Total	**13,164,587**	**(12,571,053)**	**593,534**	**10,038,299**	**(10,763,481)**	**(725,182)**

NPEI notes that the December 2008 balances in accounts 1584 RSVA Network and 1586 RSVA Connection, as well as projected interest to April 2010, were approved for disposition in NPEI's 2010 IRM Rate Applications (EB-2009-0205 and EB-2009-0206). In addition, NPEI is proposing in this application to dispose of the December 2009 balances in accounts 1584 and 1586, as well as projected interest to April 2011, as discussed in Exhibit 9.

Based on the above data, the Applicant submits that there are no significant trends in either the RSVA Network or Connection variances that would require additional adjustments to the retail transmission service rates. Therefore, NPEI submits that the 2011 RTSRs as calculated in the workform are appropriate, subject to a possible revision due to adjustments to the Uniform Transmission Rates in January 2011.

Loss Factors

To determine the total weather normalized energy purchases, the total weather normalized billed kWh is adjusted by a historical loss factor. Table 8-21 outlines NPEI's proposed loss factors. Table 8-22 demonstrates that NPEI's total loss factor on average for the past five years has been 5.60%.

The Total Loss Factor (TLF) is calculated as the Supply Facility Loss Factor (SFLF) multiplied by the Distribution Loss Factor (DLF). NPEI has used a supply facility loss factor of 1.0045, which is the standard SFLF referenced in Appendix 2-P, Section H of the Filing Requirements. The DLF calculation is based on the past five year average.

NPEI's proposed loss factor is 5.60% which is above the Board's threshold of 5%, and is lower than the currently approved loss factors for each of NPEI's service territories. (Niagara Falls current total loss factor for secondary metered customers < 5000 kW = 1.0572; Peninsula West current approved total loss factor for secondary metered customers < 5000 kW = 1.0601.)

The distribution loss factor (DLF) in Niagara Peninsula Energy's distribution system is such that the total loss factor (TLF) exceeds the OEB target level of 5%. This is due to the fact that over 90% of Niagara Peninsula Energy's service territory is rural. The number of customers per kilometer of line is significantly less in rural portions of the service territory which causes an increase in line losses. Additionally, there are a small number of customers per distribution transformer in rural portions of the service area which causes an increase in transformer losses. These factors cause the overall loss factor to be higher than that of a primarily urban utility with higher customer densities.

The table below shows NPEI's proposed loss factors for 2011.

Table 8-21 Proposed Loss Factors

Table 8-21 Proposed 2011 Loss Factors	
Proposed 2011 Loss Factors	**2011**
Supply Facilities Loss Factor	1.0045
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0513
Distribution Loss Factor - Secondary Metered Customer > 5,000 kW	n/a
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0407
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	n/a
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0560
Total Loss Factor - Secondary Metered Customer > 5,000 kW	n/a
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0454
Total Loss Factor - Primary Metered Customer > 5,000 kW	n/a

Niagara Peninsula Energy has several initiatives in place which have and will continue to reduce distribution losses including:

- Distribution transformers that are purchased for use on Niagara Peninsula Energy's system are assessed to ensure that no load and full load losses are minimized.

- Distribution transformers are sized with consideration given to minimizing losses for new or replacement installations.

- Line losses are considered by the Engineering Department when selecting a particular primary or secondary conductor size for use on Niagara Peninsula Energy's system.

- Feeders are monitored regularly and re-configured as necessary to ensure that load is evenly distributed across station transformers and feeders.

The calculations that support the proposed loss factors are shown in the following Table 8-22.

Table 8-22 Loss Factor Calculations

Table 8-22 Loss Factor Calculations							
		2005	2006	2007	2008	2009	5 Year Average
	Losses in Distributor's System						
A_1	"Wholesale" kWh delivered to distributor (higher value)	1,277,916,200	1,253,674,100	1,289,693,990	1,253,960,160	1,223,022,413	6,298,266,863
A_2	"Wholesale" kWh delivered to distributor (lower value)	1,272,191,339	1,248,057,840	1,283,916,366	1,248,342,618	1,217,543,467	6,270,051,631
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)						
C	Net "Wholesale" kWh delivered by distributor **(A_2)-(B)**	1,272,191,339	1,248,057,840	1,283,916,366	1,248,342,618	1,217,543,467	6,270,051,631
D	"Retail" kWh delivered by distributor	1,208,894,249	1,184,184,647	1,220,452,820	1,188,897,732	1,161,778,118	5,964,207,565
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)						
F	Net "Retail" kWh delivered by distributor **(D)-(E)**	1,208,894,249	1,184,184,647	1,220,452,820	1,188,897,732	1,161,778,118	5,964,207,565
G	Loss Factor in distributor's system **[(C)/(F)]**	1.0524	1.0539	1.0520	1.0500	1.0480	1.0513
	Losses Upstream of Distributor's System						
H	Supply Facility Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor **[(G)x(H)]**	1.0571	1.0587	1.0567	1.0547	1.0527	1.0560

RATE MITIGATION:

NPEI submits that the bill impacts of its proposed 2011 electricity distribution rates are reasonable and do not require rate mitigation.

EXISTING RATE CLASSES:

Residential:

This class pertains to customers residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, where energy is supplied single-phase, three wire, 60 hertz, having a normal voltage of 120/240 volts. Large residential services will include all services from 201 amp up to and including 400 amp, 120/240 volt, single phase, three wire. Further servicing details are available in the distributor's Conditions of Service.

General Service Less Than 50kW:

This class pertains to a non residential customers taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

General Service 50 to 4,999 kW:

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

Unmetered Scattered Load:

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/ consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

Sentinel Lighting:

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

Street Lighting:

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. Street lighting profile is derived through the use of a "virtual streetlight meter" that uses a street light control eye, consistent with the model type and product manufacturer of devices currently in service in the Applicant's distribution area, to simulate the exact daily conditions that the typical street light is exposed to. This simulated street light load is captured using an interval metering device, and is processed as part of the distributor's daily interval meter interrogation, validation and processing procedures. Further servicing details are available in the distributor's Conditions of Service.

microFIT Generator

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

1 **EXISTING RATE SCHEDULE:**

Niagara Peninsula Energy Inc. - Niagara Falls

TARIFF OF RATES AND CHARGES

Effective Saturday, May 01, 2010

EB-2009-0205

MONTHLY RATES AND CHARGES

Monthly Rates and Charges General

Residential

Service Charge	$	15.96
Service Charge Smart Meters	$	1.00
Distribution Volumetric Rate	$/kWh	0.0136
Distribution Volumetric Deferral Account Rate Rider – effective until Monday, April 30, 2012	$/kWh	(0.0028)
Distribution Volumetric Global Adjustment Rate Rider – effective until Monday, April 30, 2012	$/kWh	0.0011
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	47.27
Service Charge Smart Meters	$	1.00
Distribution Volumetric Rate	$/kWh	0.0100
Distribution Volumetric Deferral Account Rate Rider – effective until Monday, April 30, 2012	$/kWh	(0.0027)
Distribution Volumetric Global Adjustment Rate Rider – effective until Monday, April 30, 2012	$/kWh	0.0011
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	280.14
Service Charge Smart Meters	$	1.00
Distribution Volumetric Rate	$/kW	3.0124
Distribution Volumetric Deferral Account Rate Rider – effective until Monday, April 30, 2012	$/kW	(1.1600)
Distribution Volumetric Global Adjustment Rate Rider – effective until Monday, April 30, 2012	$/kW	0.4244
Retail Transmission Rate – Network Service Rate	$/kW	1.9973
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6277
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	23.65
Distribution Volumetric Rate	$/kWh	0.01
Distribution Volumetric Deferral Account Rate Rider – effective until Monday, April 30, 2012	$/kWh	(0.0027)
Distribution Volumetric Global Adjustment Rate Rider – effective until Monday, April 30, 2012	$/kWh	0.0011
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	1.10
Distribution Volumetric Rate	$/kW	4.0830
Distribution Volumetric Deferral Account Rate Rider – effective until Monday, April 30, 2012	$/kW	(1.2973)
Distribution Volumetric Global Adjustment Rate Rider – effective until Monday, April 30, 2012	$/kW	0.3939
Retail Transmission Rate – Network Service Rate	$/kW	1.5139
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2847
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 (per connection)	$	0.32
Distribution Volumetric Rate	$/kW	1.6919
Distribution Volumetric Deferral Account Rate Rider – effective until Monday, April 30, 2012	$/kW	(0.5038)
Retail Transmission Rate – Network Service Rate	$/kW	1.5063
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2583
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration

Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque charge (plus bank charges)	$	20.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00

Other

Specific Charge for Access to the Power Poles $/pole/year	$	22.35

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

LOSS FACTORS

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0572
Total Loss Factor - Secondary Metered Customer > 5,000 kW	
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0466
Total Loss Factor - Primary Metered Customer > 5,000 kW	

Niagara Peninsula Energy Inc. - Peninsula West

TARIFF OF RATES AND CHARGES
Effective Saturday, May 01, 2010

EB-2009-0206

MONTHLY RATES AND CHARGES

Monthly Rates and Charges General

Residential Urban

Service Charge	$	10.04
Service Charge Smart Meters	$	1.00
Distribution Volumetric Rate	$/kWh	0.0180
Low Voltage Volumetric Rate	$/kWh	0.0023
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2012	$/kWh	(0.0064)
Distribution Volumetric Global Adjustment Rate Rider – effective until April 30, 2012	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Residential Suburban

Service Charge	$	10.65
Service Charge Smart Meters	$	1.00
Distribution Volumetric Rate	$/kWh	0.0134
Low Voltage Volumetric Rate	$/kWh	0.0022
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2012	$/kWh	(0.0064)
Distribution Volumetric Global Adjustment Rate Rider – effective until April 30, 2012	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0052
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	10.35
Service Charge Smart Meters	$	1.00
Distribution Volumetric Rate	$/kWh	0.0176
Low Voltage Volumetric Rate	$/kWh	0.0018
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2012	$/kWh	(0.0065)
Distribution Volumetric Global Adjustment Rate Rider – effective until April 30, 2012	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	22.75
Service Charge Smart Meters	$	1.00
Distribution Volumetric Rate	$/kW	6.3575
Low Voltage Volumetric Rate	$/kW	0.7962
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2012	$/kW	(1.9651)
Distribution Volumetric Global Adjustment Rate Rider – effective until April 30, 2012	$/kW	0.3116
Retail Transmission Rate – Network Service Rate	$/kW	1.9309
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7693
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	5.18
Distribution Volumetric Rate	$/kWh	0.0173
Low Voltage Volumetric Rate	$/kWh	0.0021
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2012	$/kWh	(0.0064)
Distribution Volumetric Global Adjustment Rate Rider – effective until April 30, 2012	$/kWh	0.0010
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	1.04
Distribution Volumetric Rate	$/kW	0.9270
Low Voltage Volumetric Rate	$/kW	0.6051
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2012	$/kW	(2.2732)
Distribution Volumetric Global Adjustment Rate Rider – effective until April 30, 2012	$/kW	0.2799
Retail Transmission Rate – Network Service Rate	$/kW	1.4635
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3963
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 (per connection)	$	0.59
Distribution Volumetric Rate	$/kW	0.7961
Low Voltage Volumetric Rate	$/kW	0.6741
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2012	$/kW	(2.1909)
Retail Transmission Rate – Network Service Rate	$/kW	1.4562
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3678
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration

Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00

Other

Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
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	$	1,000.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35

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

LOSS FACTORS

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0601
Total Loss Factor - Secondary Metered Customer > 5,000 kW	
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0495
Total Loss Factor - Primary Metered Customer > 5,000 kW	

Proposed rate classes:

NPEI is not requesting any changes to the existing rate classes. However, NPEI is proposing to eliminate the two distinct sub-classes of the Residential class that are currently approved for Peninsula West: Residential Urban and Residential Suburban. In this application, NPEI is proposing to harmonize the monthly service charge and distribution volumetric charge for all rate classes, resulting in a single Residential class for all of NPEI's residential customers.

Proposed rates and charges:

NPEI will continue to have two proposed schedule of rates and charges, one for Niagara Falls territory customers and one for Peninsula West customers. This is due to the Deferral and Variance Rate Rider for balances up to December 31, 2008. In the 2010 IRM rate applications EB-2009-0205 and EB-2009-0206 NPEI received Board approval to dispose of these balances over a two year period.

Niagara Peninsula Energy Inc. - Niagara Falls
Proposed schedule of rates and charges
Effective May 1, 2011

Residential

Service Charge	per month	16.55
Service Charge Smart Meters	per month	1.00
Distribution Volumetric Rate	$/kWh	0.0167
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kWh	0.0011
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kWh	(0.0028)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0016
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0001
Low Voltage Rider	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	per month	38.45
Service Charge Smart Meters	per month	1.00
Distribution Volumetric Rate	$/kWh	0.0141
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kWh	0.0011
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kWh	(0.0027)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0019
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.0013)
Low Voltage Rider	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	per month	222.81
Service Charge Smart Meters	per month	1.00
Distribution Volumetric Rate	$/kW	4.0311
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kW	0.4244
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kW	(1.1600)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.6442
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.6119)
Low Voltage Rider	$/kWh	0.1042
Retail Transmission Rate – Network Service Rate	$/kW	2.1173
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5483
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	19.87
Distribution Volumetric Rate	$/kWh	0.0139
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kWh	0.0011
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kWh	(0.0027)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0016
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.0005)
Low Voltage Rider	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	per month	7.19
Distribution Volumetric Rate	$/kW	8.9771
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kW	0.3939
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kW	(1.2973)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.9780
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	2.1482
Low Voltage Rider	$/kWh	0.0871
Retail Transmission Rate – Network Service Rate	$/kW	1.5676
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2938
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 (per connection)	per month	0.80
Distribution Volumetric Rate	$/kW	3.1398
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kW	0.0000
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kW	(0.5038)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.6613
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.6329)
Low Voltage Rider	$/kWh	0.0801
Retail Transmission Rate – Network Service Rate	$/kW	1.6006
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1895
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

microFIT GENERATOR SERVICE CLASSIFICATION

Service Charge (per connection) delivery component - effective September 21, 2009	$	5.25

Specific Service Charges

Customer Administration

Returned cheque charge (plus bank charges)	$	20.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Other		
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
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	$	1,000.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35

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

LOSS FACTORS

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0560
Total Loss Factor - Secondary Metered Customer > 5,000 kW	
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0454
Total Loss Factor - Primary Metered Customer > 5,000 kW	

1

Niagara Peninsula Energy Inc. - Peninsula West
Proposed schedule of rates and charges
Effective May 1, 2011

Residential

Service Charge	per month	16.55
Service Charge Smart Meters	per month	1.00
Distribution Volumetric Rate	$/kWh	0.0167
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kWh	0.0007
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kWh	(0.0064)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0016
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0001
Low Voltage Rider	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	per month	38.45
Service Charge Smart Meters	per month	1.00
Distribution Volumetric Rate	$/kWh	0.0141
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kWh	0.0007
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kWh	(0.0065)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0019
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.0013)
Low Voltage Rider	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0039
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	per month	222.81
Service Charge Smart Meters	per month	1.00
Distribution Volumetric Rate	$/kW	4.0311
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kW	0.3116
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kW	(1.9651)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.6442
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.6119)
Low Voltage Rider	$/kWh	0.1042
Retail Transmission Rate – Network Service Rate	$/kW	2.1173
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5483
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	per month	19.87
Distribution Volumetric Rate	$/kWh	0.0139
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kWh	0.0010
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kWh	(0.0064)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.0016
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.0005)
Low Voltage Rider	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	per month	7.19
Distribution Volumetric Rate	$/kW	8.9771
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kW	0.2799
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kW	(2.2732)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.9780
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	2.1482
Low Voltage Rider	$/kWh	0.0871
Retail Transmission Rate – Network Service Rate	$/kW	1.5676
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2938
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 (per connection)	per month	0.80
Distribution Volumetric Rate	$/kW	3.1398
Distribution Volumetric Global Adjustment Rate Rider – May 2010 to April 30, 2012	$/kW	0.0000
Distribution Volumetric Deferral Account Rate Rider – May 2010 to April 30, 2012	$/kW	(2.1909)
Distribution Volumetric Global Adjustment Rate Rider – May 2011 to April 30, 2012	$/kWh	0.6613
Distribution Volumetric Deferral Account Rate Rider – May 2011 to April 30, 2012	$/kWh	(0.6329)
Low Voltage Rider	$/kWh	0.0801
Retail Transmission Rate – Network Service Rate	$/kW	1.6006
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1895
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

microFIT GENERATOR SERVICE CLASSIFICATION

Service Charge (per connection) delivery component - effective September 21, 2009	$	5.25

Specific Service Charges

Customer Administration

Returned cheque charge (plus bank charges)	$	20.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00

Other

Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
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	$	1,000.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35

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

LOSS FACTORS

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0560
Total Loss Factor - Secondary Metered Customer > 5,000 kW	
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0454
Total Loss Factor - Primary Metered Customer > 5,000 kW	

The following Table 8-23 reconciles the 2011 distribution rate calculations based on the 2011 Proposed Rates and the total base revenue required.

Table 8-23 Test Year Distribution Revenue Reconciliation

2010 Test Year Distribution Revenue Reconciliation

Customer Class	Fixed Distribution Revenue	Variable Distribution Revenue	Transformer Allowance Credit	Total Distribution Revenue	Expected
Residential	$ 9,314,307	$ 7,809,918		$ 17,124,224	$ 17,120,305
GS < 50 kW	$ 2,008,156	$ 1,748,701		$ 3,756,856	$ 3,748,236
GS >50	$ 2,268,212	$ 7,468,391	($392,476)	$ 9,344,127	$ 9,344,029
Large Use	$ -	$ -	$0	$ -	$ -
Sentinel Lights	$ 48,302	$ 7,333		$ 55,635	$ 55,635
Street Lighting	$ 119,188	$ 64,744		$ 183,932	$ 183,928
USL	$ 110,898	$ 33,163		$ 144,061	$ 143,961
Total	**$ 13,869,063**	**$ 17,132,249**	**($392,476)**	**$ 30,608,837**	**$ 30,596,095**

Difference Due to Rate Rounding

-$ 12,742

Rate and Bill Impacts:

Appendix 8-A to this Exhibit presents the results of the assessment of customer total bill impacts by level of consumption by customer per rate class and per the total customer class.

Impacts are shown using the applicable current approved rates and the proposed 2011 distribution rates.

The total bill impacts are calculated for each rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

Appendix 8-A Table of Rate and Bill Impacts

NIAGARA FALLS BILL IMPACTS *(Monthly Consumptions)*

RESIDENTIAL

Consumption: 100 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			15.96			16.55	0.59	3.70%	50.75%
Distribution (kWh)	100	0.0136	1.36	100	0.0167	1.67	0.31	22.79%	5.12%
Low Voltage Rider (kWh)	100	0.0000	0.00	100	0.0003	0.03	0.03	#DIV/0!	0.09%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	3.07%
LRAM & SSM Rider (kWh)	100		0.00	100	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	100	(0.0028)	(0.28)	100	(0.0028)	(0.28)	0.00	0.00%	(0.86%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	100		0.00	100	0.0001	0.01	0.01	#DIV/0!	0.03%
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	100	0.0011	0.11	100	0.0011	0.11	0.00	0.00%	0.34%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	100		0.00	100	0.0016	0.16	0.16	#DIV/0!	0.49%
Distribution Sub-Total			**18.15**			**19.25**	**1.10**	**6.06%**	**59.03%**
Retail Transmisssion (kWh)	106	0.0099	1.05	106	0.0101	1.07	0.02	2.23%	3.28%
Delivery Sub-Total			**19.20**			**20.32**	**1.12**	**5.85%**	**62.31%**
Other Charges (kWh)	106	0.0139	1.47	106	0.0135	1.43	(0.04)	(2.80%)	4.37%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.77%
Cost of Power Commodity (kWh)	106	0.0650	6.87	106	0.0650	6.86	(0.01)	(0.11%)	21.05%
Total Bill Before Taxes			**27.79**			**28.86**	**1.07**	**3.87%**	**88.50%**
HST		13.00%	3.61		13.00%	3.75	0.14	3.87%	11.50%
Total Bill			**31.40**			**32.61**	**1.21**	**3.87%**	**100.00%**

RESIDENTIAL

Consumption: 250 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			15.96			16.55	0.59	3.70%	32.23%
Distribution (kWh)	250	0.0136	3.40	250	0.0167	4.18	0.78	22.79%	8.13%
Low Voltage Rider (kWh)	250	0.0000	0.00	250	0.0003	0.08	0.08	#DIV/0!	0.15%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	1.95%
LRAM & SSM Rider (kWh)	250		0.00	250	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	250	(0.0028)	(0.70)	250	(0.0028)	(0.70)	0.00	0.00%	(1.36%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	250		0.00	250	0.0001	0.03	0.03	#DIV/0!	0.05%
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	250	0.0011	0.28	250	0.0011	0.28	0.00	0.00%	0.54%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	250		0.00	250	0.0016	0.40	0.40	#DIV/0!	0.78%
Distribution Sub-Total			**19.94**			**21.80**	**1.87**	**9.36%**	**42.45%**
Retail Transmisssion (kWh)	264	0.0099	2.62	264	0.0101	2.68	0.06	2.23%	5.21%
Delivery Sub-Total			**22.55**			**24.48**	**1.92**	**8.53%**	**47.66%**
Other Charges (kWh)	264	0.0139	3.67	264	0.0135	3.56	(0.10)	(2.80%)	6.94%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.49%
Cost of Power Commodity (kWh)	264	0.0650	17.18	264	0.0650	17.16	(0.02)	(0.11%)	33.41%
Total Bill Before Taxes			**43.65**			**45.45**	**1.80**	**4.13%**	**88.50%**
HST		13.00%	5.67		13.00%	5.91	0.23	4.13%	11.50%
Total Bill			**49.32**			**51.36**	**2.04**	**4.13%**	**100.00%**

RESIDENTIAL

Consumption		2010 BILL			2011 BILL			IMPACT		
500 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			15.96			16.55	0.59	3.70%	20.04%
	Distribution (kWh)	500	0.0136	6.80	500	0.0167	8.35	1.55	22.79%	10.11%
	Low Voltage Rider (kWh)	500	0.0000	0.00	500	0.0003	0.15	0.15	#DIV/0!	0.18%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	1.21%
	LRAM & SSM Rider (kWh)	500		0.00	500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh) May 2010-April 2012	500	(0.0028)	(1.40)	500	(0.0028)	(1.40)	0.00	0.00%	(1.69%)
	Deferrral & Variance Acct (kWh) May 2011-April 2012	500		0.00	500	0.0001	0.05	0.05	#DIV/0!	0.06%
	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	500	0.0011	0.55	500	0.0011	0.55	0.00	0.00%	0.67%
	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	500		0.00	500	0.0016	0.80	0.80	#DIV/0!	0.97%
	Distribution Sub-Total			**22.91**			**26.05**	**3.14**	**13.71%**	**31.54%**
	Retail Transmisssion (kWh)	529	0.0099	5.23	528	0.0101	5.35	0.12	2.23%	6.48%
	Delivery Sub-Total			**28.14**			**31.40**	**3.26**	**11.57%**	**38.01%**
	Other Charges (kWh)	529	0.0139	7.33	528	0.0135	7.13	(0.21)	(2.80%)	8.63%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.30%
	Cost of Power Commodity (kWh)	529	0.0650	34.36	528	0.0650	34.32	(0.04)	(0.11%)	41.55%
	Total Bill Before Taxes			**70.09**			**73.10**	**3.01**	**4.30%**	**88.50%**
	HST		13.00%	9.11		13.00%	9.50	0.39	4.30%	11.50%
	Total Bill			**79.20**			**82.60**	**3.40**	**4.30%**	**100.00%**

RESIDENTIAL NF territory

Consumption		2010 BILL			2011 BILL			IMPACT		
800 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			15.96			16.55	0.59	3.70%	13.47%
	Distribution (kWh)	800	0.0136	10.88	800	0.0167	13.36	2.48	22.79%	10.87%
	Low Voltage Rider (kWh)	800	0.0000	0.00	800	0.0003	0.24	0.24	#DIV/0!	0.20%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.81%
	LRAM & SSM Rider (kWh)	800		0.00	800	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh) May 2010-April 2012	800	(0.0028)	(2.24)	800	(0.0028)	(2.24)	0.00	0.00%	(1.82%)
	Deferrral & Variance Acct (kWh) May 2011-April 2012	800		0.00	800	0.0001	0.08	0.08	#DIV/0!	0.07%
	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	800	0.0011	0.88	800	0.0011	0.88	0.00	0.00%	0.72%
	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	800		0.00	800	0.0016	1.28	1.28	#DIV/0!	1.04%
	Distribution Sub-Total			**26.48**			**31.15**	**4.67**	**17.64%**	**25.35%**
	Retail Transmisssion (kWh)	846	0.0099	8.37	845	0.0101	8.56	0.19	2.23%	6.97%
	Delivery Sub-Total			**34.85**			**39.71**	**4.86**	**13.94%**	**32.32%**
	Other Charges (kWh)	846	0.0139	11.73	845	0.0135	11.40	(0.33)	(2.80%)	9.28%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.20%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	31.74%
	Cost of Power Commodity (kWh)	246	0.0750	18.43	245	0.0750	18.36	(0.07)	(0.39%)	14.94%
	Total Bill Before Taxes			**104.27**			**108.72**	**4.46**	**4.27%**	**88.50%**
	HST		13.00%	13.55		13.00%	14.13	0.58	4.27%	11.50%
	Total Bill			**117.82**			**122.86**	**5.04**	**4.27%**	**100.00%**

RESIDENTIAL

Consumption		2010 BILL			2011 BILL			IMPACT		
1,000 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			15.96			16.55	0.59	3.70%	11.02%
	Distribution (kWh)	1,000	0.0136	13.60	1,000	0.0167	16.70	3.10	22.79%	11.12%
	Low Voltage Rider (kWh)	1,000	0.0000	0.00	1,000	0.0003	0.30	0.30	#DIV/0!	0.20%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.67%
	LRAM & SSM Rider (kWh)	1,000		0.00	1,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh) May 2010-April 2012	1,000	(0.0028)	(2.80)	1,000	(0.0028)	(2.80)	0.00	0.00%	(1.86%)
	Deferrral & Variance Acct (kWh) May 2011-April 2012	1,000		0.00	1,000	0.0001	0.10	0.10	#DIV/0!	0.07%
	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	1,000	0.0011	1.10	1,000	0.0011	1.10	0.00	0.00%	0.73%
	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	1,000		0.00	1,000	0.0016	1.60	1.60	#DIV/0!	1.06%
	Distribution Sub-Total			**28.86**			**34.55**	**5.69**	**19.72%**	**23.00%**
	Retail Transmisssion (kWh)	1,057	0.0099	10.47	1,056	0.0101	10.70	0.23	2.23%	7.12%
	Delivery Sub-Total			**39.33**			**45.25**	**5.92**	**15.06%**	**30.12%**
	Other Charges (kWh)	1,057	0.0139	14.67	1,056	0.0135	14.26	(0.41)	(2.80%)	9.49%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.17%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	25.96%
	Cost of Power Commodity (kWh)	457	0.0750	34.29	456	0.0750	34.20	(0.09)	(0.26%)	22.76%
	Total Bill Before Taxes			**127.53**			**132.96**	**5.42**	**4.25%**	**88.50%**
	HST		13.00%	16.58		13.00%	17.28	0.70	4.25%	11.50%
	Total Bill			**144.11**			**150.24**	**6.13**	**4.25%**	**100.00%**

RESIDENTIAL

Consumption		2010 BILL			2011 BILL			IMPACT		
1,500 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			15.96			16.55	0.59	3.70%	7.57%
	Distribution (kWh)	1,500	0.0136	20.40	1,500	0.0167	25.05	4.65	22.79%	11.45%
	Low Voltage Rider (kWh)	1,500	0.0000	0.00	1,500	0.0003	0.45	0.45	#DIV/0!	0.21%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.46%
	LRAM & SSM Rider (kWh)	1,500		0.00	1,500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh) May 2010-April 2012	1,500	(0.0028)	(4.20)	1,500	(0.0028)	(4.20)	0.00	0.00%	(1.92%)
	Deferrral & Variance Acct (kWh) May 2011-April 2012	1,500		0.00	1,500	0.0001	0.15	0.15	#DIV/0!	0.07%
	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	1,500	0.0011	1.65	1,500	0.0011	1.65	0.00	0.00%	0.75%
	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	1,500		0.00	1,500	0.0016	2.40	2.40	#DIV/0!	1.10%
	Distribution Sub-Total			**34.81**			**43.05**	**8.24**	**23.67%**	**19.69%**
	Retail Transmisssion (kWh)	1,586	0.0099	15.70	1,584	0.0101	16.05	0.35	2.23%	7.34%
	Delivery Sub-Total			**50.51**			**59.10**	**8.59**	**17.01%**	**27.02%**
	Other Charges (kWh)	1,586	0.0139	22.00	1,584	0.0135	21.38	(0.62)	(2.80%)	9.78%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.11%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	17.83%
	Cost of Power Commodity (kWh)	986	0.0750	73.94	984	0.0750	73.80	(0.14)	(0.18%)	33.75%
	Total Bill Before Taxes			**185.69**			**193.53**	**7.84**	**4.22%**	**88.50%**
	HST		13.00%	24.14		13.00%	25.16	1.02	4.22%	11.50%
	Total Bill			**209.83**			**218.69**	**8.86**	**4.22%**	**100.00%**

GENERAL SERVICE < 50 kW-NF Territory

Consumption
2,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			47.27			38.45	(8.82)	(18.66%)	12.77%
Distribution (kWh)	2,000	0.0100	20.00	2,000	0.0141	28.20	8.20	41.00%	9.36%
Low Voltage Rider (kWh)	2,000	0.0000	0.00	2,000	0.0003	0.60	0.60	#DIV/0!	0.20%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.33%
LRAM & SSM Rider (kWh)	2,000		0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	2,000	(0.0027)	(5.40)	2,000	(0.0027)	(5.40)	0.00	0.00%	(1.79%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	2,000		0.00	2,000	(0.0013)	(2.60)	(2.60)	#DIV/0!	(0.86%)
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	2,000	0.0011	2.20	2,000	0.0011	2.20	0.00	0.00%	0.73%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	2,000		0.00	2,000	0.0019	3.80	3.80	#DIV/0!	1.26%
Distribution Sub-Total			**65.07**			**66.25**	**1.18**	**1.81%**	**22.00%**
Retail Transmisssion (kWh)	2,114	0.0091	19.24	2,112	0.0090	19.09	(0.15)	(0.77%)	6.34%
Delivery Sub-Total			**84.31**			**85.34**	**1.03**	**1.22%**	**28.34%**
Other Charges (kWh)	2,114	0.0139	29.33	2,112	0.0135	28.51	(0.82)	(2.80%)	9.47%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.08%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	12.95%
Cost of Power Commodity (kWh)	1,514	0.0750	113.58	1,512	0.0750	113.40	(0.18)	(0.16%)	37.66%
Total Bill Before Taxes			**266.47**			**266.50**	**$0.03**	**0.01%**	**88.50%**
HST		13.00%	34.64		13.00%	34.65	0.00	0.01%	11.50%
Total Bill			**301.11**			**301.15**	**$0.03**	**0.01%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
4,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			47.27			38.45	(8.82)	(18.66%)	6.81%
Distribution (kWh)	4,000	0.0100	40.00	4,000	0.0141	56.40	16.40	41.00%	10.00%
Low Voltage Rider (kWh)	4,000	0.0000	0.00	4,000	0.0003	1.20	1.20	#DIV/0!	0.21%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.18%
LRAM & SSM Rider (kWh)	4,000		0.00	4,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	4,000	(0.0027)	(10.80)	4,000	(0.0027)	(10.80)	0.00	0.00%	(1.91%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	4,000		0.00	4,000	(0.0013)	(5.20)	(5.20)	#DIV/0!	(0.92%)
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	4,000	0.0011	4.40	4,000	0.0011	4.40	0.00	0.00%	0.78%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	4,000		0.00	4,000	0.0019	7.60	7.60	#DIV/0!	1.35%
Distribution Sub-Total			**81.87**			**93.05**	**11.18**	**13.66%**	**16.49%**
Retail Transmisssion (kWh)	4,229	0.0091	38.48	4,224	0.0090	38.18	(0.30)	(0.77%)	6.77%
Delivery Sub-Total			**120.35**			**131.23**	**10.88**	**9.04%**	**23.26%**
Other Charges (kWh)	4,229	0.0139	58.66	4,224	0.0135	57.02	(1.64)	(2.80%)	10.11%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.04%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	6.91%
Cost of Power Commodity (kWh)	3,629	0.0750	272.16	3,624	0.0750	271.80	(0.36)	(0.13%)	48.17%
Total Bill Before Taxes			**490.43**			**499.30**	**$8.88**	**1.81%**	**88.50%**
HST		13.00%	63.76		13.00%	64.91	1.15	1.81%	11.50%
Total Bill			**554.18**			**564.21**	**$10.03**	**1.81%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
10,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			47.27			38.45	(8.82)	(18.66%)	2.84%
Distribution (kWh)	10,000	0.0100	100.00	10,000	0.0141	141.00	41.00	41.00%	10.42%
Low Voltage Rider (kWh)	10,000	0.0000	0.00	10,000	0.0003	3.00	3.00	#DIV/0!	0.22%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.07%
LRAM & SSM Rider (kWh)	10,000		0.00	10,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	10,000	(0.0027)	(27.00)	10,000	(0.0027)	(27.00)	0.00	0.00%	(1.99%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	10,000		0.00	10,000	(0.0013)	(13.00)	(13.00)	#DIV/0!	(0.96%)
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	10,000	0.0011	11.00	10,000	0.0011	11.00	0.00	0.00%	0.81%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	10,000		0.00	10,000	0.0019	19.00	19.00	#DIV/0!	1.40%
Distribution Sub-Total			**132.27**			**173.45**	**41.18**	**31.13%**	**12.82%**
Retail Transmisssion (kWh)	10,572	0.0091	96.21	10,560	0.0090	95.46	(0.75)	(0.77%)	7.05%
Delivery Sub-Total			**228.48**			**268.91**	**40.43**	**17.70%**	**19.87%**
Other Charges (kWh)	10,572	0.0139	146.66	10,560	0.0135	142.56	(4.10)	(2.80%)	10.53%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.02%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	2.88%
Cost of Power Commodity (kWh)	9,972	0.0750	747.90	9,960	0.0750	746.99	(0.91)	(0.12%)	55.19%
Total Bill Before Taxes			**1,162.29**			**1,197.71**	**$35.43**	**3.05%**	**88.50%**
HST		13.00%	151.10		13.00%	155.70	4.61	3.05%	11.50%
Total Bill			**1,313.38**			**1,353.41**	**$40.03**	**3.05%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
12,500 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			47.27			38.45	(8.82)	(18.66%)	2.29%
Distribution (kWh)	12,500	0.0100	125.00	12,500	0.0141	176.25	51.25	41.00%	10.48%
Low Voltage Rider (kWh)	12,500	0.0000	0.00	12,500	0.0003	3.75	3.75	#DIV/0!	0.22%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.06%
LRAM & SSM Rider (kWh)	12,500		0.00	12,500	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	12,500	(0.0027)	(33.75)	12,500	(0.0027)	(33.75)	0.00	0.00%	(2.01%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	12,500		0.00	12,500	(0.0013)	(16.25)	(16.25)	#DIV/0!	(0.97%)
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	12,500	0.0011	13.75	12,500	0.0011	13.75	0.00	0.00%	0.82%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	12,500		0.00	12,500	0.0019	23.75	23.75	#DIV/0!	1.41%
Distribution Sub-Total			**153.27**			**206.95**	**53.68**	**35.02%**	**12.30%**
Retail Transmisssion (kWh)	13,215	0.0091	120.26	13,200	0.0090	119.32	(0.93)	(0.77%)	7.09%
Delivery Sub-Total			**273.53**			**326.27**	**52.75**	**19.28%**	**19.40%**
Other Charges (kWh)	13,215	0.0139	183.33	13,200	0.0135	178.20	(5.13)	(2.80%)	10.59%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.01%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	2.32%
Cost of Power Commodity (kWh)	12,615	0.0750	946.13	12,600	0.0750	944.99	(1.13)	(0.12%)	56.17%
Total Bill Before Taxes			**1,442.23**			**1,488.71**	**$46.49**	**3.22%**	**88.50%**
HST		13.00%	187.49		13.00%	193.53	6.04	3.22%	11.50%
Total Bill			**1,629.72**			**1,682.25**	**$52.53**	**3.22%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
15,000 kWh	Monthly Service Charge			47.27			38.45	(8.82)	(18.66%)	1.91%
	Distribution (kWh)	15,000	0.0100	150.00	15,000	0.0141	211.50	61.50	41.00%	10.52%
	Low Voltage Rider (kWh)	15,000	0.0000	0.00	15,000	0.0003	4.50	4.50	#DIV/0!	0.22%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.05%
	LRAM & SSM Rider (kWh)	15,000		0.00	15,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh) May 2010-April 2012	15,000	(0.0027)	(40.50)	15,000	(0.0027)	(40.50)	0.00	0.00%	(2.01%)
	Deferrral & Variance Acct (kWh) May 2011-April 2012	15,000		0.00	15,000	(0.0013)	(19.50)	(19.50)	#DIV/0!	(0.97%)
	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	15,000	0.0011	16.50	15,000	0.0011	16.50	0.00	0.00%	0.82%
	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	15,000		0.00	15,000	0.0019	28.50	28.50	#DIV/0!	1.42%
	Distribution Sub-Total			**174.27**			**240.45**	**66.18**	**37.98%**	**11.96%**
	Retail Transmisssion (kWh)	15,858	0.0091	144.31	15,840	0.0090	143.19	(1.12)	(0.77%)	7.12%
	Delivery Sub-Total			**318.58**			**383.64**	**65.06**	**20.42%**	**19.08%**
	Other Charges (kWh)	15,858	0.0139	219.99	15,840	0.0135	213.84	(6.15)	(2.80%)	10.63%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.01%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	1.94%
	Cost of Power Commodity (kWh)	15,258	0.0750	1,144.35	15,240	0.0750	1,142.99	(1.36)	(0.12%)	56.83%
	Total Bill Before Taxes			**1,722.17**			**1,779.72**	**$57.55**	**3.34%**	**88.50%**
	HST		13.00%	223.88		13.00%	231.36	7.48	3.34%	11.50%
	Total Bill			**1,946.05**			**2,011.08**	**$65.03**	**3.34%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption		2010 BILL			2011 BILL			IMPACT		
30,000 kWh / 100 kW		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			280.14			222.81	(57.33)	(20.46%)	6.01%
	Distribution (kW)	100	3.0124	301.24	100	4.0311	403.11	101.87	33.82%	10.87%
	Low Voltage Rider (kW)	100	0		100	0.1042	10.42	10.42	#DIV/0!	0.28%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.03%
	LRAM & SSM Rider (kW)	100		0.00	100	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW) May 2010-April 2012	100	(1.1600)	(116.00)	100	(1.1600)	(116.00)	0.00	0.00%	(3.13%)
	Deferrral & Variance Acct (kW) May 2011-April 2012	100		0.00	100	(0.6119)	(61.19)	(61.19)	#DIV/0!	(1.65%)
	Global Adjustmenr Rate Rider (kW) May 2010 - April 2012 Non-RPP Only.	100	0.4244	42.44	100	0.4244	42.44	0.00	0.00%	1.14%
	Global Adjustmenr Rate Rider (kW) May 2011 - April 2012 Non-RPP Only.	100		0.00	100	0.6442	64.42	64.42	#DIV/0!	1.74%
	Distribution Sub-Total			**508.82**			**567.01**	**58.19**	**11.44%**	**15.29%**
	Retail Transmisssion (kW)	100	3.625	362.50	100	3.6656	366.56	4.06	1.12%	9.88%
	Delivery Sub-Total			**871.32**			**933.57**	**62.25**	**7.14%**	**25.17%**
	Other Charges (kWh)	31,716	0.0139	439.98	31,680	0.0135	427.68	(12.30)	(2.80%)	11.53%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.01%
	Cost of Power Commodity (kWh)	31,716	0.0606	1,922.62	31,680	0.0606	1,920.42	(2.20)	(0.11%)	51.78%
	Total Bill Before Taxes			**3,234.17**			**3,281.92**	**47.75**	**1.48%**	**88.50%**
	HST		13.00%	420.44		13.00%	426.65	6.21	1.48%	11.50%
	Total Bill			**3,654.62**			**3,708.57**	**53.95**	**1.48%**	**100.00%**

GENERAL SERVICE > 50 kW- NF Territory

Consumption		2010 BILL			2011 BILL			IMPACT		
65,000 kWh / 180 kW		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			280.14			222.81	(57.33)	(20.46%)	2.99%
	Distribution (kW)	180	3.0124	542.23	180	4.0311	725.60	183.37	33.82%	9.75%
	Low Voltage Rider (kW)	180	0		180	0.1042	18.76	18.76	#DIV/0!	0.25%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.01%
	LRAM & SSM Rider (kW)	180		0.00	180	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW) May 2010-April 2012	180	(1.1600)	(208.80)	180	(1.1600)	(208.80)	0.00	0.00%	(2.80%)
	Deferrral & Variance Acct (kW) May 2011-April 2012	180		0.00	180	(0.6119)	(110.14)	(110.14)	#DIV/0!	(1.48%)
	Global Adjustmenr Rate Rider (kW) May 2010 - April 2012 Non-RPP Only.	180	0.4244	76.39	180	0.4244	76.39	0.00	0.00%	1.03%
	Global Adjustmenr Rate Rider (kW) May 2011 - April 2012 Non-RPP Only.	180		0.00	180	0.6442	115.96	115.96	#DIV/0!	1.56%
	Distribution Sub-Total			**690.96**			**841.57**	**150.61**	**21.80%**	**11.30%**
	Retail Transmisssion (kW)	180	3.625	652.50	180	3.6656	659.81	7.31	1.12%	8.86%
	Delivery Sub-Total			**1,343.46**			**1,501.38**	**157.91**	**11.75%**	**20.16%**
	Other Charges (kWh)	68,718	0.0139	953.29	68,639	0.0135	926.63	(26.66)	(2.80%)	12.45%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	68,718	0.0606	4,165.69	68,639	0.0606	4,160.92	(4.77)	(0.11%)	55.88%
	Total Bill Before Taxes			**6,462.69**			**6,589.18**	**126.49**	**1.96%**	**88.50%**
	HST		13.00%	840.15		13.00%	856.59	16.44	1.96%	11.50%
	Total Bill			**7,302.84**			**7,445.77**	**142.93**	**1.96%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
200,000 kWh
500 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			280.14			222.81	(57.33)	(20.46%)	1.01%
Distribution (kW)	500	3.0124	1,506.20	500	4.0311	2,015.55	509.35	33.82%	9.18%
Low Voltage Rider (kW)	500	0		500	0.1042	52.10	52.10	#DIV/0!	0.24%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.00%
LRAM & SSM Rider (kW)	500		0.00	500	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW) May 2010-April 2012	500	(1.1600)	(580.00)	500	(1.1600)	(580.00)	0.00	0.00%	(2.64%)
Deferrral & Variance Acct (kW) May 2011-April 2012	500		0.00	500	(0.6119)	(305.95)	(305.95)	#DIV/0!	(1.39%)
Global Adjustmenr Rate Rider (kW) May 2010 - April 2012 Non-RPP Only.	500	0.4244	212.20	500	0.4244	212.20	0.00	0.00%	0.97%
Global Adjustmenr Rate Rider (kW) May 2011 - April 2012 Non-RPP Only.	500		0.00	500	0.6442	322.10	322.10	#DIV/0!	1.47%
Distribution Sub-Total			**1,419.54**			**1,939.81**	**520.27**	**36.65%**	**8.84%**
Retail Transmisssion (kW)	500	3.625	1,812.50	500	3.6656	1,832.80	20.30	1.12%	8.35%
Delivery Sub-Total			**3,232.04**			**3,772.61**	**540.57**	**16.73%**	**17.19%**
Other Charges (kWh)	211,440	0.0139	2,933.20	211,198	0.0135	2,851.17	(82.03)	(2.80%)	12.99%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	211,440	0.0606	12,817.49	211,198	0.0606	12,802.83	(14.67)	(0.11%)	58.32%
Total Bill Before Taxes			**18,982.98**			**19,426.86**	**443.88**	**2.34%**	**88.50%**
HST		13.00%	2,467.79		13.00%	2,525.49	57.70	2.34%	11.50%
Total Bill			**21,450.77**			**21,952.35**	**501.58**	**2.34%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
800,000 kWh
2,000 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			280.14			222.81	(57.33)	(20.46%)	0.26%
Distribution (kW)	2,000	3.0124	6,024.80	2,000	4.0311	8,062.20	2,037.40	33.82%	9.26%
Low Voltage Rider (kW)	2,000	0		2,000	0.1042	208.40	208.40	#DIV/0!	0.24%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.00%
LRAM & SSM Rider (kW)	2,000		0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW) May 2010-April 2012	2,000	(1.1600)	(2,320.00)	2,000	(1.1600)	(2,320.00)	0.00	0.00%	(2.67%)
Deferrral & Variance Acct (kW) May 2011-April 2012	2,000		0.00	2,000	(0.6119)	(1,223.80)	(1,223.80)	#DIV/0!	(1.41%)
Global Adjustmenr Rate Rider (kW) May 2010 - April 2012 Non-RPP Only.	2,000	0.4244	848.80	2,000	0.4244	848.80	0.00	0.00%	0.98%
Global Adjustmenr Rate Rider (kW) May 2011 - April 2012 Non-RPP Only.	2,000		0.00	2,000	0.6442	1,288.40	1,288.40	#DIV/0!	1.48%
Distribution Sub-Total			**4,834.74**			**7,087.81**	**2,253.07**	**46.60%**	**8.14%**
Retail Transmisssion (kW)	2,000	3.625	7,250.00	2,000	3.6656	7,331.21	81.21	1.12%	8.42%
Delivery Sub-Total			**12,084.74**			**14,419.02**	**2,334.28**	**19.32%**	**16.56%**
Other Charges (kWh)	845,760	0.0139	11,732.81	844,792	0.0135	11,404.69	(328.11)	(2.80%)	13.10%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	845,760	0.0606	51,269.97	844,792	0.0606	51,211.30	(58.67)	(0.11%)	58.83%
Total Bill Before Taxes			**75,087.77**			**77,035.27**	**1,947.50**	**2.59%**	**88.50%**
HST		13.00%	9,761.41		13.00%	10,014.59	253.18	2.59%	11.50%
Total Bill			**84,849.18**			**87,049.86**	**2,200.68**	**2.59%**	**100.00%**

Street Lighting -NF Territory

Billing Determinants
1 Connections
49.60 kWh
0.13 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	1	0.3200	0.32	1	0.8005	0.80	0.48	150.16%	12.48%
Distribution (kW)	0	1.6919	0.23	0	3.1398	0.42	0.19	85.58%	6.57%
Low Voltage Rider (kW)	0	0		0	0.0801	0.01	0.01	#DIV/0!	0.17%
LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW) May 2010-April 2012	0	(0.5038)	(0.07)	0	(0.5038)	(0.07)	0.00	0.00%	(1.05%)
Deferrral & Variance Acct (kW) May 2011-April 2012	0		0.00	0	(0.6329)	(0.08)	(0.08)	#DIV/0!	(1.32%)
Global Adjustmenr Rate Rider (kW) May 2010 - April 2012 Non-RPP Only.	0	0.0000	0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
Global Adjustmenr Rate Rider (kW) May 2011 - April 2012 Non-RPP Only.	0		0.00	0	0.6613	0.09	0.09	#DIV/0!	1.38%
Distribution Sub-Total			**0.48**			**1.17**	**0.69**	**143.79%**	**18.22%**
Retail Transmisssion (kW)	0	2.7646	0.37	0	2.7901	0.37	0.00	0.92%	5.83%
Delivery Sub-Total			**0.85**			**1.54**	**0.69**	**81.48%**	**24.06%**
Other Charges (kWh)	52	0.0139	0.73	52	0.0135	0.71	(0.02)	(2.80%)	11.03%
Other Charges (per month)			0.25			0.25	0.00	0.00%	3.90%
Cost of Power Commodity (kWh)	52	0.0606	3.18	52	0.0606	3.17	(0.00)	(0.11%)	49.51%
Total Bill Before Taxes			**5.01**			**5.67**	**0.67**	**13.36%**	**88.50%**
HST		13.00%	0.65		13.00%	0.74	0.09	13.36%	11.50%
Total Bill			**5.66**			**6.41**	**0.76**	**13.36%**	**100.00%**

Sentinel Lighting - NF Territory

Billing Determinants		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
1 Connections	Monthly Service Charge	1	1.1000	1.10	1	7.1862	7.19	6.09	553.29%	49.89%
43.57 kWh	Distribution (kW)	0	4.0830	0.49	0	8.9771	1.08	0.59	119.87%	7.48%
0.12 kW	Low Voltage Rider (kW)	0	0		0	0.0871	0.01	0.01	#DIV/0!	0.07%
	LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW) May 2010-April 2012	0	(1.2973)	(0.16)	0	(1.2973)	(0.16)	0.00	0.00%	(1.08%)
	Deferrral & Variance Acct (kW) May 2011-April 2012	0		0.00	0	2.1482	0.26	0.26	#DIV/0!	1.79%
	Global Adjustmenr Rate Rider (kW) May 2010 - April 2012 Non-RPP Only.	0	0.3939	0.05	0	0.3939	0.05	0.00	0.00%	0.33%
	Global Adjustmenr Rate Rider (kW) May 2011 - April 2012 Non-RPP Only.	0		0.00	0	0.9780	0.12	0.12	#DIV/0!	0.81%
	Distribution Sub-Total			**1.48**			**8.54**	**7.06**	**476.47%**	**59.30%**
	Retail Transmisssion (kW)	0	2.7986	0.34	0	2.8614	0.34	0.01	2.24%	2.38%
	Delivery Sub-Total			**1.82**			**8.88**	**7.07**	**388.83%**	**61.68%**
	Other Charges (kWh)	46	0.0139	0.64	46	0.0135	0.62	(0.02)	(2.80%)	4.31%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	1.74%
	Cost of Power Commodity (kWh)	46	0.0650	2.99	46	0.0650	2.99	(0.00)	(0.11%)	20.76%
	Total Bill Before Taxes			**5.70**			**12.75**	**7.05**	**123.59%**	**88.50%**
	HST		13.00%	0.74		13.00%	1.66	0.92	123.59%	11.50%
	Total Bill			**6.44**			**14.40**	**7.96**	**123.59%**	**100.00%**

Unmetered Scattered - NF Territory

Consumption		2010 BILL			2011 BILL			IMPACT		
250 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			23.65			19.87	(3.78)	(16.00%)	37.66%
	Distribution (kWh)	250	0.0100	2.50	250	0.0139	3.48	0.98	39.00%	6.59%
	Low Voltage Rider (kWh)	250	0.0000	0.00	250	0.0003	0.08	0.08	#DIV/0!	0.14%
	LRAM & SSM Rider (kWh)	250		0.00	250	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh) May 2010-April 2012	250	(0.0027)	(0.68)	250	(0.0027)	(0.68)	0.00	0.00%	(1.28%)
	Deferrral & Variance Acct (kWh) May 2011-April 2012	250		0.00	250	(0.0005)	(0.13)	(0.13)	#DIV/0!	(0.24%)
	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	250	0.0011	0.28	250	0.0011	0.28	0.00	0.00%	0.52%
	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	250		0.00	250	0.0016	0.40	0.40	#DIV/0!	0.76%
	Distribution Sub-Total			**25.75**			**23.29**	**(2.46)**	**(9.55%)**	**44.16%**
	Retail Transmisssion (kWh)	264	0.009	2.38	264	0.0091	2.41	0.03	1.36%	4.57%
	Delivery Sub-Total			**28.13**			**25.70**	**(2.43)**	**(8.63%)**	**48.73%**
	Other Charges (kWh)	264	0.0139	3.67	264	0.0135	3.56	(0.10)	(2.80%)	6.76%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.47%
	Cost of Power Commodity (kWh)	264	0.0650	17.18	264	0.0650	17.16	(0.02)	(0.11%)	32.53%
	Total Bill Before Taxes			**49.22**			**46.68**	**(2.55)**	**(5.18%)**	**88.50%**
	HST		13.00%	6.40		13.00%	6.07	(0.33)	(5.18%)	11.50%
	Total Bill			**55.62**			**52.74**	**(2.88)**	**(5.18%)**	**100.00%**

RESIDENTIAL URBAN

Consumption: 100 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			10.04			16.55	6.51	64.84%	51.46%
Distribution (kWh)	100	0.0180	1.80	100	0.0167	1.67	(0.13)	(7.22%)	5.19%
Low Voltage Rider (kWh)	100	0.0023	0.23	100	0.0003	0.03	(0.20)	(86.96%)	0.09%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	3.11%
LRAM & SSM Rider (kWh)	100		0.00	100	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	100	(0.0064)	(0.64)	100	(0.0064)	(0.64)	0.00	0.00%	(1.99%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	100		0.00	100	0.0001	0.01	0.01	#DIV/0!	0.03%
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	100	0.0007	0.07	100	0.0007	0.07	0.00	0.00%	0.22%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	100		0.00	100	0.0016	0.16	0.16	#DIV/0!	0.50%
Distribution Sub-Total			**12.50**			**18.85**	**6.35**	**50.80%**	**58.61%**
Retail Transmisssion (kWh)	106	0.0103	1.09	106	0.0101	1.07	(0.02)	(2.01%)	3.33%
Delivery Sub-Total			**13.59**			**19.92**	**6.33**	**46.56%**	**61.94%**
Other Charges (kWh)	106	0.0139	1.47	106	0.0135	1.43	(0.05)	(3.06%)	4.43%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.78%
Cost of Power Commodity (kWh)	106	0.0650	6.89	106	0.0650	6.86	(0.03)	(0.39%)	21.34%
Total Bill Before Taxes			**22.20**			**28.46**	**6.26**	**28.18%**	**88.50%**
HST		13.00%	2.89		13.00%	3.70	0.81	28.18%	11.50%
Total Bill			**25.09**			**32.16**	**7.07**	**28.18%**	**100.00%**

RESIDENTIAL URBAN

Consumption: 250 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			10.04			16.55	6.51	64.84%	32.95%
Distribution (kWh)	250	0.0180	4.50	250	0.0167	4.18	(0.33)	(7.22%)	8.31%
Low Voltage Rider (kWh)	250	0.0023	0.58	250	0.0003	0.08	(0.50)	(86.96%)	0.15%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	1.99%
LRAM & SSM Rider (kWh)	250		0.00	250	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	250	(0.0064)	(1.60)	250	(0.0064)	(1.60)	0.00	0.00%	(3.19%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	250		0.00	250	0.0001	0.03	0.03	#DIV/0!	0.05%
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	250	0.0007	0.18	250	0.0007	0.18	0.00	0.00%	0.35%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	250		0.00	250	0.0016	0.40	0.40	#DIV/0!	0.80%
Distribution Sub-Total			**14.69**			**20.80**	**6.11**	**41.59%**	**41.41%**
Retail Transmisssion (kWh)	265	0.0103	2.73	264	0.0101	2.68	(0.05)	(2.01%)	5.33%
Delivery Sub-Total			**17.42**			**23.48**	**6.06**	**34.76%**	**46.74%**
Other Charges (kWh)	265	0.0139	3.68	264	0.0135	3.56	(0.11)	(3.06%)	7.10%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.50%
Cost of Power Commodity (kWh)	265	0.0650	17.23	264	0.0650	17.16	(0.07)	(0.39%)	34.16%
Total Bill Before Taxes			**38.57**			**44.45**	**5.88**	**15.23%**	**88.50%**
HST		13.00%	5.01		13.00%	5.78	0.76	15.23%	11.50%
Total Bill			**43.59**			**50.23**	**6.64**	**15.23%**	**100.00%**

RESIDENTIAL URBAN

Consumption		2010 BILL			2011 BILL			IMPACT		
500 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			10.04			16.55	6.51	64.84%	20.60%
	Distribution (kWh)	500	0.0180	9.00	500	0.0167	8.35	(0.65)	(7.22%)	10.39%
	Low Voltage Rider (kWh)	500	0.0023	1.15	500	0.0003	0.15	(1.00)	(86.96%)	0.19%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	1.24%
	LRAM & SSM Rider (kWh)	500		0.00	500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh) May 2010-April 2012	500	(0.0064)	(3.20)	500	(0.0064)	(3.20)	0.00	0.00%	(3.98%)
	Deferrral & Variance Acct (kWh) May 2011-April 2012	500		0.00	500	0.0001	0.05	0.05	#DIV/0!	0.06%
	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	500	0.0007	0.35	500	0.0007	0.35	0.00	0.00%	0.44%
	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	500		0.00	500	0.0016	0.80	0.80	#DIV/0!	1.00%
	Distribution Sub-Total			**18.34**			**24.05**	**5.71**	**31.13%**	**29.94%**
	Retail Transmisssion (kWh)	530	0.0103	5.46	528	0.0101	5.35	(0.11)	(2.01%)	6.66%
	Delivery Sub-Total			**23.80**			**29.40**	**5.60**	**23.53%**	**36.59%**
	Other Charges (kWh)	530	0.0139	7.35	528	0.0135	7.13	(0.23)	(3.06%)	8.87%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.31%
	Cost of Power Commodity (kWh)	530	0.0650	34.45	528	0.0650	34.32	(0.13)	(0.39%)	42.72%
	Total Bill Before Taxes			**65.86**			**71.10**	**5.24**	**7.96%**	**88.50%**
	HST		13.00%	8.56		13.00%	9.24	0.68	7.96%	11.50%
	Total Bill			**74.42**			**80.34**	**5.92**	**7.96%**	**100.00%**

RESIDENTIAL URBAN - PW Territory

Consumption		2010 BILL			2011 BILL			IMPACT		
800 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			10.04			16.55	6.51	64.84%	13.88%
	Distribution (kWh)	800	0.0180	14.40	800	0.0167	13.36	(1.04)	(7.22%)	11.20%
	Low Voltage Rider (kWh)	800	0.0023	1.84	800	0.0003	0.24	(1.60)	(86.96%)	0.20%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.84%
	LRAM & SSM Rider (kWh)	800		0.00	800	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh) May 2010-April 2012	800	(0.0064)	(5.12)	800	(0.0064)	(5.12)	0.00	0.00%	(4.29%)
	Deferrral & Variance Acct (kWh) May 2011-April 2012	800		0.00	800	0.0001	0.08	0.08	#DIV/0!	0.07%
	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	800	0.0007	0.56	800	0.0007	0.56	0.00	0.00%	0.47%
	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	800		0.00	800	0.0016	1.28	1.28	#DIV/0!	1.07%
	Distribution Sub-Total			**22.72**			**27.95**	**5.23**	**23.02%**	**23.44%**
	Retail Transmisssion (kWh)	848	0.0103	8.74	845	0.0101	8.56	(0.18)	(2.01%)	7.18%
	Delivery Sub-Total			**31.46**			**36.51**	**5.05**	**16.07%**	**30.62%**
	Other Charges (kWh)	848	0.0139	11.76	845	0.0135	11.40	(0.36)	(3.06%)	9.56%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.21%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	32.71%
	Cost of Power Commodity (kWh)	248	0.0750	18.61	245	0.0750	18.36	(0.25)	(1.33%)	15.40%
	Total Bill Before Taxes			**101.08**			**105.52**	**4.45**	**4.40%**	**88.50%**
	HST		13.00%	13.14		13.00%	13.72	0.58	4.40%	11.50%
	Total Bill			**114.22**			**119.24**	**5.03**	**4.40%**	**100.00%**

RESIDENTIAL URBAN

Consumption: 1,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			10.04			16.55	6.51	64.84%	11.36%
Distribution (kWh)	1,000	0.0180	18.00	1,000	0.0167	16.70	(1.30)	(7.22%)	11.46%
Low Voltage Rider (kWh)	1,000	0.0023	2.30	1,000	0.0003	0.30	(2.00)	(86.96%)	0.21%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.69%
LRAM & SSM Rider (kWh)	1,000		0.00	1,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	1,000	(0.0064)	(6.40)	1,000	(0.0064)	(6.40)	0.00	0.00%	(4.39%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	1,000		0.00	1,000	0.0001	0.10	0.10	#DIV/0!	0.07%
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	1,000	0.0007	0.70	1,000	0.0007	0.70	0.00	0.00%	0.48%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	1,000		0.00	1,000	0.0016	1.60	1.60	#DIV/0!	1.10%
Distribution Sub-Total			**25.64**			**30.55**	**4.91**	**19.15%**	**20.96%**
Retail Transmisssion (kWh)	1,060	0.0103	10.92	1,056	0.0101	10.70	(0.22)	(2.01%)	7.34%
Delivery Sub-Total			**36.56**			**41.25**	**4.69**	**12.83%**	**28.31%**
Other Charges (kWh)	1,060	0.0139	14.71	1,056	0.0135	14.26	(0.45)	(3.06%)	9.78%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.17%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	26.76%
Cost of Power Commodity (kWh)	460	0.0750	34.51	456	0.0750	34.20	(0.31)	(0.89%)	23.47%
Total Bill Before Taxes			**125.02**			**128.96**	**3.93**	**3.15%**	**88.50%**
HST		13.00%	16.25		13.00%	16.76	0.51	3.15%	11.50%
Total Bill			**141.28**			**145.72**	**4.44**	**3.15%**	**100.00%**

RESIDENTIAL URBAN

Consumption: 1,500 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			10.04			16.55	6.51	64.84%	7.81%
Distribution (kWh)	1,500	0.0180	27.00	1,500	0.0167	25.05	(1.95)	(7.22%)	11.82%
Low Voltage Rider (kWh)	1,500	0.0023	3.45	1,500	0.0003	0.45	(3.00)	(86.96%)	0.21%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.47%
LRAM & SSM Rider (kWh)	1,500		0.00	1,500	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	1,500	(0.0064)	(9.60)	1,500	(0.0064)	(9.60)	0.00	0.00%	(4.53%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	1,500		0.00	1,500	0.0001	0.15	0.15	#DIV/0!	0.07%
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	1,500	0.0007	1.05	1,500	0.0007	1.05	0.00	0.00%	#DIV/0!
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	1,500		0.00	1,500	0.0016	2.40	2.40	#DIV/0!	#DIV/0!
Distribution Sub-Total			**32.94**			**37.05**	**4.11**	**12.48%**	**17.48%**
Retail Transmisssion (kWh)	1,590	0.0103	16.38	1,584	0.0101	16.05	(0.33)	(2.01%)	7.57%
Delivery Sub-Total			**49.32**			**53.10**	**3.78**	**7.67%**	**25.06%**
Other Charges (kWh)	1,590	0.0139	22.06	1,584	0.0135	21.38	(0.68)	(3.06%)	10.09%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.12%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	18.40%
Cost of Power Commodity (kWh)	990	0.0750	74.26	984	0.0750	73.80	(0.46)	(0.62%)	34.83%
Total Bill Before Taxes			**184.89**			**187.53**	**2.64**	**1.43%**	**88.50%**
HST		13.00%	24.04		13.00%	24.38	0.34	1.43%	11.50%
Total Bill			**208.92**			**211.91**	**2.99**	**1.43%**	**100.00%**

RESIDENTIAL SUBURBAN

Consumption: 100 kWh	2010 BILL Volume	2010 BILL RATE $	2010 BILL CHARGE $	2011 BILL Volume	2011 BILL RATE $	2011 BILL CHARGE $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge			10.65			16.55	5.90	55.40%	51.46%
Distribution (kWh)	100	0.0134	1.34	100	0.0167	1.67	0.33	24.63%	5.19%
Low Voltage Rider (kWh)	100	0.0022	0.22	100	0.0003	0.03	(0.19)	(86.36%)	0.09%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	3.11%
LRAM & SSM Rider (kWh)	100		0.00	100	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	100	(0.0064)	(0.64)	100	(0.0064)	(0.64)	0.00	0.00%	(1.99%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	100		0.00	100	0.0001	0.01	0.01	#DIV/0!	0.03%
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	100	0.0007	0.07	100	0.0007	0.07	0.00	0.00%	0.22%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	100		0.00	100	0.0016	0.16	0.16	#DIV/0!	0.50%
Distribution Sub-Total			**12.64**			**18.85**	**6.21**	**49.13%**	**58.61%**
Retail Transmisssion (kWh)	106	0.0103	1.09	106	0.0101	1.07	(0.02)	(2.01%)	3.33%
Delivery Sub-Total			**13.73**			**19.92**	**6.19**	**45.06%**	**61.94%**
Other Charges (kWh)	106	0.0139	1.47	106	0.0135	1.43	(0.05)	(3.06%)	4.43%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.78%
Cost of Power Commodity (kWh)	106	0.0650	6.89	106	0.0650	6.86	(0.03)	(0.39%)	21.34%
Total Bill Before Taxes			**22.34**			**28.46**	**6.12**	**27.37%**	**88.50%**
HST		13.00%	2.90		13.00%	3.70	0.80	27.37%	11.50%
Total Bill			**25.25**			**32.16**	**6.91**	**27.37%**	**100.00%**

RESIDENTIAL SUBURBAN

Consumption: 250 kWh	2010 BILL Volume	2010 BILL RATE $	2010 BILL CHARGE $	2011 BILL Volume	2011 BILL RATE $	2011 BILL CHARGE $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge			10.65			16.55	5.90	55.40%	32.95%
Distribution (kWh)	250	0.0134	3.35	250	0.0167	4.18	0.83	24.63%	8.31%
Low Voltage Rider (kWh)	250	0.0022	0.55	250	0.0003	0.08	(0.48)	(86.36%)	0.15%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	1.99%
LRAM & SSM Rider (kWh)	250		0.00	250	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	250	(0.0064)	(1.60)	250	(0.0064)	(1.60)	0.00	0.00%	(3.19%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	250		0.00	250	0.0001	0.03	0.03	#DIV/0!	0.05%
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	250	0.0007	0.00	250	0.0007	0.18	0.18	#DIV/0!	0.35%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	250		0.00	250	0.0016	0.40	0.40	#DIV/0!	0.80%
Distribution Sub-Total			**13.95**			**20.80**	**6.85**	**49.10%**	**41.41%**
Retail Transmisssion (kWh)	265	0.0103	2.73	264	0.0101	2.68	(0.05)	(2.01%)	5.33%
Delivery Sub-Total			**16.68**			**23.48**	**6.80**	**40.74%**	**46.74%**
Other Charges (kWh)	265	0.0139	3.68	264	0.0135	3.56	(0.11)	(3.06%)	7.10%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.50%
Cost of Power Commodity (kWh)	265	0.0650	17.23	264	0.0650	17.16	(0.07)	(0.39%)	34.16%
Total Bill Before Taxes			**37.83**			**44.45**	**6.62**	**17.49%**	**88.50%**
HST		13.00%	4.92		13.00%	5.78	0.86	17.49%	11.50%
Total Bill			**42.75**			**50.23**	**7.48**	**17.49%**	**100.00%**

RESIDENTIAL SUBURBAN

Consumption
500 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			10.65			16.55	5.90	55.40%	20.60%
Distribution (kWh)	500	0.0134	6.70	500	0.0167	8.35	1.65	24.63%	10.39%
Low Voltage Rider (kWh)	500	0.0022	1.10	500	0.0003	0.15	(0.95)	(86.36%)	0.19%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	1.24%
LRAM & SSM Rider (kWh)	500		0.00	500	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	500	(0.0064)	(3.20)	500	(0.0064)	(3.20)	0.00	0.00%	(3.98%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	500		0.00	500	0.0001	0.05	0.05	#DIV/0!	0.06%
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	500	0.0007	0.35	500	0.0007	0.35	0.00	0.00%	0.44%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	500		0.00	500	0.0016	0.80	0.80	#DIV/0!	1.00%
Distribution Sub-Total			**16.60**			**24.05**	**7.45**	**44.88%**	**29.94%**
Retail Transmisssion (kWh)	530	0.0103	5.46	528	0.0101	5.35	(0.11)	(2.01%)	6.66%
Delivery Sub-Total			**22.06**			**29.40**	**7.34**	**33.28%**	**36.59%**
Other Charges (kWh)	530	0.0139	7.35	528	0.0135	7.13	(0.23)	(3.06%)	8.87%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.31%
Cost of Power Commodity (kWh)	530	0.0650	34.45	528	0.0650	34.32	(0.13)	(0.39%)	42.72%
Total Bill Before Taxes			**64.12**			**71.10**	**6.98**	**10.89%**	**88.50%**
HST		13.00%	8.34		13.00%	9.24	0.91	10.89%	11.50%
Total Bill			**72.45**			**80.34**	**7.89**	**10.89%**	**100.00%**

RESIDENTIAL SUBURBAN - PW Territory

Consumption		2010 BILL			2011 BILL			IMPACT		
800 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			10.65			16.55	5.90	55.40%	13.88%
	Distribution (kWh)	800	0.0134	10.72	800	0.0167	13.36	2.64	24.63%	11.20%
	Low Voltage Rider (kWh)	800	0.0022	1.76	800	0.0003	0.24	(1.52)	(86.36%)	0.20%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.84%
	LRAM & SSM Rider (kWh)	800		0.00	800	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh) May 2010-April 2012	800	(0.0064)	(5.12)	800	(0.0064)	(5.12)	0.00	0.00%	(4.29%)
	Deferrral & Variance Acct (kWh) May 2011-April 2012	800		0.00	800	0.0001	0.08	0.08	#DIV/0!	0.07%
	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	800	0.0007	0.56	800	0.0007	0.56	0.00	0.00%	0.47%
	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	800		0.00	800	0.0016	1.28	1.28	#DIV/0!	1.07%
	Distribution Sub-Total			**19.57**			**27.95**	**8.38**	**42.82%**	**23.44%**
	Retail Transmisssion (kWh)	848	0.0103	8.74	845	0.0101	8.56	(0.18)	(2.01%)	7.18%
	Delivery Sub-Total			**28.31**			**36.51**	**8.20**	**28.99%**	**30.62%**
	Other Charges (kWh)	848	0.0139	11.76	845	0.0135	11.40	(0.36)	(3.06%)	9.56%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.21%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	32.71%
	Cost of Power Commodity (kWh)	248	0.0750	18.61	245	0.0750	18.36	(0.25)	(1.33%)	15.40%
	Total Bill Before Taxes			**97.93**			**105.52**	**7.60**	**7.76%**	**88.50%**
	HST		13.00%	12.73		13.00%	13.72	0.99	7.76%	11.50%
	Total Bill			**110.66**			**119.24**	**8.59**	**7.76%**	**100.00%**

RESIDENTIAL SUBURBAN

Consumption: 1,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			10.65			16.55	5.90	55.40%	11.36%
Distribution (kWh)	1,000	0.0134	13.40	1,000	0.0167	16.70	3.30	24.63%	11.46%
Low Voltage Rider (kWh)	1,000	0.0022	2.20	1,000	0.0003	0.30	(1.90)	(86.36%)	0.21%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.69%
LRAM & SSM Rider (kWh)	1,000		0.00	1,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	1,000	(0.0064)	(6.40)	1,000	(0.0064)	(6.40)	0.00	0.00%	(4.39%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	1,000		0.00	1,000	0.0001	0.10	0.10	#DIV/0!	0.07%
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	1,000	0.0007	0.70	1,000	0.0007	0.70	0.00	0.00%	0.48%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	1,000		0.00	1,000	0.0016	1.60	1.60	#DIV/0!	1.10%
Distribution Sub-Total			**21.55**			**30.55**	**9.00**	**41.76%**	**20.96%**
Retail Transmisssion (kWh)	1,060	0.0103	10.92	1,056	0.0101	10.70	(0.22)	(2.01%)	7.34%
Delivery Sub-Total			**32.47**			**41.25**	**8.78**	**27.04%**	**28.31%**
Other Charges (kWh)	1,060	0.0139	14.71	1,056	0.0135	14.26	(0.45)	(3.06%)	9.78%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.17%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	26.76%
Cost of Power Commodity (kWh)	460	0.0750	34.51	456	0.0750	34.20	(0.31)	(0.89%)	23.47%
Total Bill Before Taxes			**120.93**			**128.96**	**8.02**	**6.63%**	**88.50%**
HST		13.00%	15.72		13.00%	16.76	1.04	6.63%	11.50%
Total Bill			**136.65**			**145.72**	**9.07**	**6.63%**	**100.00%**

RESIDENTIAL SUBURBAN

Consumption: 1,500 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			10.65			16.55	5.90	55.40%	7.81%
Distribution (kWh)	1,500	0.0134	20.10	1,500	0.0167	25.05	4.95	24.63%	11.82%
Low Voltage Rider (kWh)	1,500	0.0022	3.30	1,500	0.0003	0.45	(2.85)	(86.36%)	0.21%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.47%
LRAM & SSM Rider (kWh)	1,500		0.00	1,500	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	1,500	(0.0064)	(9.60)	1,500	(0.0064)	(9.60)	0.00	0.00%	(4.53%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	1,500		0.00	1,500	0.0001	0.15	0.15	#DIV/0!	0.07%
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	1,500	0.0007	1.05	1,500	0.0007	1.05	0.00	0.00%	0.50%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	1,500		0.00	1,500	0.0016	2.40	2.40	#DIV/0!	1.13%
Distribution Sub-Total			**26.50**			**37.05**	**10.55**	**39.81%**	**17.48%**
Retail Transmisssion (kWh)	1,590	0.0103	16.38	1,584	0.0101	16.05	(0.33)	(2.01%)	7.57%
Delivery Sub-Total			**42.88**			**53.10**	**10.22**	**23.84%**	**25.06%**
Other Charges (kWh)	1,590	0.0139	22.06	1,584	0.0135	21.38	(0.68)	(3.06%)	10.09%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.12%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	18.40%
Cost of Power Commodity (kWh)	990	0.0750	74.26	984	0.0750	73.80	(0.46)	(0.62%)	34.83%
Total Bill Before Taxes			**178.45**			**187.53**	**9.08**	**5.09%**	**88.50%**
HST		13.00%	23.20		13.00%	24.38	1.18	5.09%	11.50%
Total Bill			**201.65**			**211.91**	**10.26**	**5.09%**	**100.00%**

GENERAL SERVICE < 50 kW - PW Territory

Consumption
2,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			10.35			38.45	28.10	271.50%	13.18%
Distribution (kWh)	2,000	0.0176	35.20	2,000	0.0141	28.20	(7.00)	(19.89%)	9.67%
Low Voltage Rider (kWh)	2,000	0.0018	3.60	2,000	0.0003	0.60	(3.00)	(83.33%)	0.21%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.34%
LRAM & SSM Rider (kWh)	2,000		0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	2,000	(0.0065)	(13.00)	2,000	(0.0065)	(13.00)	0.00	0.00%	(4.46%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	2,000		0.00	2,000	(0.0013)	(2.60)	(2.60)	#DIV/0!	(0.89%)
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	2,000	0.0007	1.40	2,000	0.0007	1.40	0.00	0.00%	0.48%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	2,000		0.00	2,000	0.0019	3.80	3.80	#DIV/0!	1.30%
Distribution Sub-Total			**38.55**			**57.85**	**19.30**	**50.06%**	**19.84%**
Retail Transmisssion (kWh)	2,120	0.0092	19.51	2,112	0.0090	19.09	(0.41)	(2.12%)	6.55%
Delivery Sub-Total			**58.06**			**76.94**	**18.89**	**32.53%**	**26.38%**
Other Charges (kWh)	2,120	0.0139	29.41	2,112	0.0135	28.51	(0.90)	(3.06%)	9.78%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.09%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	13.37%
Cost of Power Commodity (kWh)	1,520	0.0750	114.02	1,512	0.0750	113.40	(0.62)	(0.54%)	38.88%
Total Bill Before Taxes			**240.73**			**258.10**	**$17.37**	**7.22%**	**88.50%**
HST		13.00%	31.30		13.00%	33.55	2.26	7.22%	11.50%
Total Bill			**272.03**			**291.66**	**$19.63**	**7.22%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
4,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			10.35			38.45	28.10	271.50%	7.05%
Distribution (kWh)	4,000	0.0176	70.40	4,000	0.0141	56.40	(14.00)	(19.89%)	10.34%
Low Voltage Rider (kWh)	4,000	0.0018	7.20	4,000	0.0003	1.20	(6.00)	(83.33%)	0.22%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.18%
LRAM & SSM Rider (kWh)	4,000		0.00	4,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	4,000	(0.0065)	(26.00)	4,000	(0.0065)	(26.00)	0.00	0.00%	(4.77%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	4,000		0.00	4,000	(0.0013)	(5.20)	(5.20)	#DIV/0!	(0.95%)
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	4,000	0.0007	2.80	4,000	0.0007	2.80	0.00	0.00%	0.51%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	4,000		0.00	4,000	0.0019	7.60	7.60	#DIV/0!	1.39%
Distribution Sub-Total			**65.75**			**76.25**	**10.50**	**15.97%**	**13.98%**
Retail Transmisssion (kWh)	4,240	0.0092	39.01	4,224	0.0090	38.18	(0.83)	(2.12%)	7.00%
Delivery Sub-Total			**104.76**			**114.43**	**9.67**	**9.23%**	**20.99%**
Other Charges (kWh)	4,240	0.0139	58.82	4,224	0.0135	57.02	(1.80)	(3.06%)	10.46%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.05%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	7.15%
Cost of Power Commodity (kWh)	3,640	0.0750	273.03	3,624	0.0750	271.80	(1.23)	(0.45%)	49.85%
Total Bill Before Taxes			**475.87**			**482.50**	**$6.64**	**1.39%**	**88.50%**
HST		13.00%	61.86		13.00%	62.73	0.86	1.39%	11.50%
Total Bill			**537.73**			**545.23**	**$7.50**	**1.39%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption: 10,000 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			10.35			38.45	28.10	271.50%	2.94%
Distribution (kWh)	10,000	0.0176	176.00	10,000	0.0141	141.00	(35.00)	(19.89%)	10.80%
Low Voltage Rider (kWh)	10,000	0.0018	18.00	10,000	0.0003	3.00	(15.00)	(83.33%)	0.23%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.08%
LRAM & SSM Rider (kWh)	10,000		0.00	10,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	10,000	(0.0065)	(65.00)	10,000	(0.0065)	(65.00)	0.00	0.00%	(4.98%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	10,000		0.00	10,000	(0.0013)	(13.00)	(13.00)	#DIV/0!	(1.00%)
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	10,000	0.0007	7.00	10,000	0.0007	7.00	0.00	0.00%	0.54%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	10,000		0.00	10,000	0.0019	19.00	19.00	#DIV/0!	1.45%
Distribution Sub-Total			**147.35**			**131.45**	**(15.90)**	**(10.79%)**	**10.07%**
Retail Transmisssion (kWh)	10,601	0.0092	97.53	10,560	0.0090	95.46	(2.07)	(2.12%)	7.31%
Delivery Sub-Total			**244.88**			**226.91**	**(17.97)**	**(7.34%)**	**17.38%**
Other Charges (kWh)	10,601	0.0139	147.06	10,560	0.0135	142.56	(4.50)	(3.06%)	10.92%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.02%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	2.99%
Cost of Power Commodity (kWh)	10,001	0.0750	750.08	9,960	0.0750	746.99	(3.08)	(0.41%)	57.20%
Total Bill Before Taxes			**1,181.27**			**1,155.71**	**(25.56)**	**(2.16%)**	**88.50%**
HST		13.00%	153.56		13.00%	150.24	(3.32)	(2.16%)	11.50%
Total Bill			**1,334.83**			**1,305.95**	**($28.88)**	**(2.16%)**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption: 12,500 kWh

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			10.35			38.45	28.10	271.50%	2.37%
Distribution (kWh)	12,500	0.0176	220.00	12,500	0.0141	176.25	(43.75)	(19.89%)	10.86%
Low Voltage Rider (kWh)	12,500	0.0018	22.50	12,500	0.0003	3.75	(18.75)	(83.33%)	0.23%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.06%
LRAM & SSM Rider (kWh)	12,500		0.00	12,500	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kWh) May 2010-April 2012	12,500	(0.0065)	(81.25)	12,500	(0.0065)	(81.25)	0.00	0.00%	(5.01%)
Deferrral & Variance Acct (kWh) May 2011-April 2012	12,500		0.00	12,500	(0.0013)	(16.25)	(16.25)	#DIV/0!	(1.00%)
Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	12,500	0.0007	8.75	12,500	0.0007	8.75	0.00	0.00%	0.54%
Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	12,500		0.00	12,500	0.0019	23.75	23.75	#DIV/0!	1.46%
Distribution Sub-Total			**181.35**			**154.45**	**(26.90)**	**(14.83%)**	**9.52%**
Retail Transmisssion (kWh)	13,251	0.0092	121.91	13,200	0.0090	119.32	(2.59)	(2.12%)	7.35%
Delivery Sub-Total			**303.26**			**273.77**	**(29.49)**	**(9.72%)**	**16.87%**
Other Charges (kWh)	13,251	0.0139	183.83	13,200	0.0135	178.20	(5.63)	(3.06%)	10.98%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.02%
Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	2.40%
Cost of Power Commodity (kWh)	12,651	0.0750	948.84	12,600	0.0750	944.99	(3.85)	(0.41%)	58.23%
Total Bill Before Taxes			**1,475.18**			**1,436.21**	**(38.97)**	**(2.64%)**	**88.50%**
HST		13.00%	191.77		13.00%	186.71	(5.07)	(2.64%)	11.50%
Total Bill			**1,666.96**			**1,622.92**	**($44.04)**	**(2.64%)**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption		2010 BILL			2011 BILL			IMPACT		
15,000 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			10.35			38.45	28.10	271.50%	1.98%
	Distribution (kWh)	15,000	0.0176	264.00	15,000	0.0141	211.50	(52.50)	(19.89%)	10.90%
	Low Voltage Rider (kWh)	15,000	0.0018	27.00	15,000	0.0003	4.50	(22.50)	(83.33%)	0.23%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.05%
	LRAM & SSM Rider (kWh)	15,000		0.00	15,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh) May 2010-April 2012	15,000	(0.0065)	(97.50)	15,000	(0.0065)	(97.50)	0.00	0.00%	(5.03%)
	Deferrral & Variance Acct (kWh) May 2011-April 2012	15,000		0.00	15,000	(0.0013)	(19.50)	(19.50)	#DIV/0!	(1.01%)
	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	15,000	0.0007	10.50	15,000	0.0007	10.50	0.00	0.00%	0.54%
	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	15,000		0.00	15,000	0.0019	28.50	28.50	#DIV/0!	1.47%
	Distribution Sub-Total			**215.35**			**177.45**	**(37.90)**	**(17.60%)**	**9.15%**
	Retail Transmisssion (kWh)	15,902	0.0092	146.29	15,840	0.0090	143.19	(3.10)	(2.12%)	7.38%
	Delivery Sub-Total			**361.64**			**320.64**	**(41.00)**	**(11.34%)**	**16.53%**
	Other Charges (kWh)	15,902	0.0139	220.59	15,840	0.0135	213.84	(6.76)	(3.06%)	11.02%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.01%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.00%	2.01%
	Cost of Power Commodity (kWh)	15,302	0.0750	1,147.61	15,240	0.0750	1,142.99	(4.62)	(0.40%)	58.92%
	Total Bill Before Taxes			**1,769.10**			**1,716.72**	**(52.38)**	**(2.96%)**	**88.50%**
	HST		13.00%	229.98		13.00%	223.17	(6.81)	(2.96%)	11.50%
	Total Bill			**1,999.08**			**1,939.89**	**($59.19)**	**(2.96%)**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
30,000 kWh	Monthly Service Charge			22.75			222.81	200.06	879.38%	6.18%
100 kW	Distribution (kW)	100	6.3575	635.75	100	4.0311	403.11	(232.64)	(36.59%)	11.18%
	Low Voltage Rider (kW)	100	0.7962	79.62	100	0.1042	10.42	(69.20)	(86.91%)	0.29%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.03%
	LRAM & SSM Rider (kW)	100		0.00	100	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW) May 2010-April 2012	100	(1.9651)	(196.51)	100	(1.9651)	(196.51)	0.00	0.00%	(5.45%)
	Deferrral & Variance Acct (kW) May 2011-April 2012	100		0.00	100	(0.6119)	(61.19)	(61.19)	#DIV/0!	(1.70%)
	Global Adjustmenr Rate Rider (kW) May 2010 - April 2012 Non-RPP Only.	100	0.3116	31.16	100	0.3116	31.16	0.00	0.00%	0.86%
	Global Adjustmenr Rate Rider (kW) May 2011 - April 2012 Non-RPP Only.	100		0.00	100	0.6442	64.42	64.42	#DIV/0!	1.79%
	Distribution Sub-Total			**573.77**			**475.22**	**(98.55)**	**(17.18%)**	**13.18%**
	Retail Transmisssion (kW)	100	3.7002	370.02	100	3.6656	366.56	(3.46)	(0.93%)	10.17%
	Delivery Sub-Total			**943.79**			**841.78**	**(102.01)**	**(10.81%)**	**23.35%**
	Other Charges (kWh)	31,803	0.0139	441.19	31,680	0.0135	427.68	(13.51)	(3.06%)	11.86%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.01%
	Cost of Power Commodity (kWh)	31,803	0.0606	1,927.90	31,680	0.0606	1,920.42	(7.47)	(0.39%)	53.27%
	Total Bill Before Taxes			**3,313.12**			**3,190.13**	**(122.99)**	**(3.71%)**	**88.50%**
	HST		13.00%	430.71		13.00%	414.72	(15.99)	(3.71%)	11.50%
	Total Bill			**3,743.83**			**3,604.85**	**(138.98)**	**(3.71%)**	**100.00%**

GENERAL SERVICE > 50 kW - PW Territory

Consumption		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
55,000 kWh	Monthly Service Charge			22.75			222.81	200.06	879.38%	3.51%
175 kW	Distribution (kW)	175	6.3575	1,112.56	175	4.0311	705.44	(407.12)	(36.59%)	11.13%
	Low Voltage Rider (kW)	175	0.7962	139.34	175	0.1042	18.24	(121.10)	(86.91%)	0.29%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.02%
	LRAM & SSM Rider (kW)	175		0.00	175	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW) May 2010-April 2012	175	(1.9651)	(343.89)	175	(1.9651)	(343.89)	0.00	0.00%	(5.42%)
	Deferrral & Variance Acct (kW) May 2011-April 2012	175		0.00	175	(0.6119)	(107.08)	(107.08)	#DIV/0!	(1.69%)
	Global Adjustmenr Rate Rider (kW) May 2010 - April 2012 Non-RPP Only.	175	0.3116	54.53	175	0.3116	54.53	0.00	0.00%	0.86%
	Global Adjustmenr Rate Rider (kW) May 2011 - April 2012 Non-RPP Only.	175		0.00	175	0.6442	112.74	112.74	#DIV/0!	1.78%
	Distribution Sub-Total			**986.29**			**663.78**	**(322.51)**	**(32.70%)**	**10.47%**
	Retail Transmisssion (kW)	175	3.7002	647.54	175	3.6656	641.48	(6.05)	(0.93%)	10.12%
	Delivery Sub-Total			**1,633.82**			**1,305.26**	**(328.56)**	**(20.11%)**	**20.59%**
	Other Charges (kWh)	58,306	0.0139	808.84	58,079	0.0135	784.07	(24.77)	(3.06%)	12.37%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	58,306	0.0606	3,534.48	58,079	0.0606	3,520.78	(13.70)	(0.39%)	55.54%
	Total Bill Before Taxes			**5,977.39**			**5,610.36**	**(367.03)**	**(6.14%)**	**88.50%**
	HST		13.00%	777.06		13.00%	729.35	(47.71)	(6.14%)	11.50%
	Total Bill			**6,754.45**			**6,339.71**	**(414.75)**	**(6.14%)**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption		2010 BILL			2011 BILL			IMPACT		
200,000 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
500 kW	Monthly Service Charge			22.75			222.81	200.06	879.38%	1.04%
	Distribution (kW)	500	6.3575	3,178.75	500	4.0311	2,015.55	(1,163.20)	(36.59%)	9.40%
	Low Voltage Rider (kW)	500	0.7962	398.10	500	0.1042	52.10	(346.00)	(86.91%)	0.24%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.00%
	LRAM & SSM Rider (kW)	500		0.00	500	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW) May 2010-April 2012	500	(1.9651)	(982.55)	500	(1.9651)	(982.55)	0.00	0.00%	(4.58%)
	Deferrral & Variance Acct (kW) May 2011-April 2012	500		0.00	500	(0.6119)	(305.95)	(305.95)	#DIV/0!	(1.43%)
	Global Adjustmenr Rate Rider (kW) May 2010 - April 2012 Non-RPP Only.	500	0.3116	155.80	500	0.3116	155.80	0.00	0.00%	0.73%
	Global Adjustmenr Rate Rider (kW) May 2011 - April 2012 Non-RPP Only.	500		0.00	500	0.6442	322.10	322.10	#DIV/0!	1.50%
	Distribution Sub-Total			**2,773.85**			**1,480.86**	**(1,292.99)**	**(46.61%)**	**6.91%**
	Retail Transmisssion (kW)	500	3.7002	1,850.10	500	3.6656	1,832.80	(17.30)	(0.93%)	8.55%
	Delivery Sub-Total			**4,623.95**			**3,313.66**	**(1,310.29)**	**(28.34%)**	**15.46%**
	Other Charges (kWh)	212,020	0.0139	2,941.25	211,198	0.0135	2,851.17	(90.07)	(3.06%)	13.30%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	212,020	0.0606	12,852.65	211,198	0.0606	12,802.83	(49.83)	(0.39%)	59.73%
	Total Bill Before Taxes			**20,418.10**			**18,967.91**	**(1,450.19)**	**(7.10%)**	**88.50%**
	HST		13.00%	2,654.35		13.00%	2,465.83	(188.52)	(7.10%)	11.50%
	Total Bill			**23,072.45**			**21,433.74**	**(1,638.71)**	**(7.10%)**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption		2010 BILL			2011 BILL			IMPACT		
800,000 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
2,000 kW	Monthly Service Charge			22.75			222.81	200.06	879.38%	0.26%
	Distribution (kW)	2,000	6.3575	12,715.00	2,000	4.0311	8,062.20	(4,652.80)	(36.59%)	9.49%
	Low Voltage Rider (kW)	2,000	0.7962	1,592.40	2,000	0.1042	208.40	(1,384.00)	(86.91%)	0.25%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.00%
	LRAM & SSM Rider (kW)	2,000		0.00	2,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW) May 2010-April 2012	2,000	(1.9651)	(3,930.20)	2,000	(1.9651)	(3,930.20)	0.00	0.00%	(4.63%)
	Deferrral & Variance Acct (kW) May 2011-April 2012	2,000		0.00	2,000	(0.6119)	(1,223.80)	(1,223.80)	#DIV/0!	(1.44%)
	Global Adjustmenr Rate Rider (kW) May 2010 - April 2012 Non-RPP Only.	2,000	0.3116	623.20	2,000	0.3116	623.20	0.00	0.00%	0.73%
	Global Adjustmenr Rate Rider (kW) May 2011 - April 2012 Non-RPP Only.	2,000		0.00	2,000	0.6442	1,288.40	1,288.40	#DIV/0!	1.52%
	Distribution Sub-Total			**11,024.15**			**5,252.01**	**(5,772.14)**	**(52.36%)**	**6.18%**
	Retail Transmisssion (kW)	2,000	3.7002	7,400.40	2,000	3.6656	7,331.21	(69.19)	(0.93%)	8.63%
	Delivery Sub-Total			**18,424.55**			**12,583.22**	**(5,841.33)**	**(31.70%)**	**14.81%**
	Other Charges (kWh)	848,080	0.0139	11,764.99	844,792	0.0135	11,404.69	(360.29)	(3.06%)	13.42%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	848,080	0.0606	51,410.61	844,792	0.0606	51,211.30	(199.31)	(0.39%)	60.27%
	Total Bill Before Taxes			**81,600.40**			**75,199.47**	**(6,400.93)**	**(7.84%)**	**88.50%**
	HST		13.00%	10,608.05		13.00%	9,775.93	(832.12)	(7.84%)	11.50%
	Total Bill			**92,208.45**			**84,975.40**	**(7,233.05)**	**(7.84%)**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
1,600,000 kWh
4,000 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			22.75			222.81	200.06	879.38%	0.13%
Distribution (kW)	4,000	6.3575	25,430.00	4,000	4.0311	16,124.40	(9,305.60)	(36.59%)	9.50%
Low Voltage Rider (kW)	4,000	0.7962	3,184.80	4,000	0.1042	416.80	(2,768.00)	(86.91%)	0.25%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.00%
LRAM & SSM Rider (kW)	4,000		0.00	4,000	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW) May 2010-April 2012	4,000	(1.9651)	(7,860.40)	4,000	(1.9651)	(7,860.40)	0.00	0.00%	(4.63%)
Deferrral & Variance Acct (kW) May 2011-April 2012	4,000		0.00	4,000	(0.6119)	(2,447.60)	(2,447.60)	#DIV/0!	(1.44%)
Global Adjustmenr Rate Rider (kW) May 2010 - April 2012 Non-RPP Only.	4,000	0.3116	1,246.40	4,000	0.3116	1,246.40	0.00	0.00%	0.73%
Global Adjustmenr Rate Rider (kW) May 2011 - April 2012 Non-RPP Only.	4,000		0.00	4,000	0.6442	2,576.80	2,576.80	#DIV/0!	1.52%
Distribution Sub-Total			**22,024.55**			**10,280.21**	**(11,744.34)**	**(53.32%)**	**6.06%**
Retail Transmisssion (kW)	4,000	3.7002	14,800.80	4,000	3.6656	14,662.42	(138.38)	(0.93%)	8.64%
Delivery Sub-Total			**36,825.35**			**24,942.63**	**(11,882.72)**	**(32.27%)**	**14.70%**
Other Charges (kWh)	1,696,160	0.0139	23,529.98	1,689,584	0.0135	22,809.39	(720.59)	(3.06%)	13.44%
Other Charges (per month)			0.25			0.25	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	1,696,160	0.0606	102,821.22	1,689,584	0.0606	102,422.61	(398.61)	(0.39%)	60.36%
Total Bill Before Taxes			**163,176.80**			**150,174.88**	**(13,001.92)**	**(7.97%)**	**88.50%**
HST		13.00%	21,212.98		13.00%	19,522.73	(1,690.25)	(7.97%)	11.50%
Total Bill			**184,389.78**			**169,697.62**	**(14,692.17)**	**(7.97%)**	**100.00%**

Street Lighting - PW Territory

Billing Determinants
1 Connections
52.13 kWh
0.14 kW

	2010 BILL			2011 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	1	0.5900	0.59	1	0.8005	0.80	0.21	35.68%	12.51%
Distribution (kW)	0	0.7961	0.11	0	3.1398	0.43	0.32	294.40%	6.79%
Low Voltage Rider (kW)	0	0.6741	0.09	0	0.0801	0.01	(0.08)	(88.12%)	0.17%
LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
Deferrral & Variance Acct (kW) May 2010-April 2012	0	(2.1909)	(0.30)	0	(2.1909)	(0.30)	0.00	0.00%	(4.74%)
Deferrral & Variance Acct (kW) May 2011-April 2012	0		0.00	0	(0.6329)	(0.09)	(0.09)	#DIV/0!	(1.37%)
Global Adjustmenr Rate Rider (kW) May 2010 - April 2012 Non-RPP Only.	0	0.0000	0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
Global Adjustmenr Rate Rider (kW) May 2011 - April 2012 Non-RPP Only.	0		0.00	0	0.6613	0.09	0.09	#DIV/0!	1.43%
Distribution Sub-Total			**0.49**			**0.95**	**0.46**	**93.14%**	**14.80%**
Retail Transmisssion (kW)	0	2.824	0.39	0	2.7901	0.39	(0.00)	(1.20%)	6.04%
Delivery Sub-Total			**0.88**			**1.33**	**0.45**	**51.29%**	**20.83%**
Other Charges (kWh)	55	0.0139	0.77	55	0.0135	0.74	(0.02)	(3.06%)	11.61%
Other Charges (per month)			0.25			0.25	0.00	0.00%	3.91%
Cost of Power Commodity (kWh)	55	0.0606	3.35	55	0.0606	3.34	(0.01)	(0.39%)	52.14%
Total Bill Before Taxes			**5.25**			**5.66**	**0.42**	**7.92%**	**88.50%**
HST		13.00%	0.68		13.00%	0.74	0.05	7.92%	11.50%
Total Bill			**5.93**			**6.40**	**0.47**	**7.92%**	**100.00%**

Sentinel Lighting - PW Territory

Billing Determinants		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
1 Connections	Monthly Service Charge	1	1.0400	1.04	1	7.1862	7.19	6.15	590.98%	50.41%
43.57 kWh	Distribution (kW)	0	0.9270	0.11	0	8.9771	1.08	0.97	868.40%	7.56%
0.12 kW	Low Voltage Rider (kW)	0	0.6051	0.07	0	0.0871	0.01	(0.06)	(85.61%)	0.07%
	LRAM & SSM Rider (kW)	0		0.00	0	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW) May 2010-April 2012	0	(2.2732)	(0.27)	0	(2.2732)	(0.27)	0.00	0.00%	(1.91%)
	Deferrral & Variance Acct (kW) May 2011-April 2012	0		0.00	0	2.1482	0.26	0.26	#DIV/0!	1.81%
	Global Adjustmenr Rate Rider (kW) May 2010 - April 2012 Non-RPP Only.	0	0.2799	0.03	0	0.2799	0.03	0.00	0.00%	0.24%
	Global Adjustmenr Rate Rider (kW) May 2011 - April 2012 Non-RPP Only.	0		0.00	0	0.9780	0.12	0.12	#DIV/0!	0.82%
	Distribution Sub-Total			**0.98**			**8.41**	**7.43**	**754.09%**	**59.00%**
	Retail Transmisssion (kW)	0	2.8598	0.34	0	2.8614	0.34	0.00	0.05%	2.41%
	Delivery Sub-Total			**1.33**			**8.75**	**7.43**	**559.21%**	**61.40%**
	Other Charges (kWh)	46	0.0139	0.64	46	0.0135	0.62	(0.02)	(3.06%)	4.36%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	1.75%
	Cost of Power Commodity (kWh)	46	0.0650	3.00	46	0.0650	2.99	(0.01)	(0.39%)	20.98%
	Total Bill Before Taxes			**5.22**			**12.61**	**7.39**	**141.63%**	**88.50%**
	HST		13.00%	0.68		13.00%	1.64	0.96	141.63%	11.50%
	Total Bill			**5.90**			**14.25**	**8.36**	**141.63%**	**100.00%**

Unmetered Scattered - PW Territory

Consumption		2010 BILL			2011 BILL			IMPACT		
250 kWh		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
	Monthly Service Charge			5.18			19.87	14.69	283.51%	38.45%
	Distribution (kWh)	250	0.0173	4.33	250	0.0139	3.48	(0.85)	(19.65%)	6.73%
	Low Voltage Rider (kWh)	250	0.0021	0.53	250	0.0003	0.08	(0.45)	(85.71%)	0.15%
	LRAM & SSM Rider (kWh)	250		0.00	250	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh) May 2010-April 2012	250	(0.0064)	(1.60)	250	(0.0064)	(1.60)	0.00	0.00%	(3.10%)
	Deferrral & Variance Acct (kWh) May 2011-April 2012	250		0.00	250	(0.0005)	(0.13)	(0.13)	#DIV/0!	(0.24%)
	Global Adjustmenr Rate Rider (kWh) May 2010 - April 2012 Non-RPP Only.	250	0.0010	0.25	250	0.0010	0.25	0.00	0.00%	0.48%
	Global Adjustmenr Rate Rider (kWh) May 2011 - April 2012 Non-RPP Only.	250		0.00	250	0.0016	0.40	0.40	#DIV/0!	0.77%
	Distribution Sub-Total			**8.68**			**22.34**	**13.66**	**157.38%**	**43.24%**
	Retail Transmisssion (kWh)	265	0.0092	2.44	264	0.0091	2.41	(0.03)	(1.11%)	4.67%
	Delivery Sub-Total			**11.12**			**24.75**	**13.63**	**122.62%**	**47.90%**
	Other Charges (kWh)	265	0.0139	3.68	264	0.0135	3.56	(0.11)	(3.06%)	6.90%
	Other Charges (per month)			0.25			0.25	0.00	0.00%	0.48%
	Cost of Power Commodity (kWh)	265	0.0650	17.23	264	0.0650	17.16	(0.07)	(0.39%)	33.21%
	Total Bill Before Taxes			**32.27**			**45.73**	**13.45**	**41.69%**	**88.50%**
	HST		13.00%	4.20		13.00%	5.94	1.75	41.69%	11.50%
	Total Bill			**36.47**			**51.67**	**15.20**	**41.69%**	**100.00%**

Appendix 8-B NPEI's RST Rates Adjustment Model

Ontario

Name of LDC: Niagara Peninsula Energy Inc. - Niagara Falls
File Number: EB-2010-0138
Version : 1.0

LDC Information

Applicant Name	**Niagara Peninsula Energy Inc. - Niagara Falls**
OEB Application Number	**EB-2010-0138**
LDC Licence Number	**ED-2007-0749**
Application Type	**COS**

Name of LDC: Niagara Peninsula Energy Inc. - Niagara Falls
File Number: EB-2010-0138
Version : 1.0

Rate Class And 2010 RTSR Rates

Enter Rate Group and Rate Class in the same order as listed on your current Tariff sheet and Rate Generator.

Enter the RTSR-Network and RTSR-Connection rates as approved on your current Tariff sheet.

Rate Group	Rate Class	Vol Metric	RTSR - Network	RTSR - Connection
RES	Residential	kWh	0.0053	0.0048
GSLT50	General Service Less Than 50 kW	kWh	0.0048	0.0042
GSGT50	General Service 50 to 4,999 kW	kW	1.9802	1.6642
USL	Unmetered Scattered Load	kWh	0.0048	0.0043
Sen	Sentinel Lighting	kW	1.4661	1.3906
SL	Street Lighting	kW	1.4970	1.2785

Name of LDC: **Niagara Peninsula Energy Inc. - Niagara Falls**
File Number: **EB-2010-0138**
Version : 1.0

2009 Distributor Billing Determinants

Enter the most recently reported RRR billing determinants

Loss Adjusted Metered kWh	Yes
Loss Adjusted Metered kW	No

Rate Class	Vol Metric	Metered kWh A	Metered kW B	Applicable Loss Factor C	Load Factor D = A / (B * 730)	Loss Adjusted Billed kWh E = A * C
Residential	kWh	396,244,635	0	1.0572		418,909,828
General Service Less Than 50 kW	kWh	128,615,455	0	1.0572		135,972,259
General Service 50 to 4,999 kW	kW	636,588,343	1,697,684	1.0572	51.39%	673,001,196
Unmetered Scattered Load	kWh	2,045,397	0	1.0572		2,162,394
Sentinel Lighting	kW	432,939	699	1.0572	84.89%	457,703
Street Lighting	kW	7,275,676	26,756	1.0572	37.27%	7,691,845
Total		1,171,202,445	1,725,139			1,238,195,225

Name of LDC: Niagara Peninsula Energy Inc. - Niagara Falls
File Number: EB-2010-0138
Version : 1.0

Uniform Transmission and Hydro One Sub-Transmission Rates

Uniform Transmission Rates

Rate Description	Vol Metric	Effective January 1, 2009 Rate	Effective July 1, 2009 Rate	Effective January 1, 2010 Rate	Effective January 1, 2011 Rate
Network Service Rate	kW	$ 2.57	$ 2.66	$ 2.97	$ 2.97
Line Connection Service Rate	kW	$ 0.70	$ 0.70	$ 0.73	$ 0.73
Transformation Connection Service Rate	kW	$ 1.62	$ 1.57	$ 1.71	$ 1.71

Hydro One Sub-Transmission Rates

Rate Description	Vol Metric	Effective May 1, 2008 Rate	Effective May 1, 2009 Rate	Effective May 1, 2010 Rate	Effective May 1, 2011 Rate
Network Service Rate	kW	$ 2.01	$ 2.24	$ 2.65	$ 2.65
Line Connection Service Rate	kW	$ 0.50	$ 0.60	$ 0.64	$ 0.64
Transformation Connection Service Rate	kW	$ 1.38	$ 1.39	$ 1.50	$ 1.50
Both Line and Transformation Connection Service Rate	kW	$ 1.88	$ 1.99	$ 2.14	$ 2.14

Hydro One Sub-Transmission Rate Rider 6A

Rate Description	Vol Metric	Effective May 1, 2008 Rate	Effective May 1, 2009 Rate	Effective May 1, 2010 Rate	Effective May 1, 2011 Rate
RSVA Transmission network – 4714 – which affects 1584	kW	$ -	$ -	$ 0.0470	$ 0.0470
RSVA Transmission connection – 4716 – which affects 1586	kW	$ -	$ -	-$ 0.0250	-$ 0.0250
RSVA LV – 4750 – which affects 1550	kW	$ -	$ -	$ 0.0580	$ 0.0580
RARA 1 – 2252 – which affects 1590	kW	$ -	$ -	-$ 0.0750	-$ 0.0750
Hydro One Sub-Transmission Rate Rider 6A	kW	$ -	$ -	$ 0.0050	$ 0.0050

Name of LDC: Niagara Peninsula Energy Inc. - Niagara Falls
File Number: EB-2010-0138
Version : 1.0

2009 Historical Wholesale Transmission

Enter billing detail for wholesale transmission for the same reporting period as the billing determinants on sheet B1.2.

IESO

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	179,169	$2.57	$ 460,464	195,406	$0.70	$ 136,784	123,378	$1.62	$ 199,872	$ 336,657
February	134,614	$2.57	$ 345,958	129,375	$0.70	$ 90,562	118,223	$1.62	$ 191,521	$ 282,084
March	155,523	$2.57	$ 399,694	155,523	$0.70	$ 108,866	115,603	$1.62	$ 187,277	$ 296,143
April	136,656	$2.57	$ 351,207	139,675	$0.70	$ 97,773	105,104	$1.62	$ 170,268	$ 268,041
May	129,981	$2.57	$ 334,052	136,240	$0.70	$ 95,368	104,265	$1.62	$ 168,909	$ 264,278
June	189,846	$2.57	$ 487,903	191,737	$0.70	$ 134,216	144,322	$1.62	$ 233,802	$ 368,017
July	173,697	$2.66	$ 462,034	174,350	$0.70	$ 122,045	132,698	$1.57	$ 208,336	$ 330,381
August	213,910	$2.66	$ 569,000	218,129	$0.70	$ 152,690	162,874	$1.57	$ 255,712	$ 408,403
September	158,604	$2.66	$ 421,887	160,492	$0.70	$ 112,344	121,059	$1.57	$ 190,063	$ 302,407
October	135,996	$2.66	$ 361,749	136,156	$0.70	$ 95,309	99,849	$1.57	$ 156,763	$ 252,072
November	149,812	$2.66	$ 398,499	152,275	$0.70	$ 106,593	111,918	$1.57	$ 175,711	$ 282,304
December	159,205	$2.66	$ 423,486	163,732	$0.70	$ 114,612	119,493	$1.57	$ 187,604	$ 302,216
Total	1,917,013	$2.62	$5,015,933	1,953,089	$0.70	$1,367,163	1,458,786	$1.59	$2,325,839	$3,693,001

Hydro One

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Line Transformation Units Billed	Line Transformation Rate	Line Transformation Amount	Total Line Amount
January	36,164	$2.01	$ 72,690	36,168	$0.50	$ 18,084	54,610	$1.45	$ 79,216	$ 97,300
February	34,552	$2.01	$ 69,450	34,584	$0.50	$ 17,292	57,858	$1.46	$ 84,222	$ 101,514
March	30,462	$2.01	$ 61,229	30,634	$0.50	$ 15,317	56,701	$1.46	$ 82,806	$ 98,123
April	30,152	$2.01	$ 60,606	30,192	$0.50	$ 15,096	53,607	$1.46	$ 78,127	$ 93,223
May	24,940	$2.07	$ 51,563	25,013	$0.53	$ 13,132	47,553	$1.46	$ 69,501	$ 82,632
June	32,517	$2.24	$ 72,838	32,561	$0.60	$ 19,537	33,653	$1.44	$ 48,356	$ 67,893
July	31,233	$2.24	$ 69,962	31,260	$0.60	$ 18,756	41,005	$1.45	$ 59,499	$ 78,255
August	37,014	$2.24	$ 82,910	37,060	$0.60	$ 22,236	23,028	$1.40	$ 32,255	$ 54,491
September	30,438	$2.24	$ 68,181	30,438	$0.60	$ 18,263	49,987	$1.46	$ 73,086	$ 91,349
October	29,128	$2.24	$ 65,247	44,223	$0.60	$ 26,534	70,000	$1.45	$ 101,293	$ 127,826
November	30,216	$2.24	$ 67,684	30,216	$0.60	$ 18,130	59,217	$1.46	$ 86,751	$ 104,881
December	34,242	$2.24	$ 76,702	34,348	$0.60	$ 20,609	57,982	$1.46	$ 84,604	$ 105,213
Total	381,058	$2.15	$ 819,061	396,697	$0.56	$ 222,984	605,201	$1.45	$ 879,716	$1,102,701

Total

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Line Transformation Units Billed	Line Transformation Rate	Line Transformation Amount	Total Line Amount

Name of LDC: Niagara Peninsula Energy Inc. - Niagara Falls
File Number: EB-2010-0138
Version : 1.0

Current Wholesale Transmission

The purpose of this sheet is to calculate the expected billing when current 2010 UTR rates are applied against historical (2009) transmission units.

IESO

Month	Network			Line Connection			Transformation Connection			Total Line
	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	179,169	$2.9700	$ 532,132	195,406	$0.7300	$ 142,646	123,378	$1.7100	$ 210,976	$ 353,623
February	134,614	$2.9700	$ 399,804	129,375	$0.7300	$ 94,444	118,223	$1.7100	$ 202,161	$ 296,605
March	155,523	$2.9700	$ 461,903	155,523	$0.7300	$ 113,532	115,603	$1.7100	$ 197,681	$ 311,213
April	136,656	$2.9700	$ 405,869	139,675	$0.7300	$ 101,963	105,104	$1.7100	$ 179,728	$ 281,691
May	129,981	$2.9700	$ 386,045	136,240	$0.7300	$ 99,456	104,265	$1.7100	$ 178,293	$ 277,749
June	189,846	$2.9700	$ 563,841	191,737	$0.7300	$ 139,968	144,322	$1.7100	$ 246,791	$ 386,758
July	173,697	$2.9700	$ 515,880	174,350	$0.7300	$ 127,275	132,698	$1.7100	$ 226,914	$ 354,189
August	213,910	$2.9700	$ 635,312	218,129	$0.7300	$ 159,234	162,874	$1.7100	$ 278,515	$ 437,749
September	158,604	$2.9700	$ 471,054	160,492	$0.7300	$ 117,159	121,059	$1.7100	$ 207,011	$ 324,170
October	135,996	$2.9700	$ 403,908	136,156	$0.7300	$ 99,394	99,849	$1.7100	$ 170,742	$ 270,135
November	149,812	$2.9700	$ 444,940	152,275	$0.7300	$ 111,161	111,918	$1.7100	$ 191,380	$ 302,541
December	159,205	$2.9700	$ 472,839	163,732	$0.7300	$ 119,524	119,493	$1.7100	$ 204,333	$ 323,857
Total	1,917,013	$2.9700	$5,693,528	1,953,089	$0.7300	$1,425,755	1,458,786	$1.7100	$2,494,524	$3,920,279

Hydro One

Month	Network			Line Connection			Line Transformation			Total Line
	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
	Includes Hydro One Rate Rider B1.3 UTR's and Sub-Transmission Cell K48			Includes Hydro One Rate Rider B1.3 UTR's and Sub-Transmission Cell K50						
January	36,164	$2.6970	$ 97,534	36,168	$0.6150	$ 22,243	54,610	$1.5000	$ 81,915	$ 104,158
February	34,552	$2.6970	$ 93,187	34,584	$0.6150	$ 21,269	57,858	$1.5000	$ 86,787	$ 108,056
March	30,462	$2.6970	$ 82,156	30,634	$0.6150	$ 18,840	56,701	$1.5000	$ 85,051	$ 103,891
April	30,152	$2.6970	$ 81,320	30,192	$0.6150	$ 18,568	53,607	$1.5000	$ 80,411	$ 98,979
May	24,940	$2.6970	$ 67,263	25,013	$0.6150	$ 15,383	47,553	$1.5000	$ 71,330	$ 86,712
June	32,517	$2.6970	$ 87,698	32,561	$0.6150	$ 20,025	33,653	$1.5000	$ 50,480	$ 70,505
July	31,233	$2.6970	$ 84,235	31,260	$0.6150	$ 19,225	41,005	$1.5000	$ 61,508	$ 80,732
August	37,014	$2.6970	$ 99,826	37,060	$0.6150	$ 22,792	23,028	$1.5000	$ 34,542	$ 57,334
September	30,438	$2.6970	$ 82,091	30,438	$0.6150	$ 18,719	49,987	$1.5000	$ 74,981	$ 93,700
October	29,128	$2.6970	$ 78,558	44,223	$0.6150	$ 27,197	70,000	$1.5000	$ 105,000	$ 132,197
November	30,216	$2.6970	$ 81,493	30,216	$0.6150	$ 18,583	59,217	$1.5000	$ 88,826	$ 107,408
December	34,242	$2.6970	$ 92,351	34,348	$0.6150	$ 21,124	57,982	$1.5000	$ 86,973	$ 108,097
Total	381,058	$2.6970	$1,027,712	396,697	$0.6150	$ 243,969	605,201	$1.5000	$ 907,801	$1,151,770

Total

Month	Network			Line Connection			Line Transformation			Total Line
	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount

Name of LDC: Niagara Peninsula Energy Inc. - Niagara Falls
File Number: EB-2010-0138
Version : 1.0

Forecast Wholesale Transmission

The purpose of this sheet is to calculate the expected billing when forecasted 2011 UTR rates are applied against historical (2009) transmission units.

IESO

	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	179,169	$2.9700	$ 532,132	195,406	$0.7300	$ 142,646	123,378	$1.7100	$ 210,976	$ 353,623
February	134,614	$2.9700	$ 399,804	129,375	$0.7300	$ 94,444	118,223	$1.7100	$ 202,161	$ 296,605
March	155,523	$2.9700	$ 461,903	155,523	$0.7300	$ 113,532	115,603	$1.7100	$ 197,681	$ 311,213
April	136,656	$2.9700	$ 405,869	139,675	$0.7300	$ 101,963	105,104	$1.7100	$ 179,728	$ 281,691
May	129,981	$2.9700	$ 386,045	136,240	$0.7300	$ 99,456	104,265	$1.7100	$ 178,293	$ 277,749
June	189,846	$2.9700	$ 563,841	191,737	$0.7300	$ 139,968	144,322	$1.7100	$ 246,791	$ 386,758
July	173,697	$2.9700	$ 515,880	174,350	$0.7300	$ 127,275	132,698	$1.7100	$ 226,914	$ 354,189
August	213,910	$2.9700	$ 635,312	218,129	$0.7300	$ 159,234	162,874	$1.7100	$ 278,515	$ 437,749
September	158,604	$2.9700	$ 471,054	160,492	$0.7300	$ 117,159	121,059	$1.7100	$ 207,011	$ 324,170
October	135,996	$2.9700	$ 403,908	136,156	$0.7300	$ 99,394	99,849	$1.7100	$ 170,742	$ 270,135
November	149,812	$2.9700	$ 444,940	152,275	$0.7300	$ 111,161	111,918	$1.7100	$ 191,380	$ 302,541
December	159,205	$2.9700	$ 472,839	163,732	$0.7300	$ 119,524	119,493	$1.7100	$ 204,333	$ 323,857
Total	1,917,013	$2.9700	$5,693,528	1,953,089	$0.7300	$1,425,755	1,458,786	$1.7100	$2,494,524	$3,920,279

Hydro One

	Network			Line Connection			Line Transformation			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
	Includes Hydro One Rate Rider B1.3 UTR's and Sub-Transmission Cell M48			Includes Hydro One Rate Rider B1.3 UTR's and Sub-Transmission Cell M50						
January	36,164	$2.6970	$ 97,534	36,168	$0.6150	$ 22,243	54,610	$1.5000	$ 81,915	$ 104,158
February	34,552	$2.6970	$ 93,187	34,584	$0.6150	$ 21,269	57,858	$1.5000	$ 86,787	$ 108,056
March	30,462	$2.6970	$ 82,156	30,634	$0.6150	$ 18,840	56,701	$1.5000	$ 85,051	$ 103,891
April	30,152	$2.6970	$ 81,320	30,192	$0.6150	$ 18,568	53,607	$1.5000	$ 80,411	$ 98,979
May	24,940	$2.6970	$ 67,263	25,013	$0.6150	$ 15,383	47,553	$1.5000	$ 71,330	$ 86,712
June	32,517	$2.6970	$ 87,698	32,561	$0.6150	$ 20,025	33,653	$1.5000	$ 50,480	$ 70,505
July	31,233	$2.6970	$ 84,235	31,260	$0.6150	$ 19,225	41,005	$1.5000	$ 61,508	$ 80,732
August	37,014	$2.6970	$ 99,826	37,060	$0.6150	$ 22,792	23,028	$1.5000	$ 34,542	$ 57,334
September	30,438	$2.6970	$ 82,091	30,438	$0.6150	$ 18,719	49,987	$1.5000	$ 74,981	$ 93,700
October	29,128	$2.6970	$ 78,558	44,223	$0.6150	$ 27,197	70,000	$1.5000	$ 105,000	$ 132,197
November	30,216	$2.6970	$ 81,493	30,216	$0.6150	$ 18,583	59,217	$1.5000	$ 88,826	$ 107,408
December	34,242	$2.6970	$ 92,351	34,348	$0.6150	$ 21,124	57,982	$1.5000	$ 86,973	$ 108,097
Total	381,058	$2.6970	$1,027,712	396,697	$0.6150	$ 243,969	605,201	$1.5000	$ 907,801	$1,151,770

Total

	Network			Line Connection			Line Transformation			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount

Name of LDC: Niagara Peninsula Energy Inc. - Niagara Falls
File Number: EB-2010-0138
Version : 1.0

Adjust RTSR-Network to Current Network Wholesale

The purpose of this sheet is to re-align current RTSR-Network to recover current wholesale Network costs.

Rate Class	Vol Metric	Current RTSR - Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount
		(A) Column H Sheet B1.1	(B) Column O Sheet B1.2	(C) Column I Sheet B1.2	(D) = (A) * (B) or (A) * (C)
Residential	kWh	$ 0.0053	418,909,828	0	$ 2,220,222
General Service Less Than 50 kW	kWh	$ 0.0048	135,972,259	0	$ 652,667
General Service 50 to 4,999 kW	kW	$ 1.9802	673,001,196	1,697,684	$ 3,361,754
Unmetered Scattered Load	kWh	$ 0.0048	2,162,394	0	$ 10,379
Sentinel Lighting	kW	$ 1.4661	457,703	699	$ 1,025
Street Lighting	kW	$ 1.4970	7,691,845	26,756	$ 40,054
			1,238,195,225	1,725,139	$ 6,286,101
					(E)

Name of LDC: Niagara Peninsula Energy Inc. - Niagara Falls
File Number: EB-2010-0138
Version : 1.0

Adjust RTSR-Connection to Forecast Connection Wholesale

The purpose of this sheet is to update re-aligned RTSR-Connection rates to recover forecast wholesale Connection costs.

Rate Class	Vol Metric	Adjusted RTSR - Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount
		(A) Column S Sheet D1.2	(B) Column O Sheet B1.2	(C) Column I Sheet B1.2	(D) = (A) * (B) or (A) * (C)
Residential	kWh	$ 0.0045	418,909,828	0	$ 1,870,769
General Service Less Than 50 kW	kWh	$ 0.0039	135,972,259	0	$ 531,322
General Service 50 to 4,999 kW	kW	$ 1.5483	673,001,196	1,697,684	$ 2,628,577
Unmetered Scattered Load	kWh	$ 0.0040	2,162,394	0	$ 8,651
Sentinel Lighting	kW	$ 1.2938	457,703	699	$ 904
Street Lighting	kW	$ 1.1895	7,691,845	26,756	$ 31,826
			1,238,195,225	1,725,139	$ 5,072,049
					(E)

Table of Contents

EXHIBIT 9 – DEFERRAL AND VARIANCE ACCOUNTS

Status of Deferral and Variance Accounts

This Schedule contains descriptions of the Deferral and Variance Accounts ("DVAs") used by NPEI in 2009, and the balances as at December 31, 2009. NPEI notes that the December 2009 balances as per the continuity schedule do not agree to the 2009 trial balance reported through the Electricity Reporting and Record Keeping Requirements ("RRR"). The differences largely relate to the 2008 balances approved for disposition in NPEI's 2010 IRM Rate Applications (EB-2009-0205 and EB-2009-0206). As per the Filing Requirements, reconciliation between the continuity schedule balances and the amounts reported in RRR 2.1.7 is included in Appendix B to this Exhibit. The Deferral and Variance Account Continuity Schedule is included in Appendix A.

Based on the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR) (EB-2008-0046), NPEI reports the Deferral and Variance accounts according to the two prescribed groupings:

Group 1 Accounts

1550 Retail Settlement Variance Account – Low Voltage Charges

This account is used to record the net of the amount charged by the host distributor to an embedded distributor for Low Voltage services and the amount billed to customers based on NPEI's approved LV rates. NPEI uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

This account is used to record the net of the amount charged by the Independent Electricity System Operator ("IESO") based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, and the amount billed to customers using the OEB-approved Wholesale Market Service Rate. NPEI uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission network services, and the amount billed to customers using the OEB-approved Transmission Network Charge. NPEI uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission connection services, and the amount billed to customers using the OEB-approved Transmission Connection Charge. NPEI uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1588 Retail Settlement Variance Account – Power

This account is used to recover the net difference between the energy amount billed to customers and the energy charge to NPEI using the settlement invoice from the IESO. NPEI uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1588 Retail Settlement Variance Account - Power, Sub-account Global Adjustment

This account is used to recover the net difference between the provincial benefit amount billed to customers and the global adjustment charge to NPEI using the settlement invoice from the IESO. NPEI uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1595 Disposition and Recovery of Regulatory Balances

This account is used to record the disposition and recoveries of deferral and variance account balances for electricity distributors receiving approval to recover (or refund) account balances as part of the regulatory process. The sub-account "Disposition of Account Balances Approved in 2010" captures amounts approved for recovery (or refund) through the 2010 rate review process. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

Group 2 Accounts

1508 Other Regulatory Assets - Sub-account Incremental Capital Charges

As per the Accounting Procedures Handbook ("APH"), USoA account 1508 shall include the amounts of regulatory-created assets, not included in other accounts, resulting from the ratemaking actions of the Board. As per the Accounting Procedures Handbook Frequently Asked Questions issued October 2009 (Question 18), the sub-account "Incremental Capital Charges" is used to record charges arising from an incremental capital module approved for Hydro One (EB-2008-0187) effective May 2009. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1508 Other Regulatory Assets - Sub-account IFRS Incremental Costs

As per the Accounting Procedures Handbook ("APH"), USoA account 1508 shall include the amounts of regulatory-created assets, not included in other accounts, resulting from the ratemaking actions of the Board. As per the Accounting Procedures Handbook Frequently Asked Questions issued October 2009 (Question 1), the sub-account "Deferred IFRS Transition Costs" is used to record one-time, administrative incremental costs relating to the transition to

International Financial Reporting Standards ("IFRS"). The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1518 Retail Cost Variance Account – Retail Service Charges

This account is used to record the net of revenues derived from retail services and the incremental costs of providing retail services other than those costs related to a Service Transition Request ("STR").

1548 Retail Cost Variance Account – Service Transaction Requests

This account is used to record the net of revenues derived from Service Transaction Request services and the incremental costs of providing the STR services.

1555 Smart Meter Capital and Recovery Offset Variance

This account records the net of the amounts paid for capitalized direct costs related to the smart meter program and the amounts charged to customers using the OEB-approved smart meter rate adder. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1556 Smart Meter OM&A Variance

This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

1562 Deferred Payments in Lieu of Taxes

Description: This account records the amount resulting from the OEB-approved PILs methodology for determining the 2001 deferral account allowance and the PILs proxy amount determined for 2002 and subsequent years.

1563 Contra Account-Deferred Payments in Lieu of Taxes

This account records the amount resulting from the OEB-approved PILs methodology using the third accounting method approved for recording entries in account 1562 in accordance with the Board's accounting instructions for PILs as set out in the April 2003 Frequently Asked Questions on the APH.

1565 Conservation and Demand Management Expenditures and Recoveries

Amounts recorded in this account track the costs incurred for conservation and demand management activities and expenditures, and the revenue proxy amount equivalent to the distributor's (first generation) third tranche of the market adjusted revenue requirement or an amount otherwise approved by the Board.

1566 Conservation and Demand Management Contra Account

This account shall be used to record the offsetting entry for amounts recorded in account 1565, Conservation and Demand Management Expenditures and Recoveries, for the reversal of entries to the accounts of original entries.

1582 Retail Settlement Variance Account - One-time Wholesale Market Service

This account is used to record the net of non-recurring amounts not included in the Wholesale Market Service Rate charged by the IESO based on the settlement invoice and the amount charged to customers for the same services using the OEB-approved rate. NPEI uses the accrual method and has used this method consistently over time for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

Account Balances

The following Table 9-1 contains the account balances as at December 2009:

Table 9-1 Deferral and Variance Account Balances as at December 31, 2009

Account Description	Account Number	Principal Balance as at Dec 2009	Interest Balance as at Dec 2009	December 2009 Total
Group 1 Accounts				
Low Voltage Account	1550	(465,376)	(1,251)	(466,626)
RSVA Wholesale Market Service Charge Account	1580	(422,914)	(44,579)	(467,493)
RSVA Retail Transmission Network Charges Account	1584	161,644	(11,604)	150,041
RSVA Retail Transmission Connection Charge Account	1586	(409,712)	(9,851)	(419,563)
RSVA Power (excluding Global Adjustment) Account	1588	(848,384)	7,875	(840,509)
RSVA Power - Sub-Account - Global Adjustment Account	1588	1,135,692	3,101	1,138,793
Disposition and Recovery of Regulatory Balances Account	1595	(9,651,750)	1,876,921	(7,774,829)
Group 1 Accounts Total		(10,500,800)	1,820,613	(8,680,187)
Group 2 Accounts				
Other Regulatory Assets Account- Sub-Account - HONI Incremental Capital	1508	4,141	7	4,148
Other Regulatory Assets Account- Sub-Account - IFRS Incremental Costs	1508	299	0	299
Retail Cost Variance Account - Retail	1518	463,917		463,917
Retail Cost Variance Account - STR	1548	343,178		343,178
Smart Meter Capital and Recovery Offset Variance Account	1555	943,245	(14,764)	928,481
Smart Meter OM&A Variance Account	1556	170,536	1,571	172,107
Deferred PILs Account	1562	(3,989,245)	(758,038)	(4,747,283)
Deferred PILs Contra Account	1563	3,989,245	(16,436)	3,972,809
CDM Expenditures and Recoveries Account	1565	(744,666)		(744,666)
CDM Contra Account	1566	744,666		744,666
RSVA - One-time Wholesale Market Service	1582	5,905	1,355	7,260
Group 2 Accounts Total		1,931,223	(786,305)	1,144,918
Deferral and Variance Accounts Total		**(8,569,577)**	**1,034,307**	**(7,535,270)**

Table 9-2 below shows the prescribed interest rates that were used to compute carrying charges, where applicable, on the deferral and variance account balances.

Table 9-2 Prescribed Interest Rates

Quarter by Year	Prescribed Interest Rate (%)
Q3 2010	0.89
Q2 2010	0.55
Q1 2010	0.55
Q4 2009	0.55
Q3 2009	0.55
Q2 2009	1.00
Q1 2009	2.45
Q4 2008	3.35
Q3 2008	3.35
Q2 2008	4.08
Q1 2008	5.14
Q4 2007	5.14
Q3 2007	4.59
Q2 2007	4.59
Q1 2007	4.59
Q4 2006	4.59
Q3 2006	4.59
Q2 2006	4.14
Q1 2006	7.25
Q4 2005	7.25
Q3 2005	7.25
Q2 2005	7.25
Q1 2005	7.25

NPEI received approval in its 2010 IRM Rate Applications (EB-2009-0205 and EB-2009-0206) to dispose of RSVA balances as at December 31, 2008 and projected interest to April 30, 2010. These approved amounts are included in account 1595 in Table 9-1.

Disposition of Deferral and Variance Accounts

In the EDDVAR Report (EB-2008-0046), the Board indicates that "at the time of rebasing, all Account balances should be reviewed and disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline."

NPEI is proposing to dispose of the December 31, 2009 balances in the following accounts, as well as projected interest to April 2011, where applicable:

Group 1:

- 1550 Low Voltage Account
- 1580 RSVA Wholesale Market Services Charge Account
- 1584 RSVA Retail Transmission Network Charges Account
- 1586 RSVA Retail Transmission Connection Charge Account
- 1588 RSVA Power (including Global Adjustment sub-account)

Group 2:

- 1508 Other Regulatory Assets – Sub-account Incremental Capital Charges
- 1518 RCVA Retail Account
- 1548 RCVA Service Transaction Account
- 1565 CDM Expenditures and Recovery Account
- 1566 CDM Contra Account
- 1582 Onetime Wholesale Market Service Account

The balances proposed for disposition include Group 1 account balances of ($915,526) and Group 2 balances of $818,624, for a total of ($96,902), as set out in Table 9-3 below:

Table 9-3 Balances Proposed for Disposition

Account Description	Account Number	Principal Balance as at Dec 2009	Interest Balance as at Dec 2009	Projected Interest to Dec 2010	Projected Interest to April 2011	Total for Disposition
Group 1 Accounts						
Low Voltage Account	1550	(465,376)	(1,251)	(3,711)	(1,862)	(472,199)
RSVA Wholesale Market Service Charge Account	1580	(422,914)	(44,579)	(3,373)	(1,692)	(472,557)
RSVA Retail Transmission Network Charges Account	1584	161,644	(11,604)	1,289	647	151,976
RSVA Retail Transmission Connection Charge Account	1586	(409,712)	(9,851)	(3,267)	(1,639)	(424,470)
RSVA Power (excluding Global Adjustment) Account	1588	(848,384)	7,875	(6,766)	(3,394)	(850,669)
RSVA Power - Sub-Account - Global Adjustment Account	1588	1,135,692	3,101	9,057	4,543	1,152,393
Group 1 Accounts Total		(849,050)	(56,308)	(6,771)	(3,396)	(915,526)
Group 2 Accounts						
Other Regulatory Assets Account- Sub-Account - HONI Incremental Capital	1508	4,141	7	33	17	4,198
Retail Cost Variance Account - Retail	1518	463,917				463,917
Retail Cost Variance Account - STR	1548	343,178				343,178
CDM Expenditures and Recoveries Account	1565	(744,666)				(744,666)
CDM Contra Account	1566	744,666				744,666
RSVA - One-time Wholesale Market Service	1582	5,905	1,355	47	24	7,330
Group 2 Accounts Total		817,142	1,362	80	40	818,624
Deferral and Variance Accounts Total		**(31,908)**	**(54,947)**	**(6,691)**	**(3,356)**	**(96,902)**

NPEI is proposing to not dispose of the balances in the following accounts at this time:

Group 2:

- 1508 Other Regulatory Assets – Sub-account IFRS Incremental Costs
- 1555 Smart Meter Capital and Recovery Offset Variance Account
- 1556 Smart Meter OM&A Variance Account
- 1562 Deferred PILs Account
- 1563 Deferred PILs Contra Account

In the following section, NPEI sets out the justification for its submission that the accounts listed above should not be disposed of at this time.

1595 Disposition and Recovery of Regulatory Balances Account

The only amounts that NPEI has included in account 1595 belong in the sub-account "Disposition of Account Balances Approved in 2010". This balance was approved for disposition in NPEI's 2010 IRM Rate Applications (EB-2009-0205 and EB-2009-0206) via rate riders that are in effect from May 1, 2010 to April 30, 2012. As such, the balance in this account is still being refunded to customers. Once the rate riders terminate, any residual balance remaining will be brought forward by NPEI for disposition in a subsequent rate application.

1508 Other Regulatory Assets – Sub-account IFRS Incremental Costs

As of December 31, 2009, NPEI had only incurred a very small amount of incremental costs associated with the transition to IFRS. At the present time, it appears that qualifying entities with rate-regulated activities may be permitted to postpone the adoption of IFRS until January 1, 2013. NPEI expects to incur additional incremental IFRS related costs during 2010 – 2012, and proposes that the entire balance, including the small 2009 amount, be submitted for disposition at a later date.

1555 Smart Meter Capital and Recovery Offset Variance Account

1556 Smart Meter OM&A Variance Account

NPEI is proposing that the balances in 1555 and 1556 not be disposed of at this time. However, NPEI is requesting that an amount of $4,175,010 be approved for inclusion in rate base in 2011. This amount represents NPEI's capital expenditures only, up to June 30, 2010. This balance has been audited, and the Auditor's report is included as Appendix C to this Exhibit. NPEI anticipates that all of its smart meters will be installed by the fall of 2010, and expects to commence time-of-use ("TOU") billing in late 2011. NPEI requests that the smart meter funding adder of $1.00 per month be continued. Once NPEI's smart meter installation and transition to TOU billing is complete, and the full amount of all of capital and OM&A costs known, NPEI will file a subsequent application to propose disposition of all remaining items included in 1555 and 1556. The Smart Meter section below provides further details on NPEI's proposed smart meter treatment.

1562 Deferred PILs Account

1563 Deferred PILs Contra Account

NPEI submits that the disposition of the balances in 1562 and 1563 is not appropriate at this time until the outcome of the Board's proceeding EB-2008-0381 "PILs Combined Proceeding regarding Account 1562, Deferred Payment in Lieu of Taxes ("PILS")" is known.

The following accounts will be discontinued if approved for disposition:

- 1565 CDM Expenditures and Recovery Account
- 1566 CDM Contra Account

Proposed Methodology for Disposition

The EDDVAR Report specifies:

a) The Board believes that a cost allocation methodology should apply to all electricity distributors. The default cost allocation methodology will be based on the allocation factors determined in the Board's combined Decision for Recovery of Regulatory Assets – Phase 2 Decision dated December 9, 2004.

b) The Board is of the view that volumetric rate riders should be used to dispose of the Account balances, consistent with its findings in the Phase 2 Decision. The Board is also of the view that the default disposition period used to clear the Account balances through a rate rider should be one year.

With respect to a) above, NPEI confirms that the default cost allocation methodology has been used to derive the proposed rate riders. In particular, NPEI has used the following allocators:

- kWh for accounts 1550 LV, 1580 RSVA Wholesale Market Services, 1584 RSVA Network, 1586 RSVA Connection, 1588 RSVA Power (Excluding Global Adjustment) and 1582 RSVA One-time Wholesale Market Services.

- Non-RPP kWh for 1588 RSVA Power Global Adjustment sub-account.

- Distribution Revenue for 1508 Other Regulatory Assets – Sub-account Incremental Capital

- Number of Customers for 1518 RCVA Retail and 1548 RCVA STR.

Regarding b) above, NPEI agrees that volumetric rate riders over a one year period are appropriate to dispose of the proposed balances.

In allocating the account balances to the rate classes based on the allocators listed above, NPEI has used actual 2009 data for allocators, as given in Table 9-4 below.

Table 9-4 2009 Data for Deferral and Variance Account Allocation

Rate Class	Billed kWh	Billed kW	Billed kWh to Non-RPP Customers	Customer Counts	Distribution Revenue
Residential	396,244,635	-	61,080,512	45,167	13,491,773
General Service < 50 kW	128,615,455	-	20,771,188	4,389	3,365,595
General Service > 50 kW	636,588,343	1,697,684	546,705,425	847	8,581,980
Sentinel Lights	432,939	-	168,213	157	6,643
Streetlighting	7,275,676	26,756	874,674	4	67,318
Unmetered and Scattered	2,045,397	699	984,170	152	119,866
Total	1,171,202,445	1,725,139	630,584,182	50,716	25,633,175

The resulting allocations are given below in Table 9-5.

Table 9-5 Allocations by Rate Class

Rate Class	Billed kWh	Billed kW	Billed kWh to Non-RPP Customers	Customer Counts	Distribution Revenue
Residential	33.8%	0.0%	9.7%	89.06%	52.6%
General Service < 50 kW	11.0%	0.0%	3.3%	8.65%	13.1%
General Service > 50 kW	54.4%	98.4%	86.7%	1.67%	33.5%
Sentinel Lights	0.0%	0.0%	0.0%	0.31%	0.0%
Streetlighting	0.6%	1.6%	0.1%	0.01%	0.3%
Unmetered and Scattered	0.2%	0.0%	0.2%	0.30%	0.5%
Total	100.0%	100.0%	100.0%	100.00%	100.0%

Applying the allocations given in Table 9-5 to the proposed balances for disposition given in Table 9-3 gives the dollar amounts to be collected from each rate class. These amounts are set out in Table 9-6 (all accounts excluding Global Adjustment) and Table 9-7 (Global Adjustment) below:

Table 9-6 Balance Allocations (Excluding Global Adjustment)

USoA Account Number	Deferral and Variance Accounts (Excluding Global Adjustment Sub-Account)	Balance for Disposition	Residential	GS < 50 kW	GS > 50 kW	Sentinel Lights	Streetlighting	Unmetered and Scattered	Total
Group 1 Accounts									
1550	Low Voltage Account	$ (472,199)	$ (159,756)	$ (51,855)	$ (256,656)	$ (175)	$ (2,933)	$ (825)	$ (472,199)
1580	RSVA - Wholesale Market Service Charge	$ (472,557)	$ (159,877)	$ (51,894)	$ (256,851)	$ (175)	$ (2,936)	$ (825)	$ (472,557)
1584	RSVA - Retail Transmission Network Charge	$ 151,976	$ 51,417	$ 16,689	$ 82,604	$ 56	$ 944	$ 265	$ 151,976
1586	RSVA - Retail Transmission Connection Charge	$ (424,470)	$ (143,608)	$ (46,613)	$ (230,714)	$ (157)	$ (2,637)	$ (741)	$ (424,470)
1588	RSVA - Power (excluding Global Adjustment)	$ (850,669)	$ (287,801)	$ (93,416)	$ (462,367)	$ (314)	$ (5,284)	$ (1,486)	$ (850,669)
	Subtotal - Group 1 Accounts	$ (2,067,919)	$ (699,624)	$ (227,088)	$ (1,123,984)	$ (764)	$ (12,846)	$ (3,611)	$ (2,067,919)
Group 2 Accounts									
1508	Other Regulatory Assets - HONI Incremental Capital Charge	$ 4,198	$ 2,210	$ 551	$ 1,406	$ 1	$ 11	$ 20	$ 4,198
1518	Retail Cost Variance Account - Retail	$ 463,917	$ 413,158	$ 40,148	$ 7,748	$ 1,436	$ 37	$ 1,390	$ 463,917
1548	Retail Cost Variance Account - STR	$ 343,178	$ 305,630	$ 29,699	$ 5,731	$ 1,062	$ 27	$ 1,029	$ 343,178
1582	RSVA - One-time Wholesale Market Service	$ 7,330	$ 2,480	$ 805	$ 3,984	$ 3	$ 46	$ 13	$ 7,330
	Subtotal - Group 2 Accounts	$ 818,623	$ 723,478	$ 71,203	$ 18,869	$ 2,502	$ 120	$ 2,451	$ 818,623
	Total for Disposition	$ (1,249,295)	$ 23,854	$ (155,885)	$ (1,105,115)	$ 1,738	$ (12,726)	$ (1,160)	$ (1,249,295)
	Balance to be collected or refunded per year	**$ (1,249,295)**	**$ 23,854**	**$ (155,885)**	**$ (1,105,115)**	**$ 1,738**	**$ (12,726)**	**$ (1,160)**	**$ (1,249,295)**

Table 9-7 Balance Allocation for Global Adjustment

USoA Account Number	Deferral and Variance Accounts (Global Adjustment Sub-Account)	Balance for Disposition	Residential	GS < 50 kW	GS > 50 kW	Sentinel Lights	Streetlighting	Unmetered and Scattered	Total
Group 1 Accounts									
1588	RSVA - Power (Global Adjustment Sub-Account)	$ 1,152,393	$ 111,625	$ 37,959	$ 999,104	$ 307	$ 1,598	$ 1,799	$ 1,152,393
	Subtotal - Group 1 Accounts	$ 1,152,393	$ 111,625	$ 37,959	$ 999,104	$ 307	$ 1,598	$ 1,799	$ 1,152,393
	Total for Disposition	$ 1,152,393	$ 111,625	$ 37,959	$ 999,104	$ 307	$ 1,598	$ 1,799	$ 1,152,393
	Balance to be collected or refunded per year	**$ 1,152,393**	**$ 111,625**	**$ 37,959**	**$ 999,104**	**$ 307**	**$ 1,598**	**$ 1,799**	**$ 1,152,393**

Table 9-8 below shows the total dollars to be collected or refunded to each rate class.

Table 9-8 Total Balance Allocations

USoA Account Number	Deferral and Variance Accounts (Excluding Global Adjustment Sub-Account)	Balance for Disposition	Residential	GS < 50 kW	GS > 50 kW	Sentinel Lights	Streetlighting	Unmetered and Scattered	Total
Group 1 Accounts									
1550	Low Voltage Account	$ (472,199)	$ (159,756)	$ (51,855)	$ (256,656)	$ (175)	$ (2,933)	$ (825)	$ (472,199)
1580	RSVA - Wholesale Market Service Charge	$ (472,557)	$ (159,877)	$ (51,894)	$ (256,851)	$ (175)	$ (2,936)	$ (825)	$ (472,557)
1584	RSVA - Retail Transmission Network Charge	$ 151,976	$ 51,417	$ 16,689	$ 82,604	$ 56	$ 944	$ 265	$ 151,976
1586	RSVA - Retail Transmission Connection Charge	$ (424,470)	$ (143,608)	$ (46,613)	$ (230,714)	$ (157)	$ (2,637)	$ (741)	$ (424,470)
1588	RSVA - Power (excluding Global Adjustment)	$ (850,669)	$ (287,801)	$ (93,416)	$ (462,367)	$ (314)	$ (5,284)	$ (1,486)	$ (850,669)
1588	RSVA - Power (Global Adjustment Sub-Account)	$ 1,152,393	$ 111,625	$ 37,959	$ 999,104	$ 307	$ 1,598	$ 1,799	$ 1,152,393
	Subtotal - Group 1 Accounts	$ (915,526)	$ (588,000)	$ (189,129)	$ (124,880)	$ (457)	$ (11,248)	$ (1,813)	$ (915,526)
Group 2 Accounts									
1508	Other Regulatory Assets - HONI Incremental Capital Charge	$ 4,198	$ 2,210	$ 551	$ 1,406	$ 1	$ 11	$ 20	$ 4,198
1518	Retail Cost Variance Account - Retail	$ 463,917	$ 413,158	$ 40,148	$ 7,748	$ 1,436	$ 37	$ 1,390	$ 463,917
1548	Retail Cost Variance Account - STR	$ 343,178	$ 305,630	$ 29,699	$ 5,731	$ 1,062	$ 27	$ 1,029	$ 343,178
1582	RSVA - One-time Wholesale Market Service	$ 7,330	$ 2,480	$ 805	$ 3,984	$ 3	$ 46	$ 13	$ 7,330
	Subtotal - Group 2 Accounts	$ 818,623	$ 723,478	$ 71,203	$ 18,869	$ 2,502	$ 120	$ 2,451	$ 818,623
	Total for Disposition	$ (96,902)	$ 135,478	$ (117,926)	$ (106,011)	$ 2,045	$ (11,128)	$ 639	$ (96,902)
	Balance to be collected or refunded per year	**$ (96,902)**	**$ 135,478**	**$ (117,926)**	**$ (106,011)**	**$ 2,045**	**$ (11,128)**	**$ 639**	**$ (96,902)**

In order to calculate the proposed rate riders, the balances that are allocated to each rate class are divided by the appropriate forecast 2011 volumemetric, kWh or kW. The forecast 2011 billing determinants used to derive the rate riders are given in Table 9-9.

Table 9-9 2011 Forecast Billing Determinants

Rate Class	Forecast Billed kWh	Forecast Billed kW	Forecast Billed kWh for Non-RPP Customers	Forecast Billed kW for Non-RPP Customers
Residential	459,406,923	-	70,816,883	-
General Service < 50 kW	121,437,543	-	19,611,967	-
General Service > 50 kW	623,806,670	1,806,009	535,728,457	1,551,010
Sentinel Lights	292,817	809	113,770	314
Streetlighting	7,467,591	20,107	897,746	2,417
Unmetered and Scattered	2,335,428	-	1,123,722	-
Total	1,214,746,971	1,826,926	628,292,545	1,553,742

The resulting rate riders are set out in Table 9-10 below.

Table 9-10 Proposed Rate Riders

Class	Residential	GS < 50 kW	GS > 50 kW	Sentinel Lights	Streetlighting	Unmetered and Scattered
Deferral/Variance Account Rate Riders	$ 0.0001	$ (0.0013)	$ (0.6119)	$ 2.1482	$ (0.6329)	$ (0.0005)
Global Adjustment Rate Rider (applies to Non-RPP customers)	$ 0.0016	$ 0.0019	$ 0.6442	$ 0.9780	$ 0.6613	$ 0.0016
Billing Determinants	kWh	kWh	kW	kW	kW	kWh

NPEI notes that, in its 2010 IRM Rate Applications the Board approved Deferral and Variance account and Global Adjustment rate riders for Niagara Falls (EB-2009-0205) and Peninsula West (EB-2009-0206). These rate riders were approved for a two year period from May 1, 2010 to April 30, 2012. If the rate riders submitted in the current COS application are approved, NPEI will then have two sets of rate riders in effect for the 2011 rate year. A summary of the approved and proposed riders is given below for Niagara Falls (Table 9-11) and Peninsula West (Table 9-12).

Table 9-11 Total of Rate Riders in Effect for 2011 – Niagara Falls

Type	Customer Class	Volume Metric	Approved in 2010 IRM Application EB-2009-0205	Applied for in 2011 COS Application EB-2010-0138	Total Rate Rider for 2011
Deferral / Variance Account	Residential	kWh	(0.0028)	0.0001	(0.0027)
	GS < 50 kW	kWh	(0.0027)	(0.0013)	(0.0040)
	GS > 50 kW	kW	(1.1600)	(0.6119)	(1.7719)
	Sentinel Lights	kW	(1.2973)	2.1482	0.8509
	Streetlighting	kW	(0.5038)	(0.6329)	(1.1367)
	Unmetered and Scattered	kWh	(0.0027)	(0.0005)	(0.0032)
Global Adjustment	Residential	kWh	0.0011	0.0016	0.0027
	GS < 50 kW	kWh	0.0011	0.0019	0.0030
	GS > 50 kW	kW	0.4244	0.6442	1.0686
	Sentinel Lights	kW	0.3939	0.9780	1.3719
	Streetlighting	kW	0.0000	0.6613	0.6613
	Unmetered and Scattered	kWh	0.0011	0.0016	0.0027

Table 9-12 Total of Rate Riders in Effect for 2011 – Peninsula West

Type	Customer Class	Volume Metric	Approved in 2010 IRM Application EB-2009-0206	Applied for in 2011 COS Application EB-2010-0138	Total Rate Rider for 2011
Deferral / Variance Account	Residential	kWh	(0.0064)	0.0001	(0.0063)
	GS < 50 kW	kWh	(0.0065)	(0.0013)	(0.0078)
	GS > 50 kW	kW	(1.9651)	(0.6119)	(2.5770)
	Sentinel Lights	kW	(2.2732)	2.1482	(0.1250)
	Streetlighting	kW	(2.1909)	(0.6329)	(2.8238)
	Unmetered and Scattered	kWh	(0.0064)	(0.0005)	(0.0069)
Global Adjustment	Residential	kWh	0.0007	0.0016	0.0023
	GS < 50 kW	kWh	0.0007	0.0019	0.0026
	GS > 50 kW	kW	0.3116	0.6442	0.9558
	Sentinel Lights	kW	0.2799	0.9780	1.2579
	Streetlighting	kW	0.0000	0.6613	0.6613
	Unmetered and Scattered	kWh	0.0010	0.0016	0.0026

The proposed rate riders and bill impacts that result from the disposal of the balances, as requested, are set out in Table 9-13 (for Niagara Falls customers) and Table 9-14 (for Peninsula West customers) below.

Table 9-13 Bill Impacts of Proposed Rate Riders – Niagara Falls

Customer Class	Average Monthly Billing Determinants	Volume Metric	Proposed Deferral / Variance Rate Rider	Impact of Proposed Deferral / Variance Rider on Total Bill	Proposed GA Rate Rider	Impact of Proposed GA Rider on Total Bill
Residential	800	kWh	0.0001	0.07%	0.0016	1.04%
GS < 50 kW	2,000	kWh	(0.0013)	-0.87%	0.0019	1.07%
GS > 50 kW	180	kW	(0.6119)	-1.48%	0.6442	1.56%
Sentinel Lights	0.12	kW	2.1482	1.83%	0.9780	0.83%
Streetlighting	0.13	kW	(0.6329)	-1.38%	0.6613	1.45%
Unmetered and Scattered	250	kWh	(0.0005)	-0.24%	0.0016	0.76%

Table 9-14 Bill Impacts of Proposed Rate Riders – Peninsula West

Customer Class	Average Monthly Billing Determinants	Volume Metric	Proposed Deferral / Variance Rate Rider	Impact of Proposed Deferral / Variance Rider on Total Bill	Proposed GA Rate Rider	Impact of Proposed GA Rider on Total Bill
Residential - Urban	800	kWh	0.0001	0.07%	0.0016	1.08%
Residential - Suburban	800	kWh	0.0001	0.07%	0.0016	1.08%
GS < 50 kW	2,000	kWh	(0.0013)	-0.89%	0.0019	1.30%
GS > 50 kW	175	kW	(0.6119)	-1.69%	0.6442	1.78%
Sentinel Lights	0.12	kW	2.1482	1.84%	0.9780	0.84%
Streetlighting	0.14	kW	(0.6329)	-1.43%	0.6613	1.50%
Unmetered and Scattered	250	kWh	(0.0005)	-0.24%	0.0016	0.78%

Smart Meters

In 2008, NPEI became authorized by regulation (O. Reg. 427/06) to conduct Smart Meter activities, conditional on its meters being acquired pursuant to and in compliance with the Request for Proposal issued by London Hydro Inc. NPEI is now an active distributor for the purposes of Smart Meter installations and expects to install all of its Smart Meters by the end of 2010 and to commence TOU billing in late 2011.

The following Table 9-15 (Appendix 2-R of the Filing Requirements) summarizes NPEI's Smart Meter activities by year:

Table 9-15 Smart Meter Summary

Year	Smart Meters Installed		Percentage of Applicable Customers Converted	Account 1555			Account 1556	Carrying Charges	Total
	Residential	GS<50 kW		Funding Adder Revenues Collected	Capital Expenditures	Stranded Meters	Operating Expenses		
2006				(87,708)	83,849	-	9,609	(98)	5,653
2007				(159,738)	13,967	-	12,141	(2,764)	(136,394)
2008				(160,790)	-	-	-	(7,690)	(168,480)
2009	5,217		12%	(427,293)	1,450,196	230,762	148,786	(2,641)	1,399,810
2010, to June 30	26,757	1,251	63%	(316,654)	2,626,997	958,531	45,260	1,459	3,315,594
Cumulative, to June 30, 2010	31,974	1,251	74%	(1,152,183)	4,175,010	1,189,293	215,797	(11,734)	4,416,182

Total to be Installed 44,679

As indicated in Table 9-15, NPEI had converted 12% of its target customers to smart meters by the end of 2009, and attained a further 63% in the first half of 2010, resulting in 74% installation achieved by June 30, 2010.

NPEI is requesting that the amount of capital expenditures incurred to June 30, 2010 be approved for inclusion in rate base in 2011. The amount for which NPEI is seeking approval is $4,175,010. This balance has been audited, and the Auditor's report is included as Appendix C to this Exhibit. Accordingly, NPEI has included the amount of $4,175,010 as an addition to account 1860 in the 2010 fixed asset continuity schedule contained in Exhibit 2. If approved, this will result in the revenue requirement associated with these expenditures being recovered in rates from 2011 forward.

The capital amount of $4,175,010 represents the costs of 33,225 meters that were installed on customers' premises as at June 30, 2010, and 10,996 meters that were received into inventory at June 30, 2010, awaiting installation. Table 9-16 below breaks out the capital amounts of meters that were installed and those in inventory. As Table 9-16 indicates, the resulting capital cost per meter installed is $100.07. This cost per meter does not include any OM&A expense.

Table 9-16 Smart Meter Capital Cost per Meter

Reference	Description	Count	Cost	Cost/Meter	Comment
A	Total number of meters purchased to June 30, 2010	44,221			Total number of meters from all invoices that support audited capital balance.
B	Number of meters installed to June 30, 2010	33,225			Per Table 9.15
C	Balance of meters, in inventory at June 30, 2010	10,996			C = A - B
D	Cost of meters in inventory, at purchase cost of $77.30 per meter		-		D = C * Purchase Price of $77.30
E	Total amount of Smart Meter capital costs to June 30, 2010		4,175,010		Audited balance
F	Remove cost of meters in inventory		-		
G	Balance, capital costs of meters installed		4,175,010		G = E - F
H	Total capital cost per installed meter			125.66	J = G / B

NPEI is also requesting that the $1.00 per month smart meter funding adder that was approved in the 2010 IRM Rate Applications (EB-2009-0205 and EB-2009-0206) be continued in 2011. Once NPEI's smart meter installation and transition to TOU billing is complete, and the full amount of all of capital and OM&A costs known, NPEI will file a subsequent application to propose disposition of all remaining items included in 1555 and 1556, including:

- The revenue requirement up to Dec 31, 2010 on the capital expenditure amount if $4,175,010.
- The revenue requirement on any additional capital expenditures.
- All smart meter OM&A expenses and appropriate revenue requirement.
- Amounts recovered through the approved smart meter funding adders.
- Stranded meters, net of scrap proceeds.
- Carrying charges.

Recovery of Late Payment Penalty Litigation Costs

1. As part of this application, Niagara Peninsula Energy Inc. will be not seeking recovery of a onetime expense in the amount of $168,220 which is expected to be paid on June 30, 2011. If this payment is made, it will serve to resolve long-standing litigation against all former municipal electric utilities ("MEUs") in the Province in relation to late payment penalty ("LPP") charges collected pursuant to, first, Ontario Hydro rate schedules and, after industry restructuring, Ontario Energy Board rate orders (the "LPP Class Action").

2. On July 22, 2010, The Honourable Mr. Justice Cumming of the Ontario Superior Court of Justice approved a settlement of the LPP Class Action, the principal terms of which are the following:
    a) Former MEUs collectively pay $17 million in damages;
    b) Payment is not due until June 30, 2011; and
    c) Amounts paid, after deduction for class counsel fee, will be paid to the Winter Warmth Fund or similar charities.

3. Subject to any appeal and the right of the LDCs to terminate the settlement if more than 10,000 plaintiff class members opt out of the settlement, NPEI will make a payment of $168,220 by June 30, 2011. This amount represents NPEI's share of the settlement, applicable taxes and legal fees. NPEI believes that the settlement is in its best interest and the best interest of its customers and that the payment in connection with the settlement will be a prudent one.

4. The LDCs propose that, following expiry of applicable appeal and opt out periods (the "Date of Final Determination")[1], the Board hold a generic hearing to determine if the costs incurred in this litigation and settlement are recoverable

[1] The Date of Final Determination falls on the 30th day after the plaintiff opt out notice is published in *The Globe and Mail*, which will occur after the expiry of the appeal period. The Date of Final Determination is expected to occur on September 22, 2010.

from customers and, if so, the form and timing of recovery from customers. If the Board agrees to hold this generic hearing, the LDCs will collectively file written evidence to address the prudence of the settlement, the costs incurred, the methodology of allocating total settlement costs amongst the LDCs, the proposed method of recovery, and any other matters the Board determines appropriate.

5. If the Board determines that it will not hold a generic proceeding, NPEI asks to be advised of this fact by the Date of Final Determination so that it can file, to permit adjudication as part of this proceeding, written evidence to address the prudence of the settlement, the costs incurred, the methodology of allocating total settlement costs amongst the LDCs, the proposed method and timing of recovery, and any other matters the Board determines appropriate.

APPENDIX A- Regulatory Asset Continuity Schedule

SHEET 1 - Regulatory Assets - Continuity Schedule

If account balances have been disposed in a previous application, for applicable accounts, fill out the Continuity Schedule from the date of last disposition.

Account Description	Account Number	2005 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, 2A]	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
Group 1 Accounts										
Low Voltage Account	1550	$ -					$ -			$ -
RSVA - Wholesale Market Service Charge	1580	$ 2,903,497	$ 1,243,090				$ 4,146,587	$ 321,171	$ 331,165	$ 652,336
RSVA - Retail Transmission Network Charge	1584	$ 216,963	$ (111,459)				$ 105,504	$ 74,299	$ (7,354)	$ 66,945
RSVA - Retail Transmission Connection Charge	1586	$ (1,243,045)	$ 396,018				$ (847,027)	$ 41,312	$ (229,402)	$ (188,090)
RSVA - Power (excluding Global Adjustment)	1588	$ (3,327,387)	$ 6,907,094				$ 3,579,707	$ (194,978)	$ 188,422	$ (6,556)
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -	$ (6,128,274)				$ (6,128,274)	$ -	$ (82,683)	$ (82,683)
Recovery of Regulatory Asset Balances	1590	$ (2,308,829)	$ (1,567,433)				$ (3,876,263)	$ 1,083	$ (34,076)	$ (32,992)
Disposition and Recovery of Regulatory Balances[10]	1595						$ -			$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ (3,758,802)	$ 739,036		$ -	$ -	$ (3,019,766)	$ 242,887	$ 166,071	$ 408,959
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ (3,758,802)	$ 6,867,310		$ -	$ -	$ 3,108,508	$ 242,887	$ 248,754	$ 491,642
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ (6,128,274)		$ -	$ -	$ (6,128,274)	$ -	$ (82,683)	$ (82,683)
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 115,866	$ 164,581	$ (21,155)			$ 259,292	$ 2,373	$ 11,310	$ 13,682
Other Regulatory Assets - Sub-Account - Pension Contributions	1508						$ -			$ -
Other Regulatory Assets - Sub-Account Deferred IFRS Transition Cos	1508						$ -			$ -
Other Regulatory Assets - Sub-Account - HONI Incremental Capital	1508	$ 1,719,777	$ -	$ (1,719,777)			$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508						$ -			$ -
Retail Cost Variance Account - Retail	1518	$ 542,160	$ 135,174	$ (15,067)			$ 662,267			$ -
Retail Cost Variance Account - STR	1548	$ 313,916	$ 74,920	$ (267)			$ 388,569			$ -
Misc. Deferred Debits	1525	$ 54,558	$ 233,894	$ (123,650)			$ 164,803	$ -	$ 5,651	$ 5,651
LV Variance Account	1550						$ -			$ -
Renewable Connection Capital Deferral Account	1531									
Renewable Connection OM&A Deferral Account	1532									
Smart Grid Capital Deferral Account	1534									
Smart Grid OM&A Deferral Account	1535									
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Ca	1555	$ -	$ -	$ -			$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Re	1555	$ -	$ -	$ -			$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - St	1555	$ -	$ -	$ -			$ -	$ -	$ -	$ -
Smart Meter OM&A Variance	1556	$ -	$ -	$ -			$ -			$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ -	$ 287,779	$ (1,276,574)			$ (988,795)	$ -	$ (11,375)	$ (11,375)
CDM Contra	1566	$ -	$ 397,492	$ (35,549)			$ 361,943	$ -	$ -	$ -
Qualifying Transition Costs [5]	1570	$ 1,943,272	n/a	n/a		$ 45,992	$ 1,989,265	$ 244,593	$ 112,633	$ 357,227
Pre-Market Opening Energy Variances Total [5]	1571	$ 3,755,720	n/a	n/a		$ 245,160	$ 4,000,880	$ 690,978	$ 398,336	$ 1,089,313
Extra-Ordinary Event Costs	1572	$ 228,632	$ 539,216	$ (767,848)			$ -	$ -	$ -	$ -
Deferred Rate Impact Amounts	1574						$ -			$ -
RSVA - One-time Wholesale Market Service	1582	$ 58,583	$ 5,905				$ 64,488	$ -	$ 8,428	$ 8,428
Other Deferred Credits	2425						$ -			$ -
Group 2 Sub-Total		$ 8,732,485	$ 1,838,960	$ (3,959,887)	$ -	$ 291,152	$ 6,902,711	$ 937,944	$ 524,984	$ 1,462,927
Deferred Payments in Lieu of Taxes	1562					**see PILs reconciliation requested**				
2006 PILs & Taxes Variance	1592					**see PILs reconciliation requested**				
Sub-total						**see PILs reconciliation requested**				
Total		$ 4,973,683	$ 2,577,996	$ (3,959,887)	$ -	$ 291,152	$ 3,882,944	$ 1,180,831	$ 691,055	$ 1,871,886
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [8]	1563					**see PILs reconciliation requested**				
Disposition and Recovery of Regulatory Balances[10]	1595									

F:\Accounting\2011 Rate Application\2011 Rate App documents\Exhibit 9\[Continuity_Schedule_EDDVAR.XLS]Continuity Schedu

Completed versions of the Regulatory Assets Continuty Schedule are required to be filed in working Microsoft Excel format.

Carrying Charge Rates for Projected Interest:

Jan 1, 2010 to June 30, 2010	0.55%
July 1, 2010 to Sept 30, 2010	0.89%
Oct 1, 2010 to Dec 31, 2010	1.20%
Jan 1, 2011 to April 30, 2011	1.20%

[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.
[2A] Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1595 per disposition of account balances as ordered by the Board.
[3] Provide supporting statement indicating nature of this adjustments and periods they relate to
[4] Not included in sub-total
[5] Closed April 30, 2002
[6] For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
[7] Please describe "other" components of 1508 and add more component lines if necessary.
[8] 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.
[9] Interest projected on December 31, 2009 closing principal balance.
[10] Include Account 1595 as part of Group 1 accounts (line 26) for review and disposition if the recovery (or refund) period has been completed, and the audited financial statements

support the underlying residual balance in account 1595. If the recovery (or refund) period has not been completed, include the balances in Account 1595 on a memo basis only (

SHEET 1 - Regulatory Assets - Continuity Schedule

Account Description	Account Number	2006										
		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, 2A]**	**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**
Group 1 Accounts												
Low Voltage Account	1550	$ -	$ 43,014					$ 43,014	$ -	$ 194		$ 194
RSVA - Wholesale Market Service Charge	1580	$ 4,146,587	$ (1,342,980)				$ (2,903,496)	$ (99,889)	$ 652,336	$ 207,692	$ (689,309)	$ 170,719
RSVA - Retail Transmission Network Charge	1584	$ 105,504	$ (187,373)				$ (131,390)	$ (213,260)	$ 66,945	$ 640	$ (74,689)	$ (7,104)
RSVA - Retail Transmission Connection Charge	1586	$ (847,027)	$ 1,649,227				$ (1,554,753)	$ (752,553)	$ (188,090)	$ (13,103)	$ 199,785	$ (1,408)
RSVA - Power (excluding Global Adjustment)	1588	$ 3,579,707	$ (5,529,293)				$ 3,327,387	$ 1,377,801	$ (6,556)	$ 241,664	$ 375,306	$ 610,414
RSVA - Power - Sub-Account - Global Adjustment	1588	$ (6,128,274)	$ 3,977,721					$ (2,150,553)	$ (82,683)	$ (216,330)		$ (299,013)
Recovery of Regulatory Asset Balances	1590	$ (3,876,263)	$ (2,474,436)				$ 8,351,673	$ 2,000,974	$ (32,992)	$ (74,168)	$ 1,846,789	$ 1,739,628
Disposition and Recovery of Regulatory Balances[10]	1595	$ -						$ -	$ -			$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ (3,019,766)	$ (3,864,119)		$ -	$ -	$ 7,089,421	$ 205,536	$ 408,959	$ 146,591	$ 1,657,882	$ 2,213,431
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ 3,108,508	$ (7,841,840)		$ -	$ -	$ 7,089,421	$ 2,356,088	$ 491,642	$ 362,921	$ 1,657,882	$ 2,512,444
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ (6,128,274)	$ 3,977,721		$ -	$ -	$ -	$ (2,150,553)	$ (82,683)	$ (216,330)	$ -	$ (299,013)
Group 2 Accounts												
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 259,292	$ 55,670	$ (43,062)			$ (224,082)	$ 47,818	$ 13,682	$ 12,641	$ (11,786)	$ 14,537
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account Deferred IFRS Transition Cos	1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - HONI Incremental Capital	1508	$ -						$ -	$ -			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -						$ -	$ -			$ -
Retail Cost Variance Account - Retail	1518	$ 662,267	$ 141,609	$ (22,022)			$ (542,160)	$ 239,694	$ -	$ (375)	$ (1,663)	$ (2,038)
Retail Cost Variance Account - STR	1548	$ 388,569	$ 84,214	$ (1,821)			$ (313,915)	$ 157,048	$ -	$ 937	$ (5,284)	$ (4,347)
Misc. Deferred Debits	1525	$ 164,803	$ 2,666	$ (1,224)			$ (143,140)	$ 23,104	$ 5,651	$ 2,376	$ (6,524)	$ 1,503
LV Variance Account	1550	$ -						$ -	$ -			$ -
Renewable Connection Capital Deferral Account	1531											
Renewable Connection OM&A Deferral Account	1532											
Smart Grid Capital Deferral Account	1534											
Smart Grid OM&A Deferral Account	1535											
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Ca	1555	$ -	$ 173,762	$ (89,913)				$ 83,849	$ -	$ (292)		$ (292)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Re	1555	$ -	$ 32,417	$ (120,124)				$ (87,708)	$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - St	1555	$ -	$ -	$ -				$ -	$ -	$ -		$ -
Smart Meter OM&A Variance	1556	$ -	$ 9,609	$ -				$ 9,609	$ -	$ 195		$ 195
Conservation and Demand Management Expenditures and Recoveries	1565	$ (988,795)	$ 198,892	$ (524,668)				$ (1,314,571)	$ (11,375)	$ 11,375		$ -
CDM Contra	1566	$ 361,943	$ 285,546	$ (12,232)				$ 635,257	$ -			$ -
Qualifying Transition Costs [5]	1570	$ 1,989,265	n/a	n/a		$ (182,603)	$ (1,806,661)	$ 0	$ 357,227	$ 14,368	$ (345,613)	$ 25,982
Pre-Market Opening Energy Variances Total [5]	1571	$ 4,000,880	n/a	n/a			$ (4,000,879)	$ 0	$ 1,089,313	$ 79,117	$ (1,277,421)	$ (108,991)
Extra-Ordinary Event Costs	1572	$ -						$ -	$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
RSVA - One-time Wholesale Market Service	1582	$ 64,488	$ -				$ (58,583)	$ 5,905	$ 8,428	$ 3,483	$ (9,591)	$ 2,321
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Group 2 Sub-Total		$ 6,902,711	$ 984,386	$ (815,066)	$ -	$ (182,603)	$ (7,089,421)	$ (199,993)	$ 1,462,927	$ 123,824	$ (1,657,882)	$ (71,130)
Deferred Payments in Lieu of Taxes	1562						**see PILs reconciliation requested**					
2006 PILs & Taxes Variance	1592						**see PILs reconciliation requested**					
Sub-total							**see PILs reconciliation requested**					
Total		$ 3,882,944	$ (2,879,733)	$ (815,066)	$ -	$ (182,603)	$ -	$ 5,542	$ 1,871,886	$ 270,415	$ -	$ 2,142,301
The following is not included in the total claim but are included on a memo basis:												
Deferred PILs Contra Account [8]	1563						**see PILs reconciliation requested**					
Disposition and Recovery of Regulatory Balances[10]	1595											

F:\Accounting\2011 Rate Application\2011 Rate App documents\Exhibit 9\[Continuity_Schedule_EDDVAR.XLS]Continuity Schedule

Completed versions of the Regulatory Assets Continuty Schedule are required to be filed in working Microsoft Excel format.

Carrying Charge Rates for Projected Interest:

Jan 1, 2010 to June 30, 2010	0.55%
July 1, 2010 to Sept 30, 2010	0.89%
Oct 1, 2010 to Dec 31, 2010	1.20%
Jan 1, 2011 to April 30, 2011	1.20%

SHEET 1 - Regulatory Assets - Continuity Schedule

		2007								
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, 2A]**	**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**
Group 1 Accounts										
Low Voltage Account	1550	$ 43,014	$ (35,323)				$ 7,691	$ 194	$ (932)	$ (738)
RSVA - Wholesale Market Service Charge	1580	$ (99,889)	$ (1,314,503)				$ (1,414,392)	$ 170,719	$ 60,034	$ 230,753
RSVA - Retail Transmission Network Charge	1584	$ (213,260)	$ (376,615)				$ (589,875)	$ (7,104)	$ 13,140	$ 6,037
RSVA - Retail Transmission Connection Charge	1586	$ (752,553)	$ (664,330)				$ (1,416,883)	$ (1,408)	$ (68,644)	$ (70,051)
RSVA - Power (excluding Global Adjustment)	1588	$ 1,377,801	$ (2,949,256)				$ (1,571,455)	$ 610,414	$ (214,995)	$ 395,419
RSVA - Power - Sub-Account - Global Adjustment	1588	$ (2,150,553)	$ 2,038,911				$ (111,642)	$ (299,013)	$ (47,921)	$ (346,934)
Recovery of Regulatory Asset Balances	1590	$ 2,000,974	$ (3,018,508)				$ (1,017,534)	$ 1,739,628	$ 63,085	$ 1,802,714
Disposition and Recovery of Regulatory Balances[10]	1595	$ -					$ -	$ -		$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ 205,536	$ (6,319,624)		$ -	$ -	$ (6,114,088)	$ 2,213,431	$ (196,232)	$ 2,017,199
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ 2,356,088	$ (8,358,535)		$ -	$ -	$ (6,002,446)	$ 2,512,444	$ (148,311)	$ 2,364,133
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ (2,150,553)	$ 2,038,911		$ -	$ -	$ (111,642)	$ (299,013)	$ (47,921)	$ (346,934)
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 47,818	$ 242,941	$ (181,948)			$ 108,812	$ 14,537	$ 2,130	$ 16,668
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account Deferred IFRS Transition Cos	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - HONI Incremental Capital	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Retail Cost Variance Account - Retail	1518	$ 239,694	$ 163,704	$ (29,330)			$ 374,068	$ (2,038)	$ (465)	$ (2,503)
Retail Cost Variance Account - STR	1548	$ 157,048	$ 95,293	$ (19,666)			$ 232,675	$ (4,347)	$ 566	$ (3,781)
Misc. Deferred Debits	1525	$ 23,104	$ 61,082	$ (84,187)			$ (0)	$ 1,503	$ (1,503)	$ -
LV Variance Account	1550	$ -					$ -	$ -		$ -
Renewable Connection Capital Deferral Account	1531									
Renewable Connection OM&A Deferral Account	1532									
Smart Grid Capital Deferral Account	1534									
Smart Grid OM&A Deferral Account	1535									
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Ca	1555	$ 83,849	$ 13,967	$ -			$ 97,816	$ (292)	$ (3,570)	$ (3,862)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Re	1555	$ (87,708)	$ 9,272	$ (169,010)			$ (247,446)	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - St	1555	$ -	$ -	$ -			$ -	$ -	$ -	$ -
Smart Meter OM&A Variance	1556	$ 9,609	$ 12,141	$ -			$ 21,750	$ 195	$ 806	$ 1,001
Conservation and Demand Management Expenditures and Recoveries	1565	$ (1,314,571)	$ 475,215	$ (180,586)			$ (1,019,942)	$ -	$ -	$ -
CDM Contra	1566	$ 635,257	$ 131,986	$ (22,577)			$ 744,666	$ -	$ -	$ -
Qualifying Transition Costs [5]	1570	$ 0	n/a	n/a		$ (0)	$ -	$ 25,982	$ (25,982)	$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ 0	n/a	n/a		$ -	$ 0	$ (108,991)	$ (26,073)	$ (135,063)
Extra-Ordinary Event Costs	1572	$ -					$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -					$ -	$ -		$ -
RSVA - One-time Wholesale Market Service	1582	$ 5,905	$ -				$ 5,905	$ 2,321	$ (1,267)	$ 1,053
Other Deferred Credits	2425	$ -					$ -	$ -		$ -
Group 2 Sub-Total		$ (199,993)	$ 1,205,602	$ (687,303)	$ -	$ (0)	$ 318,305	$ (71,130)	$ (55,358)	$ (126,488)
Deferred Payments in Lieu of Taxes	1562					see PILs reconciliation requested				
2006 PILs & Taxes Variance	1592					see PILs reconciliation requested				
Sub-total						see PILs reconciliation requested				
Total		$ 5,542	$ (5,114,022)	$ (687,303)	$ -	$ (0)	$ (5,795,783)	$ 2,142,301	$ (251,590)	$ 1,890,711
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [8]	1563					see PILs reconciliation requested				
Disposition and Recovery of Regulatory Balances[10]	1595									

F:\Accounting\2011 Rate Application\2011 Rate App documents\Exhibit 9\[Continuity_Schedule_EDDVAR.XLS]Continuity Schedule

Completed versions of the Regulatory Assets Continuty Schedule are required to be filed in working Microsoft Excel format.

Carrying Charge Rates for Projected Interest:

Jan 1, 2010 to June 30, 2010	0.55%
July 1, 2010 to Sept 30, 2010	0.89%
Oct 1, 2010 to Dec 31, 2010	1.20%
Jan 1, 2011 to April 30, 2011	1.20%

SHEET 1 - Regulatory Assets - Continuity Schedule

Account Description	Account Number	2008 Opening Principal Amounts as of Jan-1-08	Transactions (additions) during 2008, excluding interest and adjustments [6]	Transactions (reductions) during 2008, excluding interest and adjustments [6]	Adjustments during 2008 - instructed by Board [2, 2A]	Adjustments during 2008 - other [3]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec31-08	Closing Interest Amounts as of Dec-31-08
Group 1 Accounts										
Low Voltage Account	1550	$ 7,691	$ (108,949)				$ (101,258)	$ (738)	$ (1,033)	$ (1,772)
RSVA - Wholesale Market Service Charge	1580	$ (1,414,392)	$ (486,456)				$ (1,900,848)	$ 230,753	$ 41,947	$ 272,700
RSVA - Retail Transmission Network Charge	1584	$ (589,875)	$ (621,837)				$ (1,211,712)	$ 6,037	$ 15,093	$ 21,129
RSVA - Retail Transmission Connection Charge	1586	$ (1,416,883)	$ (409,682)				$ (1,826,564)	$ (70,051)	$ (52,315)	$ (122,366)
RSVA - Power (excluding Global Adjustment)	1588	$ (1,571,455)	$ 245,754				$ (1,325,701)	$ 395,419	$ (95,022)	$ 300,397
RSVA - Power - Sub-Account - Global Adjustment	1588	$ (111,642)	$ 1,752,406				$ 1,640,764	$ (346,934)	$ 72,800	$ (274,134)
Recovery of Regulatory Asset Balances	1590	$ (1,017,534)	$ 398,808				$ (618,726)	$ 1,802,714	$ (1,292,590)	$ 510,124
Disposition and Recovery of Regulatory Balances[10]	1595	$ -					$ -	$ -		$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ (6,114,088)	$ 770,045		$ -	$ -	$ (5,344,043)	$ 2,017,199	$ (1,311,120)	$ 706,079
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ (6,002,446)	$ (982,361)		$ -	$ -	$ (6,984,808)	$ 2,364,133	$ (1,383,920)	$ 980,213
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ (111,642)	$ 1,752,406		$ -	$ -	$ 1,640,764	$ (346,934)	$ 72,800	$ (274,134)
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 108,812	$ 89,357	$ (198,169)			$ (0)	$ 16,668	$ (16,668)	$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account Deferred IFRS Transition Cos	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - HONI Incremental Capital	1508	$ -					$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -		$ -
Retail Cost Variance Account - Retail	1518	$ 374,068	$ 639,060	$ (592,725)			$ 420,403	$ (2,503)	$ 2,503	$ -
Retail Cost Variance Account - STR	1548	$ 232,675	$ 426,563	$ (368,963)			$ 290,275	$ (3,781)	$ 3,781	$ -
Misc. Deferred Debits	1525	$ (0)	$ 104,982	$ (104,982)			$ 0	$ -		$ -
LV Variance Account	1550	$ -					$ -	$ -		$ -
Renewable Connection Capital Deferral Account	1531									
Renewable Connection OM&A Deferral Account	1532									
Smart Grid Capital Deferral Account	1534									
Smart Grid OM&A Deferral Account	1535									
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Ca	1555	$ 97,816	$ -	$ -			$ 97,816	$ (3,862)	$ (7,690)	$ (11,553)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Re	1555	$ (247,446)	$ 4,860	$ (165,650)			$ (408,235)	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - St	1555	$ -	$ -	$ -			$ -	$ -	$ -	$ -
Smart Meter OM&A Variance	1556	$ 21,750	$ -	$ -			$ 21,750	$ 1,001	$ -	$ 1,001
Conservation and Demand Management Expenditures and Recoveries	1565	$ (1,019,942)	$ 292,275	$ (17,000)			$ (744,666)	$ -	$ -	$ -
CDM Contra	1566	$ 744,666	$ -	$ -			$ 744,666	$ -	$ -	$ -
Qualifying Transition Costs [5]	1570	$ -	n/a	n/a		$ -	$ -	$ -	$ -	$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ 0	n/a	n/a		$ (0)	$ -	$ (135,063)	$ 135,063	$ -
Extra-Ordinary Event Costs	1572	$ -					$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -					$ -	$ -		$ -
RSVA - One-time Wholesale Market Service	1582	$ 5,905	$ -				$ 5,905	$ 1,053	$ 235	$ 1,288
Other Deferred Credits	2425	$ -					$ -	$ -		$ -
Group 2 Sub-Total		$ 318,305	$ 1,557,098	$ (1,447,489)	$ -	$ (0)	$ 427,914	$ (126,488)	$ 117,223	$ (9,264)
Deferred Payments in Lieu of Taxes	1562					**see PILs reconciliation requested**				
2006 PILs & Taxes Variance	1592					**see PILs reconciliation requested**				
Sub-total						**see PILs reconciliation requested**				
Total		$ (5,795,783)	$ 2,327,143	$ (1,447,489)	$ -	$ (0)	$ (4,916,129)	$ 1,890,711	$ (1,193,896)	$ 696,815
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [8]	1563					**see PILs reconciliation requested**				
Disposition and Recovery of Regulatory Balances[10]	1595									

F:\Accounting\2011 Rate Application\2011 Rate App documents\Exhibit 9\[Continuity_Schedule_EDDVAR.XLS]Continuity Schedule

Completed versions of the Regulatory Assets Continuty Schedule are required to be filed in working Microsoft Excel format.

Carrying Charge Rates for Projected Interest:

Jan 1, 2010 to June 30, 2010	0.55%
July 1, 2010 to Sept 30, 2010	0.89%
Oct 1, 2010 to Dec 31, 2010	1.20%
Jan 1, 2011 to April 30, 2011	1.20%

SHEET 1 - Regulatory Assets - Continuity Schedule

Account Description	Account Number	2009 Opening Principal Amounts as of Jan-1-09	Transactions (additions) during 2009, excluding interest and adjustments [6]	Transactions (reductions) during 2009, excluding interest and adjustments [6]	Adjustments during 2009 - instructed by Board [2, 2A]	Adjustments during 2009 - other [3]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec31-09	Adjustments during 2009 - instructed by Board [2, 2A]	Closing Interest Amounts as of Dec-31-09
Group 1 Accounts											
Low Voltage Account	1550	$ (101,258)	$ (465,376)		$ 101,258		$ (465,376)	$ (1,772)	$ (2,579)	$ 3,100	$ (1,251)
RSVA - Wholesale Market Service Charge	1580	$ (1,900,848)	$ (422,915)		$ 1,900,849		$ (422,914)	$ 272,700	$ (69,509)	$ (247,771)	$ (44,579)
RSVA - Retail Transmission Network Charge	1584	$ (1,211,712)	$ 161,645		$ 1,211,711		$ 161,644	$ 21,129	$ (27,496)	$ (5,237)	$ (11,604)
RSVA - Retail Transmission Connection Charge	1586	$ (1,826,564)	$ (409,713)		$ 1,826,565		$ (409,712)	$ (122,366)	$ (33,807)	$ 146,322	$ (9,851)
RSVA - Power (excluding Global Adjustment)	1588	$ (1,325,701)	$ (3,972,205)		$ 4,449,521		$ (848,384)	$ 300,397	$ (50,481)	$ (242,041)	$ 7,875
RSVA - Power - Sub-Account - Global Adjustment	1588	$ 1,640,764	$ 1,135,691		$ (1,640,764)		$ 1,135,692	$ (274,134)	$ 24,620	$ 252,615	$ 3,101
Recovery of Regulatory Asset Balances	1590	$ (618,726)	$ 93,745		$ 1,802,611		$ 1,277,630	$ 510,124	$ (3,848)	$ (1,783,906)	$ (1,277,630)
Disposition and Recovery of Regulatory Balances[10]	1595	$ -					$ -	$ -			$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ (5,344,043)	$ (3,879,128)		$ 9,651,751	$ -	$ 428,580	$ 706,079	$ (163,099)	$ (1,876,918)	$ (1,333,938)
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ (6,984,808)	$ (5,014,819)		$ 11,292,515	$ -	$ (707,112)	$ 980,213	$ (187,719)	$ (2,129,533)	$ (1,337,039)
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ 1,640,764	$ 1,135,691		$ (1,640,764)	$ -	$ 1,135,692	$ (274,134)	$ 24,620	$ 252,615	$ 3,101
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ (0)					$ (0)	$ -			$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -					$ -	$ -			$ -
Other Regulatory Assets - Sub-Account Deferred IFRS Transition Cos	1508	$ -	$ 299				$ 299	$ -	$ 0		$ 0
Other Regulatory Assets - Sub-Account - HONI Incremental Capital	1508	$ -	$ 4,141	$ -			$ 4,141	$ -	$ 7		$ 7
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -					$ -	$ -			$ -
Retail Cost Variance Account - Retail	1518	$ 420,403	$ 43,908	$ (394)			$ 463,917	$ -			$ -
Retail Cost Variance Account - STR	1548	$ 290,275	$ 55,360	$ (2,458)			$ 343,178	$ -			$ -
Misc. Deferred Debits	1525	$ 0					$ 0	$ -			$ -
LV Variance Account	1550	$ -					$ -	$ -			$ -
Renewable Connection Capital Deferral Account	1531										
Renewable Connection OM&A Deferral Account	1532										
Smart Grid Capital Deferral Account	1534										
Smart Grid OM&A Deferral Account	1535										
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Ca	1555	$ 97,816	$ 1,753,854	$ (303,657)			$ 1,548,013	$ (11,553)	$ (3,211)		$ (14,764)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Re	1555	$ (408,235)	$ 80,316	$ (507,609)			$ (835,529)	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - St	1555	$ -	$ 237,263	$ (6,502)			$ 230,762	$ -			$ -
Smart Meter OM&A Variance	1556	$ 21,750	$ 165,123	$ (16,337)			$ 170,536	$ 1,001	$ 570		$ 1,571
Conservation and Demand Management Expenditures and Recoverie	1565	$ (744,666)	$ -	$ (0)			$ (744,667)	$ -			$ -
CDM Contra	1566	$ 744,666	$ -	$ -			$ 744,666	$ -			$ -
Qualifying Transition Costs [5]	1570	$ -	n/a	n/a			$ -	$ -			$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ -	n/a	n/a			$ -	$ -			$ -
Extra-Ordinary Event Costs	1572	$ -					$ -	$ -			$ -
Deferred Rate Impact Amounts	1574	$ -					$ -	$ -			$ -
RSVA - One-time Wholesale Market Service	1582	$ 5,905	$ -				$ 5,905	$ 1,288	$ 67		$ 1,355
Other Deferred Credits	2425	$ -					$ -	$ -			$ -
Group 2 Sub-Total		$ 427,914	$ 2,340,264	$ (836,956)	$ -	$ -	$ 1,931,222	$ (9,264)	$ (2,567)	$ -	$ (11,831)
Deferred Payments in Lieu of Taxes	1562					**see PILs reconciliation requested**					
2006 PILs & Taxes Variance	1592					**see PILs reconciliation requested**					
Sub-total						**see PILs reconciliation requested**					
Total		$ (4,916,129)	$ (1,538,864)	$ (836,956)	$ 9,651,751	$ -	$ 2,359,802	$ 696,815	$ (165,666)	$ (1,876,918)	$ (1,345,769)
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [8]	1563					**see PILs reconciliation requested**					
Disposition and Recovery of Regulatory Balances[10]	1595				$ (9,651,750)		$ (9,651,750)			$ 1,876,921	$ 1,876,921

F:\Accounting\2011 Rate Application\2011 Rate App documents\Exhibit 9\[Continuity_Schedule_EDDVAR.XLS]Continuity Schedule

Completed versions of the Regulatory Assets Continuty Schedule are required to be filed in working Microsoft Excel format.

Carrying Charge Rates for Projected Interest:

Jan 1, 2010 to June 30, 2010	0.55%
July 1, 2010 to Sept 30, 2010	0.89%
Oct 1, 2010 to Dec 31, 2010	1.20%
Jan 1, 2011 to April 30, 2011	1.20%

SHEET 1 - Regulatory Assets - Continuity Schedule

Account Description	Account Number	Projected Interest on Dec 31 -09 balance from Jan 1, 2010 to Dec 31, 2010 [9]	Projected Interest on Dec 31 -09 balance from Jan 1, 2011 to April 30, 2011 [9, 10]	Total Claim before Forecasted Transactions in 2010 and 2011	*Optional* *Forecasted Transactions, Excluding Interest from Jan 1, 2010 to Dec 31, 2010*	*Optional* *Forecasted Transactions, Excluding Interest from Jan 1, 2011 to April 30, 2011 [10]*	*Optional* *Projected Interest from Jan 1, 2010 to April 30, 2011 on Forecasted Transactions (Excl Interest) from Jan 1, 2010 to Dec 31, 2010*	*Optional* *Projected Interest from Jan 1, 2011 to April 30, 2011 on Forecasted Transactions (Excl Interest) from Jan 1, 2011 to Apr 30, 2011 [10]*	*Forecasted Transactions in 2010 and 2011, not included in Total Claim*
Group 1 Accounts									
Low Voltage Account	1550	$ (3,711)	$ (1,862)	$ (472,199)					$ -
RSVA - Wholesale Market Service Charge	1580	$ (3,373)	$ (1,692)	$ (472,557)					$ -
RSVA - Retail Transmission Network Charge	1584	$ 1,289	$ 647	$ 151,976					$ -
RSVA - Retail Transmission Connection Charge	1586	$ (3,267)	$ (1,639)	$ (424,470)					$ -
RSVA - Power (excluding Global Adjustment)	1588	$ (6,766)	$ (3,394)	$ (850,669)					$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ 9,057	$ 4,543	$ 1,152,393					$ -
Recovery of Regulatory Asset Balances	1590			$ 0					$ -
Disposition and Recovery of Regulatory Balances[10]	1595			$ -					$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ (6,771)	$ (3,396)	$ (915,526)	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ (15,828)	$ (7,939)	$ (2,067,919)	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ 9,057	$ 4,543	$ 1,152,393	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts									
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508			$ (0)					$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			$ -					$ -
Other Regulatory Assets - Sub-Account Deferred IFRS Transition Cos	1508			$ 299					$ -
Other Regulatory Assets - Sub-Account - HONI Incremental Capital	1508	$ 33	$ 17	$ 4,198					$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -					$ -
Retail Cost Variance Account - Retail	1518			$ 463,917					$ -
Retail Cost Variance Account - STR	1548			$ 343,178					$ -
Misc. Deferred Debits	1525			$ 0					$ -
LV Variance Account	1550			$ -					$ -
Renewable Connection Capital Deferral Account	1531			$ -					$ -
Renewable Connection OM&A Deferral Account	1532			$ -					$ -
Smart Grid Capital Deferral Account	1534			$ -					$ -
Smart Grid OM&A Deferral Account	1535			$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Ca	1555	$ 12,345	$ 6,192	$ 1,551,786					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Re	1555	$ (6,663)	$ (3,342)	$ (845,534)					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - St	1555	$ 1,840	$ 923	$ 233,525					$ -
Smart Meter OM&A Variance	1556	$ 1,360	$ 682	$ 174,149					$ -
Conservation and Demand Management Expenditures and Recoveries	1565			$ (744,667)					$ -
CDM Contra	1566			$ 744,666					$ -
Qualifying Transition Costs [5]	1570			$ -					$ -
Pre-Market Opening Energy Variances Total [5]	1571			$ -					$ -
Extra-Ordinary Event Costs	1572			$ -					$ -
Deferred Rate Impact Amounts	1574			$ -					$ -
RSVA - One-time Wholesale Market Service	1582	$ 47	$ 24	$ 7,330					$ -
Other Deferred Credits	2425			$ -					$ -
Group 2 Sub-Total		$ 8,963	$ 4,495	$ 1,932,848	$ -	$ -	$ -	$ -	$ -
Deferred Payments in Lieu of Taxes	1562								
2006 PILs & Taxes Variance	1592								
Sub-total				$ -					$ -
Total		$ 2,191	$ 1,099	$ 1,017,323	$ -	$ -	$ -	$ -	$ -
The following is not included in the total claim but are included on a memo basis:									
Deferred PILs Contra Account [8]	1563								
Disposition and Recovery of Regulatory Balances[10]	1595			$ (7,774,829)					

F:\Accounting\2011 Rate Application\2011 Rate App documents\Exhibit 9\[Continuity_Schedule_EDDVAR.XLS]Continuity Schedule

Completed versions of the Regulatory Assets Continuty Schedule are required to be filed in working Microsoft Excel format.

Carrying Charge Rates for Projected Interest:

Jan 1, 2010 to June 30, 2010	0.55%
July 1, 2010 to Sept 30, 2010	0.89%
Oct 1, 2010 to Dec 31, 2010	1.20%
Jan 1, 2011 to April 30, 2011	1.20%

Appendix B – Reconciliation of Continuity Schedule to RRR Trial Balance

APPENDIX B - Reconciliation of Continuity Schedule to RRR Trial Balance

				Reconciling Items					
Account	Per Continuity Schedule 2009 Ending Balance	Per 2009 RRR Trial Balance	Difference	Transfer Principal Balances to 1595 [1]	Transfer Interest Balances to 1595 [1]	Projected Interest Jan 1, 2010 to Apr 30, 2011.	General Ledger Entries Made in 2010	Rounding	Unreconciled Difference
1550	(472,199)	(570,984)	98,785	101,258	3,100	(5,573)			0
1580	(472,557)	(2,120,571)	1,648,014	1,900,849	(247,771)	(5,064)			0
1584	151,976	(1,056,433)	1,208,410	1,211,711	(5,237)	1,936			0
1586	(424,470)	(2,392,450)	1,967,981	1,826,565	146,322	(4,906)			0
1588	301,724	(2,521,048)	2,822,772	2,808,757	10,574	3,441			0
1590	0	(112,444)	112,444	1,802,611	(1,783,906)	0	93,739		(0)
1595	(7,774,829)		(7,774,829)	(9,651,750)	1,876,921	0			0
1508	4,497	4,448	50			50			(0)
1518	463,917	463,917	0						0
1548	343,178	343,178	0						0
1525			0						0
1531			0						0
1532			0						0
1534			0						0
1535			0						0
1555	939,777	929,482	10,295			11,295	(1,001)		0
1556	174,149	171,106	3,043			2,042	1,001		(0)
1565	(744,667)	(744,667)	0						0
1566	744,666	744,667	(1)					(1)	0
1570			0						0
1571			0						0
1572			0						0
1574			0						0
1582	7,330	7,260	71			71			0
2425			0						0

[1] These balances were approved for disposition in NPEI's 2010 IRM Rate Applications (EB-2009-0205 and EB-2009-0206). The amounts have been included under 2009 in the Continuity Schedule, but were recorded in the General Ledger in 2010.

APPENDIX C- Auditor's Report on Smart Meter Expenditures

crawford
smith &
swallow

NIAGARA PENINSULA ENERGY INC.
SMART METER EXPENDITURES

Audited Financial Information

April 1, 2009 to June 30, 2010

crawford
smith &
swallow

NIAGARA PENINSULA ENERGY INC.
SMART METER EXPENDITURES

Audited Financial Information

April 1, 2009 to June 30, 2010

Table of Contents

Crawford, Smith and Swallow
Chartered Accountants LLP

4741 Queen Street
Niagara Falls, Ontario
L2E 2M2
Telephone (905) 356-4200
Telecopier (905) 356-3410

Offices in:
Niagara Falls, Ontario
St. Catharines, Ontario
Fort Erie, Ontario
Niagara-on-the-Lake, Ontario
Port Colborne, Ontario

crawford
smith &
swallow

AUDITORS' REPORT

To the Ontario Energy Board

At the request of Niagara Peninsula Energy Inc. (NPEI), we have audited the Smart Meter schedule of expenditures of NPEI for the period April 1, 2009 to June 30, 2010, prepared in accordance with the Ontario Energy Boards Smart Meter Funding and Cost Recovery Guidelines. This financial information is the responsibility of the management of NPEI. Our responsibility is to express an opinion on this financial information 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 this financial information is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial information. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial information.

In our opinion, this schedule presents fairly, in all material respects, the expenditures of the NPEI's Smart Meter Program for the period April 1, 2009 to June 30, 2010 in accordance with the Ontario Energy Boards Smart Meter Funding and Cost Recovery Guidelines.

This financial information, which has not been, and was not intended to be, prepared in accordance with Canadian generally accepted accounting principles, is solely for the information and use of the Board of Directors of NPEI and the Ontario Energy Board for complying with the Smart Meter Funding and Cost Recovery Guidelines. This financial information is not intended to be and should not be used by anyone other than the specified users or for any other purpose.

Crawford, Smith and Swallow

Niagara Falls, Ontario
August 23, 2010

CRAWFORD, SMITH AND SWALLOW
CHARTERED ACCOUNTANTS LLP

LICENSED PUBLIC ACCOUNTANTS

NIAGARA PENINSULA ENERGY INC.

SCHEDULE OF SMART METER EXPENDITURES
for the period April 1, 2009 to June 30, 2010

	$
Smart meters capital labour	8,758
Smart meters capital material	6,798
Smart meters capital accounts payable purchases	3,763,995
Smart meters installation	337,574
Smart meters workforce automation	21,057
Smart meters software license	7,500
Smart meters professional fees	27,078
Smart meters MDMR integration	2,250
	4,175,010