Niagara Peninsula Energy Inc.
7447 Pin Oak Drive
P.O. Box 120
Niagara Falls, ON
L2E 6S9

September 23, 2014

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

Re: Cost of Service Application EB-2014-0096

Dear Ms. Walli:

Niagara Peninsula Energy Inc. ("NPEI") hereby submits its Application for 2015 Distribution Rates.

An electronic copy has been submitted to the Board through the RESS system, and two hard copies and one CD will be delivered to the OEB office.

This document is being filed pursuant to the Board's e-Filing Services.

Yours truly,

Niagara Peninsula Energy Inc.

Suzanne Wilson, CPA, CA
VP Finance

Niagara Peninsula Energy Inc.

2015 COS

Application

EB-2014-0096

Rates Effective: May 1, 2015

Date Filed: September 23, 2014

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Exhibit 1

ADMINISTRATION

Exhibit 1

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Exhibit 1

Tab 2 of 6

Executive Summary

Legal Application

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 pursuant to section 78 of the Ontario Energy Board Act, 1998 for 2015 distribution rates and related matters.

APPLICATION:

1. The Applicant is 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 is a licensed electricity distributor operating pursuant to license ED-2007-0749. NPEI carries on the business of distributing electricity to approximately 51,500 customers within the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham pursuant to a distribution license (ED-2007-0749) issued by the Ontario Energy Board (the "Board") and charges Board authorized rates (EB-2013-0154) for the distribution service it provides.

2. NPEI hereby applies to the Ontario Energy Board (the "OEB") for an order or orders made pursuant to Section 78 of the *Ontario Energy Board Act, 1998 (the "OEB Act")*, as amended, approving just and reasonable rates for the distribution of electricity based on a 2015 Test Year, effective May 1, 2015.

3. NPEI followed Chapter 2 of the OEB's Filing Requirements for Transmission and Distribution Applications dated July 18, 2014 and Chapter 5 of the OEB's Filing Requirements for the Consolidated Distribution System Plan dated March 28, 2013.

4. The 2015 distribution rates proposed by the Applicant will result in overall bill impacts for residential, GS < 50kW, GS>50kW, Unmetered Scattered Load (USL), sentinel and street light customers as detailed in Table 1-1 below. A full list of the bill impacts applicable to all customer classes is found at E8/T13/S1/Att1. The proposed schedule of rates and charges in this Application are identified in E8/T11/S1/Att.2.

Table of Bill Impacts

Monthly Bill Impacts
Summary

	Volume		Total Distribution Charges only excluding Pass through		Total Delivery Charges including Distribution		Total Bill	
Customer Class	kWh	kW	$ Change	% Change	$ Change	% Change	$ Change	% Change
Residential	800		$ 0.81	2.73%	$ 4.72	11.53%	$ 4.77	3.74%
GS<50 kw	2000		$ (4.21)	-6.06%	$ 4.77	5.13%	$ 4.77	1.54%
GS>50 kW	65000	180	$ (306.49)	-32.51%	$ (50.94)	-2.83%	$ (54.84)	-0.62%
USL	250		$ (0.04)	-0.17%	$ 1.28	4.97%	$ 1.29	2.42%
Sentinel	44	0.12	$ 2.61	17.67%	$ 3.12	20.54%	$ 3.17	15.73%
Streetlighting	50	0.13	$ (0.08)	-4.42%	$ 0.52	23.60%	$ 0.52	6.87%

5. This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on this Application.

6. The Applicant certifies that the information provided in this application is accurate at the time of this filing.

7. NPEI acknowledges that the Board will publish an update to the Rate of Return and Short Term Debt Rate and that these matters will affect the Revenue Requirement that NPEI has requested in this Application.

8. The Applicant requests that a copy of all documents filed with the Board in this proceeding be served on the Applicant.

9 NPEI requests that the OEB make its Rate Order effective May 1, 2015 in accordance with the Filing Requirements. NPEI is not seeking to align its rate year with its fiscal year in the 2015 Cost of Service rate Application.

10. NPEI applies for an Order or Orders approving the proposed distribution rates and other charges set out in the Proposed Rate Tariff in E8/T11/S1/Att.2 as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2015, or as soon as possible thereafter; and

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

DATED at: Niagara Falls, Ontario. This 23rd day of September, 2014.

All of which is respectfully submitted,

Original Signed By

Suzanne Wilson, CPA, CA
Vice-President, Finance
Niagara Peninsula Energy Inc.

Executive Summary

This section of NPEI's application provides an overview of the key elements of our application and our overall business strategy.

The summaries provided below for each exhibit of this application will highlight how NPEI's strategy supports the four areas of focus identified by the Board in the RRFE report, customer focus; operational effectiveness; public policy responsiveness; and financial performance.

NPEI's Mission, Vision and Values are as follows;

NPEI's Mission Statement is:
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.

NPEI's Vision Statement is:
Deliver environmentally responsible and sustainable energy for the future of our communities.

NPEI's Values are:
To conduct ourselves with commitment to the values of: Integrity, fairness, responsibility, respect and transparency.

NPEI's priorities are to:
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 and engage our current and future customers

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

NPEI's strategic goals are customer satisfaction; facilities optimization; public policy; safety and wellness and corporate leadership. Each of these goals is explained in further detail in E1/T2/S3.

NPEI's strategic goals are highlighted throughout this application and are the core areas of focus for NPEI. The strategic goals can be tied into one of the areas of focus as identified by the OEB in their RRFE. In June 2014, a third party consultant was engaged to assist NPEI with the development of a Customer Engagement Plan and a Customer Engagement Baseline Report. See E1/T3/S1/Att.2 and Att.3 included with this application. NPEI also, completed its first Customer Satisfaction Survey in June 2014. See E1/T3/S1/Att.4 for details of the survey and results.

In this proceeding, NPEI is seeking the following approvals:

- Approval to charge rates effective May 1, 2015 to recover a service revenue requirement of $30,971,328, as set out in E6/T1/S1/Att1.
- Approval of proposed rates as set out in E8/T11/S1/Att2.
- Approval of the proposed capital structure, with a deemed common equity component of 40% and a deemed debt component of 60%, as set out in E5/T1/S1/Att1.
- Approval of the proposed loss factor as set out in E8/T9/S1/Att1.
- Approval to continue to charge the Wholesale Market Service Rate and the Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of NPEI's 2011 Distribution Rates (EB-2010-0138).

- Approval of the proposed Retail Transmission – Network Service and Retail Transmission – Connection rates, in accordance with the Guideline for Electricity Distribution Retail Transmission Service (G-2008-0001), Revision 1.0 issued July 22, 2009.
- Approval to continue the Specific Service Charges approved in the OEB Decision and Order in the matter of NPEI's 2011 Distribution Rates (EB-2010-0138)
- Approval to continue the Transformer Allowance approved in the OEB Decision and Order in the matter of NPEI's 2011 Distribution Rates (EB-2010-0138).
- Approval to continue the Micro FIT Generator monthly charge $5.40 per month
- Approval to dispose of Group 1 and Group 2 Deferral and Variance Account balances as at December 31, 2013 with interest to April 30, 2015, over a one-year period.
- Approval to dispose of the 1588-Power Global Adjustment variance account, by way of a distinct rate rider charged to customers not subject to the Regulated Price Plan.
- Approval to use the Board Approved 1595 account – Disposition and Recovery of Regulatory Balances and sub-accounts to record the disposition and recoveries of Deferral and Variance account balances.
- Approval of the recovery of Stranded Meter Assets over a two year period.
- Approval to transfer to Account 1576 the difference between CGAAP and MIFRS amortization in 2013 and 2014BY, and to dispose of over a two year period.

NPEI's Scorecard 2013

On March 5, 2014, the Board issued its report on Performance Measurement for Electricity Distributors: A Scorecard Approach. The report sets out the Board's policies on the measures that will be used by the Board to assess a distributor's effectiveness and improvement in customer focus; operational effectiveness; public policy responsiveness; and financial performance to the benefit of existing and future customers.

NPEI has included its scorecard attached below, which demonstrates, as part of the Application, our performance over the past five years based on the measures of the Board.

Based on the results of the performance measurements identified in NPEI's scorecard, the following three performance measures were not met by NPEI and explanations are provided below;

Customer Focus: In the areas of service quality –

New Residential/Small Business Services Connected on Time

The 2013 trend for NPEI shows a lower than the 90% Industry Average, at 79.20% attributed to a change in process for servicing new Subdivision Lots within the service area. In the spirit of efficiency & cost effectiveness, NPEI had partnered with Enbridge Gas, who had a Field Crew dedicated to supplying a common trench and duct installation service, from the Service Lead to the meter-base, while they installed the Gas Service. A common stepped trench was excavated, in which the electrical conduit and gas pipe were installed. A coordinated effort between both companies ensured that Line-staff from NPEI were present to install & splice the secondary conductor, and roll out the CATV & Bell Drops, while the Enbridge Crews tapped into the Gas Main and connected the meter. Upon completion the Enbridge Crew performed backfill services of the Trench. The economy of scale realized included, a single call from the Homebuilder to arrange for the provision of servicing from both Utilities upon receipt of appropriate approvals, a single agency arranging locate services for the common trench, a single backhoe and trench for excavation and restoration of both Utilities, a flat rate fee paid by NPEI to Enbridge for the service provision passed through to the builder, and fewer service lead damage claims.

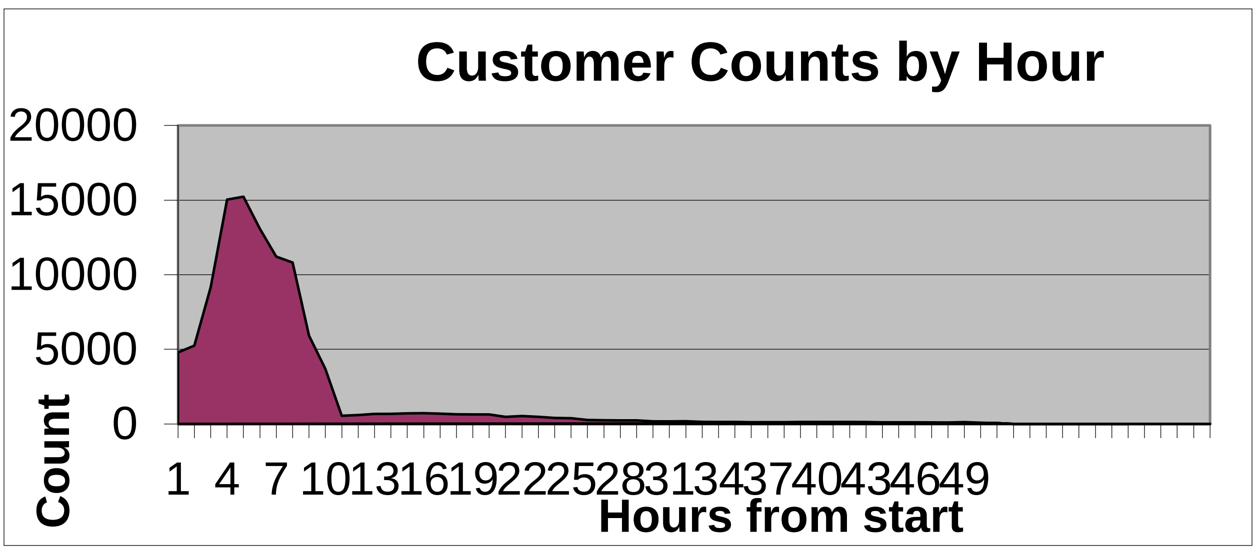
In 2013 Enbridge elected to have a Contractor provide Service Lead installation on their behalf, and deploy their own Crews to other Operations. The new Contractor did not include the services formerly supplied to NPEI within their scope. Until NPEI could negotiate with the Enbridge Contractor to supply these services, new Residential Services needed to be installed and connected. An Electrical Contractor was hired to perform this work on NPEI's behalf, but due to a duplication of efforts, the process was no longer as efficient as previously experienced. Both Contractors could not be on site at the same time, causing delays. Coordinating locates became difficult due to a lack of information dissemination between agencies for services installed to the locate provider. Service lead damage claims increased, due to smaller lot sizes making the installation of two separate trenches, while maintaining safe equipment clearance from installed plant difficult, further complicating and delaying service connection.

After several negotiations, NPEI and the Enbridge Contractor were able to reach an agreement for service provision. A cost structure was agreed to, Documentation for Equipment Inspections, Insurance, and Safety Training were reviewed, and the Contractor had Staff Members attend a training course offered by the IHSA to certify secondary splicing competence. Homebuilders were notified that the Enbridge Contractor would now be supplying the service previously afforded by Enbridge and the process to follow. With the Contractor Staff trained to perform secondary splices, NPEI Crews no longer needed to attend the site until the meter install and connection at the transformer was required. This will further streamline the process for service connections, and the statistics should reflect these changes in 2014.

Operational Effectiveness – In the area of System Reliability –

Average Number of Hours that Power to a Customer is Interrupted (SAIDI) and Average Number of Times that Power to a Customer is Interrupted (SAIFI)

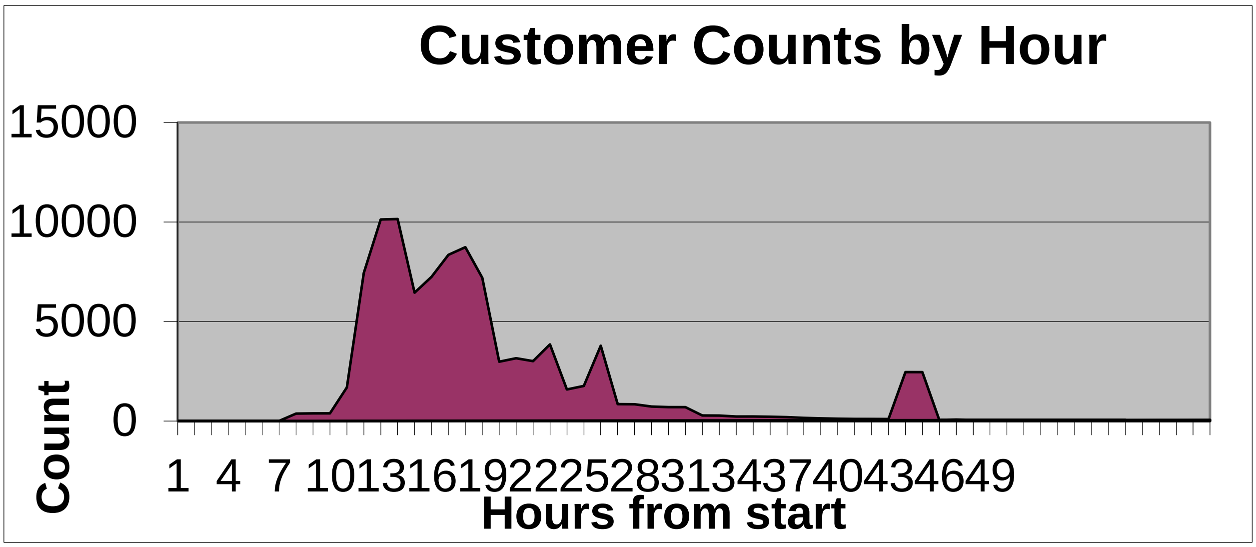
The 2013 trend for NPEI shows a higher than the Average hours of interruption at 5.31 than previously experienced at 1.77-3.19. This can be explained by two incidents of severe weather events that NPEI experienced. The first event was a hot weather event with high winds, torrential rains, and a large amount of lightning starting on Friday night of July 19th, 2013, and crews affecting repairs throughout the weekend with accumulated damage repair costs of $180,423.34. Below is a graph demonstrating the customers experiencing an outage by Hours elapsed, and a chart with Customer Counts by Feeder during this event.



July 19, 2013 Storm - Customer Outage Report

FEEDER	COUNTS
18M1	4758
18M2	2471
18M4	63
Niagara West 2	2383
Niagara West 5	1260
Vineland F1	1768
Vineland F2	1901
12M33	1880
Total	16484

The second severe weather event was a cold weather Ice Event which most of Southern Ontario experienced on December 22, 2013. Below is a graph demonstrating the number of Customers experiencing an outage by hours elapsed during the event, followed by a chart showing smart meters reporting outage within the NPEI OMS.



SMART METER ALARMS

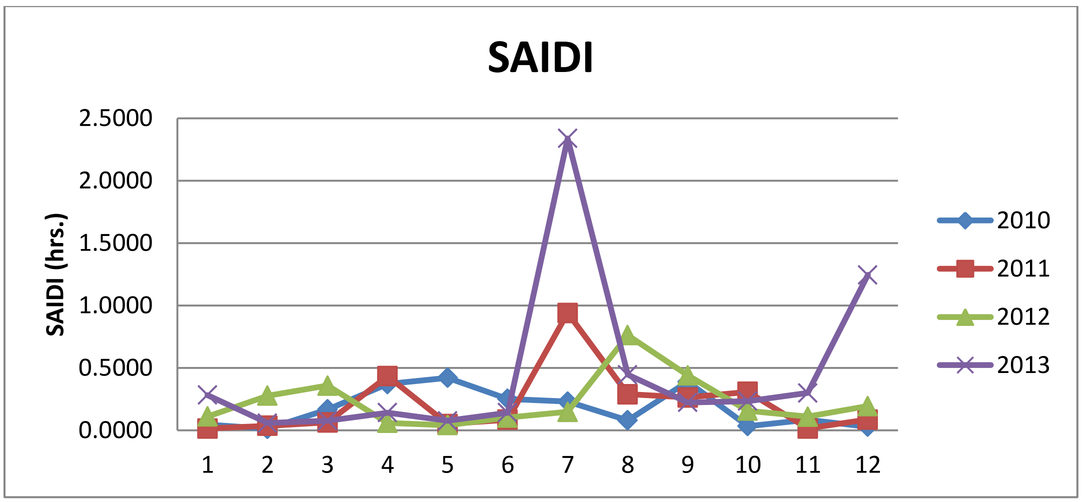
DAY	CALL COUNT
12/21/2013	165
12/22/2013	9461
12/23/2013	789
12/24/2013	115
12/25/2013	14
12/26/2013	8
12/27/2013	2

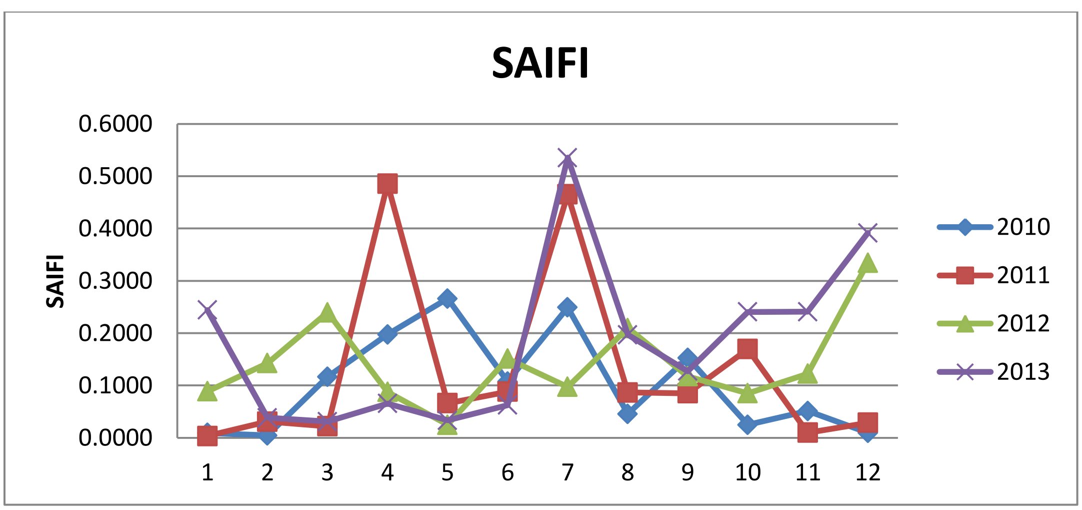
The following two charts demonstrate the Historical SAIDI & SAIFI illustrating the trends between 2010 & 2013. The **System Average Interruption Duration Index (SAIDI)** is commonly used as a reliability indicator by electric power utilities. SAIDI is the average outage duration for each customer served.

$$\mathrm{SAIDI} = \frac{\text{sum of all customer interruption durations}}{\text{total number of customers served}}$$

The **System Average Interruption Frequency Index (SAIFI)** is commonly used as a reliability indicator by electric power utilities. SAIFI is the average number of interruptions that a customer would experience.

$$\text{SAIFI} = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}}$$





By studying the 2013 data in each graph, it is possible to see the effect of the two weather events on the statistics. But the data for other years without events out of NPEI's control, demonstrates that NPEI's statistics are well within acceptable limits, based upon industry standards.

Public Responsiveness: Conservation and demand management metrics are included and NPEI has achieved 94.7% of its Net Cumulative Energy Savings target of 58.04 GWh. Connections of renewable generation metrics are also included and have been reported as having been connected and completed on time in the year when NPEI has a connection request. The target of Net Annual Peak Demand Savings of 15.49 MW was only 12.9% achieve at the end of 2013. It is very unlikely NPEI will achieve the peak demand target of 15.49MW by the end of 2014.

Financial Ratios: Four financial metrics are included in the scorecard and NPEI indicates that the liquidity and leverage ratios are increasing. Profitability (return on equity-both deemed and actual) metrics show that NPEI’s actual return for 2013 is less than the deemed return.

With NPEI’s strategy implementation, the following sections A to J provide a summary of the key elements of NPEI’s application.

Attachment 1 of 1

NPEI's 2013 Scorecard

Find... 1 of 1+ 50%

Main Report

Scorecard - Niagara Peninsula Energy Inc.

8/29/2014

Performance Outcomes	Performance Categories	Measures		2009	2010	2011	2012	2013	Trend	Target Industry	Target Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		87.90%	84.70%	81.70%	89.30%	79.20%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	83.20%	99.60%	96.20%		90.00%	
		Telephone Calls Answered On Time		61.00%	41.50%	70.30%	76.10%	80.70%		65.00%	
	Customer Satisfaction	First Contact Resolution									
		Billing Accuracy									
		Customer Satisfaction Survey Results									
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Public Safety [measure to be determined]									
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		3.19	1.77	2.58	2.31	5.31			at least within 1.77 - 3.19
		Average Number of Times that Power to a Customer is Interrupted		1.33	1.06	1.53	1.23	1.94			at least within 1.06 - 1.53
	Asset Management	Distribution System Plan Implementation Progress									
	Cost Control	Efficiency Assessment					3	3			
		Total Cost per Customer [See Note below]		$650	$676	$690	$687	$672			
		Total Cost per Km of Line [See Note below]		$16,856	$17,710	$17,881	$17,863	$17,408			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved)				9.00%	10.00%	12.90%			15.49MW
		Net Cumulative Energy Savings (Percent of target achieved)				34.00%	62.00%	94.70%			58.04GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time			100.00%	100.00%		100.00%			
		New Micro-embedded Generation Facilities Connected On Time						95.79%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.56	1.57	1.40	1.69	1.87			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.50	0.52	0.61	0.70	0.80			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)			9.58%	9.58%	9.58%			
			Achieved			6.03%	7.23%	6.71%			

Legend: up, down, flat, target met, target not met

Note
These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.

A. Overall business strategy

In October 2012, the Ontario Energy Board (OEB) released its report "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach". There were four outcomes established by the OEB in the Renewed Regulatory Framework for Electricity Distributors ("RRFE") report; Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance. These four outcomes are detailed along with performance category measures on NPEI's scorecard. NPEI's strategic goals are as follows:

1. CUSTOMER SATISFACTION

- Enhance customer satisfaction through high quality service.
- Promote the efficient use of electricity through education, and delivery of conservation initiatives.
- Continue to deliver reliable electricity at reasonable rates.
- Minimize system outages.

2. FACILITIES OPTIMIZATION

- Plan expansion of the transformation and distribution systems to meet the electrical needs of current and future customers.
- Refurbish aging plant facilities and equipment in a cost effective manner.
- Enhance system performance and reliability

3. PUBLIC POLICY

- Incorporate the Green Energy Act requirements into the system.
- Implement Smart Grid initiatives to improve reliability and accommodate embedded generation.
- Successfully implement conservation and demand programs.
- Support environmental programs (Reduce, Reuse, and Recycle).

4. SAFETY AND WELLNESS

- Promote safety awareness for our associates and the community.

- Strengthen NPEI's "Safety Culture"
- Promote wellness initiatives with NPEI associates.

5. CORPORATE LEADERSHIP

- Provide our associates with the necessary skills to meet customer needs and expectations.
- Maintain long-term financial viability.
- Develop resources to promote the sustainability of our operations.
- Maintain regulatory compliance.
- Continue to build value for our Shareholders.

NPEI's overall business strategy is to integrate its strategic goals with the four outcomes identified in the RRFE report using good planning and asset management, formally document consultations and engagements with our customers, maintain good corporate governance, and regularly report and monitor NPEI's financial performance.

B. Revenue Requirement

NPEI's requested Service Revenue Requirement for the 2015 Test Year is $30,971,328. The 2011 Board Approved Service Revenue Requirement was $31,780,611. The 2015 service revenue requirement represents a decrease of $809,283 or 2.55% from the 2011 Board Approved amount.

Based on the projected load forecast and customer growth for the 2015 Test Year, as provided for in this application, NPEI has estimated a revenue deficiency of $1,003,773 based on its current rates. The computation of the revenue deficiency is as shown in the RRWF in E6/T1/S1/Att.1. The principal drivers of the revenue deficiency are explained in detail in Exhibit 6, but are as highlighted below. Table 1-2 illustrates the key drivers in the revenue requirement calculation:

Table 1-2 Revenue Requirement drivers

	2015 Test Year ($)	**2011 Test Year ($)**	**Change $**	**% Change**
Average Fixed Assets	123,743,871	101,141,844	22,602,027	22.35%
+				
Working Capital Allowance	20,018,027	18,437,623	1,580,404	8.57%
=				
Rate Base	143,761,898	119,579,467	24,182,431	20.22%
X				
Cost of Capital	6.23%	6.82%	3.299%	8.60%
=				
Return on Ratebase	8,949,680	8,151,991	797,689	9.79%
+				
OM&A expenses	17,041,580	14,107,292	2,934,288	20.80%
+				
Depreciation expense	4,936,879	7,924,258	(2,987,379)	-37.70%
=				
Revenue Requirment before PILS	30,928,139	30,183,541	744,598	2.47%
+				
PILS	43,189	1,597,070	(1,553,881)	-97.30%
=				
Service Revenue Requirment	**30,971,327**	**31,780,611**	**(809,283)**	**-2.55%**

- Increase in OM&A of $2.934K or 20.8%. NPEI does not have any impact of changes in capitalization policies in this 2015 COS rate application as NPEI changed its capitalization policy related to capitalization of the stores, garage and training costs effective January 1, 2011.
- Incremental return on rate base of $798K as a result of the increase in rate base since NPEI's last Cost of Service application in 2011 of approximately $24M.
- A decrease in depreciation expense of $2,987K due to changes in accounting for estimated useful lives.
- Reduction to forecasted regulatory PILS of $1,554K due to adjustments to taxable income. The reduction of taxable income versus accounting income is mainly due to amortization recorded for accounting purposes and allowable capital cost allowance deduction for tax purposes.

C. Budgeting Assumptions

NPEI compiles budget information for three major components of the budgeting process: revenue forecasts, operation, maintenance and administration forecasts and capital forecast. Budget information was prepared for both the Bridge and Test Years. 2014BY forecasts were based on actual 2013 results, and the 2015TY projections were also reviewed in light of 2013 results.

Revenue Forecast

The revenue budget includes three components: energy revenue, distribution revenue and other revenue.

The energy revenue for 2015 was forecast using the weather normalized load forecast prepared by NPEI as presented in E3/T1/S1/Att1. Rates for energy pass-through charges are described in E3/T4/S1.

Distribution revenue was forecast using the weather normalized volumes multiplied by both current approved distribution rates and by proposed rates in order to project revenue for the 2015TY. Other revenues were reviewed on an item by item basis with each account projection being determined based on the most reliable historical indicator.

Operations, Maintenance and Expense Forecast

The OM&A expenses for the 2014BY and 2015TY were forecast using work plans, approved pay grid progression, capital budgets and prior years historical costs. The expenditures reflect the following assumptions:

Wages:

- Union Wages collective agreement expires March 31, 2015. NPEI estimated an increase of 2.5% for the purposes of preparing this rate application.

- Salaries reflect movement of the individual currently in the position along the existing salary grid with assumed cost of living adjustments similar to any increase in union wages with an effective date of January 1st.
- Other changes in staffing levels to occur include a potential retirement of the maintenance handyman, a new systems analyst, one non-unionized cashier contract terminated in October 2014, one billing clerk returning from maternity leave in 2015 and three full-time contracts for lineman apprentices.

Operating and Maintenance, Billing and Collecting, General Administration

- Costs other than labour and fleet have assumed to increase 2.0% unless they are specific in nature in which case judgment was used to project the expected expense for the bridge year or test year.

Regulatory Costs:

- 2015 Cost of Service application assumed to cost $340,250 plus $53,000 in intervenor costs. Annually, these regulatory costs total $98,313.
- Assumed OEB Annual assessments of $172,000 and $10,000 in other cost awards.
- Assumed $37,166 per year in Low-Income Energy Assistance Program (LEAP) funding.

Amortization:

- 2015 amortization is calculated based on revised asset useful lives and on a MIFRS basis.

PILS:

- Regulatory PILS as per Board model.

Capital Budget

The capital budget is formulated on a project by project basis. The maintenance program is relied on to identify any assets that must or should be removed from service and replaced in order to maintain secure and reliable supply. Projects are prioritized by location and asset condition.

Capital spending to replace existing aging infrastructure is required in order to maintain safe and reliable delivery of electricity to NPEI’s customers.

Additional information on NPEI’s approach to investment planning is included in E2/T2/S1.

D. Load Forecast Summary

The Weather Normalized Load Forecast evidence, as presented in Exhibit 3, shows that NPEI's proposed billed consumption for the 2015 Test Year is 1,185,817,112 kWh, compared to the 2011 board approved forecast of 1,223,308,130 kWh. This represents a decrease of 37,491,018 kWh, or 3.1%. NPEI's total forecast billed demand, for the applicable rate classes, for the 2015 test year is 1,761,769 kW, compared to the 2011 Board approved forecast of 1,839,327 kW. This represents a decrease of 77,558 kW, or 4.2%. NPEI has projected the total customer / connection count for the 2015 test year at 66,028, compared to the 2011 Board approved forecast of 65,533 total customers / connections, which represents an increase of 494, or 0.8%.

With regard to the overall process of load forecasting, NPEI submits that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. NPEI has the data for the amount of electricity (in kWh) purchased from the IESO and other sources for use by its customers. 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 the 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 quantity of weather normalized purchases for the Bridge Year and the Test Year which is converted to forecast billed kWh by rate class.

As detailed in Exhibit 3, Tab 1, Schedule 1, NPEI has used the following procedure to derive its proposed 2015 Test Year load forecast:

1. A forecast for 2015 weather-normalized purchased kWh is calculated using a multifactor regression model.

2. The weather-normalized purchase forecast from step 1) is divided by NPEI's five year historical loss factor to give the 2015 weather-normalized billed forecast.

3. The 2015 non-normalized billed kWh forecasts by rate class are determined using 2015 forecast customer / connection counts multiplied by the 2015 forecast usage per customer.

4. The difference between the 2015 weather normalized billed forecast (step 2) and the non-normalized forecast (step 3) represents the weather sensitive portion of the forecast.

5. The weather sensitive kWh from step 4 are allocated based on proposed weather sensitivity by rate class, resulting in weather-normalized billed kWh by rate class.

6. The weather-normalized billed kWh from step 5 are adjusted to reflect the proposed 2015 manual CDM adjustment, resulting in the final 2015 proposed billed kWh forecast by rate class.

The proposed 2015 customer / connection counts and forecast usage per customer is calculated using historical geometric mean growth rates.

The proposed billed demand, where applicable, is determined by applying an average historical ratio of kW / kWh to the forecast billed consumption

Table 1-3 below shows NPEI's historical and proposed billed kWh (by rate class and total), billed kW and customer / connection counts for 2011 Board Approved, 2011 to 2013 Actual, the 2014 Bridge Year and the 2015 Test Year.

Table 1-3: Consumption and Customer / Connection Counts

	2011 Board Approved	2011 Actual	2012 Actual	2013 Actual	2014 Weather Normalized Bridge	2015 Weather Normalized Test
Actual kWh Purchases		1,266,311,662	1,260,789,451	1,250,000,080		
Predicted kWh Purchases	1,286,014,423	1,265,208,873	1,275,140,355	1,237,576,507	1,238,461,756	1,245,167,213
% Difference		-0.1%	1.1%	-1.0%		
Purchased kWh	1,286,014,423	1,266,311,662	1,260,789,451	1,250,000,080	1,238,461,756	1,245,167,213
Distribution Losses	(62,706,294)	(33,312,835)	(46,774,137)	(47,694,815)	(50,389,228)	(50,662,053)
Manual CDM Adjustment					(3,619,024)	(8,688,049)
Billed kWh	1,223,308,130	1,232,998,827	1,214,015,314	1,202,305,265	1,184,453,504	1,185,817,112
By Class						
Residential						
Customers	46,900	45,996	45,871	46,274	46,669	47,067
kWh	462,790,265	418,849,931	414,592,237	412,298,278	402,178,821	399,166,843
Usage per Customer	9,868	9,106	9,038	8,910	8,618	8,481
General Service < 50 kW						
Customers	4,352	4,307	4,260	4,315	4,350	4,385
kWh	122,331,880	129,680,926	125,465,897	124,179,905	120,510,242	118,740,733
Usage per Customer	28,107	30,111	29,453	28,776	27,702	27,076
General Service > 50 kW						
Customers	848	859	855	863	863	862
kWh	628,090,148	675,128,624	664,095,955	655,968,805	651,859,447	657,957,068
kW	1,818,411	1,793,543	1,761,221	1,721,554	1,723,755	1,739,879
Usage per Customer	740,379	786,394	776,553	760,337	755,685	762,866
Sentinel Lights						
Connections	560	369	343	337	320	303
kWh	292,817	246,192	267,435	265,619	262,521	259,459
kW	809	679	721	716	713	705
Usage per Connection	523	667	779	787	822	857
Streetlighting						
Connections	12,408	12,540	12,507	12,702	12,845	12,989
kWh	7,467,591	7,294,838	7,329,519	7,344,781	7,411,072	7,477,962
kW	20,107	20,391	21,037	20,809	20,995	21,184
Usage per Connection	602	582	586	578	577	576
Unmetered Scattered Load						
Connections	465	424	384	422	422	422
kWh	2,335,428	1,798,316	2,264,271	2,247,877	2,231,402	2,215,047
Usage per Connection	5,020	4,241	5,904	5,332	5,293	5,255
Total of Above						
Customer/Connections	65,533	64,494	64,220	64,913	65,467	66,028
kWh	1,223,308,130	1,232,998,827	1,214,015,314	1,202,305,265	1,184,453,504	1,185,817,112
kW from applicable classes	1,839,327	1,814,614	1,782,980	1,743,079	1,745,463	1,761,769
Change from 2011 Board Approved						494
Customer/Connections						-37,491,018
kWh						-77,558
kW from applicable classes						
% Change from 2011 Board Approved						
Customer/Connections						0.8%
kWh						-3.1%
kW from applicable classes						-4.2%

A full discussion of NPEI's weather normalized load forecast is provided in Exhibit 3.

E. Rate Base and Capital Plan

Summary of Major Drivers of the Distribution System Plan

NPEI's Distribution System Plan considers many elements in deriving the overall system strategy. The main drivers are:

- Municipal Road Works.
- Reliability.
- Loss Reduction.
- Capacity.
- Safety.
- Efficiency.
- Distribution system expansion.
- Connection of new residential customers.
- Sustainment.
- Asset Condition Assessment / Equipment at End of Life.
- Unplanned failure of cables / equipment.

Many of the capital projects implemented by NPEI are driven by multiple factors. NPEI's Consolidated Distribution System Plan is included at Exhibit 2, Tab 2, Schedule 1, Attachment 1.

Rate Base Requested for the Test Year

NPEI is requesting approval for a 2015 Test Year Rate Base of $143,761,898. This represents an increase of $24,194,209 or 20.2% over NPEI's last Board-approved Rate Base of $119,567,689, as approved in NPEI's 2011 COS Application (EB-2010-0138). The increase in Rate Base consists of an increase in the average net book value of capital assets of $22,613,805 and an increase in working capital allowance of $1,580,404.

Table 1-4 below provides a summary of NPEI's historical and proposed rate base.

Table 1-4: Summary of Rate Base

Description	2010 Actual	2011 Board Approved	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Gross Fixed Assets	199,799,030	209,143,663	205,934,427	215,869,067	227,308,720	242,097,159	253,282,427
Accumulated Depreciation	(99,765,867)	(106,916,695)	(104,809,919)	(111,886,125)	(115,799,422)	(121,477,482)	(126,414,361)
Net Book Value	100,033,164	102,226,968	101,124,508	103,982,941	111,509,298	120,619,677	126,868,066
Average Net Book Value		101,130,066	100,578,836	102,553,725	107,746,120	116,064,488	123,743,871
Working Capital		122,917,489	128,749,974	136,002,927	144,712,291	152,230,470	153,984,823
Working Capital Allowance %		15%	15%	15%	15%	15%	13%
Working Capital Allowance		18,437,623	19,312,496	20,400,439	21,706,844	22,834,570	20,018,027
Rate Base		119,567,689	119,891,332	122,954,164	129,452,963	138,899,058	143,761,898
			Increase in Rate Base (2015 over 2011 Board Approved) ($):				24,194,209
			Increase in Rate Base (2015 over 2011 Board Approved) (%):				20.2%

Capital Expenditures Requested for the Test Year

NPEI is requesting approval for 2015 Test Year Capital Expenditures of $11,185,268. This represents an increase of $1,840,635 or 19.7% over NPEI's last Board-approved Capital Expenditures of $9,344,633, as approved in NPEI's 2011 COS Application (EB-2010-0138).

Table 1-5 below provides a summary of NPEI's proposed Capital Expenditures for the 2015 Test Year.

Table 1-5: 2015 Proposed Capital Expenditures

	Project	2015 Test Year
System Access		
	Subdivisions	587,004
	Line Relocation due to Municipal Requirements < Materiality	500,000
	Demand based system reinforcements for new commercial services	1,007,500
	Niagara Parks Commission	818,905
	Capital contributions	-827,800
Sub-Total System Access		**2,085,609**
	Miscellaneous System Access	343,500
Total System Access		**2,429,109**
System Renewal		
	Station #22 North of Pew	507,139
	Station #22 South of Pew	143,724
	Crawford Street Rebuild	282,324
	Frederica Street Rebuild	676,144
	Jordan Phase II	449,324
	OH to UG Rolling Acres Phase I	570,500
	System Sustainment/Minor Betterments	680,000
	Replace poles identified with limited structural integrity	431,729
	Replacement of Submersibles & Kiosks with EFD switches and posi-tects	647,029
	Replacement of Transformers with >50PPM PCB Content	495,104
	NWTC Metering	289,605
	Willodell Rebuild	310,710
	Willoughby Dr. Extension	383,293
	Willoughby Drive	372,191
Sub-Total System Renewal		**6,238,817**
	Miscellaneous System Renewal	144,237
Total System Renewal		**6,383,054**
System Service		
	Smart meters	143,150
	Switchgear replacement program	250,002
	King Street 27.6 kV	114,460
	Wi-Max Project	215,000
Sub-Total System Service		**722,612**
	Miscellaneous	203,000
Total System Service		**925,612**
General Plant		
	Building	44,000
	Computer Hardware	240,248
	Computer Software	368,740
	Vehicles	698,878
	General Equipment	95,627
Sub-Total General Plant		**1,447,492**
	Miscellaneous-General Plant	0
Total General Plant		**1,447,492**
Total		**11,185,268**
	2011 Board-Approved Capital Expenditures (EB-2011-0138)	**9,344,633**
	Increase in Capital Expenditures (2015 over 2011 Board-approved) ($)	**1,840,635**
	Increase in Capital Expenditures (2015 over 2011 Board-approved) (%)	**19.7%**

Renewable Energy Connections / Expansions, Smart Grid, and Regional Planning Initiatives

For the 2015 Test Year, NPEI has included $215,000 in its proposed capital expenditures relating to an ongoing WiMax project.

Renewable Energy Connection Costs (Regulation 330/09)

NPEI confirms that it has not seeking any costs to make eligible investments as described in section 79.1 of the OEB Act and O. Reg. 330/09 under the Act.

Further details of NPEI's Rate Base and Capital Plan are provided in Exhibit 2.

F. OM&A Expense

Overall Cost Drivers and Cost Trends

Cost drivers are reviewed in detail in E4/T2/S1. Since NPEI's last rebasing application in 2011 there have been many changes in the electricity distribution sector which have translated into incremental OM&A expenditures. Some of these changes include:

- Implementation of smart meters
- Time of use pricing
- Mandated conservation and demand management programs
- Requirements under the Green Energy Act with respect to renewable generation
- Implementation of revised depreciation and capitalization policies for regulatory accounting purposes as a result of rate regulated entities being required to convert to IFRS effective January 1, 2015.

The City of Niagara Falls resumed all water billing, customer service and collection activities effective May 1, 2014.

OM&A for the Test Year vs. 2011 Board Approved Amount

NPEI is requesting recovery of total OM&A expenses excluding depreciation in the 2015 Test Year of $17,041,580. In 2011, OM&A expenses of $14,076,682 were approved by the Board. This represents an increase in OM&A of $2,965K or 21.06% since the last Board approved amount.

- Of the $2,965K increase, labour and benefits accounts for $1,944K or 22%. As noted above smart meter labour $188K, water related labour ($120K + $475K) and a new systems analyst ($111K) accounts for the majority of the increase other than wage inflationary increases of 2.9% in 2012, 3.1% in 2013, 3.1% in

2014 and an estimated 2.5% in 2015. Inflationary increases total $1,270K of the $1,944K increase.

- Meter reading costs associated with smart meters and MIST noted above account for $332K of the increase from 2011 Board approved through to the 2015 test year.
- Information technology expenses $141K, due to NPEI's investment in software and hardware from 2011 to 2015 as well as NPEI implemented its disaster recovery plan and increased redundancy in 2012 and 2013 to improve operational efficiencies and reduce down time. NPEI has installed mobile lap-tops in its fleet to improve communication and efficiencies in the operations, maintenance and service truck areas. NPEI also increased redundancy of its internet links in 2013.
- Bad debt expense has decreased ($123K) due to increased collection activities by NPEI. NPEI's outside services for collections has increased by $40K from 2011 to the 2015 test year.
- Engineering software maintenance fees increased by $55K due to increased licenses for NPEI's GIS system, and outage management module that was added in 2011.
- Legal, consulting, regulatory, property insurance and property taxes increased by $245K from 2011 to 2015. The property insurance included in the 2011 Board approved amount related to the new service centre located in Smithville was under estimated. The property taxes for NPEI's Smithville service centre are approximately $76K annually.
- Allocated costs related to water were included in the 2011 Board Approved amount at $260K. Water billing and related activities returned to the City of Niagara Falls in 2014. As a result, most of these allocated costs will still exist in 2015 however there will no longer be any shared value with water related activities. For example, the cost of a bill form, postage and envelope were split

between hydro and water. The bill form, postage and envelope will still exist in 2015 however the 50% previously recovered from water will not. These costs were offset by a reduction in postage, third party temporary labour as a result of restructuring.

- Transformer station operations and maintenance expenses have increased $98K from 2011 to 2015. Beginning in 2013, NPEI recorded all costs related to the Kalar transformer station in accounts 5015 and 5112 including property taxes, property insurance, maintenance, and utility expenses. Prior to 2013, these expenses were recorded in various other GL expenses.
- Underground locates have increased $70K from 2011 to 2015 due to an increase in activity. The 2015 amount for locates expense is comparable to the 2013 actuals.
- Maintenance of poles outside services has decreased by $100K from 2011 to 2015. This is due to NPEI using its own labour to do maintenance of poles activities. Labour related to maintenance of poles has increased by $180K from 2011 to 2015.

Inflation Rates used for OM&A Forecasts

A labour inflation rate has been used to calculate 2015 salaries, wages and benefits for the 2015 test year. The current labour agreement between NPEI and Local Union No 636 of the International Brotherhood of Electrical Workers (I.B.E.W.) expires March 31, 2015. For the purposes of preparing the 2015 COS rate application NPEI has estimated a 2.5% increase on wages effective April 1, 2015 and the same increase for salaried employees effective January 1st.

Other costs expected to be impacted by inflation have been projected to increase 2% in the 2015 OM&A test year figures or as specified in Exhibit 4 due to the nature of the OM&A expense.

Total Compensation for the Test Year

Total compensation is projected at $13,536K for the 2015 test year as compared to the 2011 Board approved amount of $10,976K. This represents an increase of $2,559K or 23.3%. See Table 4-9 in E4/T3/S2 for details of wages and benefits.

Wages have increased by $1.9M or 20.8%.

Management FTE's increased by 7, of which four of these FTE's were included in the non-unionized group in the 2011 Board Approved FTE's. Three new management positions since 2011 Board Approved include a CDM coordinator, a Regulatory Affairs and Accounting Manager and a Business Applications Support Manager. These new positions account for approximately $300K of the total increase.

Non-unionized and unionized FTE's decreased by 9.8. Four non-unionized positions were hired as management. Three of these FTE's are a result of the water billing activities returning to the City of Niagara Falls in 2014. In the 2015 test year NPEI has included 1.2 FTE's which are non-unionized co-op apprentices. All remaining FTE's are either management or unionized.

Payroll inflationary increases account for approximately $1.2M of the total increase.

Benefits increased by $634K or 36.3% from the 2011 Board Approved to the 2015 test year. Of this increase OMERS increased $507K or 79.6% from the 2011 Board Approved to the 2015 test year. Health, dental, LTD and life insurance premiums and benefits for active and retired employees increased by $128K or 11.5% from the 2011 Board Approved to the 2015 test year.

Summary

As highlighted in greater detail in Exhibit 8, the overall bill impact to NPEI's customers in this Application is reasonable. As noted above, many of the operating costs driving the increase in the distribution rates since the 2011 Board approved amounts were due to regulatory changes and due to water billing, customer service and collection activities returning back to the City of Niagara Falls.

G. Cost of Capital

NPEI has followed the Report of the Board on Cost of Capital for Ontario's Regulated Utilities dated December 11, 2009 to determine its capital structure and relied on the Board's November 25, 2013 Cost of Capital parameter Updates Letter for the most recent cost of capital parameters. NPEI will update the cost of capital parameters when new parameters are made available prior to the Board's decision regarding NPEI's 2015 Distribution Rates.

H. Cost Allocation and Rate Design

The Cost Allocation Model used by NPEI is version 3.2 issued on June 26, 2014. NPEI has followed the policies as outlined in the March 31, 2011 report and as presented within the Cost Allocation Model.

Current Cost Allocation Study Requirements

On March 31, 2011 the Board issued its Report of the Board on the Review of Electricity Distribution Cost Allocation Policy, EB-2010-0219. This report contained several revisions to the Board's policy with respect to cost allocation that were to be implemented through cost of service applications beginning with the 2012 test year. In the report, the Board noted that the default weighting factors should now be used only in exceptional circumstances and that distributors were expected to develop their own weighting factors that better reflect rate class costing.

NPEI developed its own weighting factors for the 2015 cost allocation study as outlined below. See Exhibit 7/T1/S1 for a detailed discussion related to the weighting factors for Services (Account #1855) and Billing and Collection.

Table 1-6 below illustrates the changes in the Weighting factors from 2011 to 2015 for services in account 1855 and billing and collecting activities.

Table 1-6 Weighting Factors

	Services - 1855		Billing and Collecting	
Customer Class	Default Weights used in 2011	NPEI Weight for 2015	Default Weights used in 2011	NPEI Weight for 2015
Residential	1.00	1.0	1.00	1.0
GS < 50 kW	2.00	2.5	2.00	1.5
GS> 50 kW	10.00	9.0	7.00	2.0
Sentinel	1.00	0.3	1.00	0.8
Streetlight	1.00	0.3	1.00	0.8
Unmetered Scattered Load	1.00	0.3	5.00	0.8

For the 2015 Cost Allocation model, NPEI followed a consistent approach with the initial 2006 and 2011 studies in terms of breaking out 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. The current model incorporates the 2015 test year customer numbers, kWh load forecast, and kW demand values. There have been no direct allocations within the model.

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. NPEI filed a Cost Allocation Study with the 2011 Cost of Service rate application. The 2011 Cost Allocation Study was based on information from the amalgamated companies. The 2015 Cost Allocation Study will be compared to the 2011 Cost Allocation Study in this rate application.

In terms of load profiles, NPEI utilized the load profiles that Hydro One prepared for the 2006 Cost Allocation model and scaled the profiles to match the 2015 load forecast. The 2015 demand values are based on the weather normalized load forecast used to design rates.

Revenue to Cost Ratios Updated for 2015

As per the Report of the Board (EB-2010-0219) dated March 31, 2011 the Board updated the revenue to cost ratios range for the GS > 50 kW rate class and the Sentinel light rate class. The table below 1-7 shows a comparison of the ranges between the 2011 Cost Allocation Study and the 2015 Cost Allocation study.

Table 1-7 Revenue to Cost Ratios Comparison

Class	2015 Board Targets Min to Max		2011 Board Targets Min to Max	
Class	85.0%	115.0%	85.0%	115.0%
Residential	80.0%	120.0%	80.0%	120.0%
GS < 50	80.0%	120.0%	80.0%	180.0%
Streetlight	70.0%	120.0%	70.0%	120.0%
Sentinel Lights	80.0%	120.0%	70.0%	120.0%
Unmetered Scattered Load	80.0%	120.0%	80.0%	120.0%

Current Revenue to Cost Ratios

The results of the revenue to cost ratios from the current 2015 Cost Allocation study are per Table 1-8.

Table 1-8 Revenue to Cost Ratio Current 2015 CA Study

Cost Allocation Based Calculations

Class	Revenue Cost Ratio	Check Revenue Cost Ratios from 2015 Cost Allocation Model	Proposed Revenue to Cost Ratio	Proposed Service Revenue	Miscellaneous Revenue	Proposed Base Revenue	Board Target Low	Board Target High	Final 2011
Residential	81.1%	81.1%	85.000%	18,137,338	1,255,371	16,881,967	85%	115%	85.0%
GS < 50 kW	118.2%	118.19%	118.19%	3,944,596	188,936	3,755,660	80%	120%	109.1%
GS >50	160.3%	160.28%	145.63%	8,391,162	139,088	8,252,074	80%	120%	145.8294%
Sentinel Lights	70.9%	70.86%	80.00%	73,833	5,223	68,610	80%	120%	70.0%
Street Lighting	87.9%	87.92%	87.92%	289,299	5,755	283,544	70%	120%	70.0%
USL	120.6%	120.63%	120.00%	135,100	2,102	132,998	80%	120%	101.5%
TOTAL	100.0%	100.0%		30,971,328	1,596,475	29,374,853			

NPEI's revenue to cost ratios for four of its six rate classes has resulted in being outside the Board's ranges set in the Report of the Board on Cost Allocation released in relation to EB-2010-0219, dated March 31, 2011. These are highlighted in purple in Table 1-8 above.

In comparing the 2015 Cost Allocation study's revenue-to-cost ratios to the Final 2011 revenue-to-cost ratios, the residential rate class is below the 85% ratio which is the ratio that current distribution revenues are allocated at.

The GS > 50 kW and Sentinel lighting rate classes are no longer within the updated ranges set by the Board as per report EB-2010-0219, dated March 31, 2011, whereas both of these rate classes were within the Board's acceptable range for revenue-to-cost ratio in 2011. The Unmetered Scattered Load rate class is also not within the range set by the Board however, this rate class was within the acceptable revenue-to-cost ratio range in 2011.

The GS < 50 kW rate class and Street Light rate class are both within the range noted above in Table 1-7.

Based on the actual 2015 revenue-to-cost ratios outlined in Table 1-8, NPEI proposes the following;

GS < 50 kW rate class proposed revenue-to-cost ratio for 2015 of 118.55% as calculated by the 2015 cost allocation model as this revenue-to-cost ratio is within the Board's range.

Sentinel Light rate class proposed revenue-to-cost ratio for 2015 of 80%. The 2015 cost allocation model calculated a 70.57% revenue-to-cost ratio. NPEI proposes to move this ratio to the minimum ratio of 80% as set by the Board for this rate class for 2015.

Street Light rate class proposed revenue-to-cost ratio for 2015 of 87.82% as calculated by the 2015 cost allocation model as this revenue-to-cost ratio is within the Board's range.

Unmetered Scatter Load (USL) rate class proposed revenue-to-cost ratio for 2015 of 120%. The 2015 cost allocation model calculated a 120.48% revenue-to-cost ratio. NPEI proposes to move this ratio to the maximum ratio of 120% as set by the Board for this rate class for 2015.

The 2015 cost allocation study calculated a revenue-to-cost ratio of 161.17% for the GS > 50 kW rate class. This ratio is outside the Board's updated ranges applicable to 2015 COS rate applications. Due to the GS<50 kW rate class, and USL rate classes being very close or at the maximum ratios as noted above and due to the immaterial impact from moving the Sentinel or Street light rate classes to be closer to their maximum ratio's NPEI proposes to increase the Residential rate class revenue-to-cost ratio.

In order to achieve the maximum ratio of 120% for the GS > 50 kW rate class, the residential rate class would have to increase to 91.92%. NPEI proposes to phase in the revenue to cost ratios as presented below in Table 1-9 beginning in 2015 through to 2017.

Table 1-9 Proposed Revenue to Cost Ratios Phased In from 2015 to 2017

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2015	2016	2017	
	%	%	%	%
Residential	87.00%	89.00%	91.92%	85 - 115
GS < 50 kW	118.55	118.55%	118.55%	80 - 120
GS > 50 kW	138.36%	130.90%	120.00%	80 - 120
Street Lighting	87.82	87.82%	87.82%	70 - 120
Sentinel Lighting	80.00	80.00%	80.00%	80 - 120
Unmetered Scattered Load (USL)	120.00	120.00%	120.00%	80 - 120

Rate Design

NPEI's proposed distribution rates are set to recover the 2015 revenue requirement discussed in Exhibit 6, and reflect the proposed revenue to cost ratios presented in Exhibit 7. NPEI's proposed 2015 Rate Schedule is provided at Exhibit 8, Tab 11, Schedule 1, Attachment 2.

In designing 2015 rates, NPEI proposes to change the fixed/variable split for the Residential and General Service < 50 kW classes, and to maintain the existing fixed/variable split for the General Service > 50 kW, Unmetered Scattered Load, Sentinel Lights and Street lighting classes.

NPEI's current fixed/variable split by rate class is outlined in Table 1-10 below and NPEI's proposed Fixed/Variable Split is shown in Table 1-11 below.

Table 1-10: Current Fixed / Variable Split

2015 Projected Distribution Revenue at Existing Rates						
Rate Class	Fixed Rate	Volumetric Rate	Fixed Revenue	Variable Revenue	Fixed %	Variable %
Residential	16.06	0.0161	9,070,668	6,426,586	58.53%	41.47%
General Service < 50 kW	37.79	0.0138	1,988,703	1,638,622	54.83%	45.17%
General Service > 50 kW	179.58	4.2400	1,857,576	6,927,821	21.14%	78.86%
Unmetered Scattered Load	19.53	0.0137	98,789	30,346	76.50%	23.50%
Sentinel Lighting	12.87	16.0553	46,795	11,319	80.52%	19.48%
Street Lighting	1.15	4.4657	179,253	94,602	65.46%	34.54%

Table 1-11: Proposed Fixed / Variable Split

2015 Projected Distribution Revenue at Proposed Rates						
Rate Class	Fixed Rate	Volumetric Rate	Fixed Revenue	Variable Revenue	Fixed %	Variable %
Residential	19.96	0.0152	11,273,383	6,070,649	65.00%	35.00%
General Service < 50 kW	46.39	0.0111	2,441,279	1,314,381	65.00%	35.00%
General Service > 50 kW	159.22	3.7887	1,647,013	6,142,529	21.14%	78.86%
Unmetered Scattered Load	20.14	0.0141	101,871	31,293	76.50%	23.50%
Sentinel Lighting	15.26	19.0381	55,489	13,422	80.52%	19.48%
Street Lighting	1.19	4.6237	185,594	97,949	65.46%	34.54%

Table 1-12 below illustrates a comparison of fixed rates to the ceiling and floor amounts calculated by the 2015 Cost Allocation Model.

Table 1-12: Comparison of Fixed Rates

Comparison of Fixed Rates					
Rate Class	Current	At Existing Fixed/Variable Split	Proposed	Cost Allocation Model - Floor	Cost Allocation Model - Ceiling
Residential	16.06	17.97	19.96	6.92	28.59
General Service < 50 kW	37.79	39.13	46.39	11.71	38.26
General Service > 50 kW	179.58	159.22	159.22	55.28	179.58
Unmetered Scattered Load	19.53	20.14	20.14	0.29	19.53
Sentinel Lighting	12.87	15.26	15.26	4.33	24.43
Street Lighting	1.15	1.19	1.19	0.13	16.53

Residential

NPEI's current Board approved monthly service charge for the Residential class is $16.06 per month, and the current volumetric charge is $0.0161 per kWh. Based on 2015 projections at existing rates, the result is a fixed/variable split of 58.53% fixed revenue and 41.47% variable revenue. Applying the 58.53% fixed / 41.47% variable proportions to the proposed 2015 base revenue requirement for the Residential class would result in a monthly service charge of $17.97.

In March 2010 the Board undertook to review revenue decoupling for the province's electricity and natural gas distributors (EB-2010-0060 – Distribution Revenue Decoupling). Board staff released a paper by the Pacific Economic Group LLC, *"Review of Distribution Revenue Decoupling Mechanisms"* (the "PEG Report"). Staff prepared a Report to the Board summarizing the PEG Report and stakeholder comments. The Board suspended the initiative to complete the development of its *Renewed Regulatory Framework for Electricity* ("RRFE"). The Board indicated at the time it would restart the review once the RRFE had established the mechanisms for planning and performance. On April 3, 2014, the Board released its *Draft Report on Rate Design for Electricity Distributors* (EB-2012-0410), which proposes implementing a fixed monthly charge for distribution services for the Residential and General Service < 50 kW classes. The draft rate design report sets out three rate design proposals for revenue recovery. The Board has invited stakeholders to make comments on the proposals.

Section 2.11.2 of the Filing Requirements states: *"While the policy consultation is still ongoing, distributors can propose a fixed monthly charge within their applications based on the proposed policy options as applicable, for the Board's consideration."*

NPEI does not propose to adopt any of the three specific proposals described in the draft report for its 2015 rates. However, given that the Board has determined it will proceed with revenue decoupling for the low volume classes, NPEI submits that it is appropriate to begin increasing the fixed proportion of the Residential and General Service < 50 kW classes at this time. Therefore, NPEI proposes a 65% fixed / 35% variable split for the Residential class for 2015. This results in a Residential monthly service charge of $19.96 and a Residential volumetric charge of $0.0152 per kWh.

General Service < 50 kW

NPEI's current Board approved monthly service charge for the GS < 50 kW class is $37.79 per month, and the current volumetric charge is $0.0138 per kWh. Based on 2015 projections at existing rates, the result is a fixed/variable split of 54.83% fixed revenue and 45.17% variable revenue. Applying the 54.83% fixed / 45.17% variable proportions to the proposed 2015 base revenue requirement for the GS < 50 kW class results in a monthly service charge of $39.13.

As discussed above, given the revenue decoupling initiative, NPEI submits that it is appropriate to begin increasing the fixed proportion of the GS < 50 kW class at this time. Therefore, NPEI also proposes a 65% fixed / 35% variable split for the GS < 50 kW class for 2015. This results in a monthly service charge of $46.39 and a volumetric charge of $0.0111 per kWh.

General Service > 50 kW

NPEI's current Board approved monthly service charge for the GS > 50 kW class is $179.58 per month, and the current volumetric charge is $4.2400 per kW. Based on 2015 projections at existing rates, the result is a fixed/variable split of 21.14% fixed revenue and 78.86% variable revenue.

NPEI notes that the *Draft Report on Rate Design for Electricity Distributors* does not address revenue decoupling for the GS > 50 kW class. Accordingly, NPEI proposes to maintain the existing fixed / variable split. Applying the 21.14% fixed / 78.86% variable proportions to the proposed 2015 base revenue requirement for the GS > 50 kW class results in a monthly service charge of $159.96 and a volumetric charge of $3.7887 per kW.

<u>Unmetered Scattered Load</u>

NPEI's current Board approved monthly service charge for the Unmetered Scattered Load class is $19.53 per month, and the current volumetric charge is $0.0137 per kWh. Based on 2015 projections at existing rates, the result is a fixed/variable split of 76.50% fixed revenue and 23.50% variable revenue.

NPEI proposes to maintain the existing fixed / variable split for the Unmetered Scattered Load class. Applying the 76.50% fixed / 23.50% variable proportions to the proposed 2015 base revenue requirement for the Unmetered Scattered Load class results in a monthly service charge of $20.14 and a volumetric charge of $0.0141 per kWh.

<u>Sentinel Lights</u>

NPEI's current Board approved monthly service charge for the Sentinel Light class is $12.87 per month, and the current volumetric charge is $16.0553 per kW. Based on 2015 projections at existing rates, the result is a fixed/variable split of 80.52% fixed revenue and 19.48% variable revenue.

NPEI proposes to maintain the existing fixed / variable split for the Sentinel Light class. Applying the 80.52% fixed / 19.48% variable proportions to the proposed 2015 base revenue requirement for the Sentinel Light class results in a monthly service charge of $15.26 and a volumetric charge of $19.0381 per kW.

<u>Street lighting</u>

NPEI's current Board approved monthly service charge for the Street lighting class is $1.15 per month, and the current volumetric charge is $4.4657 per kW. Based on 2015 projections at existing rates, the result is a fixed/variable split of 65.46% fixed revenue and 34.54% variable revenue.

NPEI proposes to maintain the existing fixed / variable split for the Street lighting class. Applying the 65.46% fixed / 34.54% variable proportions to the proposed 2015 base revenue requirement for the Street lighting class results in a monthly service charge of $1.19 and a volumetric charge of $4.6237 per kW.

NPEI notes that the proposed fixed charges for two rate classes (General Service < 50 kW and Unmetered Scattered Load) are above the ceiling rates as calculated by the cost allocation model. NPEI requests that the Board accept the rate design as presented.

As discussed above, the Board has determined to proceed with revenue decoupling for the low volume classes. Therefore, NPEI submits that it is appropriate to begin moving the GS<50 kW class toward a greater proportion of fixed revenue, even if the resulting fixed charge is above the cost allocation ceiling.

For the Unmetered Scattered Load class, although the proposed fixed charge is slightly higher than the cost allocation ceiling ($20.14 proposed versus $19.53 ceiling), the proposed fixed charge was determined based on maintaining the existing fixed / variable revenue proportions. The same rate design principle of maintaining the existing fixed / variable split was also applied to the other unmetered rate classes (Sentinel Lights and Street lighting). Therefore, NPEI submits that the proposed fixed charge of $20.14 is appropriate in order to implement consistent rate design treatment among the unmetered rate classes (Unmetered Scattered Load, Sentinel Lights and Street lighting).

I. Deferral and Variance Accounts

NPEI has followed the Board's guidance in the *Accounting Procedures Handbook* ("APH") and the *Accounting Procedures Handbook Frequently Asked Questions* ("APH FAQ") for recording amounts in the deferral and variance accounts. In addition, NPEI has also been guided by the *Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative* ("EDDVAR") (EB-2008-0046, issued July 31, 2009), the *Guideline, Smart Meter Funding and Cost Recovery – Final Disposition* (G-2011-0001, issued December 15, 2011) and the *Filing Requirements for Electricity Distribution Rate Applications – 2014 Edition for 2015 Rate Applications (*revised July 18, 2014).

NPEI has completed the Board's 2015_EDDVAR_Continuity_Schedule_CoS_v2_4 Excel model (See Exhibit 9, Tab 1, Schedule 1, Attachment 1), which is also being submitted in live Excel format along with this Application.

Group 1 Accounts

NPEI last disposed of Group 1 account balances in its 2014 IRM Rate Application (EB-2013-0154), which incorporated the audited balances as at December 31, 2012. The Filing Requirements specify that the continuity schedule should show the balance details from the last disposition. Accordingly, the accompanying EDDVAR Continuity Schedule includes NPEI's Group 1 account balances from the close of 2012 onwards.

Group 2 Accounts

NPEI last disposed of Group 2 account balances in its 2011 COS Rate Application (EB-2010-0138), which incorporated the audited balances as at December 31, 2009. The Filing Requirements specify that the continuity schedule should show the balance details from the last disposition. Accordingly, the accompanying EDDVAR Continuity Schedule includes NPEI's Group 2 account balances from the close of 2009 onwards.

Other Accounts

1576 Accounting Changes under CGAAP

This account is used by NPEI to record the financial differences arising as a result of changes to accounting depreciation or capitalization policies, as mandated by the Board in 2013. NPEI has not requested disposition of Account 1576 balances in any previous proceeding.

NPEI has not made any adjustments to deferral and variance account balances that were previously approved by the Board on a final basis in previous cost of service or IRM proceeding.

Carrying charges, where applicable, have been calculated at the Board's prescribed interest rates on monthly opening principal balances. In accordance with the Filing Requirements, the most recent posted interest rate (1.47% for Quarter 3 - 2014) has been used to forecast carrying charges from to April 30, 2015.

NPEI is not requesting any new deferral or variance accounts in this Application.

The deferral and variance account balances requested for disposition consist of:

Both RPP and Non-RPP	($6,983,832)
Non-RPP only	$1,582,461
Total	($5,401,371)

NPEI is proposing four sets of Rate Riders in this application:

- Deferral/Variance Rate Riders to be effective for 1 year;
- Global Adjustment Rate Riders to be effective for 1 year;
- Account 1576 Rate Riders to be effective for 2 years;
- Stranded Meter Rate Riders to be effective for 2 years.

Table 1-13 below shows NPEI's proposed totals for disposition and proposed Rate Riders, to be effective May 1, 2015.

Table 1-13: Proposed Rate Riders

Proposed Rate Rider for Deferral / Variance Accounts Balances (excluding Global Adj.)

Disposition Period in Years: 1

Rate Class	Units	Allocated Balance	Rate Rider	
Residential	kWh	(258,487)	-0.0006	$/kWh
General Service < 50 kW	kWh	(124,020)	-0.0010	$/kWh
General Service > 50	kW	(755,503)	-0.4388	$/kW
Unmetered Scattered Load	kWh	(612)	-0.0003	$/kWh
Sentinel Lighting	kW	1,307	1.8253	$/kW
Street Lighting	kW	53,611	2.5764	$/kW
		(1,083,705)		

Proposed Rate Rider for RSVA - Global Adjustment

Disposition Period in Years: 1

Rate Class	Units	Allocated Balance	Rate Rider	
Residential	kWh	74,797	0.0023	$/kWh
General Service < 50 kW	kWh	40,890	0.0023	$/kWh
General Service > 50	kW	1,449,693	0.8894	$/kW
Unmetered Scattered Load	kWh	-	0.0000	$/kWh
Sentinel Lighting	kW	118	0.8657	$/kW
Street Lighting	kW	16,963	0.8239	$/kW
		1,582,461		

Proposed Rate Rider for Accounts 1575 and 1576

Disposition Period in Years: 2

Rate Class	Units	Allocated Balance	Rate Rider	
Residential	kWh	(2,463,502)	-0.0030	$/kWh
General Service < 50 kW	kWh	(741,981)	-0.0030	$/kWh
General Service > 50	kW	(3,919,445)	-1.1383	$/kW
Unmetered Scattered Load	kWh	(13,431)	-0.0030	$/kWh
Sentinel Lighting	kW	(1,587)	-1.1079	$/kW
Street Lighting	kW	(43,885)	-1.0545	$/kW
		(7,183,832)		

Proposed Rate Rider for Stranded Meter Disposition

Disposition Period in Years: 2

Rate Class	Units	Allocated Balance	Rate Rider	
Residential	Customer	1,008,600	0.89	$ per Month
General Service < 50 kW	Customer	275,104	2.61	$ per Month
General Service > 50		-		
Unmetered Scattered Load		-		
Sentinel Lighting		-		
Street Lighting		-		
		1,283,705		

Total for Disposition		**(5,401,371)**

Further details on NPEI's deferral and variance accounts and proposed disposition are provided in Exhibit 9.

J. Summary of Bill Impacts

The OEB Appendix 2-W is included in E8/T13/S1/Att1 and has been prepared for each NPEI rate class and presents the total bill impacts by level of consumption for customers. The impacts are calculated by comparing existing rates approved in NPEI's 2014 IRM (EB-2013-0136) to proposed distribution rates for NPEI's 2015 test year including all applicable rate riders and proposed 2015 Retail Transmission Service Rates.

Table 1-14 below details the Total Bill impact for typical NPEI customers.

Table 1-14: 2015 COS – Bill Impact for Typical NPEI Customers

	Volume		2014 Distribution Charges	2015 Proposed Distribution Charge	Distribution Charges	Distribution Charges	2014 Total Bill	2015 Proposed Total Bill	Total Bill	Total Bill
Customer Class	kWh	kW			$ Change	% Change			$ Change	% Change
Residential	800		$ 30.49	$ 34.87	$ 4.38	14.37%	$ 125.19	$ 129.95	$ 4.76	3.80%
GS<50 kw	2000		$ 92.99	$ 97.76	$ 4.77	5.13%	$ 315.05	$ 319.80	$ 4.75	1.51%
GS>50 kW	65000	180	$ 1,802.84	$ 1,751.90	$ (50.94)	-2.83%	$ 9,359.28	$ 9,304.43	$ (54.85)	-0.59%
USL	250		$ 25.78	$ 27.06	$ 1.28	4.97%	$ 51.39	$ 52.69	$ 1.30	2.53%
Sentinel	44	0.12	$ 15.18	$ 18.30	$ 3.12	20.55%	$ 19.87	$ 23.04	$ 3.17	15.95%
Streetlighting	50	0.13	$ 2.19	$ 2.71	$ 0.52	23.74%	$ 7.26	$ 7.78	$ 0.52	7.16%

Table 1-15 below details the bill impact related only to distribution for typical NPEI customers.

Table 1-15: Distribution Bill Impacts

Monthly Bill Impacts
As per Sub-Total A of Appendix 2-W

	Volume		2014 Distribution Charges	Proposed 2015 Distribution Charges	Total Distribution Charges only excluding Pass through	
Customer Class	kWh	kW	$	$	$ Change	% Change
Residential	800		29.80	30.61	$ 0.81	2.73%
GS<50 kw	2000		69.41	65.20	$ (4.21)	-6.06%
GS>50 kW	65000	180	942.78	636.29	$ (306.49)	-32.51%
USL	250		22.96	22.92	$ (0.04)	-0.17%
Sentinel	44	0.12	14.80	17.41	$ 2.61	17.67%
Streetlighting	50	0.13	1.73	1.65	$ (0.08)	-4.42%

File Number: EB-2014-0096

Date Filed: September 23, 2014

Exhibit 1

Tab 3 of 6

Customer Engagement

Customer Engagement

The *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRFE Report") contemplates enhanced engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations. NPEI strives to provide superior service to our customers, and continues to improve our level of customer engagement.

Customer Service Clerks are available to assist customers both over the phone and in person. NPEI also has a Customer Service Lead and Customer Service Supervisors on staff, to ensure that complex customer issues are escalated when necessary and promptly resolved.

NPEI has proactively engaged customers on a regular basis by participating in community events to raise awareness about electrical safety, conservation and demand management, and understanding their bills. Direct communication with our customers is done through messages on the outside of billing envelopes, messages on the front of the monthly bills, billing inserts, website interaction, social media, and customer surveys.

Electrical Safety

Each year, NPEI implements electrical safety seminars in local schools. These seminars were initiated in the 1980s, and were originally conducted by operations employees of Niagara Falls Hydro (one of NPEI's predecessor LDCs.) NPEI subsequently engaged a third party contractor to provide the seminars, which are given at a number of schools within NPEI's service territory each year.

Conservation

The Conservation and Demand Management ("CDM") work conducted by NPEI includes a significant outreach to our customers. NPEI has consistently encouraged our customers to conserve electrical usage and reduce demand by active participation in the OPA's CDM programs. NPEI participates in a number of community events with displays highlighting the current CDM program offerings. Our CDM Program Advisor makes direct contact with our larger customers regarding CDM and assists them with their OPA applications. NPEI's CDM efforts have resulted in significant consumption reduction, with NPEI's 2013 Scorecard indicating that 94.7% of our 2011-2014 target has been achieved at the end of 2013.

Monthly Bills

Most NPEI customers receive a physical bill in the mail, and NPEI uses this opportunity to communicate additional information via messages on the outside of the envelope, separate inserts, and messages on the bill itself. Many of the messages are coordinated with the OEB, OPA, and other agencies, and include information about retailers, rate changes, conservation and demand management programs, electrical safety, and references to our website. A growing number of NPEI's customers are opting for e-billing, where communication can be accomplished using email and NPEI's web portal.

Website and Phone Contact

NPEI's maintains a comprehensive website that is used to provide a wide variety of information to our customers, including:

- E-billing.
- Smart Meters.
- Deposit and Collection Policy.
- Payment Options.
- 24 Hour Emergency Service.
- Capital Projects.
- Scheduled and Current Outages.
- Conservation and Demand Management.
- NPEI's Conditions of Service.
- Corporate Information.

The "Contact Us" section allows customers to communicate with us via telephone, regular mail, or email. A toll free number is provided for those customers who are within our service area but outside the local calling zone. In 2013, NPEI received an average of 5216 telephone calls per month, and an average of 399 enquiries per month. In addition, our Customer Service staff proactively contact customers who are behind in their payments to make them aware of alternative arrangements and other resources they can access.

NPEI has a web portal, "My Account", which provides customers with access to their energy data in electronic format as well as their electronic bills. NPEI has tracked customer feedback on the portal, and as upgraded the My Account platform as a result of the feedback. NPEI is in the process of adding more self-serve options for its customers, including new account process, update of account information and application of payment plans.

Customer Surveys

NPEI conducted its first formal customer survey in June 2014. The results of this survey will allow NPEI to further incorporate customer needs and preferences into its planning process. The customer priorities identified by the survey include: utility response time and communication and education to customers on how to save on their monthly bills. Based on the survey results, NPEI plans to address customer needs and preferences in several projects and processes, including:

1. Education and Information to Customers:
    - Call-Center Tracking of Customers' Inquiries, Complaints and Feedback with Implications for DS Planning.
    - Outages and First Responses.
    - Capital Improvement Projects and Construction Work.
    - REG Opportunities, Programs, Modalities and Connections Procedures.
    - Customer Access to Energy Data.
    - Customer Education on Electricity Bills and Price.
    - CDM Engagement Actions.
    - Electricity Storage.

2. Customer Consultation Work
    - CDM Market Characterization Customer Interviews and Site Visits.
    - Call-Centre Transactional Survey.
    - Biennial Customer Satisfaction Survey.

3. Service-Territory Stakeholder Consultations
    - CDM Market Characterization Market Actor Interviews.
    - Results of Regular Stakeholder Meetings
    - Consultation with Technical Service Providers

4. Participation in Consultations with OPA & HONI
    - Consultations in Regional Processes
    - Consultations with HONI
    - Consultations on REG Interconnection
    - Consultations on REG Investments

The Board's Appendix 2-AC has been completed, and is included at Exhibit 1, Tab 3, Schedule 1, Attachment 1.

NPEI's Customer Engagement Plan is included at Exhibit 1, Tab 3, Schedule 1, Attachment 2.

NPEI's Customer Engagement Baseline Report is included at Exhibit 1, Tab 3, Schedule 1, Attachment 3.

NPEI's 2014 Customer Survey is included at Exhibit 1, Tab 3, Schedule 1, Attachment 4.

Attachment 1 of 4

OEB Appendix 2-AC Customer Engagement

File Number:	EB-2014-0096
Exhibit:	1
Tab:	3
Schedule:	1
Page:	1
Date:	29-Aug-14

Appendix 2-AC
Customer Engagement Activities Summary

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
1. Definition and Schedule of Customer Engagement Plan	Identification that in order to document and respond to customer needs and preferences, plan needed to be in place. Within the plan, define principles of customer engagement, the documentation and process to be followed to track customer needs and preferences. Schedule quarterly meetings. Follow through on lessons learned.	Take an integrated approach to customer engagement: efficient engegement, investigate DS, smart grid, renewables, CDM. Coordinated, effective planning and plan. Created a standard consultation form to document the purpose of each consultation activity, whether the distributor initiated the consultation activity or was invited to participate in it, the nature and prospective tming of the final deliverables. Documentation of meeting minutes, survey result tables, interview notes. Plan to complete quarterly review meetings and Year End report of progress of customer engagement. Created a solid basis for monitoring and tracking.
2. Identify customer needs, preferences, priorities: use of data analytics from customer surveys, customer call activity, outages. Take a long term perspective by applying principles of customer engagement over a 5 year period of distribution system plan.	Customer needs and preferences identified: utility response time, communication and education to customers on how to save on their monthly bill. Integration of customer needs/preferences/priorities in DS planning and plan.	Bi-annual survey completed; incorporate changes to customer service reporting, call scripts. Call trending and reporting of customer inquiries, complaints and feedback, review of customer inquiries including response time. Post outage review of data. Document information to customers on outages and first response. Communicate to customers on capital improvement projects and construction work. As DS planning progresses, NPEI will identify any new issue emerging from customer comment that may necessitate customer input. NPEI will increase in perception that customers feel that they are being consulted and their views are being addressed.
3. Facilitate customer access to energy consumption data and behind the meter services.	Make options available to facilitate customer access to consumption data in an electronic format. Provide customers with ability to make decisions affecting electricity costs. Educate customers on energy bills and price.	NPEI has a web portal, My Account, which it provides access to its customers to their energy data in electronic format, as well as, their electronic bills. NPEI has tracked customers feedback on the portal and has upgraded the My Account platform as a result of feedback. NPEI is in progress of adding more self service options for the customer including new account process, update of account information, application of payment plans. NPEI will highlight any improvements made year to year within the Annual Customer Engagement Year End report.
4. Consult with the Ontario Power Authority, with the regionally interconnected distributors and with the transmittor.	Participation in any regional planning process. Integrate final consultation on any potentional regional planning processes that will impact NPEI in their Distribution System Plan.	NPEI will obtain letter from OPA and from Hydro One that no region process is currently under way. NPEI did learn that as a utility we are in OPA group 3, meaning that there are no regional investments impacting our area within the next 5 years. NPEI will document information to customer on REG opportunities, modalities and connection.
5. Conservation program access and Site Visits	Access to conservation programs for all accounts, understand from customers what is needed and wanted from conservation programs	NPEI completed data collection and consultation to determine key market characters within service area. NPEI completed market character interviews and site visits. NPEI will integrate tracking consultation topics into CDM engagement activities.
6. Educate and inform customers	Deliver OPA contracted province-wide conservation and demand management programs	One on one customer meetings, group events, community events. Applicant representatives for business to assist with application process for conservation programs.
7. Customer Consultations	CDM market characterization. Customer interviews and site visits	Identify market segments to achieve kWh savings. Customer preferences needs and priorities related to CDM and other DSP matters from greenhouses, hotel/motel sectors
8. Service territory stakeholder consultations	CDM market characterization. Customer interviews and site visits	Particular market actors ie. assist with identifying and implementing strategies for conservation energy demand savings for customers

Note: Use "ALT-ENTER" to go to the next line within a cell

Attachment 2 of 4

NPEI Customer Engagment Plan

NPEI Customer Engagement Plan

Date: July 31, 2014

Submitted to:
Niagara Peninsula Energy Inc.

Submitted by:
ICF International
808-277 Wellington Street West, Suite
Toronto. Ontario M5V 3E4 Canada

Table of Contents

1 Introduction

In October of 2012, the Ontario Energy Board (OEB/Board), set new policy for distribution system network planning in Ontario, requiring electricity distributors to take a comprehensive and integrated approach to planning. The OEB put forth how distributors are to accomplish this planning in a recently released Board Report (Filing Requirements for Electricity Transmission and Distribution Applications Chapter 5 Consolidated Distribution System Plan Filing Requirements, March 28, 2013, referred to hereon as Chapter 5), which describes in detail how the distributor is to prepare the Distribution System Plan (DSP) and what the plan is to contain.

In particular, electricity distributors are required to meet the OEB Customer Focus Outcome by demonstrating that the distributor has responded to identified customer preferences (e.g. Conservation and Demand Management {CDM}, distributed generation, load management, access to energy data, and expectations during outages). Customer engagement is essential to achieving the Customer Focus Outcome. Distributors need to know which services are valued by their customers. These new requirements have the following implications on how distributors consult with their customers:

- The level of scrutiny imposed by the OEB on distributors with regard to how they consult with their customers and react to feedback has been increased.
- In turn, distributors are expected to document all customer engagement work more extensively than they have in the past, and, in particular, are to demonstrate how customers' views, needs, preferences and priorities are accounted for in the DSP and their distribution system operations.
- More consultation and surveying work of customers is required from distributors, although the exact nature of the new survey methods expected by the OEB is still to be determined.
- Distributors are to address customer engagement in an integrated manner both at the distribution system (DS) planning stage, when delivering the engagement activities, and when interpreting customers' feedback.
- Just as in any other aspects of DS planning, distributors should subject their customer engagement work to continuous improvement by establishing performance metrics, a feedback loop and then by making course corrections and showing progress on a year-to-year basis.

Since the DSP must serve present and future customers, customer engagement will provide support for identifying current customer needs/preferences/priorities (e.g. CDM, renewables connection, load management, storage, access to customer consumption data, and customer information needs related to understanding electricity bills) and forecasting future ones.

The purposes of this document, NPEI's Customer Engagement Plan, is to:

- Layout the overarching customer engagement strategy that NPEI intends to follow, starting from the filing of its DSP, and until the next DSP filing.
- Provide a high-level overview of the customer engagement activities (information, customer education and consultation) that are planned over the course of the two year customer engagement plan planning horizon.

NPEI retained ICF International to prepare a customer engagement strategy and plan under the direction of a cross-departmental steering committee. This document is the culmination of that work. It contains a 5-year strategy and a 2-year engagement plan, which is to be updated on a yearly basis, showing two years ahead as a sliding window.

The Customer Engagement Plan document is divided as follows:

- Section 2 – 2014-2018 Customer Engagement Strategy
  - 2.1 Compliance Framework
  - 2.2 Governance Framework
  - 2.3 Documentation, Reporting and Planning Cycle
- Section 3 – 2014-2015 Customer Engagement Plan
  - 3.1 Education and Information to Customers
  - 3.2 Customer Consultation Work
  - 3.3 Service-Territory Stakeholders Consultation Work
  - 3.4 Participation in Consultation with the OPA and HONI
  - 3.5 Consultation Topics
  - 3.6 Deliverables, Milestones and Timeline

2 2014-2018 Customer Engagement Strategy

The Five-Year Customer Engagement Strategy is a description of the approach for customer engagement that both demonstrates compliance with the OEB's new customer engagement requirements and related Customer Focus Outcome, and that aligns with NPEI's corporate Vision and Mission. The Customer Engagement Strategy is a standing framework that will be followed until updated in time for the next DSP filing.

The Engagement Strategy is divided as follows:

- Section 2.1 Compliance Framework – Describes the compliance framework and the implications regarding Chapter 5 requirements.
- Section 2.2 Governance Framework – Describes responsibility for customer engagement and integration of engagement into the DS planning and the DSP.
- Section 2.3 Documentation, Reporting and Planning Cycle – Describes how customer engagement work is to be planned, executed, documented, and reported on to achieve continuous improvement.

2.1 Compliance Framework

The OEB has defined the Customer Focus Outcome for distributors as: *services provided in a manner that responds to identified customer preferences*.

As such, the three specific goals of the five-year Customer Engagement Strategy are:

Exhibit 1 Goals of the Customer Engagement Strategy

Goal 1	Goal 2	Goal 3
• Contribute to Achievement of Customer Focus Outcome	• Provide a Framework to Meet Chapter 5 Engagement Requirements	• Develop Principles to Guide Customer Engagement Plan

Exhibit 2 describes the framework NPEI intends to use to guide its customer engagement planning and implementation.

Exhibit 2 Customer Engagement Compliance Framework

Principles of Customer Engagement	Strategic Engagement Plan Response	Engagement Outcome
Take an integrated approach to customer engagement	Leverage existing points of customer contact for broader based information gathering	Efficient engagement; minimal customer fatigue
	Implement broad based customer inquiry	Investigate DS , smart grid, renewables, storage, CDM, regional, other needs
	Involve utility staff across departments in engagement plan	Inquiry covers key aspects of DS planning
		Coordinated, effective planning and plan
Take a long term perspective	Apply principles over 5-year period of DSP	Consistent inquiry strategy over DSP planning horizon
Participate in regional planning	Engage customers in any regional planning processes, as appropriate	Customers understand and have opportunity for input into broader planning context
Serve present and future customers	Identify present and future customer needs/ preferences/ priorities and prepare/ implement appropriate responses in DSP	Solid basis for monitoring and tracking trends
		Demonstration that customer needs/preferences/priorities are served by DSP
Align utility interest with customers	Identify present and future customer needs/ preferences/ priorities and prepare/ implement appropriate responses in DSP	Understanding of customer needs/preferences/ priorities
		Integration of customer needs/preferences/priorities in DS planning and Plan
Provide information on engagement opportunities	Provide meaningful opportunities for engagement	Increase in perception of customers that they are being consulted and their views are being addressed
Measure engagement performance	Identify and track engagement performance metrics	Solid basis for monitoring and tracking trends
Achieve continuous improvement in engagement	Assess engagement performance at key intervals and make adjustments, as appropriate	Increase in representativeness of consultation and number of participants
		Increase in the perception of customers that they are being consulted, and that their views are being addressed

Principles of Customer Engagement	Strategic Engagement Plan Response	Engagement Outcome
		Increase in satisfaction of participants in consultation, including consultation format and media used
		Increase in the level of relevance or usability of the consultation outputs
Carry out engagement consistent with corporate Mission/Values/ Vision	Engage customers with integrity, fairness, responsibility respect, transparency and provide best possible service	Customer engagement meets same standard of excellence as other utility activities
Carry out engagement consistent with Conditions of Service and any relevant corporate policies	Review Conditions of Service and relevant corporate policies in Plan development/ delivery	Consistent approach to customer engagement

The strategic engagement responses, which will feed directly into the Customer Engagement Plan, flow directly from the guiding principles and are consistent with NPEI's corporate Mission, Vision, and Values. The guiding principles are based on OEB Chapter 5 requirements and the need for customer engagement to contribute positively toward NPEI's achievement and demonstration of the Customer Focus Outcome.

For each of the engagement outcomes listed here, one or more performance metrics have been identified for tracking through the year to measure performance and show improvement. The full matrix, including suggested performance metrics, is provided in Appendix B.

2.2 Governance Framework

The Customer Engagement Strategy is designed to enable NPEI to coordinate a wide array of engagement activities in an integrated fashion across departments; analyze, document and interpret the results; make DS decisions on the basis of these results more effectively; and then subject NPEI's customer engagement work to performance management, review, and then improvement year to year.

NPEI has created a Customer Engagement Steering Committee to orient, oversee as necessary, and integrate all customer engagement work done by Customer Services and IT, Operations, Engineering, Finance, and Conservation and Demand Management (CDM). Members of the Committee will also review the feedbacks and market intelligence being collected, convey it to their own team/department, decide whether and how the feedback needs to be acted on, and bring back the decisions made and report the resulting actions to the Committee for effective documentation of NPEI's progress toward the Customer Focus Outcome.

The Steering Committee is composed of:

- Chief Conservation Officer
- President and CEO
- Vice President, Customer Services & IT
- Vice President, Engineering
- Vice President, Finance
- Vice President, Operations

The Committee will have a Coordinator, who is responsible for preparing, facilitating and taking minutes. The Committee will meet on a quarterly basis. Meeting preparation will consist of collecting and gathering all preliminary consultation results. All Committee members will be responsible for launching (in some cases) and implementing operations activities that reside in their respective areas of responsibility, synthesizing early engagement results, bringing to the attention of other Committee members any issues that require resolution, and then acting on the resolution within their areas of responsibility.

The Coordinator will be responsible for coordinating the finalization of the NPEI Engagement Plan for 2014-2015, the drafting of the Customer Engagement Baseline Report, the drafting of the Year-End Report, and then the updating of the two-year Customer Engagement Plan on an annual basis. The definition of the aforementioned reports will be provided in Section 2.3. The Coordinator will be responsible for these documents to be completed, but will rely on all other Committee members and their respective teams to contribute with data, analysis, decisions and write-ups.

The Steering Committee will preside over and operationalize the establishment and the monitoring of customer engagement performance metrics as detailed in the Compliance Matrix shown in Appendix A. The Steering Committee will review these metrics and make decisions on any improvements to customer engagement year to year as measured by these metrics. The review will be documented in the Year-End Customer Engagement Reports, on an annual basis.

2.3 Reporting and Planning Cycle

The Customer Engagement framework at the core of NPEI's Engagement Strategy is a structure that will be sustainable, self-correcting, and self-improving. The Steering Committee will meet quarterly to discuss any issues that might arise during consultation and will enact a formal annual review--action--adaptation cycle documented through the following key documents, which will be updated on a regular basis:

- The **2014-2018 Five-Year Customer Engagement Strategy** The first five-year Customer Engagement Strategy will be filed with the DSP in August 2014, and will be reviewed and updated as needed every 5 years.
- The **2014-2015 Two-Year Customer Engagement Plan,** will be filed with the DSP in August 2014, and will be updated on an annual basis.
- The **2014 Customer Engagement Baseline Report** will be filed with the DSP in August 2014. The Baseline Report will provide a detailed description of NPEI's current customer engagement activities, and any conclusions, recommendations and actions planned as a result of the consultation.

- The **Customer Engagement Year-End Reports** are expected to be completed by March of each year, starting in 2015, based on data agglomerated in December of the year before. The first Year-End Report will be an update of the Baseline Report, and subsequent Year-End Reports will be an update of the report from the previous year. The content will be similar to that of the Baseline Report, but will highlight any evolution in customer needs, preferences, and priorities, and any new decisions and actions made to improve service and contribute to the achievement of the Customer Focus Outcome.
- The **Two-Year Customer Engagement Plans** are expected to be completed in March of each year, starting in 2015. Each plan will contemplate all engagement activities to be planned in the next two years. Each plan will also be an update of the plan from the prior year. The plan will focus on the activities and timeline for the two year planning horizon. The selected activities, the approach to deliver the engagement work, and the planning should be improved each year based on lessons learned from the previous years.
- The **Next Five-Year Customer Engagement Strategy** will be an adaptation/improvement from that of 2014-2018. It will be filed with the next DSP.

This reporting work is key to the integration of the customer engagement work. The reports will document findings, observations and conclusions across all of the associated engagement activities, on a yearly basis and in a concise fashion. This reporting, then review and discussion of the reports by the Steering Committee, will help to ensure that each department/team involved in, or in need of feedback and insights coming from customer engagement, will look transversally across departments and make decisions to the benefit of, and thereby enhance, the value proposition for customers.

2.3.1 Improved Documentation Practices

The reports and reporting described in Section 2.3 will improve the documentation practices of NPEI regarding customer engagement and its integration into DS planning and the DS Plan.

Regarding the coordination of infrastructure planning with customers or other third parties, the Board requires distributors to provide:

"…A distributor must provide […] a description of the consultation(s), including

- *the purpose of the consultation (e.g. Regional Planning Process);*
- *whether the distributor initiated the consultation or was invited to participate in it;*
- *the other participants in the consultation process (e.g. customers; transmitter; OPA);*
- *the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation(s) (e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan); and*
- *an indication of whether the consultation(s) have or are expected to affect the distributor's DS Plan as filed and if so, a brief explanation as to how." (Section 5.2.2 Coordinated planning with third parties. Chapter 5.)*

In order to improve the consistency in NPEI's documentation of consultation work, and to comply with the OEB's coordination requirement, NPEI's IT personnel will utilize the electronic filing system to enhance the traceability and searchability of customer engagement documents across departments.

NPEI will also create a standard consultation activity form, the Chapter-5 Consultation Form or C5C Form, which will be used by NPEI staff to document consultation activities that result directly from the Customer Engagement Plan. The C5C form is shown in Appendix D.

The Form will contain fields to:

- document the purpose of the consultation activity,
- provide a brief description of the consultation activity,
- indicate whether the distributor initiated the consultation activity or was invited to participate in it,
- describe the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation, and
- provide an indication of whether the consultation is expected to affect NPEI's DSP.

The impact, if any on the DSP, will be addressed by the DS planners and documented as part of the review and updating of the DSP.

The C5C Form will be populated and stored along-side any related consultation deliverables (e.g. meeting minutes, survey result tables, interview notes, etc.). The C5C Form will be used to document major consultation events such as CDM events, participation in regional planning activities, customer engagement interviews, focus group sessions, and regular meetings with municipalities. Since this is a new tool, its use will evolve as NPEI gains experience with it over the two-year Customer Engagement Plan.

3 2014-2015 Customer Engagement Plan

The 2014-2015 Customer Engagement Plan is NPEI's work plan to deliver customer engagement until the end of 2015. The Engagement Plan will be updated on a yearly basis in the spirit of continuous improvement, and to keep the plan current.

This Engagement Plan is divided as follows:

- **Section 3.1 Education and Information to Customers** – High-level description of the work that NPEI will carry out to educate and inform its customers about important topic areas related to electricity distribution.
- **Section 3.2 Customer Consultation Work** – High-level description of consultation activities that NPEI will carry out to obtain feedback from its customers and from key stakeholders on matters related to electricity distribution.
- **Section 3.3 Service-Territory Stakeholder Consultation Work** – High-level description of consultation activities that NPEI will carry out to obtain feedback from indirect customers, that is, service providers and/or key stakeholders in its service territory.
- **Section 3.4 Participation in Consultation with the OPA and HONI** – Actions in response to prescriptive requirements about whether and how NPEI should participate in consultation with the OPA and HONI.
- **Section 3.5 Consultation Topics** – Introduction, description and purpose of the list of consultation topics, how the list should be used, and when the list should be created, updated and revisited.
- **Section 3.6 Deliverables, Milestones and Timeline** – Milestones, deliverables and schedule of customer engagement through to the end of December 2015.

3.1 Education and Information to Customers

Providing education and information to customers on distribution system matters is an important component of achieving the Customer Focus Outcome. NPEI will achieve this through the use of an extensive array of media, which may include: its call center and customer service representatives (representatives), its website, direct mail, direct call, bill insert and/or e-bills, social media, local radio broadcasting, local press, and its CDM professionals.

NPEI's Customer Engagement Plan will provide:

- Confirmation of whether customers are being properly informed and educated about certain topic areas of importance.
- Information on NPEI's work on communications to demonstrate that NPEI is improving how it is informing and educating its customers about important topic areas.

The Customer Engagement Baseline Report will document the customer education and information activities that NPEI currently carries out. NPEI will update these descriptions on an annual basis, highlighting any improvements made, and these descriptions will form part of the Year-End reports.

The initial documentation will describe, but not be limited to:

- **Call Center Tracking:** The current tools and interface for handling, categorizing, tracking, assessing and addressing customer inquiries and complaints.
- **Outages and First Responses:** The current tools and procedures related with outages and first responses. The description may include the use of IT systems, information channels, department involved, protocols and typical sequence of action. For example, the communication channels might include: information on outages on the website, social media if any, and/or local radio broadcast, as applicable.
- **Capital Improvement Projects and Construction Work:** The triggers, frequency, nature of information and the communication channels. This may include information on incoming projects on the NPEI website. It may also include any information letters on potential disturbances (direct mail), local radio broadcast links, and publications in the local press.
- **Renewable Energy Generation (REG) Opportunities, Programs, Modalities and Connection Procedures:** Information on REG connection on NPEI's website, the representative's procedures when he or she receives a call about REG, the REG-connection information package sent to customers upon request, and information regarding the full-time engineering technician providing technical assistance to customers.
- **Approach to Providing Access to Energy Data to Customers**: The current tools and interface for access in electronic format, real time data access, and actions to date to provide customers with the ability to make decisions affecting electricity costs. It will include a description of myAccount, and related representative and customer interface and assistance, and the provision of 15-minute interval data when applicable. The feedback received to date on the myAccount platform, and then the implications, decisions made, and changes made to date to improve data access and the myAccount platform accordingly, may be included.
- **Customer Education on Electricity Bills and Price:** A description of how NPEI informs customers about rates issues, electricity bills, rate structure, time-of-use, electricity retailers, regulated price plan, market prices, weather normalization, and reasons causing rates to increase and other matters as they emerge over time. It will include a description of the process through which the representatives make use of myAccount to handle customer inquiries/complaints/comments related to their electricity bills and prices, including showing customers their energy data, and then using the energy data and the myAccount tool to educate these customers about their energy bills, how to control their energy use and, in turn, manage their energy expenses.
- **CDM Engagement Actions:** A high level summary description of the direct customer engagement work done by NPEI's CDM personnel, roving energy manager, and delivery agents, as well as a high level description of mass-market communications media used to advertise its OPA-contracted province-wide CDM programs.
- **Electricity Storage:** Description of information about the new energy storage activities province-wide and locally.

3.2 Customer Consultation Work

NPEI will continue its ongoing work in customer consultation and will also implement the following enhancements:

- Bolster its tracking of customer feedback (i.e., tracking of questions and inquiries and the transactional survey); and

- Launch new activities to obtain more comprehensive customer feedback (i.e., site visits, and customer satisfaction phone/on-line based survey).

In addition to adding and strengthening communication channels as per above, NPEI also plans to:

- Improve how NPEI documents consultation results through populating and storing the C5C form alongside survey data tables, meeting minutes and interview notes, as noted in Section 2.3 of the Customer Engagement Strategy.
- Improve how NPEI integrates consultations results across departments, acts on feedback and customer views, needs, preferences and priorities, across departments; and addresses these through the cross-departmental Steering Committee; and a feedback loop instituted through annual customer engagement reporting and planning activities, as noted in Section 2.3 of the Customer Engagement Strategy.

The existing and new customer consultation activities that NPEI intends to deliver during the 2014-2015 period include:

- **CDM Market Characterization Site Visits:** As part of its endeavours to meet its CDM targets for 2014, NPEI will carry out some market characterization work, focusing on particular key market segments that have a high achievable potential for savings and may be able to contribute to the savings targets. As part of this work, NPEI will carry out site visits of commercial and industrial facilities in market segments of interest. This consultation is expected to take place in July-September 2014. NPEI chose to carry out site visits to collect baseline information about energy intensive systems in particular market segments, and to avoid self-reporting biases and error that would occur with phone interviews. NPEI has retained ICF International to conduct this market characterization work.
- **Call-Center Tracking of Customers' Inquiries, Complaints & Feedbacks with Implications on DS Planning:** NPEI will bolster its practice and procedures surrounding the tracking of comments, inquiries and complaints. NPEI currently conducts call-type analysis on a monthly basis, the result of which is already shared with the OEB. NPEI's representatives register every inbound or outbound call in its Customer Integrated System (CIS), assigning one or a few specific labels for each of them related with the topic area. NPEI can breakdown call volume by location and topic. NPEI already tracks calls on outages (during and after), high energy bills, payment arrangement, energy data access platform(s), CDM (and each of the programs), REG, as well as capital improvement projects and construction work.

  NPEI's Vice President of Customer Services and IT reviews the call feedback on a monthly basis, identifies and assesses any trends, and makes adjustments to the call centre process as needed. In particular, if and when new "types" of comments are being recorded by the representatives, this would show in the monthly call analysis, a new label would thereby be created and subsequently monitored. This mechanism guarantees legacy trends are monitored, and new trends are identified swiftly. For example, energy storage has not been recorded as a topic area to date. If it were to become a recurring call in the "miscellaneous" category, it would quickly become a call category on its own and be tracked diligently.

  NPEI plans on improving its use of the call tracking by making enhancements to: planning, organizing and integrating the labels, comparing results against that of other consultation activities across departments, decision-making and taking actions across departments, and documenting planning, feedback and review.
- **Call-Center Transactional Survey:** NPEI's representatives deliver transactional-survey questions, as part of their regular call script. The call scripts are changed based on trends of call types and feedback from representatives. NPEI will use its CIS system as well as an

integrated survey tool to register the responses. Follow up calls and outgoing call scripts will be used to follow up on survey questions.

- **Customer Satisfaction Phone and/or Online Survey:** NPEI plans on launching a random customer satisfaction phone and/or online survey to reach customers who do not generally call NPEI to ask questions and provide feedback. This first survey is expected to take place in May-June 2014, and be conducted every second year. NPEI intends to use an UtilityPulse Survey. The channels used to disseminate the survey may include: customers who receive their bills electronically, NPEI's website, social media, incoming phone calls, and any email exchange with customers. NPEI will explore options for holding contests and awarding prizes, such as Energy Star appliances, to encourage participation in the survey. NPEI has had success in using such contests to drive participation through social media. NPEI's Customer Services and IT department will be responsible for the customer satisfaction survey.

A cornerstone of integration of the consultation activities is the shared list of consultation topics that NPEI will maintain as a living document. NPEI plans to update this list at least yearly, and then use the list, for example, to determine which call types are the most critical to track, what transactional survey questions to run and when, and what customer satisfaction phone survey questions to apply.

3.3 Service Territory Stakeholders Consultation Work

NPEI intends to gain additional perspective on its customer needs, priorities and preferences through maintaining and extending consultation to include key tradespeople and professionals involved in new REG connections and behind-the-meter services, as well as local and regional municipalities, and other utilities.

The existing and new service-territory stakeholder consultation activities that NPEI intends to deliver during the 2014-2015 period include:

- **CDM Market Characterization Interviews**: NPEI will consult with critical market actors in key market segments. The consultation will include CDM topics as well as other key DS planning topics, as necessary, which will complement the customer consultation being carried out. The consultation will be delivered through directed in-depth phone interviews during June through August of 2014. NPEI chose to use an adaptable explorative method, in-depth interviewing, because the group being consulted is comprised of a very heterogeneous mix of tradespeople, professionals, vendors, key accounts, trade organizations, etc. and because this group can provide meaningful market insights. NPEI has retained ICF International to conduct this market characterization work under the direction of the CDM group.
- **Regular Stakeholder Meetings (Also Known as Public Utility Committee Meetings):** NPEI has participated and will continue to participate in monthly meetings with key stakeholders such as: local municipalities and Niagara Region, Enbridge Gas Distribution, and the local cable and phone companies. NPEI will use this platform to consult about topics related to distribution system planning. NPEI may augment its documentation of these meetings through the use of the C5C Form, and also through minute-taking of one-on-one or small-committee ad-hoc meetings taking place around and as a result of the main monthly meeting. NPEI's Engineering and Operations departments are responsible for participating in these meetings.
- **Consultation with Customers' Technical Service Providers:** NPEI intends to carry out consultation with customers' technical service providers, i.e., tradespeople or professionals involved in new REG connection, new or modified load customer connections, or work on

behind the meter services. NPEI intends to proceed through directed phone interviews conducted by its own staff, following interaction with the service provider on normal business activities. NPEI intends to use the information acquired through these consultations to identify requirements for focus group activities that are expected to take place on an annual basis in a central location. Both consultation activities are new, and will be rolled out in 2015. NPEI plans to do the planning for the phone interviews (e.g. questionnaire) in the spring of 2015 and hold the focus groups in November or December of 2015. NPEI's Engineering and Operations Departments will be responsible for carrying out this consultation on a regular basis.

NPEI will consolidate all service-territory stakeholders' consultation topic areas in the list of consultation topics referred to in Section 3.5. NPEI plans to use the list as a tool for bringing forward meeting agenda items for the public-utility commission meetings, and/or develop interview guides or focus-group guides.

3.4 Participation in Consultation with the OPA and HONI

In Chapter 5, the OEB has specific requirements about whether and how NPEI should participate in consultation with the OPA and HONI.

To meet these requirements, NPEI will:

- **Consult in Regional Processes:** NPEI will obtain a letter from OPA and from HONI confirming that no regional process is currently underway. NPEI may build and integrate a web page to provide information on regional processes, and populate it with the letter from the OPA and from HONI, indicating that no regional process is currently underway. NPEI will check in with the OPA and HONI on an annual basis to monitor if and when regional processes might take place, and record the results and provide the documentation in the Year-End report.
- **Consult with Regionally Interconnected Distributors, as required:** NPEI only interconnects with HONI. NPEI will send a letter to HONI advising that NPEI is preparing its DSP for filing, and identifying any potential issues and request feedback. NPEI will send a letter notifying HONI when the DSP is being finalized and indicate how any issues related to HONI have been resolved. The letters will be included in the DSP filing.
- **Consult on REG Interconnection:** NPEI will send letters to OPA and Hydro One, providing the following information in advance of its DSP filing and will include those letters in its DSP filing. The information will consist of: forecast load, forecast REG connections and any planned network investment to accommodate connections; investment involving smart grid that could have an impact on assets serving regionally connected utilities, and the results of projects or activities involving demonstration of innovative processes, services, business models, or technologies; and on the projects or activities of this nature planned over the forecast period. NPEI will follow up with OPA and HONI on any matters arising from the material sent and address/document concerns and their resolution in its DSP filing.
- **Consult on REG Investments:** NPEI does not intend to do investments related to REG during the 5 year DSP plan horizon, and thereby will send to the OPA a letter 60 days in advance of the filing of the DSP, and include the letter in the DSP filing. NPEI may prepare a response letter to the OPA letter, and if so, will file this letter with the DSP filing.

3.5 Consultation Topics

The consultation topics may cover at least the following categories:

- Power Quality and Reliability
- NPEI's Handling of Outages
- NPEI's Handling of Capital Improvement Projects and Construction Work
- REG Opportunities, Programs, Modalities and Connection Procedures
- NPEI's Approach to Providing Access to Energy Data to Customers
- Price, Billings and Payment - NPEI's Customer Education Work on Electricity Bills and Price
- Conservation and Demand Management
- Electricity Storage
- Customer Communications and Customer Service Experience

On a yearly basis, NPEI plans to organize its consultation using a central, living list of consultation topics. The list will be a repository of all research and consultation topics/issues across all consultation activities (as presented in Section 3.3 and Section 3.4). For example, the list will be used to build the site-visit protocols, add key items to retrieve from call-type analysis and as part of transactional surveying; draft research questions for the customer satisfaction phone and/or online survey; suggest agenda items for the stakeholder meetings; and develop service providers' consultation questionnaires and focus-group protocol.

As a result of using a central list of consultation topics, NPEI will be able to:

- Check the exhaustiveness of the consultation by all committee members.
- Reinforce the validity of certain critical feedback through triangulation.
- Slim down questionnaires or interview guides, while making sure all topic areas are still covered by appropriate consultation methods.
- Establish a framework and a method to develop consultation aids (i.e., questionnaires, meeting agenda, site visit protocols, etc.).
- Reduce the need for all Steering Committee members to review all consultation aids.

3.6 Deliverables, Milestones and Timeline

The 2014-2015 Customer Engagement Plan is comprised of a set of activities, specific tasks within each activity, and a timeline for completion of each activity during the 2-year planning period. Appendix C contains the Customer Engagement Matrix, which itemizes the activities and tasks, and the timeline for completion.

Appendix A – Regulatory Compliance Matrix

Chapter 5 Compliance Matrix Checklist

Chapter-5 Requirements with Regard to Engagement, and How NPEI Is Showing Compliance Through Its Engagement Plan

Provides a cross-tabulation between Chapter-5 requirements and activities, mechanisms and measures laid out in the engagement plan

Chapter-5 Requirements		Compliance Demonstration
1) Customer Engagement Policy		
1.1	Take an integrated approach to customer engagement	NPEI has established a customer engagement governance framework in the form of a 5-year customer engagement strategy document, a cross-departmental steering committee, quarterly meetings, a baseline report, annual reporting of findings, observations, conclusions and implications, engagement performance metrics, and a 2-year customer Engagement Plan that will be updated yearly based on the findings of the previous year. The details of all of the above are described in the 2-year Engagement Plan. Such planning enables NPEI to coordinate a wide array of engagement activities in an integrated fashion across departments, then analyze, document and interpret the results and make DS decisons on the basis of these results more effectively.
1.2	Align utility interest with customers	The new integrated approach to customer engagement described in 1.1, as well as the new consultation activities described in the current Engagement Plan, will yield meaningful intelligence on customers' interests and means to interpret them, which in turn will infuse NPEI's DS planning over the next 5 years.
1.3	Serve present and future customers	NPEI is commited to provide a high level of service to its present and future customers. The new integrated approach to customer engagement described in 1.1, as well as the consultation activities in the current Engagement Plan, will provide NPEI with feedback from its customers, insights about their current and future preferences, needs and priorities, and information about new trends as they arise. Such information will assist NPEI to maintain or increase the level of service, and enhance the way it serves its customers based on changing conditions such as changes in demography, the emergence and adoption of new technological options and the build up of new customer expectations.
1.4	Demonstrate that customer needs/preference/priorities are served by the DS Plan	As part of the new integrated approach to customer engagement described in 1.1, NPEI will document findings, observations and conclusions accross all of its engagement activities on a yearly basis and in a concise fashion. This feedback will be provided to the DS planners for review and integration, as appropriate, into DS planning and the DS Plan. For 2014, this feedback has been incorporated into the DS Plan filed with the Board. For intervening years until the next DS Plan, feedback will be documented and addressed in the year-end customer engagement reports on a yearly basis.
1.5	Take a long term perspective	The governance framework, as described in 1.1, was built for the long run. NPEI has established a long term strategy for customer engagement to correspond to the long term perspective of 5 years of its Distribution System Plan. To ensure the currency of its engagement plan to fulfill its engagement strategy, NPEI has developed a 2 year Engagement Plan, which will be updated annually. NPEI's governance structure for customer engagement ensures that the strategy will be revisited as part of the planning of the subsequent DSP.
1.6	Measure engagement performance	The governance framework, as described in 1.1, includes the establishment and the monitoring of customer engagement performance metrics as detailed in the Customer Engagement Plan. The customer engagement Steering Commitee will review these metrics and make decisions on any improvements to the customer engagement year to year as measured by these metrics. The review will be documented in the year-end customer engagement reports on an annual basis.
1.7	Achieve continuous improvement in engagement	The governance framework, as described in 1.1, is a structure that will be sustainable, self-correcting, and self-improving because the Steering Commitee will meet quarterly to discuss any issues that might arise during consultation and will conduct lessons-learned analyses as well as discussions surrounding the engagement performance metrics. The lessons learned and the discussions will be documented in the year-end report on an annual basis. Then on the basis of these discussions and lessons learned, NPEI will update the 2-year Engagement Plan yearly, and update the 5-year Engagement Strategy every fifth year.

Chapter-5 Requirements		Compliance Demonstration
1.8	A distributor must provide: a) a description of the consultation(s), including • the purpose of the consultation (e.g. Regional Planning Process); • whether the distributor initiated the consultation or was invited to participate in it; • the other participants in the consultation process (e.g. customers; transmitter; OPA); • the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation(s) (e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan); and • an indication of whether the consultation(s) have or are expected to affect the distributor's DS Plan as filed and if so, a brief explanation as to how.	NPEI has created a standard consultation form, the Chapter-5 Consultation form or C5C Form, which will document the purpose of each consultation activity, whether the distributor initiated the consultation activity or was invited to participate in it, the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation, and an indication of whether the consultation is expected to affect NPEI's DSP. NPEI's staff involved in any consultation work will populate it, and store it along-side any consultation deliverables (e.g. meeting minutes, survey result tables, interview notes, etc.).
2) Identify Customer Needs, Preferences, Priorities		
2.1	Provide details of the mechanisms to engage customers (surveys, system data analytics and analyses, by rate class) regarding customer needs/preferences/priorities (e.g. regarding data access, renewables, behind the meter services, DG, storage, rates, level of service, CDM)	NPEI tracks customers' inquiries, complaints & feedbacks on a continuous basis through its customer integrated system (CIS). NPEI provides details on this mechanism in the Baseline Report. In particular, if and when new "types" of comments are being recorded by the customer service representatives (CSRs), this would show in the monthly call analysis, a new label would thereby be created and subsequently monitored. This mechanism guarantees legacy trends are monitored, and new trends are identified swiftly. The results of call analysis are filed with the Board on a monthly basis. NPEI Customer Service and IT reviews the call feedback on a monthly basis, identifies and assesses any trends, and makes adjustments to the call centre process as needed. NPEI confirms that calls regarding data access, renewables energy connection, distributed generation, behind-the-meter services, electricity price and rates, level of service, and conservation and demand management (CDM) are being monitored in terms of volume. Energy storage inquiries have not been identified so far as a call type because few to no calls have been registered on this topic area. NPEI has described in the Baseline Report how it intends to inform its customers about storage. NPEI might receive calls on storage as a result of the information dissemination to come, and will therefore register, then track it using exisitng mechanisms. NPEI currently has the following channels to receive feedback from its customers and key stakeholders: tracking customers' inquiries and comments through phone calls, transactional survey, and public-utility committee meetings. NPEI will bolster these channels as described in the Customer Engagement Plan. As needed, NPEI will add additional standard questions to ask customers that are interacting with representatives to obtain a more comprehensive database of customer preferences, needs and priorities. As DS planning progresses, NPEI will identify any new issue emerging from customer comment that may necessitate customer input, and will implement, as appropriate, customer input opportunities though website, tweets, other; and track, analyze, and provide the input to Operations/Engineering for addressing in DS planning. NPEI, starting in 2014, will carry out a Customer Satisfaction Survey. In 2014 NPEI will conduct a set of in-depth phone interviews and site visits with commercial and industrial customers for key customers, will deploy on-going methods to consult with technical service providers (or indirect customers) in its territory. NPEI will describe the observations, findings and conclusions from the 2014 in-depth phone interviews,and from the on-going indirect customer consultation, as well as implications on the DSP, on an annual basis in the Year-End report. To foster continuous improvement, the Year-End report will identify any issues in seeking customer input during the previous year, and will identify actions, as necessary, to improve performance. NPEI proposes to lay out observations, findings and conclusions from all of the above engagement on an annual basis in the Year-End report.
2.2	Provide details of the stages in DS planning where the information in 2.1 was used, and how/where the DSP has been affected	The DSP filed with the Board contains a description of the customer input received and how it was addressed in the DSP. In intervening years until the next DSP filing, NPEI will describe its observations, findings and conclusions from the engagement work, as well as their implications on the DSP, on an annual basis in the Year-End report.

	Chapter-5 Requirements	Compliance Demonstration
3) Facilitate Customer Access to Energy Consumption Data and Behind the Meter Services		
3.1	• Describe the options considered to facilitate customer access to consumption data in an electronic format • Identify, analyze and document mechanisms considered for real time data access considered to provide customers with ability to make decisions affecting electricity costs	NPEI has a portal through which it provides access to its customers to their energy data in electronic format, as well as electronic bills -- That is: "myAccount". Customers above 150kW also have interval meters. For these larger customers, the energy data is provided on a real-time basis. NPEI has tracked customers feedback on myAccount and has upgraded its myAccount platform as a result of this feedback. NPEI will carry on monitoring feedback on its data-access platform as laid out in 1.1. NPEI will describe and document all of the aforementionned options to facilitate access to customer data in an electronic format in detail in its Baseline Report. NPEI will update that description on a yearly basis in the Year-End report, highlighting any improvements that will be made to these options year-to-year.
3.2	Identify, analyze and document actions of behind the meter services and applications considered to provide customers with ability to make decisions affecting electricity costs	NPEI handles all comments and inquiries on high bills, electricity price and rates with a high degree of care. Representatives help the customer to access their energy data through the myAccount portal, they explain to them the influence of weather, and then they educate them about energy price and rate setting in Ontario, regulated price plan, and electricity retailers. They refer them to external sources of information on how to reduce their energy use and/or to the NPEI CDM team. The CDM program focuses on assisting the customer with behind-the-meter solutions to reduce electricity demand and consumption and to manage electricity bills more effectively. NPEI will update this information, as needed, on an annual basis, include it in the Year-End report and highlight any improvements made year-to-year.
4) Consult with the Ontario Power Authority, with the Regionally Interconnected Distributors and with the Transmitter		
4.1	• Document participation in any Regional Planning process (e.g. IRRP) • Provide final consultation deliverable document with DSP if available; if not available document status of consultation, role of NPEI, expected final deliverable date; indicate if/how consultation may affect DSP	NPEI will obtain a letter from OPA and from HONI that no regional process is currently under way. NPEI will continue to monitor any potential regional planning processes which will impact NPEI and will update the Customer Engagement Plan, to reflect any needed actions, accordingly.
4.2	Consult with regionally interconnected distributors and the transmitter in preparing the DS Plan	NPEI only interconnects with HONI. NPEI will send letter to HONI advising that NPEI is preparing its DSP for 2014 filing, and identify any potential issues and request feedback. NPEI will then send a letter notifying HONI that its DSP is being finalized and confirm how any issues related to HONI have been resolved. NPEI may integrate a web page to provide customers with information on regional processes. NPEI will populate it with the letter from the OPA that no regional process is currently underway. Whenever the situation will evolve (not anticipated within the period covered by the DSP), NPEI will use the same page to inform its customers and local stakeholders about the opportunity to participate in the regional processes, and how they may become involved.
4.3	Provide regionally interconnected distributors, transmitter and OPA information on forecast load, forecast REG connections and any planned network investment to accommodate connections; investment involving smart grid that could have impact on assets serving regionally connected utilities, and the results of projects or activities involving demonstration of innovative processes, services, business models, or technologies; and on the projects or activities of this nature planned over the forecast period	NPEI only has points of interconnection with Hydro One. NPEI will send letters to OPA and Hydro One, providing this information in advance of its DSP filing with the Board and will include those letters in its DSP filing. NPEI will follow up with NPEI and Hydro One on any matters arising from the material sent and address/document concerns and their resolution in its DSP filing.
4.4	For REG Investments: Send OPA a letter (60 days if REG, and 30 days if no REG) in advance of date distributor needs letter for inclusion in DSP, requesting a letter of comment from OPA on: the applications OPA has received from renewable generators through FIT for connection in NPEI service territory, whether distributor has consulted with OPA, or participated in planning meetings with OPA; the potential for coordination with other distributors/transmitters on implmenting the REG investments and whether the REG investments in DSP are consistent with any Regional Infrastructure Plan; and file any distributor response letter to the OPA.	NPEI does intend to do investments related to REG during the 5 year DSP plan horizon, and thereby will send to the OPA a letter 60 days in advance of the filing of the DSP, requesting OPA provide comment on the matters described in 4.7. The letter to the OPA will be contained in the DSP filing. NPEI may prepare a response letter to the OPA letter and if so, will file the response letter with the DSP filing.

Appendix B – Customer Engagement Strategy Matrix

NPEI 5-Year Customer Engagement Strategy

Goal 1	Goal 2	Goal 3
• Contribute to Achievement of Customer Focus Outcome	•Provide Framework to Meet Chapter 5 Engagement Requirements	•Develop Principles to Guide Customer Engagement

Customer Focus Outcome: Services provided in a manner that responds to identified customer preferences

Principles of Customer Engagement	Strategic Engagement Plan Response	Outcome	Metrics
Take an integrated approach to customer engagement	Leverage existing points of customer contact for broader based information gathering	Efficient engagement, minimal customer fatigue	# survey respondents per quarter
	Implement broad based customer inquiry	Investigate DS, smart grid, renewables, CDM, regional, other needs	Yes/no -- Survey includes all list of topic areas
	Involve utility staff across departments in engagement plan	Inquiry covers key aspects of DS planning	Yes/no -- Steering Commitee gathers all DS planning consultation topics, & updates the list on an annual basis
		Coordinated, effective planning and plan	Yes/no -- All quarterly Steering Committee meetings take place Yes/no -- Annual customer engagement report (year-end report) is prepared Yes/no -- Engagement Plan is updated on an annual basis
Take a long term perspective	Apply principles over 5-year period of DSP	Consistent inquiry strategy over DSP planning horizon	Yes/no -- 5-Year Strategy is prepared Yes/no -- Metrics are compared against target on a yearly basis, then updated
Participate in regional planning	Engage customers in any regional planning processes, as appropriate	Customers understand and have opportunity for input into broader planning context	Yes/no -- Availability of contact points # participants in regional planning contact points
Serve present and future customers	Identify present and future customer needs/ preferences/ priorities and prepare/ implement appropriate responses in DSP	Solid basis for monitoring and tracking trends	Yes/no -- Recurrent consultation activities include standing consultation questions year over year on key aspects
		Demonstration that customer needs/priorities/preferences are served by DS Plan	Yes/no -- Write-ups are included in year-end report on main consultations observations and findings, and implications on DS planning
Align utility interest with customers	Identify present and future customer needs/ preferences/ priorities and prepare/ implement appropriate responses in DSP	Understanding of customer needs/preferences/ priorities	Yes/no -- Open-ended questions to customer are included in consultation approach, on every given year, to allow for new trends and concerns to rise to the surface Yes/no -- Standing questions help NPEI understand trends in customer needs, preferences and priorities
		Integration of customer needs/preferences/priorities in DS planning and Plan	Yes/no -- Write-ups are included in year-end report on main consultations observations and findings, and implications on DS planning
Provide information on engagement opportunities	Provide meaningful opportunities for engagement	Increase in perception that customers feel they are being consulted and their views are being addressed	Measurement of degree to which customer perceives customer was consulted (e.g. on a 1-to-10 scale) Measurement of degree to which customer feels concerns addressed (e.g. on a 1-to-10 scale)
Measure engagement performance	Identify and track engagement performance metrics	Solid basis for monitoring and tracking trends	Yes/no -- All contact points are thoroughly documented in a standard manner
Achieve continuous improvement in engagement	Assess engagement performance at key intervals and make adjustments, as appropriate	Increase in representativeness of consultation and number of participants	Yes/no -- Over the course of each 2-year Engagement Plan, all rate classes are engaged with
		Increase in the perception of customers that they are being consulted, and that their views are being addressed	Measurement of satisfaction (e.g. on a 1-to-10 scale) that customer is being consulted and views being addressed
		Increase in satisfaction of participants in consultation, including consultation format and media used	Measurement of satisfaction (e.g. on a 1-to-10 scale), regarding the consultation activity the customer has just partaken in
		Increase in the level of relevance or usability of the consultation outputs	Departmental consultation -- Yes/no -- whether there has been improvement on usability of engagement outcome over last year
Carry out engagement consistent with Mission/Values/Vision	Engage customers with integrity, fairness, responsibility respect, transparency and provide best possible service	Customer engagement meets same standard of excellence as other utility activities	Yes/No -- All contact materials are systematically and properly reviewed for compliance before being taken to market
Carry out engagement consistent with Conditions of Service and any relevant corporate policies	Review Conditions of Service and relevant corporate policies in Plan development/ delivery	Consistent approach to customer engagement	Quality assurance review for conformity done as part of annual engagement reporting

Appendix C – Customer Engagement Plan Matrix

NPEI Customer Engagement Plan: 2014-2015

Consultation Activities - description, timing, purpose

Provides a detailed customer consultation plan that lays out consultation activities and mechanisms, and the tracking and reporting that will be done to document plan delivery. the dates shown in the matrix are completion dates except where it is an ongoing activity

ID Consultation Activities	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1) Engagement-Plan Governance Framework																							
1.1) Finalize Engagement Plan							X																
1.2) Draft Engagement-Plan Baseline Report							X																
1.3) Annual Engagement Reporting & Planning Cycle																							
Gather and Group All Feedbacks for Ending Year											X												X
2014 Year-End Report														X									
2015-2016 Customer Engagement Plan														X									
1.4) Quarterly Steering Commitee Meetings	X		X		X		X		X		X			X			X			X			X
2) Education and Information to Customers																							
2.1) Document Customer Service and IT Systems							X																
2.2) Document Information to Customers on Outages and First Responses							X																
2.3) Document Information to Customers on Capital Improvement Projects & Construction Work							X																
2.4) Document Information to Customer on REG Opportunities, Modalities & Connection							X																
2.5) Document Approach to Providing Access to Energy Data to Customers							X																
2.6) Document Approach to Educating Customers on Energy Bills and Price							X																
2.7) Document CDM Engagement Actions							X																
2.8) Inform Customers and Stakeholders About Energy Storage Activities, then Document It							X																
3) Customer Data Collection and Consultation																							
3.1) Market Characterization Interviews								X															
3.2) Market Characterization Site Visits								X															
3.3) Tracking of Customers' Inquiries, Complaints & Feedbacks																							
Tracking is an on-going operation	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->
NPEI will integrate tracking consultation topics with that of other engagement work									X														
3.4) Transactional Survey																							
Transactional surveying is an on-going operation	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->
NPEI will improve the recording of survey responses, and integration of the consultation topics with that of other engagement work									X														
3.5) Bi-Annual Customer Satisfaction Survey					X																		
4) Service-Territory Stakeholders Consultation																							
4.1) Monthly Stakeholder Meetings (a.k.a. Public Utility Commission Meetings)							X																
Stakeholder meetings is a monthly, on-going operation	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->	---->
NPEI will improve the integration and documentation									X														
4.2) Consultation with Customers' Technical Service Providers (professional/trades)										X													

ID Consultation Activities	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
5) Participation in Regional Consultation																							
5.1) Consult in Regional Processes																							
Obtain letter from OPA and HONI that no regional process is currently under way							X																
5.2) Consult with Regionally Interconnected Distributors																							
Send letter to HONI advising that NPEI is preparing DSP for 2014 filing				X																			
Send letter to HONI notifying that DSP is being finalized							X																
5.3) Consult on REG Interconnection																							
Provide Board-prescribed information to HONI and OPA					X																		
Follow up with HONI and OPA							X																
5.4) Consult on REG Investments																							
Send letter to OPA as prescribed by Board					X																		
Prepare and send a response to OPA letter as required							X																

Appendix D – Chapter-5 Compliance Form (C5C Form)

CHAPTER 5 COMPLIANCE FORM FOR CUSTOMER ENGAGEMENT ACTIVITIES

<table>
<tr><td>NPEI Staff Responsible</td><td colspan="2">Name:</td><td colspan="2">Job Title:</td></tr>
<tr><td>Consultation Activity Title</td><td colspan="4"></td></tr>
<tr><td>Brief Description</td><td colspan="4"></td></tr>
<tr><td>Purpose</td><td colspan="4"></td></tr>
<tr><td rowspan="3">NPEI's Role</td><td colspan="2">☐ Initiated Activity</td><td colspan="2">☐ Invited to Activity</td></tr>
<tr><td>☐ Chair</td><td>☐ Facilitator</td><td>☐ Participant</td><td>☐ Other: ___________________</td></tr>
<tr><td colspan="4">NPEI Staff Involved (Name, Title):</td></tr>
<tr><td rowspan="4">Details</td><td colspan="2">Location:</td><td>Date:</td><td>Number of Participants:</td></tr>
<tr><td colspan="4">Participants: If only a few, please be specific and list name(s) and organization(s); if many, please list general target audience(s):</td></tr>
<tr><td colspan="4">Status of consultation activity (e.g. complete, # additional meetings scheduled, # of total topics covered, etc.):</td></tr>
<tr><td colspan="4">List hyperlink(s) or cross reference(s) to relevant materials or attach as an appendix (if applicable):</td></tr>
<tr><td rowspan="2">Results (If applicable)</td><td colspan="4">Next steps or nature of final deliverables (e.g. meeting minutes, transcripts, tabulated survey results, Regional Integrated Resource Plan):</td></tr>
<tr><td colspan="4">Timing of final deliverables (if applicable):</td></tr>
<tr><td rowspan="2">Is the activity expected to affect the Distribution System Plan?</td><td colspan="2">☐ Yes</td><td colspan="2">☐ No</td></tr>
<tr><td colspan="4">If so, how?</td></tr>
</table>

This form is intended for NPEI Staff to document consultation activities that result directly from the Customer Engagement Plan. This form should be used to document major consultation activities such as CDM events, participation in regional planning activities, the send-out /completion of a customer satisfaction survey, focus group sessions that relate to a particular consultation activity, regular meetings with municipalities, and monthly or quarterly interviewing activities (not the results of individual interviews).

Attachment 3 of 4

NPEI Customer Engagement Baseline Report

NPEI Customer Engagement Baseline Report

August 15, 2014

Submitted to:
Sue Forcier
Niagara Peninsula Energy Inc.

Submitted by:
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Table of Contents

1 Introduction

The Customer Engagement Baseline Report (Baseline Report) is the first report which documents the activities to date, related to the implementation of the 2014-2015 Customer Engagement Plan, and thereby will serve as a baseline for future status reports on these activities. NPEI plans to update the Baseline Report annually, providing a status report – a Customer Engagement Year-End Report – on activities for the intervening period and highlighting any improvements made. The Customer Engagement Baseline Report will be filed with the Distribution System Plan (DSP) in August 2014.

The Baseline Report consists of a description of 2014 NPEI customer education, engagement, information and technical assistance activities current to June 30, 2014. This includes information on:

- Current customer education and information practices date (e.g., customer views needs/preferences/priorities).
- Customer consultation (e.g., inquiries, comments and complaints monitoring, surveying and direct engagement)
- Stakeholder consultation (e.g., regular meetings with local municipalities)
- OPA and HONI consultation (e.g., correspondence related to regional planning activities)

The type of information gathered for each component will vary depending on the activity. Where appropriate and known, an indication may be provided as to whether the consultation is expected to affect the Distribution System Plan or associated planning. With experience in preparing year-end reports, the type of, and approach to, documentation will evolve over time.

1.1 Methodology for Baseline Report

The Baseline Report requires the collection and documentation of information from across NPEI departments. Since it is also one of the key deliverables of the Customer Engagement Plan, which is overseen by a cross-departmental committee, the Steering Committee[1], the Steering Committee also directed the preparation of the Baseline Report, under the coordination of the Chief Conservation Officer.

ICF International (ICF) was retained by NPEI to assist in the preparation of the Baseline Report. ICF prepared a detailed outline of the report, a description of information needed for the report, and assigned the information gathering and reporting to particular departments; and populated the outline with information already gathered in the preparation of the 2014-2015 Customer Engagement Plan and information from the NPEI website. Each Steering Committee member coordinated the preparation and review of draft information in the Baseline Report under the member's purview, and also reviewed the draft Baseline Report, which was compiled by ICF from the information provided. ICF finalized the Baseline Report based on the comments received from the Steering Committee.

[1] The Steering Committee is comprised of the following NPEI staff: President and CEO; VP Customer Services & IT; VP Engineering, VP Finance, VP Operations; and Chief Conservation Officer.

The Baseline Report is expected to serve as a template to be updated for the preparation of the annual Customer Engagement Year-End Reports. It will be modified and enhanced over time with experience gained.

1.2 Improved Documentation Practices

NPEI intends to improve its documentation practices regarding customer engagement and its integration into distribution system planning and the distribution system plan.

In order to improve the consistency in NPEI's documentation of consultation work, NPEI created a standard consultation activity form, the Chapter-5 Consultation Form or C5C Form, which will be used by NPEI staff to document consultation activities that result directly from the Customer Engagement Plan. The C5C form is shown in Appendix A.

2 Education and Information to Customers

This section presents detailed descriptions of the customer education and information activities.

2.1 Call-Center Tracking of Customers' Inquiries, Complaints & Feedbacks with Implications on DS Planning

NPEI has a set of tools and interface for handling, categorizing, tracking, assessing and addressing customer inquiries and complaints.

NPEI Role in Activity

NPEI has a customer call centre which is managed through the Customer Services & IT department. There are a number of Ontario Energy Board (OEB/Board) reporting requirements related to the call centre (e.g. reporting on Service Quality Indexes (SQIs), the Board's Scorecard). These are reported on by NPEI elsewhere.

Description

NPEI logs, categorizes and tracks all customer inquiries, complaints, and feedback received from incoming calls and correspondence received into the call centre. NPEI's customer service and billing representatives register every inbound or outbound call in NPEI's Customer Information System (CIS): Harris Northstar product suite.

The Customer call centre encompasses incoming and outgoing calls into and from Customer Service and Billing. Customer inquiries are queued and directed to an appropriate representative based on selection of queue. For each call received, the call is categorized by type of call (Overdue, Account Inquiry, Power Interruption, and Conservation). General inquiry calls are filtered by function of the call: move, new service, and general billing inquiry (high bill, inquiry, payment method, meter read). Calls received for complaint or compliment are noted separately in order to track and follow up.

Utilization of the Harris Northstar customer care functionality, along with the Harris Executive Information System, provide a dashboard displaying call volume reporting by call type, allowing NPEI to break down call volume by representative, department, and call type. NPEI is able to track calls on each of the queues including outages (during and after), high energy bills, payment arrangement, energy data access platform(s), CDM (and each of the CDM programs), renewable energy generation matters (REG), and capital improvement projects and construction work, along with all account specific inquiry or request by call type.

A call can be assigned to a specific department or employee for follow up, and reporting of the progress of the call. Each action on the call is date and time stamped in order for NPEI to report on service quality: length of time to resolve issue, and results of the resolution. Where necessary, if a call is escalated, a recording of the call is attached to the call and referenced for follow up by supervisor. All documentation or written correspondence relative to an inquiry or request is attached to the account for reference.

On a monthly basis, NPEI's Vice President of Customer Services & IT reviews the call feedback, identifies and assesses any trends, and makes adjustments to the call centre process as needed. In particular, if and when new 'types" of calls are being recorded by the representatives, this would show in the monthly analysis, a new label would thereby be created and subsequently monitored. This mechanism guarantees legacy trends are monitored, and new trends are identified swiftly. The managers of Billing and Customer Service as well as Lead Hands of those departments take part in review of the calls to determine course of action. Training is scheduled with staff to maintain up to date communication. The review process allows managers to determine when more detailed scripting is required to assist representatives in providing correct, current, and timely information to the customer.

Results to Date

Reporting in place provides review of what types of calls are processed. High call volumes are determined and use of the Interactive Voice Response reports provides information to management on required number of resources and service quality indices (number and percentage of calls received, handled, and abandoned, and results of the queue usage). To date, payment arrangement is the highest volume of calls received. Collection calls and balance inquiry (automated dial call) rank as the next highest of calls received. On average, 10% of active customers call into the utility monthly.

Moving Forward

NPEI plans on improving its use of the call tracking by making enhancements to: planning, organizing and integrating the call types, comparing results against that of other consultation activities across departments, decision-making and taking actions across departments, and documenting planning, feedback and review.

The integration of Customer Care to operations Call Taker System will provide efficiencies as today users are entering calls relative to power outages in both systems. Further the integration will allow for a toggle free environment to assist representatives when speaking to the customer.

This work may be expected to affect the DSP planning by providing more comprehensive information related to customer needs, preferences and priorities by topics of interest to customers. This may also result in information which may be used to adjust the implementation of the DSP. The analysis of the data will be provided to the NPEI Steering Committee for consideration in determining how this information is to be treated in the DSP and in ongoing DSP planning and implementation.

2.2 Outages and First Responses

NPEI has tools and procedures related with the management of communications surrounding outages, and then the retrieval, gathering and handling of feedback from customers. These tools include information technologies and multiple communication channels. This section provides a description of the work done, tools, protocols and typical sequences of action.

NPEI Role in Activity

NPEI receives calls from direct or indirect customers signalling the outage and handles these calls to locate the outage and organize first response. NPEI informs direct and indirect customers about the outage, showing it has the situation under control, and informing customers about the expected duration of the outage.

Description – Unplanned Outages, First Response and Feedback

NPEI monitors unplanned outages through its Customer Call Centre during normal working hours and Answering Service after hours. Representatives input all of the calls into the Call Taker System, as well as the Customer Information System, which includes information such as time and location, and feed the data into the Outage Management System (OMS). NPEI's Control Room Operator along with Engineering Staff diagnose the cause of the outage, prepare a first-response plan, provide an estimated duration of the outage to Customer Services where practical, and dispatch one or many teams of Line, Engineering and Metering Technicians to the field to carry out the required inspections and repairs. Customer Services then provides the information on outage location and estimated time of reestablishment of service to all of the representatives so that they can inform the next callers. Customer Service and Billing representatives responding to calls use the Call Taker System to provide location of outage and estimated time to restoration. This information goes on NPEI's website; if warranted by the magnitude of the situation NPEI also disseminates the information on social media (NPEI has a Facebook and a Twitter feed), and for a severe outage of more than 4 hours and/or affecting more than 1,000 customers, may broadcast the information on the local radio.

During normal working hours, NPEI captures data provided from smart meters installed on the system, and has linked the meter status to the customer premise modelled within the Geographic Information System (GIS) to track meters reporting outages. The Control Room Operator then determines the response required based on predictions provided by the Outage Management System. Based on the number and location of meters reporting, the OMS performs a trace back to the first major device on the system to predict the location of first response. The Operator then dispatches the Work Order to the lap-top computer installed within the Truck of the closest Crew to the affected area to perform the inspections or repairs required. The Crews locations are tracked within a sub-set of the GIS called In-Service, to aid the Operator in decisions required for the response. Once the restoration is complete, the Operator is able to poll a sample of meters whose status had shown out, to poll the current status and determine if the situation has been resolved. The crew then closes the Work Order on their lap-top and the Operator closes off the Outage.

After normal working hours, the Answering Service provides the same support as the CSR's and dispatches the outage information to one of two On-Call Line Technicians. Depending on the magnitude of the situation, the responding Line Technician will either implement the repairs required, or Call in a Control Room Operator & representatives based on a set of criteria provided to them.

NPEI has SCADA access to all of its feeders sourced from Hydro One-owned Transformer Stations, namely Stanley & Murray T.S., Beamesville T.S., Vineland D.S.; and NPEI-owned Kalar M.T.S. and Grimsby Powers Niagara West T.S. The access to the information is provided through an Inter-Control Center Communications Protocol (ICCP) link and provides breaker status, voltage, and current. The Operator monitors these outputs on a regular basis to maintain proper operating limits of the feeders.

NPEI monitors positive or negative feedback on outages from customers from call-center tracking and social media. Since NPEI keeps a record of the source and time of the call, NPEI can directly link up a certain batch of feedback with every specific outage. Customer Services organizes internal de-brief sessions as needed; in particular, for continuous improvement. First-response procedures are improved accordingly.

During major weather events, NPEI Control Operators are in direct contact with Law Enforcement Municipal Officials, and other public utilities through the supply of a reserved Phone Line, for easier access to Staff when call levels are abnormally high, by-passing the normal protocols through the Answering Service or representatives. Often they are able to provide valuable feedback to probable outage causes or immediate public safety concerns which may assist the Operator in prioritizing Crew deployment.

NPEI Staff have protocols to follow while re-establishing power during outage events, prioritized as follows: 3-phase Main Feeders from T.S.'s sourcing Municipal Sub-stations, with supplies to critical loads taking precedence; next are 3-phase main feeders supplied by Municipal Sub-stations; then fused 3-phase laterals followed by fused 1-phase laterals; and then transformers, secondary buss, followed by individual services. Negative feedback from customers may be received during major weather events; for example, noting that utility trucks just drove past a house out of power and didn't stop, not being aware that this procedure is due to the applicable protocols. The protocols concentrate on re-supply to the most customers or critical loads first, and can be difficult for the customer to understand. The customer needs to better understand that although it may seem inefficient for trucks to return, it is the most time effective solution for restoration to the majority of customers.

Description – Planned Outages

Engineering works with Customer Services to prepare and provide information on scheduled outages, and outage preparation through the NPEI website. Outage preparation is designed to help customers prepare for a power outage; there is an on-line document which provides guidance to customers on how to prepare for an outage. There are tips on an emergency kit and other necessities, and what else a customer might need in the event of an outage. In addition, there are tips on what to do during the outage and what to do after the power is restored.

For Planned Outages of up to 500 Customers, NPEI will provide three days' notice to customers via hand delivered letters dropped off to each customer's mailbox by a Technician. Date, time, rain date and the contact Technician are outlined in the letter. Customer Service is provided with the account numbers and the date and time of the outage to be input within the CIS to aid representatives with questions from customers.

For Planned Outages over 500 Customers, NPEI will provide a weeks' notice to customers via direct mailings, radio station and newspaper notification. The Corporate Website is updated with the relevant information and Customer Service is provided with the accounts dates and times to update the CIS to aid representatives with questions from customers. Whenever a customer contacts NPEI, the representative will poll the customer's account and update contact information within the CIS for future reference.

Results to Date

NPEI tracks information on all outages via the Outage Management System which records and archives the relevant data. Information from this system is used to provide the stats required by the Board, namely SAIDI, SAIFI & CAIDI, on a yearly basis.

NPEI has gained valuable insight during the period of 2013-2014 regarding trends of widespread outages. From the Lincoln/West Lincoln area, review of information has determined a requirement to fortify lightning mitigation equipment within the system, as highlighted by a large number of failed transformer/step-down units during large lightning events. Within the Niagara Service Area the implementation of insulated base switch components resulted from a review of outages caused by animal contacts/pole fires. The Service Truck has also been given direction to replace porcelain insulated cut-outs with polymeric insulated components due to a failure rate captured by the OMS.

NPEI has utilized an Auto Dialler to warn customers about planned outages in these situations with limited success, as out-dated cell phone numbers and provision of emergency contacts by customers may not be relevant to the location where the outage will occur. Since the message is taped, and incapable of providing answers to questions, the information may not be relevant to the person answering the call (often a work number is provided).

Moving Forward

Outage management is a critical part of customer service. As a result any improvements in data collection and analysis to understand more thoroughly customer needs, preferences, priorities and satisfaction with NPEI's outage management is important for consideration in the DSP plan development and in plan implementation. The analysis of the outage data will be provided to the NPEI Steering Committee for consideration of how this information is to be treated in the DSP and in ongoing DSP planning.

NPEI is implementing a Pilot Project using Wi-Max Communication Systems to remotely monitor the status of feeders sourced from NPEI-owned Municipal Stations located within the Lincoln/West Lincoln Service Area, to provide real time data to the Operator. The distribution in this area is mainly rural, with associated long feeders to minimal loads in areas with limited communication options. The scope involves the installation of D.C. back-up systems, communication networks including towers and base stations, and the upgrade of reclosures & station breakers with communication-enabled equipment. With the information provided by this system, the Operator will have another valuable tool to aid in operational decisions, to more effectively dispatch crews, track the location of faults based on fault current inputs, minimize feeder patrol times and improve restoration times during large weather events.

2.3 Capital Improvement Projects and Construction Work

NPEI disseminates information about planned capital improvement projects and construction work on its system. The information is provided to educate customers about the project and to minimize customer inconvenience. The following section describes the triggers, frequency, and nature of information and communication channels used to disseminate information on these projects.

NPEI Role in Activity

NPEI plans capital improvement and construction work well in advance, coordinates with the affected municipalities and other utilities, plans communications surrounding each of these projects and carries out these activities according to the plan.

Description

NPEI disseminates information about upcoming projects and construction work through its website. Currently on the NPEI website there is a list of 2013 highlighted capital projects. NPEI plans on updating the list for 2014 projects.

There are a large number of routine projects that take place each year, particularly related to operations and maintenance activities. NPEI decides on what projects to undertake from information based on cyclic inspections and equipment replacement programs. These include Pole Inspection & Replacements, Municipal Sub-station Inspections & Maintenance/Refurbishments, Pad-mounted Equipment Inspection & Replacements, Kiosk Inspections & Replacement, Minor Sustainment Programs, Demand Based System Expansions, Manhole & Sidewalk Vault Inspections, Rebuild/Reinforcement/ Conversion Construction, and Road Relocation Works.

For specific capital projects, NPEI delivers letters and notices directly to the mailboxes of the affected customers 30 days before the start of the construction. If the magnitude of the project warrants it, NPEI has hosted Public Information Sessions near the area affected. This is to ensure any customer concerns can be addressed whenever practical.

NPEI also disseminates information on upcoming projects through, local radio broadcast, publications in the local press, and the use of social media, as warranted.

Results to Date

The amount and nature of communications needed is scalable; it may not be appropriate to deploy all of the tactics listed above for every project. Specific decisions about the approach are made on a project-by-project basis at the planning stage, and then included in the project workplan and budget.

Once done with the construction stage and once the new infrastructure gets energized, NPEI conducts internal debriefing sessions to identify success factors, lessons learned, and improve its practice looking forward.

Moving Forward

NPEI plans to enhance the information provided on its website. In 2015, NPEI plans to provide the list of budgeted projects for capital works for 2015 at the beginning of the calendar year. NPEI will provide an expanded but short description of each listed project. NPEI will also provide a summary, high level description of the planned maintenance.

NPEI will update the site bi-annually to indicate which projects have been completed, deferred, etc. A standard categorization will be used to report on progress.

NPEI will provide a short justification for these projects, highlighting the benefits to the community and/or the consequences of not proceeding with the investment, and perhaps a generic write up that explains the linkages between NPEI proceeding with these capital improvement and rates increases.

At this time NPEI does not foresee the provision of budgetary amounts or expenses related to projects on the Corporate Website. Direction from the Board of Directors is required for the release of this information. If required, this information could be disseminated on a case by case basis with approval from the Board. Further expansion regarding on-going maintenance and inspection programs can be provided to help customers understand how projects are prioritized and approved.

NPEI has decided to improve its distribution system planning to include customer solicitation as to what projects or initiatives are important to our customers. In providing information about capital projects, NPEI plans to provide ongoing progress reporting of capital projects and the impacts or benefits of the work that NPEI is doing.

2.4 REG Opportunities, Programs, Modalities and Connection Procedures

This section presents the customer engagement procedures and processes related to renewable energy generation (REG) opportunities for NPEI's customers and information on the responsibilities and activities of the full-time engineering technician that provides technical assistance to customers.

NPEI Role in Activity

NPEI provides information on its website and through its call centre regarding REG connection and also provides technical assistance regarding connection.

Description

NPEI currently maintains web content regarding REG connection. The website contains information regarding renewable generation to assist customers in obtaining approvals regarding connection to the NPEI distribution system and guidance on the Ontario Power Authority's Feed-in-Tariff programs (FIT programs). The website includes requirements for connecting embedded generation and details on each of the FIT programs and how to register.

NPEI has standard procedures to follow when a representative receives a telephone inquiry about REG. The initial information is recorded by the representative within the service location report system and the customer is provided with the contact information for NPEI's REG Technician. Relevant documentation is compiled, and a service location report is completed by the Technician outlining the responsibilities of the Proponent & NPEI, including any costs for which they are responsible. Connection impact assessments are initiated where relevant, payments are tracked, and when construction of the facility is complete, and upon receipt of the ESA Inspection Certificate, NPEI line staff with the REG technician perform a witness test to ensure the customer's system performs to the requirements outlined within the connection documents. All REG's are modelled within the Geographic Information Systems, documentation is signed off, contracts and test results are hyperlinked to the customer premise in the GIS, and the OPA is contacted with the connection results and details.

NPEI can share details of the REG connection requirements through an information package sent to customers, upon request; the package is also accessible on the website. The information package contains information regarding the requirements for embedded generation including site classification for energy generation facilities, safety, power quality and protection requirements, the generation connection process, a description of all necessary technical reviews, connection impact assessment, charges, metering requirement, approval, revenues available and financial settlement options. The information package was developed in 2012, and is updated based on changes to the program.

The representatives are trained to handle general inquiries related to REG and to send out the REG-connection package. Typical REG inquiries are related to capacity availability; responses include, for example, areas of system constraints, capacity availability, and inspection & witness testing scheduled dates.

To further assist customers, NPEI has a full-time engineering technician to address questions and to facilitate connection. Typical information and assistance provided by this individual includes: applicable estimates and costs, metering requirements, wiring & metering schemes, scheduling the connection & witness test, liaise with the OPA upon completion of the connection, and finalize the paperwork & provide relevant information to the Billing Department. The engineering technician does not provide advice regarding behind the meter REG matters.

NPEI can provide information and education on REG connection to the distribution system. Customers seeking help on technical aspects of REG behind the meter may be referred to vendors and service providers.

Results to Date

NPEI connected 87 MicrofFIT in 2013 and 25 MicroFITs in 1st Quarter 2014, with 6 FITs connected during the same time frame. In total, NPEI has connected 315 MicroFIT's, 12 Fit's and 9 Net Metered installations since the start of the Program. There has been a downward trend in requests due to known system constraints outside of NPEI's direct control, namely Short Circuit limitations at Niagara West T.S and Hydro One issues on the 115KV Transmission System in conjunction with the Allanburg Station. NWTS is in the process of installing Current Limiting Reactors at the T.S. which will enable additional FIT connections, with an associated Capacity Fee to any future Proponents. Completion of equipment installations is anticipated for the fall of 2014. Hydro One is also in the construction phase of equipment installations required to remove the constraints currently in place with the 115KV Transmission Network.

Moving Forward

NPEI plans to continue to monitor customer information needs and responses to the information and technical assistance provided.

Other than system constraints out of the direct control of NPEI, as outlined previously, there do not seem to be any issues with the REG Process used by NPEI. It is anticipated that a large volume of requests will resume once the constraints have been lifted, but in most cases, the technician has started the paperwork in anticipation of the capacity release, so NPEI does not anticipate any delays processing the backlog.

2.5 Access to Energy Data to Customers

This section presents a review of the options made available by NPEI for increasing customer data visibility. It includes information on the options available to the customer, and how NPEI will how survey customer preferences with regard to access to account and energy data and account update.

NPEI Role in Activity

NPEI provides access to account and energy data to customers. NPEI selected a customer web portal technology and a vendor for the technology; worked with a vendor to carry out the database integration and new portal customization work; took the new energy data platform to market; and is maintaining and operating the system in collaboration with the vendor, and can work with the vendor to upgrade the system, as required. NPEI monitors the new technological options, new features and add-ons and potential upgrades as they arise, consults with its customers, will select which options, features, or add-ons to roll out, and will proceed with the upgrades in response to customer preferences. The web portal will provide enhanced self-service features to our customers.

Description

NPEI has named its account and energy data access service, myAccount. NPEI has purchased the NorthStar Utilities Solutions: eCARe V2 and Customer Connect platforms.

NPEI provides access to energy data to customers through its myAccount web portal. The myAccount platform is accessible to all customers. The myAccount web portal allows customers to log on to a secure website to access their bill, payment and consumption histories, log service calls such as update of customer personal information, move, service requests such as tree trim, power outage, account review, pay accounts, and submit meter readings. Customers can access their account information and data anytime, as long as they have a browser and access to broadband internet. Both desktop and mobile views are available. For customers that are inaccessible to a computer or internet connection, a computer desktop is made available for customers to use from the Niagara Falls Head Office location.

All billed customers can view meter readings, and usage, with graphical display of time of use or hourly consumption where applicable. In addition to the myAccount web portal, all general service accounts above 50 kW and have an interval meter, and have access to Utilismart website to view the interval meter data. Large commercial customers can use the website to manage load and forecast energy costs.

To date, NPEI has been promoting its myAccount portal to foster utilization through bill inserts, envelopes, customer contact/call centre, website, and dissemination of information through its webpage, and social media.

The myPortal account allows customers to extract energy data information for analysis in a pdf or excel format.

Results to Date

MyAccount has improved customer service and has proven to be beneficial to our customer in learning how they are using their energy. High bill calls have decreased since the inception of myAccount. When time of use periods are updated, customers are educated to use the next-day view of consumption to determine how consumption is used.

Based on customer feedback into the customer call centre and correspondence, NPEI will provide self service tools to complete moves, apply for payment options such pre-authorized payment plan or equal payment plans, and request and retrieve data requests for customer or affiliate use.

Future enhancements such as text to customer, instant message to customer, customer alerts based on balance or consumption thresholds will be looked at in 2015.

To date, 13% of the active customer based is enrolled on myAccount. The increase to use of the myAccount product increases 1-2% per month. Through the use of conservation marketing messages and programs, NPEI promotes a greener environment, encouraging all of our customers to move to ebill and use of the myAccount portal.

Moving Forward

NPEI plans to continue to monitor customer information needs and responses to the information and technical assistance provided.

Through the NPEI website, as well as within the MyAccount web portal, NPEI encourages customers to provide comment, compliment, or complaint. These online requests are electronically transferred to the customer account as presented in the Customer Information System, and forwarded to appropriate area of the organization for update and response to the customer. Using the call tracking reporting, procedures and processes are updated, and options are made available to the customer. For example, in the call centre, tree trimming and check meter reads were a high volume call. To assist the customer, tree trim, power outage, check meter became online service requests that the customer can enter in the My Account web portal at a convenient time for the customer, rather than make a call into the utility during business hours. Any feedback directly related to a project or scope as outlined in the DSP is communicated to Engineering and Operations electronically.

With further integration between the customer information system and the Call Taker system, information will flow efficiently, amongst multiple departments and will facilitate consideration for DSP planning purposes.

2.6 Customer Education on Electricity Bills and Price

This section lays out the methods by which NPEI informs customers about electricity bills and pricing, including for example, rate structure, time-of-use billing, regulated price plan, market prices, weather normalization, reasons for rate increases and other matters as they arise.

NPEI Role in Activity

NPEI addresses high electricity bills calls as they arise. NPEI disseminates information and educational materials about electricity consumption and how to manage bills.

Description – High-Bill Call Handling

NPEI addresses high electricity bills calls as they arise and seeks to soothe any discontentment of calling customers. This is done through a diligent correction of any error on energy bills, if any, which is relatively rare, and through education on energy use, energy rates and energy management at the time of the call.

When a representative receives inquiries, complaints or comments related to customer electricity bills and prices – often these are regarding energy bills that the customers see as unreasonably high, hence these calls are referred to as “high-bill calls” – the representative goes through a standardized sequence of actions that includes:

- Diagnosing the problem through cognitive dialogue,
- Prompting the customer and helping the customer to access the myAccount platform,
- Providing direct education using the dataset and the different reporting tools of the myAccount platform,
- Showing to callers the cause of the high bill, for example, and depending on what the issue was:
    - Extreme weather,
    - Board-approved rate increase,
    - High electricity use during TOU summer peak period,
    - Potentially behind-the-meter equipment failure or malfunction, etc.
- Referring the callers to CDM resources such as the saveONenergy rebates and educational materials, or the NPEI CDM group.

The education process has been successful and as a result, high bill calls are not repetitive on an account. Typically, the education of the customer on how the customer is using energy, the communication and outline of customer tools available such as myAccount web portal, and CDM programs will resolve the issue. Customers are using the tools available; as typically, when the portal is not available, the customer is notifying NPEI as to its availability. Maintenance windows of the portal are communicated via the website and customer feedback, when myAccount is updated, is received.

Description – Unsolicited Customer Education

NPEI uses correspondence, standing web items, bill inserts, dynamic social media and the myAccount platform (See Section 2.5) to disseminate information and educational materials about electricity consumption and how to manage it. NPEI also disseminates information about energy price, rate setting, regulated price plans, time-of-use, market price, rate setting, and electricity retailers.

In some cases NPEI distributes content and educational materials, such as a time of use information packet, to educate customers on the smart meter, time of use. Updates to the regulated price plan are provided via website and bill insert (provided by the Ontario Energy Board.) Useful links to Ministry of Energy, Independent System Operator, Ontario Power Authority, and Ministry of Health are found on the website. Necessary links are added as feedback is provided. For example, we tracked an increase in the number of calls relative to the health risks associated to radio frequency and the smart meter. We sourced Ministry of Health documentation and provided it and a link onto our website to the inquiring customers. Where customers seek advice on retailers, we assist with bill comparison so that customers can make their own informed decision.

Local schools will request information regarding electricity, electricity safety and conservation. Materials and utility representation are provided to provide an informational session to Grade 5 students. Ten schools within the service territory are done each year. Material is put together to offer an interactive session that works with the curriculum.

NPEI also conveys content and materials developed by the OEB, the IESO, the Ministry of Energy and the OPA such as the OEB Bill Calculator, or the OPA's LDC-specific saveONenergy web platform (https://saveonenergy.ca/?ldc=npei).

NPEI provides links on its website regarding its rate filing and opportunities to participate in the rate proceedings.

Other items of information provided to the customer include how to understand the customer's consumption, walk through of usage and how to read the smart meter (this assists with high bill inquiries), how rates are determined, and how rate classifications are determined.

Results to Date

Unsolicited customer education is a continual improvement and progress initiative. The review of call types and information from our customers, along with the activity within the industry, direct NPEI to offering new information sessions and tools.

Moving Forward

NPEI has purchased an interactive survey tool that will be used at the end of each electronic correspondence to customers to solicit feedback regarding what topics interest the customer and the format to receive the information. Based on recent trends related with inquiries regarding electricity rates and how to manage electricity costs, NPEI has decided to improve its distribution system planning to include customer solicitation as to what projects or initiatives are important to our customers. In providing information about capital projects, NPEI plans to provide ongoing progress reporting of capital projects and the impacts or benefits of the work that NPEI is doing.

Use of interactive tools such as Customer Connect available from the web portal, myAccount, will allow customers to manage their electricity costs through view of their detailed consumption, set up of alerts direct to them when energy consumption goes beyond a threshold or directly communicate programs that may benefit them, whether it is a CDM program, Payment Assistance Program, or educational forums of relevant topics.

2.7 CDM Engagement Actions

This section contemplates the direct customer engagement work done by NPEI's CDM professionals and delivery agents as well as mass-market communications used by NPEI to advertise OPA-contracted province-wide CDM programs.

NPEI Role in Activity

NPEI is the program administrator of OPA-contracted province-wide CDM programs in its service territory. NPEI delivers all of the OPA-contracted province-wide CDM programs that OPA has made available to LDCs. NPEI manages the customer relationship regarding these programs either directly, through the assistance of delivery agents and channel partners, or both.

Description

NPEI delivers the residential, low-income, commercial and industrial OPA-contracted province-wide CDM programs in its service territory. As part of program delivery, NPEI uses an array of direct and indirect customer engagement approaches from one-on-one customer meetings, to customer group events, to participating in broader community activities/events, all of which are designed to complement the overarching province-wide program marketing of the OPA. CDM Staff act as an applicant rep, assist with the saveONenergy application process for vendors and applicants, and encourage DES studies, and energy audits to drive deeper savings. CDM staff meet with customers on a regular basis or by phone, identifying customer needs and assisting with CDM opportunities.

NPEI CDM professionals maintain ongoing relationships with the four local municipalities within its service territory and the broader Region of Niagara. NPEI is also an active member of Niagara Erie Power Alliance (NEPA) group.[2] In addition, NPEI participates in GridSmartCity Utility Partners Co-operative[3], which aligns with the provincial government's interest in LDCs' finding ways to achieve greater efficiencies in scale and scope in their operations, which may include: advancements in self-healing grids, electric vehicle infrastructure, conservation program implementation, renewable energy initiatives and cooperatives and community energy planning.

[2] NEPA is comprised of 10 utilities: NPEI, Fortis-CNP, Norfolk Power, Brant County Power, Brantford Power, Grimsby Power, Niagara on the Lake Hydro, Welland Hydro, Haldimand County Hydro, and Horizon Utilities.

[3] Utility partners include: NPEI, Waterloo North Hydro, Cambridge and North Dumfries Hydro, Kitchener-Wilmot Hydro, Burlington Hydro, Oakville Hydro, Kingston Hydro Corporation, Guelph Hydro, Milton Hydro and Halton Hills Hydro. Quarterly meetings are held.

NPEI is a member of the Niagara Electrical Association and Niagara Industrial Association. NPEI staff attend Chamber of Commerce events for the Town of Lincoln and the City of Niagara Falls. CDM staff work with the City of Niagara Falls Business Development Office to promote CDM programs.

NPEI CDM staff have fostered a collaborative relationship with Town of Lincoln and City of Niagara Falls municipal staff. Of particular note is that CDM staff worked closely with municipal staff to develop an Energy Management Plan for the City of Niagara Falls, based on building energy audits, and the Plan was submitted to the Ministry of Energy. In addition, staff worked closely with the Town of Lincoln on the new Community Centre regarding energy efficiency and with energy retrofits related to existing buildings.

NPEI uses the services of delivery agents to complement its technical assistance to customers and its marketing efforts. For example, NPEI uses a delivery agent to review and make recommendations on the approval to NPEI of applications under the commercial and industrial programs. NPEI also retains the services of a marketing company to assist with development of mass marketing and educational materials related to CDM programs. NPEI manages service provider-initiated customer engagement through activities such as direct mail, phone campaigns, and breakfast and lunch information sessions.

NPEI has retained a roving energy manager (REM) through the OPA's REM program. This has enabled NPEI's CDM staff to provide more technical services to identify and assist with identifying commercial and industrial customer projects and to provide a more comprehensive approach to energy conservation within customers' facilities. It has also enabled NPEI to reach more commercial & industrial customers. Typically, NPEI's REM will meet with customers through site visits, identify and review opportunities for CDM and assist the customer in moving forward in seeking incentives from CDM programs.

In 2014 NPEI's leadership role in CDM was recognized by the OPA through the awarding of Conservation Fund project to explore the feasibility of load-shifting the battery charging of electric golf carts in golf courses and non-road electric vehicles in industrial facilities, with a view to a broader province-wide roll-out.

NPEI takes a leadership role on CDM matters with LDCs through participation in CDM and related committees. NPEI's Chief Conservation Officer (CCO) is a member of CFAWG, the Conservation First Advisory Working Group, which is taking the lead in working with the OPA to design the details around the new CDM framework for 2015-2020. The CCO is Past Chair of the EDA Communicators Council[4]; Vice Chair of the EDA CDM Caucus, and serves as a member of the EDA Emergency Task Force and the Conservation Reporting Working Group.

Results to Date

NPEI is working diligently to meet its 2014 CDM demand and energy savings targets. Despite considerable effort expended by NPEI in cooperation with other LDCs, customers, channel partners and stakeholders to overcome operational and structural issues that limit OPA program effectiveness across all market sectors in NPEI's service territory, challenges remain; and there is limited opportunity to make adjustments to the existing suite of OPA programs. NPEI can build on the strengths and successes of the 2011-2014 programs in the new CDM framework. Details on

[4] The CCO was chair in 2012 and 2013 of the EDA Communicators Council, which addresses CDM and other utility communications matters.

NPEI's CDM performance are available in NPEI's CDM Annual Reports, which are posted on the NPEI website. Results for 2013 will be available on September 30 2014.

Moving Forward

NPEI retained ICF International in January 2014 to identify the achievable potential for conservation by sector and subsector, consistent with the OPA achievable potential results for the province, and to identify key subsectors for further market characterization, such that these sectors could be targeted in Q4 of 2014 and into the new CDM framework. The market characterization will include direct one on one customer engagement as well as interviews with key subsector market players.

This work may affect the distribution system planning by providing specific information related to customer needs of particular commercial and industrial subsectors that have been studied as part of the achievable potential work. Once the work is complete, it will be submitted to the NPEI Steering Committee for consideration in determining how this information is to be treated in the DSP and in ongoing DSP planning.

2.8 Electricity Storage

This section includes a description of the new energy storage activities taking place across the province as well as locally.

NPEI Role in Activity

NPEI provides information to customers, through its website and call centre, regarding energy storage.

Description

In March 2014, the Minister of Energy established new policy regarding the procurement of electricity storage in Ontario, setting procurement targets for the OPA and for the Independent Electricity System Operator (IESO).

In response to this new policy and to assist customers in understanding the new storage procurement opportunities, NPEI developed a plan for enhancing its website and its call centre tracking system to provide information and assistance to customers regarding this policy.

Results to Date

NPEI has been monitoring government policy regarding the procurement of electricity storage.

Moving Forward

NPEI intends to enhance its website regarding electricity storage by adding a storage section which links with both the OPA and IESO storage sites and by providing general information related to the government policy and procurement opportunities. In addition, in conducting the monthly review of call centre data, reviewers will be mindful of any emerging trends regarding caller interest in storage and consider tracking storage as a separate topic, as warranted. As part of the biennial customer survey, questions related to storage were included, such as interest in storage, whether energy storage was of interest to the customer.

This work may affect the distribution system planning by providing specific information related to customer preferences and needs based on the level of interest (e.g. number of hits to storage site, number of calls) in storage. This information can be used to help to determine the likely level of customer participation in the procurement opportunities. The level of interest and success of that interest will determine whether storage will affect the DSP and DSP planning.

3 Customer Consultation Work

Customer consultation work includes direct one on one customer engagement through interviews, site visits, call centre surveys and other forms of customer survey.

3.1 CDM Market Characterization Customer Interviews and Site Visits

This section includes a description of the plan for market characterization customer interviews and site visits.

NPEI Role in Activity

Market characterization site visits take place for particular market segments that have the potential to achieve electricity savings to contribute to meeting NPEI's electricity savings targets in 2014.

Description

NPEI is making progress toward meeting its CDM targets by the end of 2014. To help ensure that NPEI meets these targets, NPEI retained ICF International in January 2014 to identify the achievable potential for conservation by sector and subsector, consistent with the OPA achievable potential results for the province, and to identify key subsectors for further market characterization, such that these sectors could be targeted in Q4 of 2014 and into the new CDM framework. The market characterization will include direct one on one customer engagement as well as interviews with key subsector market players.

As part of the one on one engagement, ICF International in July-August of 2014 will conduct site visits to particular facilities and customer interviews within the targeted subsectors to obtain a better understanding of customer needs, preferences and priorities related to CDM and will also take the opportunity to ask particular questions related to broader customer issues such as customer bills, time permitting. These latter questions will be added to the CDM interview protocol to be used by ICF staff conducting the site visits. The site visits will be attended by NPEI's CDM staff as well, as time and scheduling permitting.

Results to Date

NPEI updated its customer data in the spring of 2014 to provide a current NAICS code for each customer. This enhanced data set was used by ICF International to model achievable potential results based on OPA's achievable potential, but customized to NPEI's service territory. These results make it easier for NPEI to do targeted engagement by subsector and will also make the results of the achievable potential work more accurate. It will enable NPEI to more readily identify customers within key subsectors for market characterization site visits and interviews.

The achievable potential results identified some key subsectors that may warrant further market characterization work; wineries, greenhouses, poultry operations and hotel/motels. Two subsectors were chosen for market characterization work: greenhouses and hotel/motels, as these offered the greatest potential savings. The market characterization work is underway; site visits and customer interviews for greenhouses and hotels/motels are near completion.

Moving Forward

The initial achievable potential results will be adjusted based on the market characterization work for greenhouses and hotels/motels, once completed. Particular opportunities for savings capture in each of these sectors will be identified including potential technologies to focus on and strategies to address market barriers.

This work may affect the distribution system planning by providing specific information related to customer preferences, needs and priorities related to CDM and other distribution system planning matters for the greenhouse and hotel/motel sectors. Any potential effect on the DSP and distribution system planning will depend on the information obtained. This will be further explored by the Steering Committee once the results of the site visits and interviews are available.

3.2 Call-Center Transactional Survey

This section contains a description of the planned improvement to the call tracking system in order to use in-bound calls to survey customers on different matters including, but not limited to, their satisfaction with the service they just received, and whether the issue they were reporting has been resolved. The transactional survey could also be used to obtain other sorts of customer feedbacks without causing any disruption by an unsolicited survey call or email.

NPEI Role in Activity

NPEI has a customer call centre which is managed through the Customer Services & IT department. NPEI modifies its procedures, as well as its CIS system, to be able to record answers to one or a few additional questions lodged at the end of an in-bound call. NPEI plans ahead, and then changes the set of questions from time to time, in order to broaden the number of research questions.

Description

NPEI's representatives deliver transactional-survey questions. These are part of their regular call script. For example "Would you like additional information regarding how to save energy or the current conservation programs?"; "You have a scheduled outage occurring in your area; have you received the dropped off letter? Would you like this information in a different format: phone, email, text?" In review of your account, you have paid using online banking, would be interested in pre-authorization payment plan?" The call scripts are changed based on trends of call types and feedback from representatives. For example, the most recent change was rate change scripting.

Results to Date

The current approach to transactional surveys is working well. However, the transactional survey responses could be tracked and tabulated in a more organized manner. NPEI has begun to identify a set of enhancements for the transactional survey. Answers to date are not stored in a manner that eases tabulation and interpretation, thereby making it challenging to draw meaningful conclusions and make decision based on feedback.

Moving Forward

NPEI will use its CIS system, as well as, an integrated survey tool to register the responses. Follow up calls and outgoing call scripts will be used to follow up on survey questions.

Moreover, NPEI will plan consultation topics in a more integrated manner along with all other consultation topics across all other consultation activities. This will allow NPEI to schedule transactional survey questions in advance to ensure coverage of a broad number of topic areas; and then tabulate and use the results in concert with results from other consultation activities to draw conclusions, make decisions, take actions and document them.

This work may affect the distribution system planning by providing more and enhanced information related to customer preferences, needs and priorities which can be considered for integration into the DSP and ongoing DSP planning.

3.3 Biennial Customer Satisfaction Survey

This section introduces the new customer satisfaction survey that NPEI will conduct to reach out to the “silent-majority” customers; that is, those customers who usually do not call or reach out to NPEI to provide direct feedbacks. NPEI will roll out a first version of the survey starting in May 2014, and then conduct a similar survey every second year.

NPEI Role in Activity

NPEI determines the need for, and overall content of, customer satisfaction surveys that may take place under its direction.

Description

NPEI retained UtilityPulse to conduct a customer satisfaction survey in May-June 2014. UtilityPulse compared NPEI results with those of Ontario and nationally. Some key results of the survey include:

- UtilityPulse found that the attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. Overall, NPEI on demonstrating credibility and trust, scored 80%, which is higher than the provincial score of 77% and in line with the national score of 80%.
- 84% of electricity bill payers are very or fairly satisfied with NPEI, compared to the Ontario score of 83% and the national score of 89%.
- 82% of customers agree that their next contact with NPEI will be a good or positive experience, which is better than the provincial score of 79% and in line with the national score of 82%.

Details of the survey results are contained in the 2014 rate filing.

Results to Date

Details of the survey results are contained in the 2014 rate filing.

Moving Forward

The results of the survey will be discussed at a Steering Committee meeting and will be integrated into the DSP planning process, as appropriate. The survey will be conducted at least every two years.

4 Service-Territory Stakeholder Consultations

Service-territory stakeholders consultation activities include, but are not limited to, CDM market characterization interviews, meetings with local and regional municipalities and utilities in the Niagara area, and consultations with technical service providers that provide direct assistance to NPEI's customers.

4.1 CDM Market Characterization Market Actor Interviews

This section includes a description of the plan for the market characterization market actor interviews and the expected results.

NPEI Role in Activity

Market characterization interviews may take place with particular market actors that have the potential to assist NPEI in understanding particular markets, and in identifying and implementing strategies to capture more program participants and electricity savings to contribute to meeting NPEI's electricity savings targets in 2014.

Description

NPEI is making progress toward meeting its CDM targets by the end of 2014. To help ensure that NPEI meets these targets, NPEI retained ICF International in January 2014 to identify the achievable potential for conservation by sector and subsector, consistent with the OPA achievable potential results for the province, and to identify key market players to assist with understanding particular markets. The market characterization will include interviews with market players (for example, vendors, contractors, or influential trade associations) doing business in particular segments and having influence on customer investment decisions in energy intensive systems such as lighting, air conditioning, electric heating and ventilation.

As part of the one on one engagement, ICF International in July-August of 2014 will conduct market player interviews to gain a better understanding of market barriers and customer needs, preferences and priorities related to CDM.

Results to Date

Interviews will market players are near completion. Site visits for greenhouses and hotels/motels, the two subsectors chosen for detailed market characterization work, are near completion. The results are being compiled, integrated and analyzed.

Moving Forward

Particular opportunities for CDM savings capture in each of these sectors will be identified including potential technologies to focus on and strategies to address market barriers. This will provide greater understanding of customer needs regarding CDM and how to address them effectively in 2014. It will also provide guidance on strategies to address CDM customer needs in the new CDM framework.

This work may affect the distribution system planning by providing specific information related to customer preferences, needs and priorities related to CDM in the key market segments of greenhouses and hotels/motels. Any potential effect on the DSP and distribution system planning will depend on the information obtained. This will be further explored by the Steering Committee once the results of the market characterization work are available.

4.2 Results of Regular Stakeholder Meetings

Regular stakeholder meetings (Public Utility Committee meetings – PUC meetings) consist of the monthly in-person meetings that NPEI participates in with key local stakeholders such as local municipalities and Niagara Region, Enbridge Gas Distribution, and the local cable and phone companies.

NPEI Role in Activity

Staff from NPEI's engineering and operations departments attend PUC meetings as a participant with other stakeholders in its service territory, referred to as Public Utility Committee meetings.

Description

NPEI participates in the local Public Utility Committee meetings hosted by the two designated Municipalities that NPEI services. These monthly meetings are attended by municipal and regional authorities, electric utilities, communication & cable T.V. utilities, gas utilities, and the Ministry of Transportation & the Ministry of Labour.

Minutes of the meeting are recorded and made public, and include discussions of short and long term planning of the various agencies in order to co-ordinate efforts, prepare budgets and mobilize staff as required, wherever relocation or rebuild work may involve any of the attending agencies.

Results to Date

NPEI regularly attends and participates in PUC meetings and keeps the meeting minutes. There is an opportunity for NPEI to take a more proactive role, as required, to try to address key distribution system planning issues through the meeting agenda.

Moving Forward

NPEI will be cognizant of the opportunity to engage stakeholders at the PUC in its distribution system matters, as appropriate. NPEI may also set up and/or attend ad hoc meetings with particular members to discuss relevant system planning matters, as appropriate. These activities are expected to lead to lead to more effective use of this engagement forum and ultimately, will contribute to a more integrated planning approach to NPEI's customer engagement and more effective reporting on engagement activities.

PUC results may affect the distribution system planning by providing specific information related to regional planning issues and the impact of regional stakeholders on NPEI's distribution system planning and plan. Any potential effect on the DSP and distribution system planning will depend on the information obtained. This will be further explored by the Steering Committee, based on the reporting to the Committee by the Operations and Engineering departments members of PUC meeting results.

4.3 Consultation with Technical Service Providers

This section presents a description of consultation activities with technical service providers, also referred to as indirect customers.

NPEI Role in Activity

Staff from NPEI's Engineering and Operations departments has informal meetings with customers' technical service providers on an ongoing basis. These include tradespeople, professionals involved in new REG connection, behind the meter servicers, etc.

Description

The technical service providers of customers provide valuable insight into customer needs, preferences and priorities. As a result, NPEI Engineering and Operations department staff meets informally with them to obtain information related to market segments, customer satisfaction, the perceived quality of service and avenues for improvement.

Results to Date

Meetings to date have been productive and helpful for distribution system planning. There is an opportunity to hold more formal engagement activities with customers' technical service providers in order to draw more meaningful and robust conclusions, and make decisions based on the feedback received.

Moving Forward

NPEI intends to proceed with a more formal approach to engagement with technical service providers in addition to maintaining informal engagement. The formal engagement will consist of directed cognitive phone interviews conducted by utility staff, following interaction with the service provider on normal business activities.

NPEI intends to use the information acquired through these consultations to identify requirements and attendees for focus group activities that are expected to take place on an annual basis in a central location.

Potential research questions include: perceived quality of new connection and REG service when compared with other nearby LDC where they also have business, power quality, quality of information available from NPEI, and potential improvement regarding the delivery of CDM programs.

Both consultation activities (interviews and focus group) are new, and will be rolled out in 2015. NPEI will do the planning for the phone interviews (e.g. questionnaire) in the spring of 2015 and expects to hold the focus groups in November or December of 2015. NPEI's Engineering and Operations departments will be responsible for carrying out this consultation on a regular basis based on a quota of interviews decided in advance by the Steering Committee.

This work may affect the distribution system planning by providing specific information related to customer preferences, needs and priorities for distribution system planning. Any potential effect on the DSP and distribution system planning will depend on the information obtained. This will be further explored by the Steering Committee, based on the reporting to the Committee by the Operations and Engineering departments members of consultation results.

5 Participation in Consultations with OPA & HONI

This section presents communications between NPEI and the Ontario Power Authority (OPA), and between NPEI and Hydro One (HONI) regarding distribution system planning matters.

5.1 Consultations in Regional Processes

The OEB has laid out specific requirements for consultation to be conducted by distributors related to regional planning processes. This section addresses how NPEI meets those requirements.

NPEI Role in Activity

NPEI is a participant in any regional planning. Regional planning is led by either OPA or HONI.

Description

NPEI monitors on an ongoing basis regional activities that may affect its distribution system.

Results to Date

To date there are no regional planning activities in Niagara Region. No regional planning activities are expected within the next 5 years.

Moving Forward

NPEI will endeavour to obtain a letter from OPA and from HONI confirming that no regional planning process is currently underway. NPEI intends to build a web page on its website to provide information on regional processes. NPEI will continue to liaise with OPA and HONI on regional planning processes that may affect NPEI.

Planned or launched regional processes may affect the distribution system planning and plan if regional processes go forward during the 5-yr DSP. Any potential effect on the DSP and distribution system planning will depend on the nature of the regional process and the timing of its deliverables and completion. Any such planning would be reported on to the Steering Committee and considered for integration into the DSP and planning, as appropriate.

5.2 Consultations with HONI

The OEB requires distributors to consult with regionally interconnected distributors and the transmitter in preparing the DSP. NPEI does not have embedded or host distributors, as a result NPEI consultation activities focus on HONI.

NPEI Role in Activity

NPEI consults with HONI on NPEI's distribution system planning to provide information to HONI on NPEI's distribution system planning and to obtain HONI input.

Description

NPEI consultation with HONI on its five-year DSP to be filed in its Cost-of-Service application of August 2014 is underway.

Results to Date

The letter from NPEI to HONI, regarding preparation of the DSP for filing, identifying any potential issues and requesting feedback was sent. To date no feedback has been received from HONI.

Moving Forward

NPEI will send a letter to HONI, notifying HONI when the DSP is being finalized and indicate how any issues related to HONI have been resolved, and how this was integrated into the DSP.

5.3 Consultations on REG Interconnection

Prior to filing a DSP, the OEB requires a distributor to provide the transmitter (in this case HONI) and the OPA specific information related to its DSP. The information covers matters such as: the forecast load, forecast REG connections, smart grid investments, planned projects and recent results of projects or activities involving innovative processes, and services, business models, or technologies.

NPEI Role in Activity

NPEI consults with HONI and OPA on REG connections within its service territory and related to its distribution system planning.

Description

NPEI consults with HONI and OPA on an ongoing basis regarding REG connection.

Results to Date

NPEI has initiated consultation activities with HONI.

Moving Forward

NPEI will send a letter to OPA and to HONI, providing the following information in advance of its DSP filing. The information covered: forecast load, forecast REG connections and any planned network investment to accommodate connections; investment involving smart grid that could have an impact on assets serving regionally connected utilities, and the results of projects or activities involving demonstration of innovative processes, services, business models; and on projects or activities of this nature planned over the forecast period. NPEI will follow up with OPA and HONI on any matters that arise from the information sent and address and document concerns, their resolution, and how this was integrated into the DSP.

5.4 Consultations on REG Investments

Prior to filing of the DSP, the OEB requires NPEI to send a letter to the OPA regarding distribution system investments related to REG.

NPEI Role in Activity

NPEI prepares material regarding distribution system investments related to REG for the OPA for comment and will address any comment received from the OPA, prior to filing of the DSP.

Description

NPEI assesses on an ongoing basis the need for distribution system investments related to REG.

Results to Date

NPEI sent a letter to OPA 60 days in advance of the filing of the DSP.

Moving Forward

NPEI will prepare a response letter to the OPA letter, if necessary, and integrate feedback obtained into distribution system planning and the DSP.

Appendix A – Chapter-5 Compliance Form (C5C Form)

niagara peninsula energy inc.

CHAPTER 5 COMPLIANCE FORM FOR CUSTOMER ENGAGEMENT ACTIVITIES

<table>
<tr><td>NPEI Staff Responsible</td><td colspan="2">Name:</td><td colspan="2">Job Title:</td></tr>
<tr><td>Consultation Activity Title</td><td colspan="4"></td></tr>
<tr><td>Brief Description</td><td colspan="4"></td></tr>
<tr><td>Purpose</td><td colspan="4"></td></tr>
<tr><td rowspan="3">NPEI’s Role</td><td colspan="2">☐ Initiated Activity</td><td colspan="2">☐ Invited to Activity</td></tr>
<tr><td>☐ Chair</td><td>☐ Facilitator</td><td>☐ Participant</td><td>☐ Other: __________________</td></tr>
<tr><td colspan="4">NPEI Staff Involved (Name, Title):</td></tr>
<tr><td rowspan="4">Details</td><td colspan="2">Location:</td><td>Date:</td><td>Number of Participants:</td></tr>
<tr><td colspan="4">Participants: If only a few, please be specific and list name(s) and organization(s); if many, please list general target audience(s):</td></tr>
<tr><td colspan="4">Status of consultation activity (e.g. complete, # additional meetings scheduled, # of total topics covered, etc.):</td></tr>
<tr><td colspan="4">List hyperlink(s) or cross reference(s) to relevant materials or attach as an appendix (if applicable):</td></tr>
<tr><td rowspan="2">Results (If applicable)</td><td colspan="4">Next steps or nature of final deliverables (e.g. meeting minutes, transcripts, tabulated survey results, Regional Integrated Resource Plan):</td></tr>
<tr><td colspan="4">Timing of final deliverables (if applicable):</td></tr>
<tr><td rowspan="2">Is the activity expected to affect the Distribution System Plan?</td><td colspan="2">☐ Yes</td><td colspan="2">☐ No</td></tr>
<tr><td colspan="4">If so, how?</td></tr>
</table>

This form is intended for NPEI Staff to document consultation activities that result directly from the Customer Engagement Plan. This form should be used to document major consultation activities such as CDM events, participation in regional planning activities, the send-out /completion of a customer satisfaction survey, focus group sessions that relate to a particular consultation activity, regular meetings with municipalities, and monthly or quarterly interviewing activities (not the results of individual interviews).

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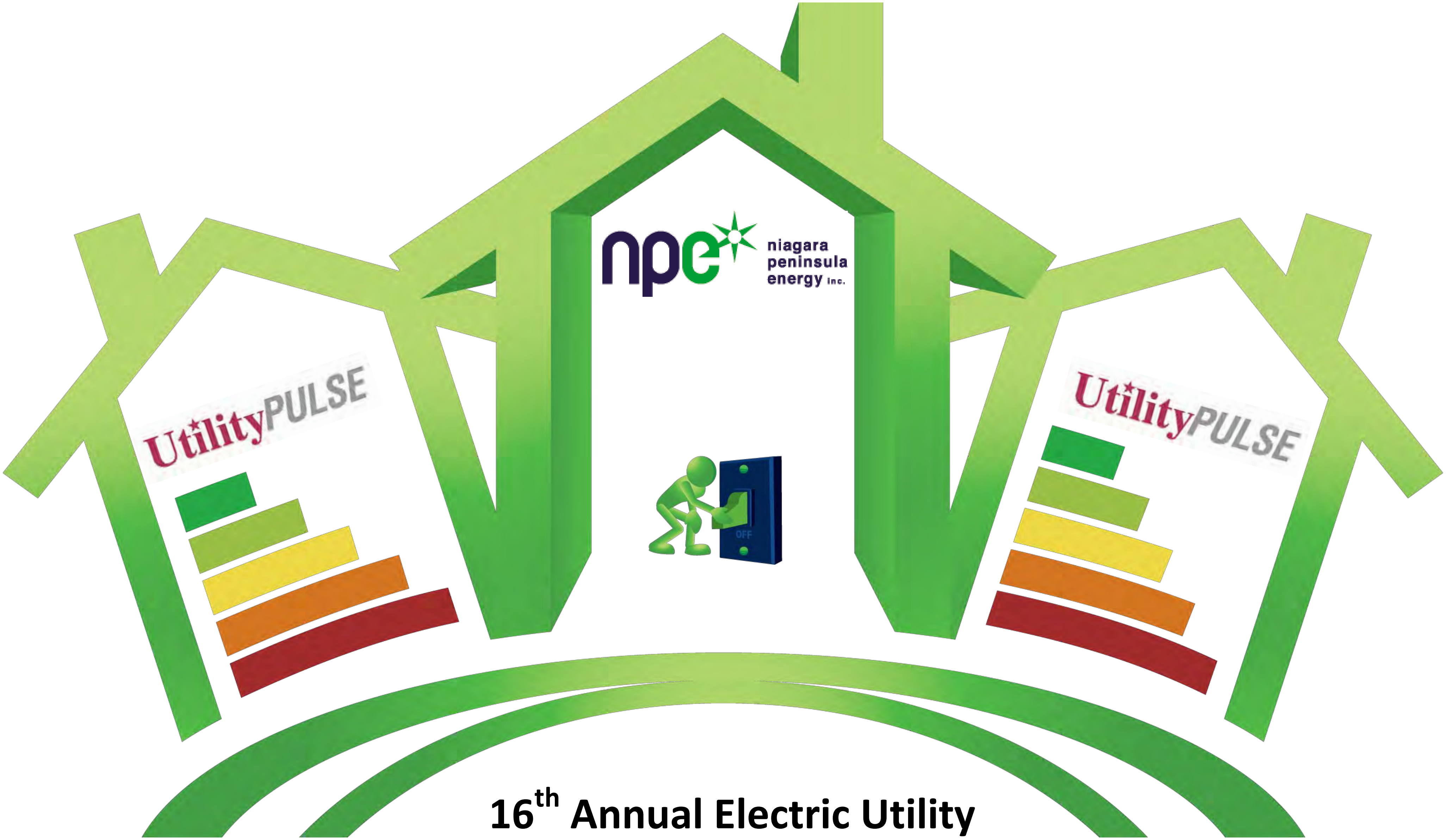
Attachment 4 of 4

2014 Customer Survey

Niagara Peninsula EnergyInc.



16th Annual Electric Utility
Customer Satisfaction Survey

The purpose of this report is to profile the connection between Niagara Peninsula Energy Inc. (NPEI) and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information that will support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.

All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

Toll free: 1-888-291-7892 or Local: 905-895-7900

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Executive summary

Rosemarie LeClair, Chair of the Ontario Energy Board, in a recent presentation (Ontario Energy Network, April 28, 2014) said the OEB's consumer centric regulatory framework defines the utility's obligation for planning, obligations for customer engagement and its responsibilities for monitoring and measuring performance results.

EB-2010-0379 Report of the Board: Scorecard Approach (ROB-SA) (March 5, 2014)

Throughout this report are connections to the OEB's Report of the Board. Where possible we have addressed the specifics in the document and, the "spirit" of the Scorecard Approach.

We believe that the data from interviewing over 10,000 electric utility customers so far, in 2014, supports 3 main conclusions:

1- Customers, almost universally, are concerned about the cost of electricity

2- Customers are resilient and can adapt to adversity, in fact, they are very tolerant when a utility goes through a very difficult situation

3- In a utility world that is used to "pushing information out", it has to invest in and hone its competencies in having 2-way interactions with customers.

Reasonable costs

9,943 Ontario survey respondents were asked if they agree or disagree with the following statement *"The cost of electricity is reasonable when compared to other utilities".* 50% agree in 2014, and 62% agreed in 2010. Satisfaction with the utility is about the same in those respective years.

We can also say that issues in the electricity industry, as a whole, show that satisfaction ratings and other important measures are lower in 2014 than they were in 2013. A customer may be upset with the amount that electricity costs, or what is going on in the industry, but that may not translate to being upset with their own local utility.

Data from the 2014 survey shows that respondents who give their utilities high marks for respect, trust, and social responsibility also give their utilities high marks for providing high quality services, and better marks for both cost efficiency and reasonableness of costs.

The attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. On demonstrating Credibility and Trust, NPEI has done well.
Overall, NPEI 80% [Ontario 77%; National 80%].

EB-2010-0379 ROB-SA: Comparability

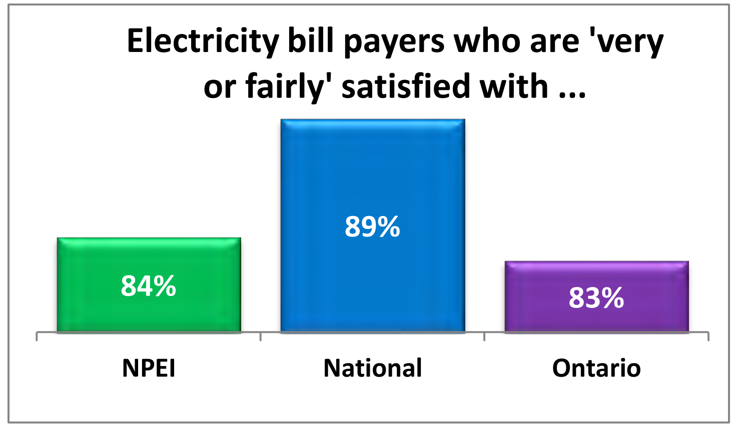
Your 2014 report contains data comparisons to:

- An Ontario-wide LDC benchmark
- A National LDC benchmark
- Previous year's ratings (where available)

- Ontario LDCs participating in the 2014 survey
- UtilityPULSE database

EB-2010-0379 ROB-SA: Customer Focus

There are 2 identified Performance Categories in the OEB Report, they are Customer Satisfaction & Service Quality. Performance measurements for these areas range from *'relatively easy to attain production statistics'* to *'harder to define and measure qualitative items'*. None-the-less this survey provides you with insights about how customers perceive performance of the utility.



Base: total respondents

EB-2010-0379 ROB-SA: Customer Focus - Customer Satisfaction - Satisfaction Survey Results

Customer satisfaction is one of the measures in the consumer centric regulatory framework. This rating is known as an effectiveness rating as it represents a sum total of perceptions and expectations that a customer has about their utility. Those expectations go far beyond "keeping the lights on", "billing me properly", and "restoring power quickly".

NPEI SATISFACTION SCORES – Electricity customers' satisfaction					
Top 2 Boxes: 'very + fairly satisfied'	**2014**	**2013**	**2012**	**2011**	**2010**
PRE: Initial Satisfaction Scores	84%	-	-	-	-
POST: End of Interview	87%	-	-	-	-

Base: total respondents / (-) not a participant of the survey year

- ***Satisfaction*** *happens when utility core services meet or exceed customer's needs, wants, or expectations.*
- ***Loyalty*** *(Affinity) occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.*

Customer Affinity

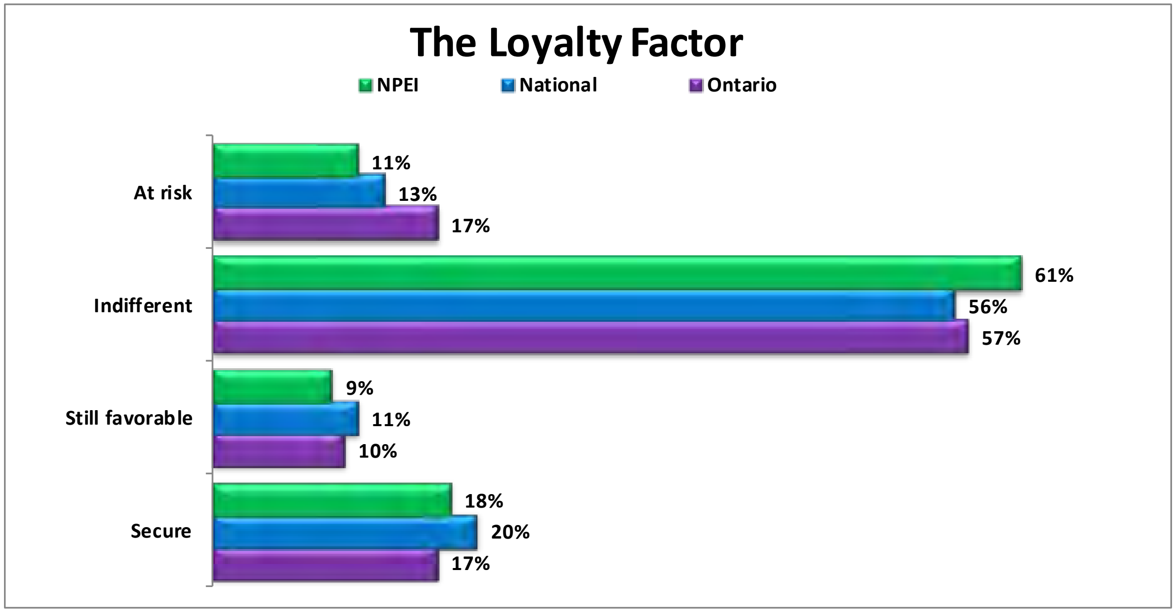
Loyalty, for private industry, is a behaviourial metric. Loyalty, for natural monopolies (like LDCs) is an attitudinal metric.

Customer Loyalty Groups				
	Secure	**Favorable**	**Indifferent**	**At Risk**
		NPEI		
2014	18%	9%	61%	11%

Base: total respondents

Even if customers can't defect, there is enormous value in making more of them loyal. Customers after all make the company's reputation. Reputation is ultimately what customers think – nothing else. To be successful and profitable, companies must take account of how they are perceived because companies do operate in a climate of opinion.

Loyal customers are more likely to see the world the way hydro management sees it. Customers feel their interests and the hydro's are often in common. Our survey results do reveal, loyal customers enhance the value of the utility. One example, 97% of Secure customers agree that overall NPEI 'provides excellent quality services' versus 62% of At Risk customers.



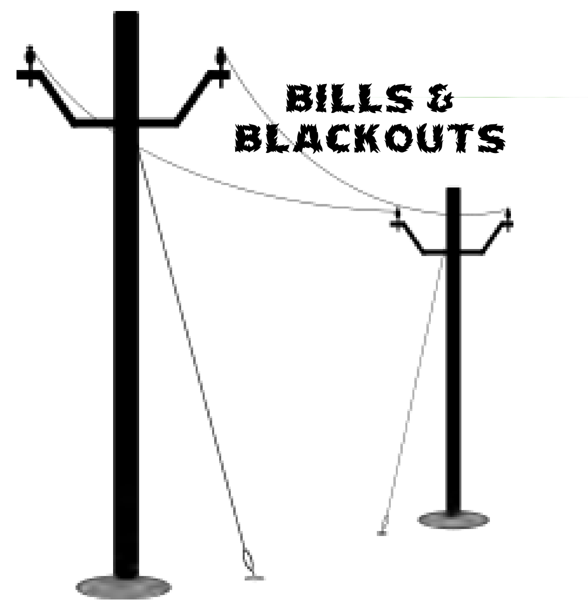
Base: total respondents

Utilities benefit from a trusted relationship with their empowered Customers. Higher levels of trust are the hallmarks of Secure customers. When people interact, either face-to-face, by telephone or on-line, if people do not trust each other, the interaction is not going to be efficient. Trust improves the speed at which the interaction can be accomplished. At Risk customers recall experiencing more outages and more billing problems than Secure customers. What makes matters worse is, At Risk customers are about 2X more likely to contact the utility to deal with it.

None-the-less problems will happen.

The Killer B's (Blackouts and Bills)

It is inevitable that there will be blackouts/power outages – the key is how a utility anticipates outages and more importantly, how it deals with them. It should also be noted that there is a disconnect between what a utility might call a "billing problem" and what a customer defines as a "billing problem". Though both viewpoints are valid, employees need to be trained to answer those which cause the most concern with customers.



Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months

	NPEI	National	Ontario
2014	51%	47%	49%
2013	-	41%	35%
2012	-	44%	46%
2011	-	43%	43%
2010	-	45%	41%

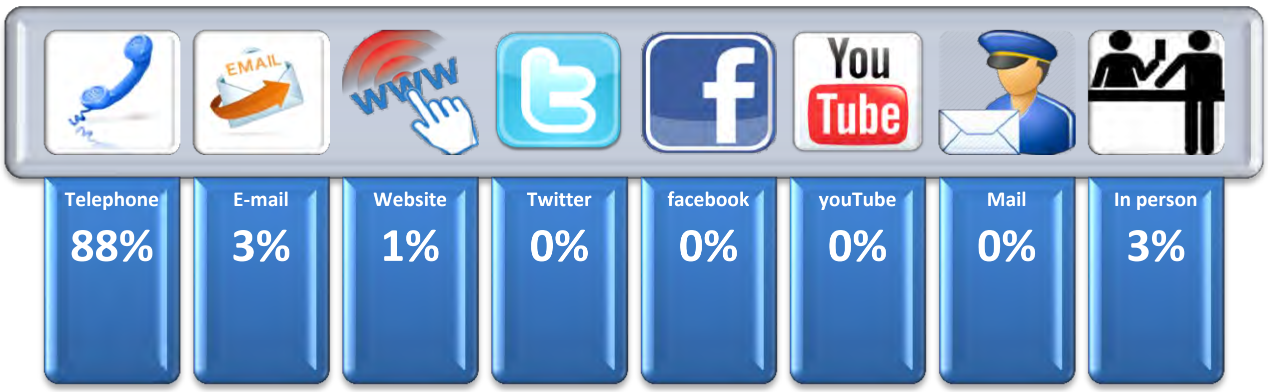
Base: total respondents / (-) not a participant of the survey year

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	NPEI	**National**	**Ontario**
2014	18%	16%	25%
2013	-	8%	10%
2012	-	12%	13%
2011	-	10%	16%
2010	-	10%	12%

Base: total respondents / (-) not a participant of the survey year

What method did you use to contact your electric utility when you had a problem?

Base: data from the full 2014 database



Customers may prefer a particular communication channel today (i.e., 88% telephone), however, that does not mean the customer who prefers the telephone will not want, or eventually want another channel for communications. In addition, there could be variances in preferences based on the type of issue or transaction.

EB-2010-0379 ROB-SA: Customer Focus – Customer Satisfaction – Billing Accuracy

There is a difference between what a customer believes is a billing problem versus a technical or production level measurement. Without the benefit of production level numbers, 84% of respondents 'agree strongly + somewhat' that the utility has "accurate billing". The Ontario benchmark rating is 77%.

EB-2010-0379 ROB-SA: Customer Focus – Customer Satisfaction – First Contact Resolution

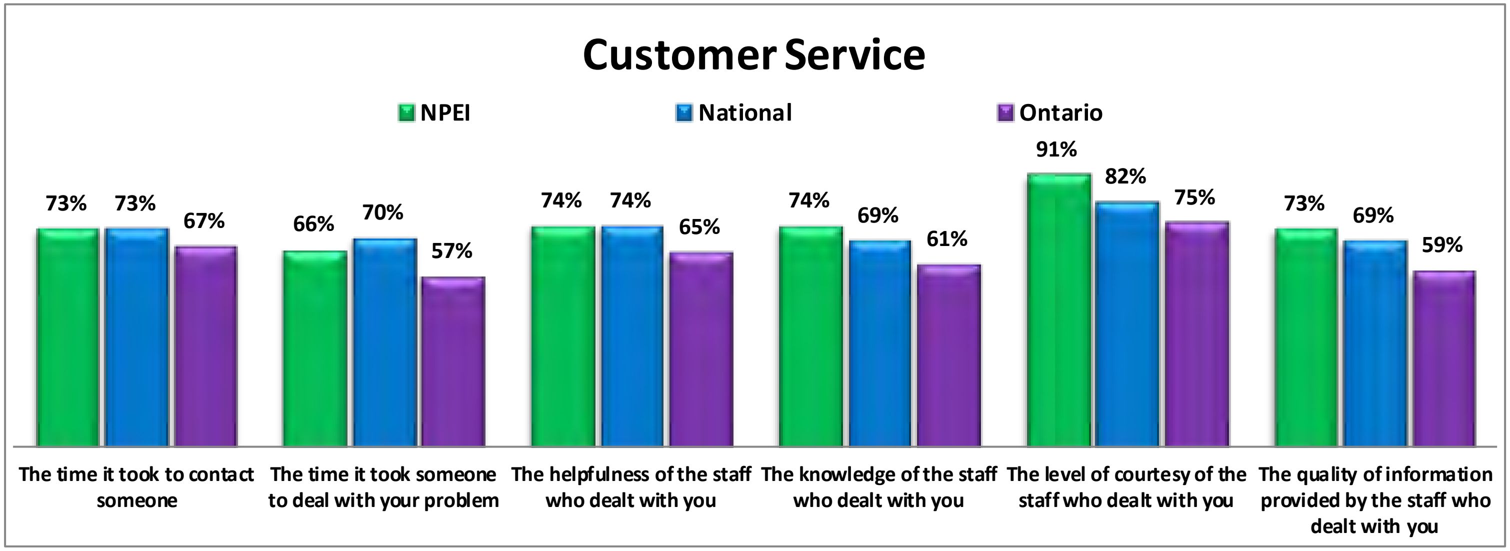
This performance measure is not defined in the EB-2010-0379 ROB-SA March 5, 2014 document. First contact resolution is an outcome base measurement which is affected by: type of problem, competency levels of staff, empowerment levels of staff, and organization culture to name a few.

Your 2014 survey gives you the following information from respondents:

1- Satisfaction with the contact experience
2- A problem solved rating
3- A Customer Experience Performance rating (CEPr)

Satisfaction with the contact experience

When there are problems, how they are handled can validate or invalidate a customer's perception about the utility's competency in handling the problem, and in running the operation. Here is how Customers, who contacted your LDC, rated their one-on-one transaction.



Base: total respondents who contacted the utility

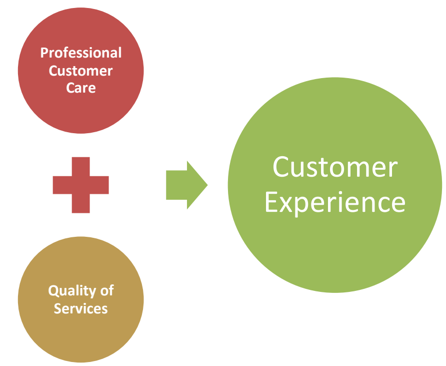
Customer expectations are on the rise and continue to change. Customers expect their utility to have customer care practices and services that are in-line with any other organization that is important to their everyday life. Setting realistic expectations and consistently delivering to those expectations are keys to higher levels of Customer satisfaction. The setting of customer expectations is tough, but the harder part is to deliver consistency.

Overall satisfaction with most recent experience			
	NPEI	**National**	**Ontario**
Top 2 Boxes: 'very + fairly satisfied'	76%	75%	62%

Base: total respondents who contacted the utility

Problem solved rating

Respondents who said that they contacted the utility were also asked "Do you consider the problem solved or not solved?" 67% of your LDC's respondents said the problem was solved. The Ontario benchmark rating is 61%.



Customer Experience Performance rating (CEPr)

What do customers anticipate contact will be with their local utility when they have a problem? Will it be adversarial, or cooperative, or pleasant, etc. High numbers in CEPr indicate that a large majority of customers would agree that their next contact will be a good or positive one.

Customer Experience Performance rating (CEPr)			
	NPEI	**National**	**Ontario**
CEPr: all respondents	82%	82%	79%

Base: total respondents

EB-2010-0379 ROB-SA: Customer Focus – Service Quality

The three performance measures identified are all time based measures. They are: New Residential Services Connected on Time; Scheduled Appointments Met on Time; and, Telephone Calls Answered on Time. These are good examples of efficiency measures. In addition to time, there are other dimensions of Service Quality that Customers value.

Customer Service Quality

Top 2 boxes, 'strongly + somewhat agree'	NPEI	National	Ontario
Deals professionally with customers' problems	82%	82%	78%
Pro-active in communicating changes and issues affecting Customers	76%	74%	73%
Quickly deals with issues that affect customers	79%	79%	74%
Customer-focused and treats customers as if they're valued	76%	74%	72%
Is a company that is 'easy to do business with'	81%	79%	75%
Cost of electricity is reasonable when compared to other utilities	58%	60%	55%
Provides good value for money	68%	67%	63%
Delivers on its service commitments to customers	85%	84%	82%

Base: total respondents with an opinion

EB-2010-0379 ROB-SA: Operational Effectiveness

With the exception of the Public Safety measure, which is yet to be defined, performance measures would typically take the form of a monitoring and measuring (quantitative) rating. Though customers may not have the benefit of numbers, they do have a perception.

Management Operations			
Top 2 boxes, 'strongly + somewhat agree'	**NPEI**	**National**	**Ontario**
Provides consistent, reliable electricity	87%	89%	86%
Quickly handles outages and restores power	85%	86%	83%
Makes electricity safety a top priority for employees and contractors	88%	89%	87%
Operates a cost effective electricity system	68%	69%	62%
Overall the utility provides excellent quality services	84%	83%	80%

Base: total respondents with an opinion

UtilityPULSE Report Card®

The purpose of the UtilityPULSE Report Card is to provide your utility with a snapshot of performance – it represents the sum total of respondents' ratings on 6 categories of attributes that research has shown are important to customers in influencing satisfaction and affinity levels with their utility.

NPEI's UtilityPULSE Report Card®

Performance

	CATEGORY	NPEI	National	Ontario
1	**Customer Care**	**B**	**B+**	**B**
	Price and Value	C+	B	C+
	Customer Service	B+	B+	B
2	**Company Image**	**A**	**B+**	**B+**
	Company Leadership	A	B+	B+
	Corporate Stewardship	B+	A	B+
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	B+
	Power Quality and Reliability	A	A	A
	OVERALL	**B+**	**B+**	**B+**

Base: total respondents

Corporate Image

Reputation, image, brand have to be actively managed. Positive impressions beget positive perceptions. Marketing communication includes positioning the utility in a way that makes customers want your utility and its services. Every utility has a brand, why not have the brand you want?

Attributes strongly linked to a hydro utility's image

	NPEI	National	Ontario
Is a respected company in the community	85%	81%	78%
A leader in promoting energy conservation	81%	78%	77%
Keeps its promises to customers and the community	82%	79%	76%
Is a socially responsible company	83%	78%	77%
Is a trusted and trustworthy company	84%	82%	77%
Adapts well to changes in customer expectations	72%	71%	68%
Is 'easy to do business with'	81%	79%	75%
Provides good value for your money	68%	67%	63%
Overall the utility provides excellent quality services	84%	83%	80%
Operates a cost effective hydro-electric system	68%	69%	62%

Base: total respondents with an opinion

Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job (as contracted), thereby fulfilling the customer's basic needs. The emotional side of the customer is about fulfilling expectations. Meeting rational needs – at best – gets the customer to a neutral state and at worst creates dissatisfaction. Emotional needs, when met, assuming base level rational needs are met, can move a customer from neutral to higher levels of satisfaction. The industry is obsessed with rational concerns about customer behaviour, but the real motivation for customer behaviour is emotional, not rational.

What do customers think about electricity costs?

Ask a utility customer – anywhere in the province of Ontario – what do they think about electricity, there is a very high probability they will say electricity costs are too high or too expensive. For customers who said that they had a billing problem in the last 12 months, and stated that the problem was "high bills" or "high rates or charges", there was very little variability between customers who could be called Secure, Favourable, Indifferent or At Risk. There was also very little variability between age groupings or income groupings.

Our survey database shows 50% more customers in 2014 citing complaints with "high bills" or "high rates or charges" than in 2010. There is a growing concern over electricity costs, especially as it relates to its portion of a household budget. This means the industry needs to monitor "ability to pay".

Is paying for electricity a worry or major problem …

	NPEI	National	Ontario
Not really a worry	57%	69%	59%
Sometimes I worry	31%	20%	26%
Often it is a major problem	6%	7%	11%
Depends	2%	3%	2%

Base: total respondents

Supplemental Insights

Recognizing that customers' interests and needs continue to shift, we have provided data and insights, on a number of subjects such as e-care, e-billing, conservation and more.

Electric Industry Knowledge & SMART Grid

Beyond knowing that they need electricity to maintain their day to day activities, does the average person feel that they are actually knowledgeable about the electric utility industry?

Knowledge level about the electric utility industry

	Ontario
Extremely knowledgeable	2%
Very knowledgeable	11%
Moderately knowledgeable	47%
Slightly knowledgeable	26%
Not very knowledgeable	14%
Don't know	1%

Base: total respondents in the Ontario Benchmark survey

Two-thirds (60%) of those polled in the Ontario Benchmark survey considered themselves moderately to extremely knowledgeable about the electric industry.

While it is evident that the SMART grid is still not a much talked about concept, only 34% have a basic or good understanding of what it is, oddly enough, 60% still think that it is important to pursue SMART grid implementation. It is also clear that the majority of respondents are very + somewhat supportive of the utility working with neighbouring utilities on SMART grid initiatives.

Level of knowledge about the SMART Grid

	Ontario
I have a fairly good understanding of what it is and how it might benefit homes and businesses	9%
I have a basic understanding of what it is and how it might work	25%
I've heard of the term, but don't know much about it	36%
I have not heard of the term	29%
Don't know	1%

Base: total respondents in the Ontario Benchmark survey

Efforts to reduce energy consumption

Do customers believe there is a real pay-off for trying to reduce their energy consumption? Does this impact overall efforts to reduce consumption? Respondents were asked *"How active have you been in trying to reduce your electricity consumption?"* (Base: total respondents in the Ontario Benchmark survey)

- 94% feel they are "very + somewhat active" in trying to reduce electricity consumption, and
- 81% of those do believe their efforts have resulted in reduced energy consumption, of which
- 44% estimate that they were able to offset an energy consumption reduction of more than 10%, and
- 72% believe that these efforts translated to savings on their electricity bills.

Level of Activity in trying to reduce electricity consumption	
	Ontario
Very active	52%
Somewhat active	42%
Neither proactive or inactive	0%
Not active	2%
Not very active	3%

Base: total respondents in the Ontario Benchmark survey

Active efforts have reduced energy consumption

81%

16%

Base: total respondents in the Ontario Benchmark survey who have been active in trying to reduce energy consumption

Estimate of percentage reduction in consumption	
	Ontario
1 – 2 %	5%
3 – 5 %	10%
6 – 8 %	4%
9 – 10 %	15%
More than 10%	44%
Don't know	21%

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

Efforts to conserve have translated into savings on your electricity bill

72%

24%

Base: total respondents in the Ontario Benchmark survey whose active efforts have reduced consumption

Energy Conservation & Efficiency

Energy efficiency can be broken down into two areas: *better use of energy through improved energy-efficient technologies;* and *energy saving through changes in customer awareness and behaviour.*

Efforts to conserve energy

Ontario LDCs	Yes	No	Already Done	Don't Know
Install energy-efficient light bulbs or lighting equipment	19%	9%	70%	1%
Install timers on lights or equipment	12%	50%	35%	2%
Shift use of electricity to lower cost periods	22%	17%	58%	3%
Install window blinds or awnings	12%	27%	60%	2%
Install a programmable thermostat	13%	25%	60%	2%
Have an energy expert conduct an energy audit	9%	71%	16%	4%
Removing old refrigerator or freezer for free	14%	44%	38%	4%
Join the peaksaverPLUS™ program	15%	49%	21%	16%
Replacing furnace with a high efficiency model	12%	33%	52%	4%
Replacing air-conditioner with a high efficiency model	14%	38%	44%	4%
Use a coupon to purchase qualified energy saving products	35%	39%	22%	5%

Base: An aggregate of respondents from 2014 participating LDCs

E-care and E-billing

Technology – specifically the internet—has allowed people access to far more information than ever before and the ability to do more than ever before.

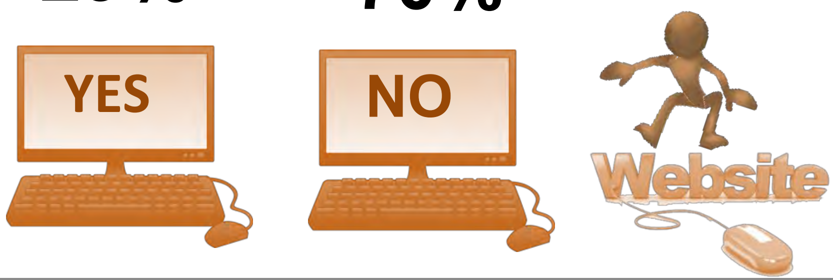
Do you have access to the internet?	
	Ontario LDCs
Yes	87%
No	13%

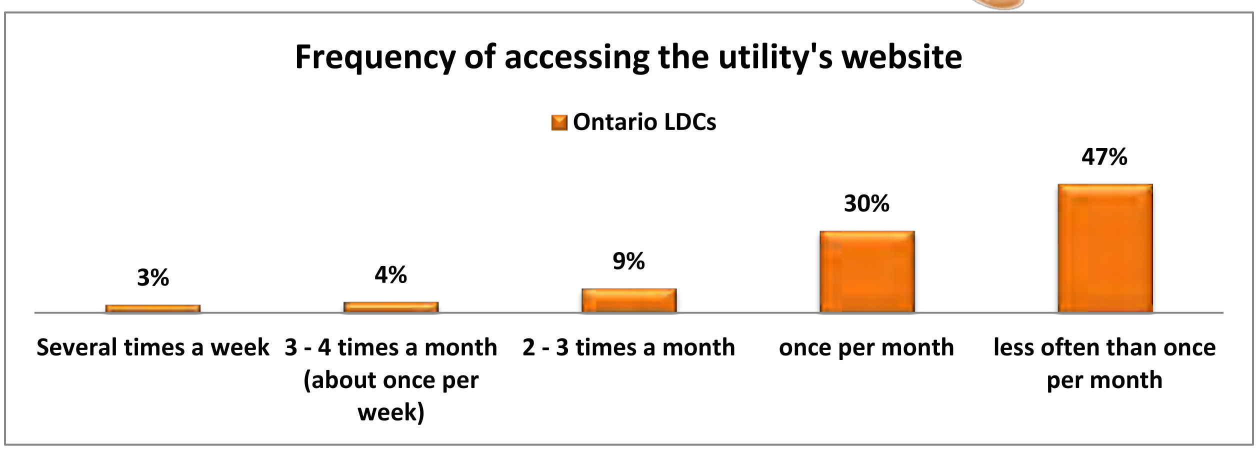
Base: An aggregate of respondents from 2014 participating LDCs

Over the past six months have you accessed your local utility website?

29% **70%**

Base: An aggregate of respondents from 2014 participating LDCs





Base: An aggregate of respondents from 2014 participating LDCs

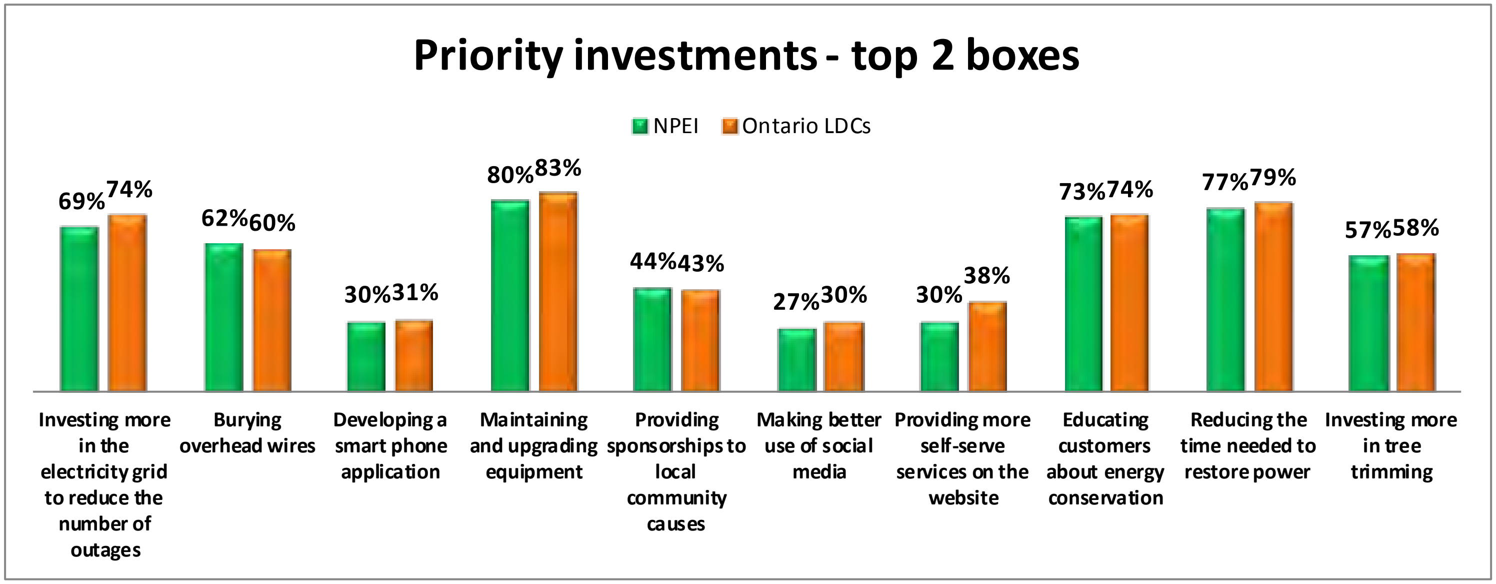
Likelihood of using the internet for future customer care needs for things such as:	
Top 2 Boxes: 'very + somewhat likely'	**Ontario LDCs**
Setting up a new account	31%
Arranging a move	38%
Accessing information about your bill	55%
Accessing information about your electricity usage	54%
Accessing energy saving tips and advice	45%
Accessing information about Time Of Use rates	51%
Maintaining information about your account or preferences	51%
Paying your bill through the utility's website	32%
Getting information about power outages	47%
Arranging for service	40%

Base: An aggregate of respondents from 2014 participating LDCs

As society becomes increasingly more familiar with technology it will become a more popular medium for giving and receiving information. One could also say, demographics will also put more pressure on the technology channels. Unfortunately, customers adopt technology on their own timetable. This causes the utility to continue to improve existing channels while building the technological channels wanted by some today, but by the year 2020, demanded by many. Will your utility be ready?

Priority Investments

While regulation and reliability are top concerns in the utility industry, aging infrastructure is now a top operational concern. Customers agree with industry insiders that infrastructure renewal is a high priority. This year, respondents were asked for their views about prioritizing investments.



Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local

Some findings shown above correlate with some of the suggestions made by respondents on things the utility could do to improve. Percentage of comments received from all Ontario respondents were:

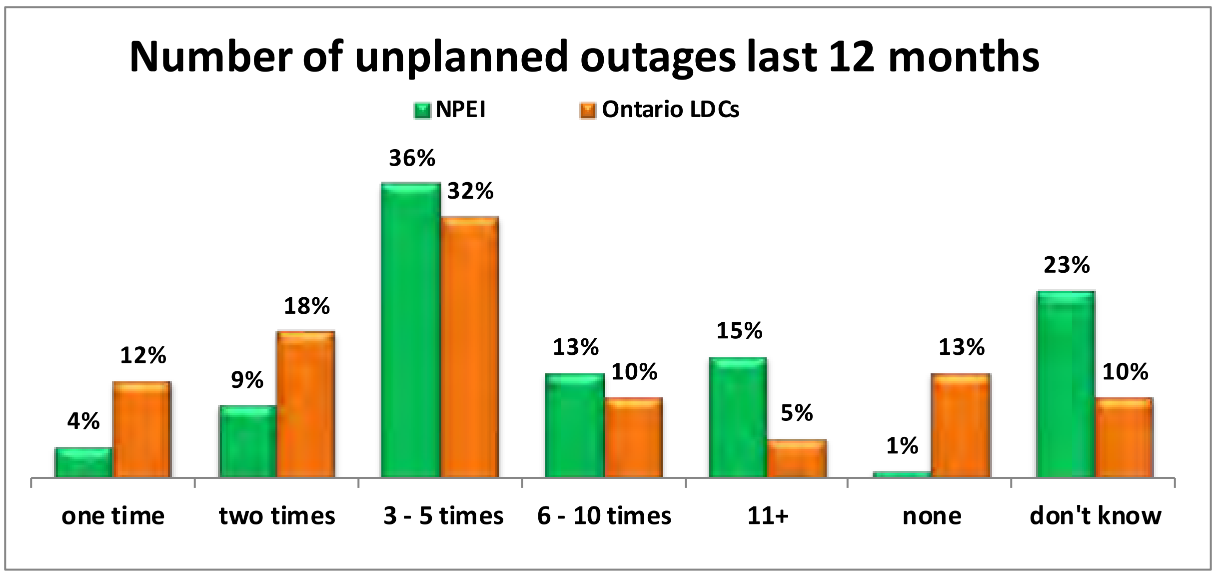
- 14% improve reliability (10% in 2010)
- 11% better maintenance (3% in 2010)

- 10% better communication (7% in 2010)

Outage Management

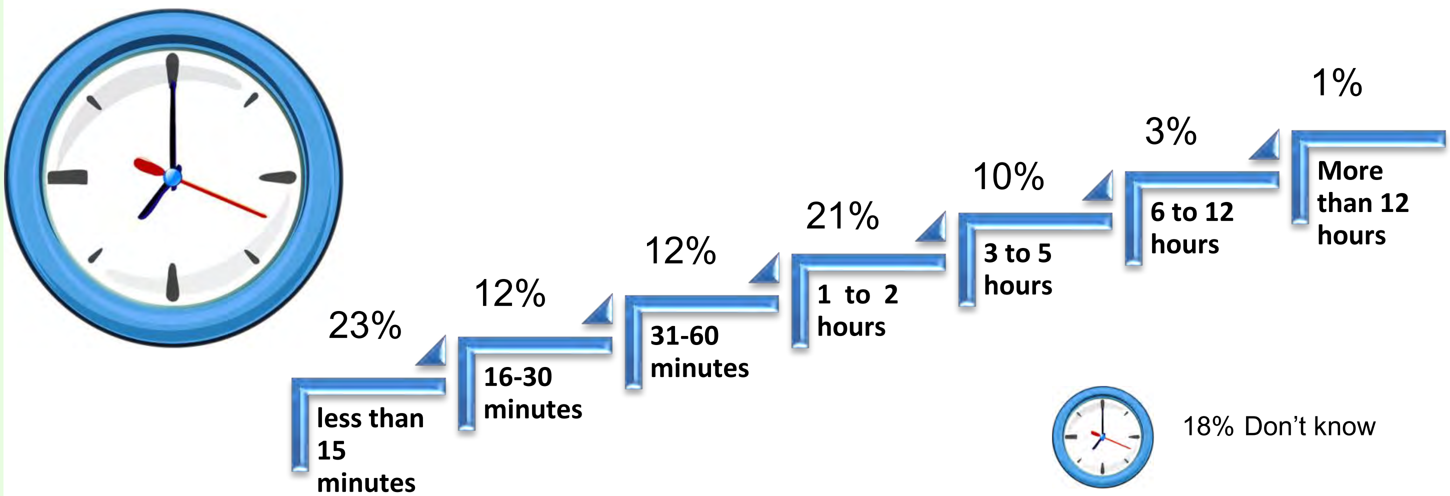
Whether an outage is planned or unplanned, the reality is that it is going to cause disruption and inconvenience under best case scenario and under worst case scenarios there could be safety and financial consequences.

However, one thing for certain, no matter what the scenario happens to be, customers are expecting their utility to keep them continually updated on the status of outages. Most importantly, and top priority, is to know the estimated restoration time. They also want to know the cause of the outage because they do not want to be a frequent outage customer.



Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

When an unplanned outage occurs, how long, on average, is the outage?



Base: 90% of total respondents from the local utility

How a utility chooses to handle, manage and communicate with customers during an outage situation does affect customers' satisfaction with their utility. Customers want timely, accurate and relevant information about an outage and customers expect a utility to use various communication channels to ensure their message is getting out there. This means not only obtaining information via the call centre and IVR but customers have increasing expectations for proactive two-way communication through social media, utility websites and modern communication devices (e.g. tablets, smartphones) and apps.

Inability to provide the above information accurately and in a timely manner will result in customer complaints, increased call volumes to your call centres, create unwanted public and media attention, and negatively impact customer satisfaction.

Utility's effectiveness during an unplanned outage

Top 2 Boxes: 'very + somewhat effective'	Ontario LDCs	NPEI
Responding to questions	61%	61%
Providing a reason for the outage	61%	51%
Providing an estimate when power will be restored	60%	54%
Responding to the power outage	81%	80%
Restoring power quickly	85%	86%
Communicating updates periodically	64%	56%
Posting information to the website	35%	25%
Using media channels for providing updates	53%	42%

Base: An aggregate of respondents from 2014 participating LDCs / 90% of total respondents from the local utility

On December 20, 2013, a severe ice storm struck the central and eastern portions of Canada and the northeastern United States. The storm's devastation caused major damage to utility distribution lines, towers, transformers, poles and entire substations and resulted in large scale outages and blackouts for long periods of time. The data suggests that customers are both tolerant and understanding when major outages take place.

Did you have a power outage during the ice storm in December 2013?

43%

39%

Base: total respondents

Percentage of Respondents who contacted their utility about the ice storm power outage	NPEI
Yes	24%
No	73%

Base: total respondents affected by the ice storm

NPEI
Length of outage (during Ice Storm 2013)

Less than 2 hours	2 – 4 hours	4+ hours or ½ day	12-18 hours or ½ - ¾ day	19-24 hours or 1 day	1 to 1.5 days	1.6 to 2 days	More than 2 days
21%	24%	23%	2%	2%	1%	1%	1%

Base: total respondents affected by the ice storm

Using social media and multi-channel communication modes still appear to be the exception when it comes to customers contacting their utilities. Results from this year's survey indicate that the telephone is still the most used and the preferred method of contact. Overall, 87% of all Ontario respondents affected by the ice storm who informed their local utility they were experiencing a power outage did so via telephone; 95% of NPEI's respondents used the telephone to contact their utility.

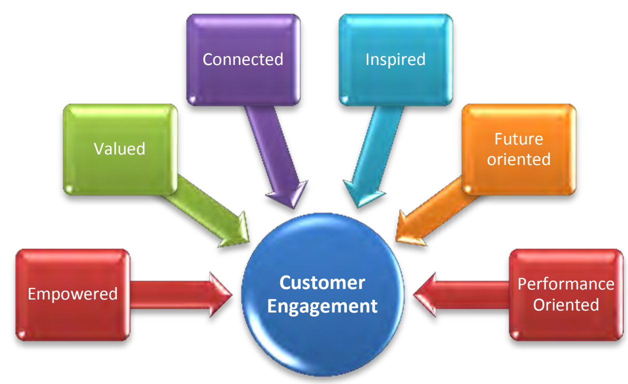
In your view, what is an acceptable period of time to go without electricity in situations like the ice storm?

Base: total respondents affected by the ice storm

• None (the power shouldn't be going out)	11%
• Less than 2 hours	20%
• 2 - 4 hours	29%
• 4+ hours or 1/2 day	17%
• 12 - 18 hours or 1/2 day to 3/4 day	3%
• 19 - 24 hours or 1 day	3%
• 1 to 1.5 days	2%
• 1 .6 to 2 days	1%
• More than 2 days	0%

Customer Centric Engagement Index (CCEI)

The EB-2010-0379 ROB-SA report includes the following: "better engage with their customers to better understand and respond to their needs…" Conducting surveys (like this one), holding town hall meetings, focus groups, etc. are examples of engaging your customers. We call this an activity based definition of engagement. Asking 100 people to complete a survey is an engagement activity.



This survey also provides you with an emotional look at engagement. The CCEI index is a gauge of the amount of goodwill that has been generated. High numbers in CCEI suggests that there is a high level of goodwill amongst your customers – this is important for two reasons. First when something goes awry for the utility, goodwill helps the utility to be resilient. Second, goodwill encourages active participation in requests to participate in engagement activities or program offerings from the utility.

Utility Customer Centric Engagement Index (CCEI)

	NPEI	National	Ontario
CCEI	78%	79%	76%

Base: total respondents

In a world of chaos and confusion what will a customer do? Find someone to help. In the electricity industry, the vast majority of customers turn to, and rely on, their local utility. Knowing that customers will turn to their electric utility requires utilities to really know their customers. Not easy when customer expectations continue to shift.

The shift is on. 15 years ago a utility could think about their customers in terms of usage, now they have to think about them in terms of personas (i.e., customer type). Currently, customer segmentation, for most utilities, consists of a number of “personas”. While this may be adequate today, in order to achieve high customer participation in programs and to optimize business processes there will be a need for granular targeting of communications.

Most utilities are quite comfortable "pushing" out communications in a one-way world. However, the shift is on because the new channels are 2-way; even without the new channels customers are expecting 2-way dialogue. The impact on a utility's marketing-communications is significant.

Value is what a customer perceives they get in exchange for what they give up. The real challenge is educating customers on the value they receive. In the absence of a value proposition the primary thing people will talk about is cost.

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2014 customer satisfaction survey derived from speaking with 405 NPEI customers [May 14 - 24, 2014]. The electric utility business has demanding customers with high expectations.

UtilityPULSE

Sid Ridgley

Simul/UtilityPULSE

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

June, 2014

Good things happen when work places work. You'll receive both strategic and pragmatic guidance about how to improve Customer satisfaction & Employee engagement with leaders that lead and a front-line that is inspired. We provide: training, consulting, surveys, diagnostic tools and keynotes. The electric utility industry is a market segment that we specialize in. We've done work for the Ontario Electrical League, the Ontario Energy Network, and both large and small utilities. For sixteen years we have been talking to 1000's of utility customers in Ontario and across Canada and we have expertise that is beneficial to every utility.

Culture, Leadership & Performance – Organizational Development	**Focus Groups, Surveys, Polls, Diagnostics**	**Customer Service Excellence**
Leadership development	Diagnostics ie. Change Readiness, Leadership Effectiveness, Managerial Competencies	Service Excellence Leadership
Strategic Planning	Surveys & Polls	Telephone Skills
Teambuilding	Customer Satisfaction and Loyalty Benchmarking Surveys	Customer Care
Organizational Culture Transformation	Organization Culture Surveys	Dealing with Difficult Customers

Benefit from our expertise in Customer Satisfaction, Leadership development, Strategy development or review, and Front-line & Top-line driven-change. We're experts in helping you assess and then transform your organization's culture to one where achieving goals while creating higher levels of customer satisfaction is important. Call us when creating an organization where more employees satisfy more customers more often, is important.

Your personal contact is:

Sid Ridgley, CSP, MBA

Phone: (905) 895-7900 Fax: (905) 895-7970 E-mail: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Exhibit 1

Tab 4 of 6

Financial Information

Financial Information

Audited Financial Statements

NPEI’s Audited Financial Statements for 2011, 2012 and 2013 are provided at E1/T4/S1/Att1.

Reconciliations of NPEI’s annual RRR Trial Balance to the Audited Financial Statements for 2011, 2012 and 2013 are provided at E1/T4/S1/Att2.

Attachment 1 of 3

Audited Financial Statements

NIAGARA PENINSULA ENERGY INC.

Financial Statements

December 31, 2013

Crawford, Smith and Swallow
Chartered Accountants LLP

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

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying financial statements of Niagara Peninsula Energy Inc., which comprise the balance sheet as at December 31, 2013, and the statements of operations, retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Niagara Peninsula Energy Inc. as at December 31, 2013, 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
June 13, 2014

CRAWFORD, SMITH AND SWALLOW
CHARTERED ACCOUNTANTS LLP

LICENSED PUBLIC ACCOUNTANTS

NIAGARA PENINSULA ENERGY INC.

BALANCE SHEET
December 31, 2013

	2013 $	2012 $
Assets - note 4		
Current assets:		
Cash	11,481,267	13,354,020
Accounts receivable	10,537,974	9,417,390
Unbilled revenue	16,625,610	13,218,878
Due from affiliated companies - note 2	2,100	19,840
PILS income taxes receivable	1,520,859	588,733
Inventory	1,621,583	1,457,820
Prepaid expenses	829,213	903,454
	42,618,606	38,960,135
Fixed Assets - note 3	126,257,737	119,863,657
Future Payment in Lieu of Taxes	1,080,652	1,591,646
	169,956,995	**160,415,438**
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	15,473,628	14,559,095
Due to affiliated companies - note 2	6,913,022	7,513,902
Current portion of customer deposits	709,338	700,199
Current portion of long-term liabilities - note 4	1,869,628	2,313,484
	24,965,616	25,086,680
Long-term liabilities:		
Long term debt - note 4	52,844,734	44,714,362
Customer deposits	746,673	737,534
Employees' accumulated vested sick leave	112,861	168,533
Employee future benefits - note 11	3,886,289	3,778,345
Regulatory liabilities - note 10	4,107,313	2,894,654
	61,697,870	52,293,428
Contingent Liabilities - note 8		
Shareholders' Equity		
Share capital - note 5	31,245,882	31,245,882
Contributed surplus	25,459,207	25,459,207
Retained earnings	26,588,420	26,330,241
	83,293,509	83,035,330
	169,956,995	**160,415,438**

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, 2013

	2013 $	2012 $
Retained Earnings, Beginning of Year	26,330,241	24,778,872
Net Income for the Year	1,458,179	2,751,369
Dividends	(1,200,000)	(1,200,000)
Retained Earnings, End of Year	**26,588,420**	**26,330,241**

See accompanying notes

NIAGARA PENINSULA ENERGY INC.

STATEMENT OF OPERATIONS
for the year ended December 31, 2013

	2013 $	2012 $
Service Revenue		
Standard supply charge	107,817,332	98,297,256
Wholesale, network and connection charges	22,742,650	22,936,780
Service charge	12,818,534	12,506,646
Distribution volumetric charge	15,090,802	15,260,687
Net Payment in lieu of taxes repayment	(1,554,749)	(365,815)
Standard supply service administration charge	142,218	138,433
Retailer revenue	45,077	50,447
	157,101,864	148,824,434
Cost of Power		
Power Purchased	130,559,982	121,234,036
Gross Profit	26,541,882	27,590,398
Other Revenue	1,956,312	2,199,947
	28,498,194	29,790,345
Expenses		
Operation and maintenance		
Distribution	6,159,706	6,620,938
Utilization	202,573	166,234
Administration and general	6,555,084	7,038,134
Billing and collecting	4,017,838	3,977,036
Depreciation	5,321,041	7,421,270
Depreciation expense on fair market value adjustment of fixed assets	1,132,277	1,137,424
	23,388,519	26,361,036
Net Income before Other Item and Payment in lieu of income taxes	5,109,675	3,429,309
Other Item		
Regulatory debit accounting changes under CGAAP	3,054,566	0
	2,055,109	3,429,309
Payments in lieu of Income Taxes		
Current	85,936	637,723
Future reduction	510,994	40,217
	596,930	677,940
Net Income for the Year	**1,458,179**	**2,751,369**

See accompanying notes

NIAGARA PENINSULA ENERGY INC.

STATEMENT OF CASH FLOWS
for the year ended December 31, 2013

	2013 $	2012 $
Cash Provided (Used) By:		
Operating Activities		
Net Income for the year	1,458,179	2,751,369
Items not involving cash		
Loss on retirement of fixed assets	67,592	0
Depreciation	5,321,041	7,421,270
Depreciation expense on fair market value adjustment of fixed assets	1,132,277	1,137,424
Future payment in lieu of taxes	510,994	40,217
Employee future benefits	107,944	67,781
Regulatory Debit	3,054,566	0
	11,652,593	11,418,061
Changes in non-cash working capital components - note 6(a)	(4,634,431)	(550,051)
	7,018,162	10,868,010
Investing Activities		
Due from/(to) affiliated companies	(583,140)	466,568
Additions to fixed assets	(12,649,048)	(10,279,705)
Regulatory costs - note 10(a)	(2,107,849)	(870,059)
	(15,340,037)	(10,683,196)
Financing Activities		
Customer deposits decrease	18,278	(7,112)
Long-term debt	7,686,516	7,788,481
Employees' accumulated vested sick leave	(55,672)	(28,205)
Cash dividends on common shares	(1,200,000)	(1,200,000)
	6,449,122	6,553,165
Increase/(Decrease) in Cash Position	(1,872,753)	6,737,979
Cash Position, Beginning of Year	13,354,020	6,616,041
Cash Position, End of Year	**11,481,267**	**13,354,020**

See accompanying notes

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 November 25, 2010, the Corporation filed a Cost of Service rate application with the OEB for rates effective May 1, 2011. The Corporation received approval for its distribution rates effective June 1, 2011.

On October 14, 2011, the Corporation filed a 3rd Generation IRM (Incentive Rate Mechanism) rate application with the OEB requesting new distribution rates effective May 1, 2012. The rate application applied for the disposal of the deferral and variance account balances as at December 31, 2010 as well as the disposition of the former PILS regulatory variance accounts. The Corporation received notice from the OEB in November 2011 to file under a separate application the disposal of the PILS regulatory variance no later than April 1, 2012.

On September 27, 2012, the Corporation received its Decision and Rate Order to dispose of Account 1562 Deferred Payments in Lieu of Taxes (EB-2012-0028). The Board approved the disposition of a credit balance of $3,001,313, consisiting of a principal credit amount of $2,511,815 plus carrying charges of $489,498 to April 30, 2012 for the Niagara Falls service area. The Board also approved

1. Significant Accounting Policies - continued

Rate setting - continued

the disposition of a debit balance of $275,742, consisting of a principal debit amount of $232,292 plus debit carrying charges of $43,450 to April 30, 2012 for the Peninsula West service area. The Board approved a 19-month disposition period, commencing October 1, 2012 and ending April 30, 2014.

On October 19, 2012, the Corporation filed a 3rd Generation IRM (Incentive Rate Mechanism) rate application (EB-2012-0150) with the OEB requesting new distribution rates effective May 1, 2013.

On August 29, 2013, the Corporation filed a 4th Generation IRM (Incentive Rate Mechanism) rate application (EB-2013-0154) with the OEB requesting new distribution rates effective May 1, 2014.

On October 10, 2013, the Corporation filed a Smart Meter Funding and Cost Recovery - Final Disposition rate application (EB-2013-0359) with the OEB requesting its final smart meter disposition rate rider (SMDR) and smart meter incremental revenue requirement rate rider (SMIRR) to be effective March 1, 2014 and May 1, 2014 respectively. Both rate riders will cease April 30, 2015.

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.

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.

1. Significant Accounting Policies - continued

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.

Asset	Amortization Period
Easements	25 to 40 years
Buildings	60 years
Electricity distribution infrastructure	10 to 60 years
Equipment	3 to 20 years

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 130 (2012-121) 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, 2013 was $1,080,383 (2012 - $930,673) for current service.

Customer 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 Corporation. 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.

1. Significant Accounting Policies - continued

Employee future benefits

The Corporation 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 render the services. In 2011, 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, 2013. 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.

Actuarial gains/(losses)

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

Past service costs

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

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 thereunder 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.

1. Significant Accounting Policies - continued

Financial instruments

The CPA Canada 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.

The Corporation has classified its financial instruments as follows:

Cash	Held-for-trading
Accounts receivable and due from affiliates	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Customer deposits	Other liabilities
Long-term liabilities	Other liabilities
Due to affiliates	Other liabilities

The Corporation is required to classify fair value measurements using a fair value hierarchy, which includes three levels of input that may be used to measure fair value:

Level 1 - Quoted prices in active markets for identical assets or liabilities;

Level 2 - Quoted prices in markets that are not active, quoted prices for similar assets or liabilities in active markets or quoted prices that are derived principally from or corroborated by observable market data or other means;

Level 3 - Unobservable inputs that are supported by little or no market activity.

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.

1. Significant Accounting Policies - continued

Measurement uncertainty - continued

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

	2013 $	2012 $
Niagara Falls Hydro Holding Corporation	0	15,850
Niagara Falls Hydro Services Inc.	(6,913,022)	(7,513,902)
Peninsula West Services Ltd.	2,100	3,990
	(6,910,922)	**(7,494,062)**

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

3. Fixed Assets

	Cost $	Accumulated Depreciation $	2013 $	2012 $
Land and land rights	3,012,532	923,903	2,088,629	2,154,207
Buildings	15,349,321	2,919,407	12,429,914	10,750,313
Distribution stations	6,961,759	3,402,553	3,559,206	3,315,486
Transmission station	6,559,702	1,379,940	5,179,762	5,364,375
Distribution lines				
-overhead	76,161,321	35,743,564	40,417,757	37,340,189
-underground	76,209,876	40,912,273	35,297,603	35,082,440
Distribution transformers	37,685,286	22,330,130	15,355,156	14,947,011
Distribution meters	7,263,915	2,139,119	5,124,796	5,412,809
Trucks and equipment	19,872,269	13,067,355	6,804,914	5,496,827
	249,075,981	**122,818,244**	**126,257,737**	**119,863,657**

3. Fixed Assets - continued

a) Fixed Asset Cost continuity

	Opening Cost 2013 $	Gross Additions 2013 $	Disposals 2013 $	Closing Cost 2013 $
Land and land rights	3,011,723	809	0	3,012,532
Buildings	13,437,736	1,911,585	0	15,349,321
Distribution stations	7,041,565	501,214	(581,020)	6,961,759
Transmission station	6,559,702	0	0	6,559,702
Distribution lines				
-overhead	71,738,553	4,422,768	0	76,161,321
-underground	74,075,261	2,134,615	0	76,209,876
Distribution transformers	36,769,143	1,188,818	(272,675)	37,685,286
Distribution meters	7,093,716	170,199	0	7,263,915
Trucks and equipment	17,908,928	2,319,040	(355,699)	19,872,269
	237,636,327	**12,649,048**	**(1,209,394)**	**249,075,981**

b) Accumulated Depreciation continuity

	Opening 2013 Accumulated Depreciation $	2013 Depreciation Expense including FMV bump $	2013 Disposals $	Closing 2013 Accumulated Depreciation $
Land and land rights	857,516	66,387	0	923,903
Buildings	2,687,423	231,984	0	2,919,407
Distribution stations	3,726,079	190,629	(514,155)	3,402,553
Transmission station	1,195,327	184,613	0	1,379,940
Distribution lines				
-overhead	34,398,364	1,345,200	0	35,743,564
-underground	38,992,821	1,919,452	0	40,912,273
Distribution transformers	21,822,132	780,673	(272,675)	22,330,130
Distribution meters	1,680,907	458,212	0	2,139,119
Trucks and equipment	12,412,101	1,010,226	(354,972)	13,067,355
	117,772,670	**6,187,376**	**(1,141,802)**	**122,818,244**

4. Long-Term Debt

	2013 $	2012 $
Long-term note payable to the City of Niagara Falls pursuant to the transfer by-law - 5.32% 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 - 5.32% 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. Requiring monthly payments of $90,594 at a fixed interest rate of 6.44% due June 2014.	533,500	1,550,452
Term loan payable to TD Bank requiring monthly payments of $93,442 at a fixed rate of 4.58%, due July 2019.	5,538,272	6,384,804
Non-revolving term loan payable to Scotia Bank for the installation of smart meters, requiring monthly payments of $37,500 plus interest at a rate of 4.97%, due September 2015.	3,037,500	3,487,500
Term loan payable to TD Bank, non-amortizing at a fixed rate of 2.80%, due June 27, 2017.	10,000,000	10,000,000
Term loan payable to TD Bank, non-amortizing at a fixed rate of 2.933%, due December 3, 2018.	10,000,000	0
	54,714,362	47,027,846
Current portion due within one year	(1,869,628)	(2,313,484)
	52,844,734	**44,714,362**

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

	$
2014	1,869,628
2015	3,515,075
2016	970,498
2017	11,016,355
2018	11,063,894

During the year, the Corporation incurred $2,445,708 (2012 - $2,699,170) of interest on long-term debt.

4. Long-Term Debt - continued

The Corporation's objectives when managing capital are to safeguard the Corporation'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. The Corporation is deemed to have a 60:40 debt to equity split.

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.

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 for 2013 was 0.58:1 (2012 - 0.56:1) The Corporation's ratio of EBITDA to interest expense plus the current portion of long-term debt and capital leases for 2013 was 2.54:1 (2012 - 2.57:1). Both covenants were met in 2013.

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 the Corporation is required to maintain a minimum debt service coverage ratio of 1.25:1. Debt service coverage is defined as: EBITDA less cash taxes, less 40% net capex 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

4. Long-Term Debt - continued

such as deferred transition costs.

EBITDA is defined as earnings before interest, income taxes, depreciation, and amortization. The Corporation's Debt service coverage actual for 2013 was 1.35:1 (2012 - 2.27:1). The Corporation's debt to capitalization ratio for 2013 was 0.51:1 (2012 - 0.37:1).
The Corporation met both bank covenants for the Toronto-Dominion Bank debt.

5. Share Capital

Authorized
Unlimited number of common shares

	2013	2012
	$	$
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:

	2013	2012
	$	$
Accounts receivable - billed	(1,120,584)	1,484,416
Unbilled revenue	(3,406,732)	(851,273)
Inventory	(163,763)	109,352
Prepaid expenses	74,241	12,603
Payments in lieu of corporate income taxes	(932,126)	1,186,666
Accounts payable and accrued liabilities	914,533	(2,491,815)
	(4,634,431)	**(550,051)**

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

	2013	2012
	$	$
Interest received	116,875	120,365
Interest paid	2,445,708	2,699,170
Payments in lieu of income taxes paid	900,000	1,299,364
Refunds of payments in lieu of income taxes received	0	1,967,230

7. Related Party Transactions

Related parties are the Corporation'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. Peninsula West Power Inc. owns 25.5% of the Corporation and 100% of the shares of Peninsula West Services Limited.
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. 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. 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.
The interest paid on the note payable to the City of Niagara Falls was $1,170,400 (2012 - $1,276,550).
The interest paid on the note payable to Niagara Falls Hydro Holding Corporation was $191,791 (2012 - $209,185).

8. Contingent Liabilities

Letter of Credit

The company has arranged for a standby letter of credit of $ 12,000,000 (2012 - $12,000,000) of which $11,910,187 ($11,910,187 - 2012) has been drawn down. The Independent Electricity Market Operator is the beneficiary for $11,910,187 (2012 - $11,909,187). This is to provide a prudential letter of credit support of the purchase of electrical power.

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, 2013, the Company has not been made aware of any additional assessments.

Participation in MEARIE covers a three year underwriting period which expires July 1, 2015. Continued participation and access to the MEARIE programs for the next underwriting period will automatically renew in July 2015 for existing Subscribers. Notice to withdraw from MEARIE must be given six months prior to the commencement of the next three year under-underwriting term.

10. Regulatory Assets/Liabilities

a) In accordance with the OEB's criteria, the Company recorded net carrying charges on the recovered amounts of $196,263, (2012 - $171,893). Under this regulation a net carrying charge expense of $196,263 in 2013, (net carrying charge expense of $171,893 - 2012) 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 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.

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

(i) 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
(ii) 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 from May 1, 2010 to April 30, 2012, was 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.

The Corporation filed its final disposition of Smart meter balances in 2013 with the Ontario Energy Board.

Deferral and variance recovery - represent costs incurred by the Corporation which have been approved for repayment through rates in excess of amounts charged to customers. This rate rider is effective from May 1, 2012 to April 30, 2014 and any balance remaining will be disposed of in a future rate application.

10. Regulatory Assets/Liabilities - continued

Deferral and variance recovery - continued

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 $1,279,644 lower (2012 - $3,442 higher) 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 $76,005 lower (2012 - $690,197 higher) than in the absence of regulation.

Deferral and variance (refund)/recovery-Payment in lieu of taxes - represents the disposition of the balance in Account 1562, Deferred Payments in Lieu of Taxes (PILS). The balance being disposed relates to the PILS from October 2001 to April 30, 2005. The PILS was originally recorded using method 3 approved by the Ontario Energy Board whereby, PILS included in the distribution rates was recorded on the income statement. The final disposition of PILS was approved by the Ontario Energy Board to be refunded/recovered from the Corporation's customers over a 19 month period commencing October 1, 2012 to April 30, 2014.

As at December 31, 2013, the company has accumulated ($4,107,313), ($2,894,654 - 2012) in regulatory liabilities on the balance sheet.

	2013	2012
	$	$
Retail settlement variances	(2,775,476)	(2,879,918)
Deferred payments in lieu of income taxes	823,065	2,377,761
Retail cost variances	317,721	247,434
Other regulatory assets	23,415	19,661
Smart Grid Deferral (Green Energy Act)	18,721	18,721
Smart meter recovery variances - note 10 (b)	2,095,314	2,028,329
Smart metering entity variance	36,956	0
Accounting changes under CGAAP	(3,054,566)	0
Deferral and variance (refund)/recovery	(769,398)	(2,328,881)
Deferral and variance (refund)/recovery-Payment in lieu of taxes	(823,065)	(2,377,761)
	(4,107,313)	**(2,894,654)**

b) Meters net book value stranded by the installation of the new smart meters included in the Smart meter recovery variances:
In 2013, the Corporation recorded $265,942 (2012- $nil)of depreciation expense related to the net book value of stranded smart meters.

	2013	2012
	$	$
Meters net book value stranded by smart meters	**1,351,366**	**1,617,308**

11. Employee Future Benefits

Defined Benefit Plan Information

	2013 $	2012 $
Employee benefit plan assets	0	0
Employee benefit plan liabilities	3,326,719	3,206,165
Employee benefit plan deficit	3,326,719	3,206,165
Unamortized actuarial gain	679,870	712,530
Unamortized past service cost	(120,300)	(140,350)
Accrued benefit obligation, end of year	**3,886,289**	**3,778,345**

	2013 $	2012 $
Accrued benefit obligation, beginning of year	3,778,345	3,710,564
Benefit (Income)/Expense for the year	238,123	203,137
Contributions/Benefit payments by the Employer	(130,179)	(135,356)
Accrued benefit obligation, end of year	**3,886,289**	**3,778,345**

An actuarial valuation was performed effective January 1, 2011, the valuation included the former Peninsula West employees. The next actuarial valuation for funding purposes will be January 1, 2014.

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 2.0% in 2011 and thereafter.

INTEREST (DISCOUNT) RATE - The obligation as at December 31, 2013, the present value of future liabilities and the expense for the year ended December 31, 2013, were determined using a discount rate of 4.0%. The rate reflects the assumed long-term yield on high quality bonds.

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 5.63% in 2012, graded down to 5.25% in 2013, 4.88% in 2014, 4.5% in 2015, 4.13% in 2016, 3.75% in 2017, 3.38% in 2018, and 3.00% in 2019 and thereafter.

DENTAL COSTS - Dental costs were assumed to increase at the CPI rate plus a further increase of 3.0%in 2012 and thereafter.

The expected average remaining service life in 2011 was fourteen years.

12. Financial Instruments

Recognition and Measurement
Level 1 - The fair value of cash, receivables, accounts payable and accrued liabilities corresponds to their carrying value due to their short-term maturity.

Level 3 - It is not practicable to determine the fair value of long-term debt and due from/(to) affiliated companies due to the limited amount of comparable market information available.

Liquidity Risk
Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations at they fall due. The Corporation's approach to managing liquidity risk is to ensure that it always has sufficient cash and credit facilities to meet its obligations when due.

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 $1,456,011 of which $746,673 is long-term and $ 709,338 is current (2012 - $1,437,733, long-term $737,534 and $700,199 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, 2013, the company had a line of credit of $ 8,000,000 (2012 - $8,000,000) of which NIL was outstanding at December 31, 2013. The line of credit is a revolving operating line that bears interest at the prime rate plus 0.0%. The line of credit is secured by the same security described in note 4.

13. Other Information

Expenses include $159,442 of inventory recognized as expense during the year.

14. Change in Accounting Estimate

During the year, the corporation undertook a study of their fixed assets. As a result of this study, the company revised the estimated useful lives of fixed assets effective January 1, 2013. This revision resulted in a decrease in amortization expense of $ 3,054,566. It is not practical to estimate the effect of this change on future periods.

15. International Financial Reporting Standards

The Canadian Accounting Standards Board ("AcSB") confirmed that publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") in place of Canadian generally accepted accounting principles for reporting purposes for fiscal years beginning on or after

15. International Financial Reporting Standards - continued

January 1, 2011. In October 2010, the AcSB approved incorporation of a one year optional deferral into Part 1 of the Chartered Professional Accountants of Canada ("CPA") Handbook for qualifying entities with activities subject to rate regulation. In March 2012, the AcSB approved incorporation of an additional one year deferral into Part 1 of the CPA Canada Handbook for qualifying entities with activities subject to rate regulation. In 2013, the AcSB extended this deferral for two additional years. Part 1 of the CPA Handbook specifies that first-time adoption is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2015. The amendment also requires that entities that do not prepare its interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose the fact. The Company has decided to defer its implementation of IFRS until January 1, 2015.

NIAGARA PENINSULA ENERGY INC.

Financial Statements

December 31, 2012

Crawford, Smith and Swallow
Chartered Accountants LLP

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INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying financial statements of Niagara Peninsula Energy Inc., which comprise the balance sheet as at December 31, 2012, and the statements of operations, retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Niagara Peninsula Energy Inc. as at December 31, 2012, 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
April 22, 2013

CRAWFORD, SMITH AND SWALLOW
CHARTERED ACCOUNTANTS LLP

LICENSED PUBLIC ACCOUNTANTS

NIAGARA PENINSULA ENERGY INC.

BALANCE SHEET
December 31, 2012

	2012 $	note 13 2011 $
Assets - note 4		
Current assets:		
Cash	13,354,020	6,616,041
Accounts receivable	9,417,390	10,901,806
Unbilled revenue	13,218,878	12,367,605
Due from affiliated companies - note 2	19,840	29,886
PILS income taxes receivable	588,733	1,775,399
Inventory	1,457,820	1,567,172
Prepaid expenses	903,454	916,057
	38,960,135	34,173,966
Fixed assets - note 3	119,863,657	118,142,647
Future payment in lieu of taxes	1,591,646	1,631,863
	160,415,438	**153,948,476**
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	14,559,095	17,050,910
Due to affiliated companies - note 2	7,513,902	7,057,380
Current portion of customer deposits	700,199	703,755
Current portion of long-term liabilities - note 4	2,313,484	2,211,519
	25,086,680	27,023,564
Long-term liabilities		
Long term debt - note 4	44,714,362	37,027,846
Customer deposits	737,534	741,089
Employees' accumulated vested sick leave	168,533	196,738
Employee future benefits - note 11	3,778,345	3,710,564
Regulatory liabilities - note 10	2,894,654	3,764,714
	52,293,428	45,440,951
Contingent Liabilities - note 8		
Shareholders' Equity		
Share capital - note 5	31,245,882	31,245,882
Contributed surplus	25,459,207	25,459,207
Retained earnings	26,330,241	24,778,872
	83,035,330	81,483,961
	160,415,438	**153,948,476**

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, 2012

	2012 $	2011 $
Retained Earnings, Beginning of Year	24,778,872	22,966,983
Net Income for the Year	2,751,369	2,311,889
Dividends	(1,200,000)	(500,000)
Retained Earnings, End of Year	**26,330,241**	**24,778,872**

See accompanying notes

NIAGARA PENINSULA ENERGY INC.

STATEMENT OF OPERATIONS
for the year ended December 31, 2012

	2012 $	2011 $
Service Revenue		
Standard supply charge	98,297,256	92,060,638
Wholesale, network and connection charges	22,936,780	22,582,044
Service charge	12,506,646	12,107,832
Distribution volumetric charge	15,260,687	14,866,503
Net Payment in lieu of taxes repayment	(365,815)	0
Standard supply service administration charge	138,433	132,759
Retailer revenue	50,447	70,048
	148,824,434	141,819,824
Cost of Power		
Power Purchased	121,234,036	114,642,681
Gross Profit	27,590,398	27,177,143
Other Revenue	2,199,947	2,100,008
	29,790,345	29,277,151
Expenses		
Operation and maintenance		
Distribution	6,620,938	6,180,533
Utilization	166,234	161,922
Administration and general	7,038,134	6,814,554
Billing and collecting	3,977,036	4,148,783
Depreciation	7,421,270	7,230,525
Depreciation expense on fair market value adjustment of fixed assets	1,137,424	1,086,669
	26,361,036	25,622,986
Net Income before Payment in lieu of income taxes	3,429,309	3,654,165
Payments in lieu of Income Taxes		
Current	637,723	189,740
Future reduction	40,217	1,152,536
	677,940	1,342,276
Net Income for the Year	2,751,369	2,311,889

See accompanying notes

NIAGARA PENINSULA ENERGY INC.

STATEMENT OF CASH FLOWS
for the year ended December 31, 2012

	2012 $	2011 $
Cash Provided (Used) By:		
Operations		
Net Income for the year	2,751,369	2,311,889
Gain on sale of fixed assets	0	16,397
Items not involving cash		
Depreciation	7,421,270	7,230,525
Depreciation expense on fair market value adjustment of fixed assets	1,137,424	1,086,669
Future payment in lieu of taxes	40,217	1,152,536
Employee future benefits	67,781	53,541
	11,418,061	11,851,557
Changes in non-cash working capital components - note 6(a)	(550,051)	2,044,237
	10,868,010	13,895,794
Investments		
Due to affiliated companies	466,568	(25,938)
Additions to fixed assets	(10,279,705)	(8,350,495)
Regulatory costs - note 10(a)	(870,059)	(3,788,515)
	(10,683,196)	(12,164,948)
Financing		
Long-term deposits decrease	(7,112)	(506,479)
Long-term bank loan payments	7,788,481	(2,116,970)
Employees' accumulated vested sick leave	(28,205)	(16,729)
Cash dividends on common shares	(1,200,000)	(500,000)
	6,553,165	(3,140,178)
Increase (Decrease) in Cash Position	6,737,979	(1,409,332)
Cash Position, Beginning of Year	6,616,041	8,025,373
Cash Position, End of Year	13,354,020	6,616,041

See accompanying notes

NIAGARA PENINSULA ENERGY INC.

NOTES TO FINANCIAL STATEMENTS
for the year ended December 31, 2012

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% 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 1.9% 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 2.1% representing the Gross Domestic Product Inflationary Price Index net of an industry productivity expectation of 1%; for a net increase of 1.1%. 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.

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.

On April 8, 2010, the OEB approved distribution rates for the Corporation, effective May 1, 2010. Such distribution rates were effectively adjusted upwards by 1.3% representing the Gross Domestic Product Inflationary Price Index net of an industry productivity expectation of 1.0%; for a net increase of 0.3%. Also the OEB approved the standard smart meter rate adder of $1.00 per metered customer per month.

On November 25, 2010, the Corporation filed a Cost of Service rate application with the OEB for rates effective May 1, 2011. The Corporation received approval for its distribution rates effective June 1, 2011.

On October 14, 2011, the Corporation filed a 3rd Generation IRM (Incentive Rate Mechanism) rate application with the OEB requesting new distribution rates effective May 1, 2012. The rate application applied for the disposal of the deferral and variance account balances as at December 31, 2010 as well as the disposition of the former PILS regulatory variance accounts. The Corporation received notice from the OEB in November 2011 to file under a separate application the disposal of the PILS regulatory variance no later than April 1, 2012.

On September 27, 2012, the Corporation received its Decision and Rate Order to dispose of Account 1562 Deferred Payments in Lieu of Taxes (EB-2012-0028). The Board approved the disposition of a credit balance of $3,001,313, consisting of a principal credit amount of $2,511,815 plus carrying charges of $489,498 to April 30, 2012 for the Niagara Falls service area. The Board also approved the disposition of a debit balance of $275,742, consisting of a principal debit amount of $232,292 plus debit carrying charges of $43,450 to April 30, 2012 for the Peninsula West service area. The Board approved a 19-month disposition period, commencing October 1, 2012 and ending April 30, 2014.

On October 19, 2012, the Corporation filed a 3rd Generation IRM (Incentive Rate Mechanism) rate application (EB-2012-0150) with the OEB requesting new distribution rates effective May 1, 2013.

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

1. Significant Accounting Policies - continued

Regulatory accounting - continued

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.

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

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 121 (2011-124) 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, 2012 was $930,673 (2011 - $744,039) 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.

1. Significant Accounting Policies - continued

Long-term deposits - continued

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.

Employees' 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 Corporation. 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 Corporation 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 render the services. In 2011, 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, 2012. 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.

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 employees.

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 thereunder 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

1. Significant Accounting Policies - continued

Payments in lieu of income taxes and capital taxes ("PILS") - continued

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.

The Corporation has classified its financial instruments as follows:

Cash	Held-for-trading
Accounts receivable and due from affiliates	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Customer deposits	Other liabilities
Long-term liabilities	Other liabilities
Due to affiliates	Other liabilities

The Corporation is required to classify fair value measurements using a fair value hierarchy, which includes three levels of input that may be used to measure fair value:

Level 1 - Quoted prices in active markets for identical assets or liabilities;

Level 2 - Quoted prices in markets that are not active, quoted prices for similar assets or liabilities in active markets or quoted prices that are derived principally from or corroborated by observable market data or other means;

Level 3 - Unobservable inputs that are supported by little or no market activity.

1. Significant Accounting Policies - continued

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

	2012 $	2011 $
Niagara Falls Hydro Holding Corporation	15,850	24,575
Niagara Falls Hydro Services Inc.	(7,513,902)	(7,056,789)
Peninsula West Services Ltd.	3,990	5,311
Peninsula West Power Inc.	0	(591)
	(7,494,062)	**(7,027,494)**

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

3. Fixed Assets

	Cost $	Accumulated Depreciation $	2012 $	2011 $
Land and land rights	3,011,723	857,516	2,154,207	2,222,111
Buildings	13,437,736	2,687,423	10,750,313	10,349,659
Distribution stations	7,041,565	3,726,079	3,315,486	2,871,612
Transmission station	6,559,702	1,195,327	5,364,375	5,510,587
Distribution lines				
-overhead	74,109,204	36,769,015	37,340,189	36,420,371
-underground	74,075,261	38,992,821	35,082,440	35,479,522
Distribution transformers	34,398,492	19,451,481	14,947,011	15,341,213
Distribution meters	7,093,716	1,680,907	5,412,809	5,696,925
Trucks and equipment	17,908,928	12,412,101	5,496,827	4,250,647
	237,636,327	**117,772,670**	**119,863,657**	**118,142,647**

3. **Fixed Assets** - continued

a) Fixed Asset Cost continuity

	Opening Cost 2012 $	Gross Additions 2012 $	Disposals 2012 $	Closing Cost 2012 $
Land and land rights	3,006,307	5,416	0	3,011,723
Buildings	12,812,041	625,695	0	13,437,736
Distribution stations	6,358,650	682,915	0	7,041,565
Transmission station	6,559,702	0	0	6,559,702
Distribution lines				
-overhead	70,674,505	3,434,699	0	74,109,204
-underground	71,888,970	2,186,291	0	74,075,261
Distribution transformers	33,727,913	911,989	(241,410)	34,398,492
Distribution meters	7,086,651	148,622	(141,557)	7,093,716
Trucks and equipment	15,586,949	2,321,979	0	17,908,928
	227,701,688	**10,317,606**	**(382,967)**	**237,636,327**

b) Accumulated Depreciation continuity

	Opening 2012 Accumulated Depreciation $	2012 Depreciation Expense including FMV bump $	2012 Disposals $	Closing 2012 Accumulated Depreciation $
Land and land rights	784,196	73,320	0	857,516
Buildings	2,462,382	225,041	0	2,687,423
Distribution stations	3,487,038	239,041	0	3,726,079
Transmission station	1,049,115	146,212	0	1,195,327
Distribution lines				
-overhead	34,254,134	2,514,881	0	36,769,015
-underground	36,409,448	2,583,373	0	38,992,821
Distribution transformers	18,386,700	1,306,191	(241,410)	19,451,481
Distribution meters	1,389,726	394,836	(103,655)	1,680,907
Trucks and equipment	11,336,302	1,075,799	0	12,412,101
	109,559,041	**8,558,694**	**(345,065)**	**117,772,670**

4. Long-Term Debt

	2012 $	2011 $
Long-term note payable to the City of Niagara Falls pursuant to the transfer by-law - 5.32% 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 - 5.32 % 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. Requiring monthly payments of $90,594 at a fixed interest rate of 6.44% due June 2014.	1,550,452	2,504,141
Term loan payable to TD Bank requiring monthly payments of $93,442 at a fixed rate of 4.58%, due July 2019.	6,384,804	7,192,634
Non-revolving term loan payable to Scotia Bank for the installation of smart meters, requiring monthly payments of $37,500 plus interest at a rate of 4.97%, due September 2015	3,487,500	3,937,500
Term loan payable to TD Bank, non-amortizing at a fixed rate of 2.80%, due June 27, 2017	10,000,000	0
	47,027,846	39,239,365
Current portion due within one year	(2,313,484)	(2,211,519)
	44,714,362	**37,027,846**

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

	$
2013	2,313,484
2014	1,869,628
2015	3,515,075
2016	970,498
2017	11,016,355

During the year, the Corporation incurred $2,254,848 (2011 - $2,605,619) of interest on long-term debt.

4. Long-Term Debt - continued

The Corporation's objectives when managing capital are to safeguard the Corporation'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. The Corporation is deemed to have a 60:40 debt to equity split. 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.

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 for 2012 was 0.52:1 (2011 - 0.51:1) The Corporation's ratio of EBITDA to interest expense plus the current portion of long-term debt and capital leases for 2012 was 2.51:1 (2011 - 2.57:1). Both covenants were met in 2012.

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 less cash taxes, less 40% net capex 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

4. Long-Term Debt - continued

deferred transition costs.

EBITDA is defined as earnings before interest, income taxes, depreciation, and amortization.
The Corporation's Debt service coverage actual for 2012 was 2.27:1 (2011 - 2.04:1).
The Corporation's debt to capitalization ratio for 2012 was 0.37:1 (2011 - 0.33:1).
The Corporation met both bank covenants for the Toronto-Dominion Bank debt.

5. Share Capital

Authorized
Unlimited number of common shares

	2012	2011
	$	$
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:

	2012	2011
	$	$
Accounts receivable - billed	1,484,416	(1,242,068)
Unbilled revenue	(851,273)	244,765
Inventory	109,352	48,969
Prepaid expenses	12,603	(159,684)
Payments in lieu of corporate income taxes	1,186,666	(1,335,231)
Accounts payable and accrued liabilities	(2,491,815)	4,487,486
	(550,051)	**2,044,237**

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

	2012	2011
	$	$
Interest received	120,365	85,242
Interest paid	2,699,170	2,844,717
Payments in lieu of income taxes paid	1,299,364	2,098,092
Refunds of payments in lieu of income taxes received	1,967,230	42,271

7. Related Party Transactions

Related parties are the Corporation'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. Peninsula West Power Inc. owns 25.5% of the Corporation and 100% of the shares of Peninsula West Services Limited.
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 Transformation 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. 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.
The interest paid on the note payable to the City of Niagara Falls was $1,276,550 ($1,595,000 - 2011).
The interest paid on the note payable to Niagara Falls Hydro Holding Corporation was $209,185 ($261,369 - 2011).

8. Contingent Liabilities

Letter of Credit

The company has arranged for a standby letter of credit of $ 12,000,000 (2011 - 12,000,000) of which $11,910,187 ($11,995,787 - 2011) has been drawn down. The Independent Electricity Market Operator is the beneficiary for $11,910,187 (2011 - $11,909,287). This is to provide a prudential letter of credit support of the purchase of electrical power.

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, 2012, the Company has not been made aware of any additional assessments.

Participation in MEARIE covers a three year underwriting period which expires July 1, 2015. Continued participation and access to the MEARIE programs for the next underwriting period will automatically renew in July 2015 for existing Subscribers. Notice to withdraw from MEARIE must be given six months prior to the commencement of the next three year under-underwriting term.

10. Regulatory Assets/Liabilities

a) In accordance with the OEB's criteria, the Company recorded net carrying charges on the recovered amounts of $171,893, (2011 - $168,254). Under this regulation a net carrying charge expense of $171,893 in 2012, (net carrying charge expense of $168,254 - 2011) 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 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.

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

(i) 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
(ii) 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 from May 1, 2010 to April 30, 2012, 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.

The Corporation will file its final disposition of Smart meter balances in 2013 with the Ontario Energy Board.

10. Regulatory Assets/Liabilities - continued

Deferral and variance recovery - represent costs incurred by the Corporation which have been approved for repayment through rates in excess of amounts charged to customers.
This rate rider is effective from May 1, 2012 to April 30, 2014 and any balance remaining will be disposed of in a future rate application.

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 $3,442 higher (2011 - $3,314,440 lower) 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 $690,197 higher (2011 - $764,237 higher) than in the absence of regulation.

Deferral and variance (refund)/recovery-Payment in lieu of taxes - represents the disposition of the balance in Account 1562, Deferred Payments in Lieu of Taxes (PILS). The balance being disposed relates to the PILS from October 2001 to April 30, 2005. The PILS was originally recorded using method 3 approved by the Ontario Energy Board whereby, PILS included in the distribution rates was recorded on the income statement. The final disposition of PILS was approved by the Ontario Energy Board to be refunded/recovered from the Corporation's customers over a 19 month period commencing October 1, 2012 to April 30, 2014.

As at December 31, 2012, the company has accumulated ($2,894,654), ($3,764,714 - 2011) in regulatory liabilities on the balance sheet.

	2012	2011
	$	$
Retail settlement variances	(2,879,918)	(3,662,087)
Deferred payments in lieu of income taxes	2,377,761	0
Retail cost variances	247,434	173,299
Other regulatory assets	19,661	14,100
Smart Grid Deferral (Green Energy Act)	18,721	18,721
Smart meter recovery variances - note 10 (b)	2,028,329	1,154,827
Special purpose charge	0	(51,748)
Deferral and variance (refund)/recovery	(2,328,881)	(1,411,826)
Deferral and variance (refund)/recovery-Payment in lieu of taxes	(2,377,761)	0
	(2,894,654)	**(3,764,714)**

b) Meters net book value stranded by the installation of the new smart meters included in the Smart meter recovery variances:

	2012	2011
	$	$
Meters net book value stranded by smart meters	1,617,308	1,579,406
	1,617,308	**1,579,406**

11. Employee Future Benefits

Defined Benefit Plan Information

	2012 $	2011 $
Employee benefit plan assets	0	0
Employee benefit plan liabilities	3,206,165	2,891,917
Employee benefit plan deficit	3,206,165	2,891,917
Unamortized actuarial gain	712,530	979,047
Unamortized past service cost	(140,350)	(160,400)
Accrued benefit obligation, end of year	**3,778,345**	**3,710,564**

	2012 $	2011 $
Accrued benefit obligation, beginning of year	3,710,564	3,657,023
Benefit (Income)/Expense for the year	203,137	172,059
Contributions/Benefit payments by the Employer	(135,356)	(118,518)
Accrued benefit obligation, end of year	**3,778,345**	**3,710,564**

An actuarial valuation was performed effective January 1, 2011, the valuation included the former Peninsula West employees. The next actuarial valuation for funding purposes will be January 1, 2014.

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 2.0% in 2011 and thereafter.

INTEREST (DISCOUNT) RATE - The obligation as at December 31, 2012, the present value of future liabilities and the expense for the year ended December 31, 2012, were determined using a discount rate of 4.0%. The rate reflects the assumed long-term yield on high quality bonds.

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 5.63% in 2012, graded down to 5.25% in 2013, 4.88% in 2014, 4.5% in 2015, 4.13% in 2016, 3.75% in 2017, 3.38% in 2018, and 3.00% in 2019 and thereafter.

DENTAL COSTS - Dental costs were assumed to increase at the CPI rate plus a further increase of 3.0%in 2012 and thereafter.

The expected average remaining service life in 2011 was fourteen years.

12. Financial Instruments

Recognition and Measurement
Level 1 - The fair value of cash, receivables, accounts payable and accrued liabilities corresponds to their carrying value due to their short-term maturity.

Level 3 - It is not practicable to determine the fair value of long-term debt and due from/(to) affiliated companies due to the limited amount of comparable market information available.

Liquidity Risk
Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations at they fall due. The Corporation's approach to managing liquidity risk is to ensure that it always has sufficient cash and credit facilities to meet its obligations when due.

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 $1,437,733 of which $737,534 is long-term and $ 700,199 is current (2011 - $1,444,844, long-term $741,089 and ($703,755 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, 2012, the company had a line of credit of $ 8,000,000 (2011 - $8,000,000) of which NIL was outstanding at December 31, 2012. The line of credit is a revolving operating line that bears interest at the prime rate plus 0.0%. The line of credit is secured by the same security described in note 4.

13. Comparative figures

Certain figures from the prior year have been restated for comparative purposes.

14. International Financial Reporting Standards

The Canadian Accounting Standards Board ("AcSB") confirmed that publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") in place of Canadian generally accepted accounting principles for reporting purposes for fiscal years beginning on or after January 1, 2011. In October 2010, the AcSB approved incorporation of a one year optional deferral into Part 1 of the Canadian Institute of Chartered Accountants ("CICA") Handbook for qualifying entities with activities subject to rate regulation. In March 2012, the AcSB approved incorporation of an additional one year deferral into Part 1 of the Canadian Institute of Chartered Accountants ("CICA") Handbook for qualifying entities with activities subject to rate regulation. In 2013, the ACSB extended this deferral for one additional year. Part 1 of the CICA Handbook specifies that first-time adoption is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2014. The amendment also requires that entities that do not prepare its interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose the fact. The Company has decided to defer its implementation of IFRS until January 1, 2014.

NIAGARA PENINSULA ENERGY INC.

Financial Statements

December 31, 2011

Crawford, Smith and Swallow
Chartered Accountants LLP

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crawford smith & swallow

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying financial statements of Niagara Peninsula Energy Inc., which comprise the balance sheet as at December 31, 2011, and the statements of operations, retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Niagara Peninsula Energy Inc. as at December 31, 2011, 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
May 14, 2012

CRAWFORD, SMITH AND SWALLOW
CHARTERED ACCOUNTANTS LLP

LICENSED PUBLIC ACCOUNTANTS

NIAGARA PENINSULA ENERGY INC.

BALANCE SHEET

December 31, 2011

	2011 $	2010 $
Assets - note 4		
Current assets:		
Cash	6,616,041	8,025,373
Accounts receivable	11,747,994	10,505,926
Unbilled revenue	11,521,417	11,766,182
Due from affiliated companies - note 2	29,886	23,499
PILS income taxes receivable	1,775,399	440,168
Inventory	1,567,172	1,616,141
Prepaid expenses	916,057	756,373
	34,173,966	33,133,662
Fixed assets - note 3	118,142,647	118,189,002
Future payment in lieu of taxes	1,631,863	2,784,399
	153,948,476	**154,107,063**
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	17,050,910	12,563,424
Due to affiliated companies - note 2	7,057,380	7,076,931
Current portion of customer deposits	703,755	956,994
Current portion of long-term liabilities - note 4	2,211,519	2,116,973
	27,023,564	22,714,322
Long-term liabilities:		
Long term debt - note 4	37,027,846	39,239,362
Customer deposits	741,089	994,329
Employees' accumulated vested sick leave	196,738	213,467
Employee future benefits - note 11	3,710,564	3,657,023
Regulatory liabilities - note 10	3,764,714	7,616,488
	45,440,951	51,720,669
Shareholders' Equity		
Share capital - note 5	31,245,882	31,245,882
Contributed surplus	25,459,207	25,459,207
Retained earnings	24,778,872	22,966,983
	81,483,961	79,672,072
Contingent Liabilities - note 8		
	153,948,476	**154,107,063**

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, 2011

	2011 $	2010 $
Retained Earnings, Beginning of Year	22,966,983	20,933,183
Net Income for the Year	2,311,889	2,533,800
Dividends	(500,000)	(500,000)
Retained Earnings, End of Year	**24,778,872**	**22,966,983**

See accompanying notes

NIAGARA PENINSULA ENERGY INC.

STATEMENT OF OPERATIONS
for the year ended December 31, 2011

	2011	2010
	$	$
Service Revenue		
Standard supply charge	92,060,638	84,373,964
Wholesale, network and connection charges	22,582,044	21,607,323
Service charge	12,107,832	11,651,393
Distribution volumetric charge	14,866,503	14,094,620
Standard supply service administration charge	132,759	128,390
Retailer revenue	70,048	78,414
	141,819,824	131,934,104
Cost of Power		
Power Purchased	114,642,681	105,981,287
Gross Profit	27,177,143	25,952,817
Other Revenue	2,100,008	2,854,341
	29,277,151	28,807,158
Expenses		
Operation and maintenance		
Distribution	6,180,533	5,584,250
Utilization	161,922	161,891
Administration and general	6,814,554	6,682,326
Billing and collecting	4,148,783	3,999,115
Depreciation	7,230,525	7,014,282
Depreciation expense on fair market value adjustment of fixed assets	1,086,669	1,233,802
	25,622,986	24,675,666
Net Income before Payments in Lieu of Income Taxes	3,654,165	4,131,492
Payments in Lieu of Income Taxes		
Current	189,740	2,050,722
Future reduction	1,152,536	(453,030)
	1,342,276	1,597,692
Net Income for the Year	2,311,889	2,533,800

See accompanying notes

NIAGARA PENINSULA ENERGY INC.

STATEMENT OF CASH FLOWS

for the year ended December 31, 2011

	2011 $	2010 $
Cash Provided (Used) By:		
Operations		
Net Income for the year	2,311,889	2,533,800
Gain on sale of fixed assets	16,397	0
Items not involving cash		
Depreciation	7,230,525	7,014,282
Depreciation expense on fair market value adjustment of fixed assets	1,086,669	1,233,802
Future payment in lieu of taxes	1,152,536	(453,030)
Employee future benefits	53,541	44,146
	11,851,557	10,373,000
Changes in non-cash working capital components - note 6(a)	2,018,299	(1,690,465)
	13,869,856	8,682,535
Investments		
Additions to fixed assets	(8,350,495)	(13,413,272)
Regulatory costs - note 10(a)	(3,788,515)	1,272,861
	(12,139,010)	(12,140,411)
Financing		
Long-term deposits decrease	(506,479)	(104,940)
Long-term bank loan payments	(2,116,970)	2,310,690
Employees' accumulated vested sick leave	(16,729)	14,710
Cash dividends on common shares	(500,000)	(500,000)
	(3,140,178)	1,720,460
Decrease in Cash Position	(1,409,332)	(1,737,416)
Cash Position, Beginning of Year	8,025,373	9,762,789
Cash Position, End of Year	6,616,041	8,025,373

See accompanying notes

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% 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 1.9% 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 2.1% representing the Gross Domestic Product Inflationary Price Index net of an industry productivity expectation of 1%; for a net increase of 1.1%. 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.

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.

On April 8, 2010, the OEB approved distribution rates for the Corporation, effective May 1, 2010. Such distribution rates were effectively adjusted upwards by 1.3% representing the Gross Domestic Product Inflationary Price Index net of an industry productivity expectation of 1.0%; for a net increase of 0.3%. Also the OEB approved the standard smart meter rate adder of $1.00 per metered customer per month.

On November 25, 2010, the Corporation filed a Cost of Service rate application with the OEB for rates effective May 1, 2011. The Corporation received approval for its distribution rates effective June 1, 2011.

On October 14, 2011, the Corporation filed a 3rd Generation IRM (Incentive Rate Mechanism) rate application with the OEB requesting new distribution rates effective May 1, 2012. The rate application applied for the disposal of the deferral and variance account balances as at December 31, 2010 as well as the disposition of the former PILS regulatory variance accounts. The Corporation received notice from the OEB in November 2011 to file under a separate application the disposal of the PILS regulatory variance no later than April 1, 2012.

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.

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.

1. Significant Accounting Policies - continued

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

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 124 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, 2011 was $744,039 (2010 - $634,212) 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 Corporation. 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.

1. Significant Accounting Policies - continued

Employee future benefits

The Corporation 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 render the services. In 2011, 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, 2011. 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.

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 employees.

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 thereunder 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.

1. Significant Accounting Policies - continued

Financial instruments - continued

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.

The Corporation has classified its financial instruments as follows:

Cash	Held-for-trading
Accounts receivable and due from affiliates	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Customer deposits	Other liabilities
Long-term liabilities	Other liabilities
Due to affiliates	Other liabilities

The Corporation is required to classify fair value measurements using a fair value hierarchy, which includes three levels of input that may be used to measure fair value:

Level 1 - Quoted prices in active markets for identical assets or liabilities;

Level 2 - Quoted prices in markets that are not active, quoted prices for similar assets or liabilities in active markets or quoted prices that are derived principally from or corroborated by observable market data or other means;

Level 3 - Unobservable inputs that are supported by little or no market activity.

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

	2011 $	2010 $
Niagara Falls Hydro Holding Corporation	24,575	21,514
Niagara Falls Hydro Services Inc.	(7,056,789)	(7,076,931)
Peninsula West Services Ltd.	5,311	1,985
Peninsula West Power Inc.	(591)	0
	(7,027,494)	**(7,053,432)**

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

3. Fixed Assets

	Cost $	Accumulated Depreciation $	2011 $	2010 $
Land and land rights	3,006,307	784,196	2,222,111	2,288,251
Buildings	12,812,041	2,462,382	10,349,659	10,443,186
Distribution stations	6,358,650	3,487,038	2,871,612	2,277,354
Transmission station	6,559,702	1,049,115	5,510,587	5,656,596
Distribution lines				
-overhead	70,674,505	34,254,134	36,420,371	35,144,781
-underground	71,888,970	36,409,448	35,479,522	36,587,401
Distribution transformers	33,727,913	18,386,700	15,341,213	15,673,956
Distribution meters	7,086,651	1,389,726	5,696,925	6,101,560
Trucks and equipment	15,586,949	11,336,302	4,250,647	4,015,917
	227,701,688	**109,559,041**	**118,142,647**	**118,189,002**

a) Fixed Asset Cost continuity

	Opening Cost 2011 $	Gross Additions 2011 $	Disposals 2011 $	Closing Cost 2011 $
Land and land rights	3,006,307	0	0	3,006,307
Buildings	12,690,262	121,779	0	12,812,041
Distribution stations	5,558,870	799,780	0	6,358,650
Transmission station	6,559,702	0	0	6,559,702
Distribution lines			0	0
-overhead	67,028,319	3,646,186	0	70,674,505
-underground	70,274,727	1,614,243	0	71,888,970
Distribution transformers	33,037,207	899,999	(209,294)	33,727,913
Distribution meters	7,212,520	110,391	(236,260)	7,086,651
Trucks and equipment	14,879,924	1,158,116	(451,092)	15,586,949
	220,247,838	**8,350,495**	**(896,645)**	**227,701,688**

3. Fixed Assets - continued

b) Accumulated Depreciation continuity

	Opening 2011 Accumulated Depreciation	2011 Depreciation Expense including FMV bump	2011 Disposals	Closing 2011 Accumulated Depreciation
	$	$	$	$
Land and land rights	718,056	66,140	0	784,196
Buildings	2,247,076	215,306	0	2,462,382
Distribution stations	3,281,516	205,523	0	3,487,038
Transmission station	903,106	146,009	0	1,049,115
Distribution lines				
-overhead	31,883,538	2,370,595	0	34,254,134
-underground	33,687,326	2,722,122	0	36,409,448
Distribution transformers	17,363,251	1,232,742	(209,294)	18,386,700
Distribution meters	1,110,960	451,768	(173,002)	1,389,726
Trucks and equipment	10,864,009	906,987	(434,695)	11,336,302
	102,058,839	**8,317,193**	**(816,990)**	**109,559,041**

4. Long-Term Debt

	2011	2010
	$	$
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. Requiring monthly payments of $90,594 at a fixed interest rate of 6.44% due June 2014.	2,504,141	3,398,502
Term loan payable to TD Bank requiring monthly payments of $93,442 at a fixed rate of 4.58%, due July 2019.	7,192,634	7,965,243
Non-revolving term loan payable to Scotia Bank for the installation of smart meters, requiring monthly payments of $37,500 plus interest at a rate of 4.97%, due September 2015	3,937,500	4,387,500
	39,239,365	41,356,335
Current portion due within one year	(2,211,519)	(2,116,973)
	37,027,846	**39,239,362**

4. Long-Term Debt - continued

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

	$
2012	2,211,519
2013	2,313,484
2014	1,869,628
2015	3,477,575
2016	970,498

During the year, the Corporation incurred $2,605,619 (2010 - $2,596,366) of interest on long-term debt.

The Corporation's objectives when managing capital are to safeguard the Corporation'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. The Corporation is deemed to have a 60:40 debt to equity split.
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.

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 for 2011 was 0.51:1 (2010 - 0.52:1)
The Corporation's ratio of EBITDA to interest expense plus the current portion of long-term debt and capital leases for 2011 was 2.57:1 (2010 - 2.62:1). Both covenants were met in 2011.

4. Long-Term Debt - continued

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 less cash taxes, less 40% net capex 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.
The Corporation's Debt service coverage actual for 2011 was 2.04:1 (2010 - 1.69:1).
The Corporation's debt to capitalization ratio for 2011 was 0.33:1 (2010 - 0.35:1).
The Corporation met both bank covenants for the Toronto-Dominion Bank debt.

5. Share Capital

Authorized
Unlimited number of common shares

	2011 $	2010 $
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:

	2011 $	2010 $
Accounts receivable - billed	(1,242,068)	(949,128)
Unbilled revenue	244,765	2,563,217
Inventory	48,969	(334,631)
Prepaid expenses	(159,684)	(221,768)
Payments in lieu of corporate income taxes	(1,335,231)	(860,416)
Accounts payable and accrued liabilities	4,487,486	(2,366,935)
Due to affiliated companies	(25,938)	479,196
	2,018,299	**(1,690,465)**

6. Statement of Cash Flows - continued

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

	2011 $	2010 $
Interest received	85,242	93,028
Interest paid	2,844,717	2,678,588
Payments in lieu of income taxes paid	2,098,092	2,911,138
Refunds of payments in lieu of income taxes received	42,271	0

7. Related Party Transactions

Related parties are the Corporation'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. Peninsula West Power Inc. owns 25.5% of the Corporation and 100% of the shares of Peninsula West Services Limited.
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 Transformation 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. 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.
The interest paid on the note payable to the City of Niagara Falls was $1,595,000 ($1,595,000 - 2010).
The interest paid on the note payable to Niagara Falls Hydro Holding Corporation was $261,369 ($261,369 - 2010).

8. Contingent Liabilities

Letter of Credit

The company has arranged for a standby letter of credit of $ 12,000,000 (2010 - 12,000,000) of which $11,995,787 ($11,995,787 - 2010) has been drawn down. The Independent Electricity Market Operator is the beneficiary for $11,909,287 (2010 - $11,909,287). This is to provide a prudential letter of credit support of the purchase of electrical power. An additional $86,500 (2010 - $86,500) 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.

8. 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.

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.
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.

On April 21, 2010, the local distribution companies ("LDC's") reached a settlement which the principal terms were as follows:

a) LDCs would collectively pay $17 million in damages, based on a recovery of approximately 9% of LPP revenues, inclusive of pre-judgement interest;
b) Payment would not be due until June 30, 2011
c) Amounts paid, after deduction for counsel fees, costs and applicable interest, would be paid to the Winter Warmth Fund or similar charities; and
d) LDCs would be at liberty to seek Ontario Energy Board permission to recover settlement costs through rates.

The Ontario Superior Court of Justice approved the settlement in the Minutes of Settlement dated April 21, 2010. The Corporation's share of the Minutes of Settlement is $167,381. The Corporation made the payment to a "similar charity" on June 15, 2011.

On February 22, 2011, the Ontario Energy Board issued a Decision and Order approving the LDC's to recover the costs and damages arising from the settlement of the LPP class action on the basis of distribution revenues. The rate rider for purposes of recovery shall be a fixed customer charge recovered over a period of one year effective May 1, 2011. The Corporation filed its application for recovery of the late payment penalty class action settlement on March 1, 2011 and was approved to recover the the $167,381 in its rates from May 1, 2011 to April 30, 2012.

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, 2011, the Company has not been made aware of any additional assessments.

Participation in MEARIE covers a three year underwriting period which expires July 1, 2012. Continued participation and access to the MEARIE programs for the next underwriting period will automatically renew in July 2012 for existing Subscribers. Notice to withdraw from MEARIE must be given six months prior to the commencement of the next three year under-underwriting term.

10. Regulatory Assets/Liabilities

a) In accordance with the OEB's criteria, the Company recorded net carrying charges on the recovered amounts of $168,254, (2010 - ($723,009)). Under this regulation a net carrying charge revenue of $ 168,254 in 2011, (net carrying charge expense of $723,009 - 2010) 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:

(i) 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

(ii) 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.

10. Regulatory Assets/Liabilities - continued

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, 2010, 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.

The Corporation filed a Cost of Service rate application for rates effective May 1, 2011. The rate application includes a continuation of the $1.00 smart meter rate rider for an additional year effective May 1, 2011.

Deferral and variance recovery - represent costs incurred by the Corporation which have been approved for repayment through rates in excess of amounts charged to customers. This rate rider is effective from May 1, 2010 to April 20, 2012 and any balance remaining will be disposed of in a future rate application.

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 $3,314,440 lower (2010 - $1,306,983 lower) 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 $764,237 (2010 - $242,260 higher) higher than in the absence of regulation.

As at December 31, 2011, the company has accumulated ($ 3,764,715), ($ 7,616,488 - 2010) in regulatory liabilities on the balance sheet.

	2011	2010
	$	$
Retail settlement variances	(3,662,087)	(4,112,269)
Retail cost variances	173,299	909,381
Other regulatory assets	14,100	7,603
Smart Grid Deferral (Green Energy Act)	18,721	12,399
Smart meter recovery variances - note 10 (b)	1,154,827	617,493
Special purpose charge	(51,748)	152,846
Deferral and variance recovery	(1,411,826)	(5,203,941)
	(3,764,714)	**(7,616,488)**

10. Regulatory Assets/Liabilities - continued

b) Meters net book value stranded by the installation of the new smart meters included in the Smart meter recovery variances:

	2011	2010
	$	$
Meters net book value stranded by smart meters	1,579,406	1,516,147
	1,579,406	**1,516,147**

11. Employee Future Benefits

Defined Benefit Plan Information

	2011	2010
	$	$
Employee benefit plan assets	0	0
Employee benefit plan liabilities	2,891,917	2,882,675
Employee benefit plan deficit	2,891,917	2,882,675
Unamortized actuarial gain	979,047	954,798
Unamortized past service cost	(160,400)	(180,450)
Accrued benefit obligation, end of year	**3,710,564**	**3,657,023**

	2011	2010
	$	$
Accrued benefit obligation, beginning of year	3,657,023	3,612,877
Benefit (Income)/Expense for the year	172,059	189,616
Contributions/Benefit payments by the Employer	(118,518)	(145,470)
Accrued benefit obligation, end of year	**3,710,564**	**3,657,023**

An actuarial valuation was performed effective January 1, 2011, the valuation included the former Peninsula West employees. The next actuarial valuation for funding purposes will be January 1, 2014.

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 2.0% in 2011 and thereafter.

INTEREST (DISCOUNT) RATE - The obligation as at December 31, 2011, the present value of future liabilities and the expense for the year ended December 31, 2011, were determined using a discount rate of 5.0%. The rate reflects the assumed long-term yield on high quality bonds.

11. Employee Future Benefits - continued

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 5.63% in 2012, graded down to 5.25% in 2013, 4.88% in 2014, 4.5% in 2015, 4.13% in 2016, 3.75% in 2017, 3.38% in 2018, and 3.00% in 2019 and thereafter.

DENTAL COSTS - Dental costs were assumed to increase at the CPI rate plus a further increase of 3.0% in 2012 and thereafter.

The expected average remaining service life in 2011 was fourteen years.

12. Financial Instruments

Recognition and Measurement

Level 1 - The fair value of cash, receivables, accounts payable and accrued liabilities corresponds to their carrying value due to their short-term maturity.

Level 3 - It is not practicable to determine the fair value of long-term debt and due from/(to) affiliated companies due to the limited amount of comparable market information available.

Liquidity Risk

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations at they fall due. The Corporation's approach to managing liquidity risk is to ensure that it always has sufficient cash and credit facilities to meet its obligations when due.

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 $1,444,844 of which $741,089 is long-term and $ 703,755 is current (2010 - $1,951,323, long-term $994,329 and ($956,994 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, 2011, the company had a line of credit of $ 8,000,000 (2010 - $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.

Attachment 2 of 3

RRR Financial Reconciliation

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2013

RRR Part 1
Trial Balance Mapped to Financial Statement Grouping
2.1.13

	RRR = Financial Statements December 2013	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water and PILS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1005 Cash	11,478,494.77				11,478,494.77		
1010 Cash Advance and Working Funds	2,772.16	11,481,266.93			2,772.16	11,481,266.93	
1100 Custom Accounts Receivable	9,577,985.91				9,577,985.91		
1104 Accounts Receivable - Recoverable Work	913,242.10				913,242.10		
1110 Other Accounts Receivable	551,223.15				551,223.15		
1130 Accumulated Provision for Uncollectible Accts	(504,477.49)	10,537,973.67			(504,477.49)	10,537,973.67	
1120 Accrued Utility Revenues	16,625,609.62	16,625,609.62			16,625,609.62	16,625,609.62	
1200 Accounts Receivable from Associated Companies	2,100.49	2,100.49			2,100.49	2,100.49	
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	1,520,859.00	1,520,859.00			1,520,859.00	1,520,859.00	
1180 Prepayments	827,286.07				827,286.07		
1606 Organization	1,926.45	829,212.52			1,926.45	829,212.52	
1330 Plant Materials and Operating Supplies	1,621,583.12	1,621,583.12	42,618,605.35		1,621,583.12	1,621,583.12	42,618,605.35
1705 Land	82,347.02				82,347.02		
1708 Buildings and Fixtures	3,693,130.15				3,693,130.15		
1715 Station Equipment	2,726,687.83				2,726,687.83		
1735 Underground Conduit	1,090.59				1,090.59		
1740 Underground Conductors and Devices	138,793.40				138,793.40		
1805 Land	424,925.77				424,925.77		
1806 Land Rights	1,604,396.58				1,604,396.58		
1808 Buildings and Fixtures	111,638.13				111,638.13		
1815 Transformer Station Equipment - Normally Primary	75,243.58				75,243.58		
1820 Distribution Station Equipment - Normally Primary	6,354,039.79				6,354,039.79		
1830 Poles, Towers and Fixtures	43,552,108.21				43,552,108.21		
1835 Overhead Conductors and Devices	28,184,729.14				28,184,729.14		
1840 Underground Conduit	9,663,793.74				9,663,793.74		
1845 Underground Conductors and Devices	66,575,037.95				66,575,037.95		
1850 Line Transformers	37,356,216.71				37,356,216.71		
1855 Services	5,430,060.80				5,430,060.80		
1860 Meters	6,952,486.36				6,952,486.36		
1865 Other Installations on Customer's Premises	439.87				439.87		
1875 Street Lighting and Signal Systems	21,835.21				21,835.21		
1905 Land	508,969.83				508,969.83		
1908 Buildings and Fixtures	15,117,430.20				15,117,430.20		
1910 Leasehold Improvements	120,252.32				120,252.32		
1915 Office Furniture and Equipment	1,493,564.37				1,493,564.37		
1920 Computer Equipment-Hardware	3,777,674.42				3,777,674.42		
1925 Computer Software	2,691,706.16				2,691,706.16		
1930 Transportation Equipment	8,580,007.54				8,580,007.54		
1935 Stores Equipment	236,413.92				236,413.92		
1940 Tools, Shop and Garage Equipment	1,954,825.97				1,954,825.97		
1945 Measurement and Testing Equipment	204,006.18				204,006.18		
1955 Communication Equipment	846,784.65				846,784.65		
1960 Miscellaneous Equipment	72,951.31				72,951.31		
1980 System Supervisory Equipment	128,960.64				128,960.64		
1995 Contributions and Grants - Credit	(21,516,864.10)				(21,516,864.10)		
2005 Property Under Capital Leases	143,036.00				143,036.00		
2060 Electric Plant Acquisition Adjustment	142,276.60				142,276.60		
2065 Other Electric Plant Adjustment	45,509,515.44			(45,509,515.44)	0.00		
2105 Accumulated Amortization of Electric Utility-Plant	(115,848,161.50)				(115,848,161.50)		
2140 Accumulated Amortization of Electric Plant	(142,276.60)				(142,276.60)		
2160 Accumulated Amortization of Other Utility Plant	(30,712,337.16)	126,257,737.02	126,257,737.02	30,712,337.16	0.00	111,460,558.74	111,460,558.74

	RRR = Financial Statements December 2013	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water and PILS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
2296 Future Income Taxes - Current	1,080,651.59	1,080,651.59	1,080,651.59		1,080,651.59	1,080,651.59	1,080,651.59
2205 Accounts Payable	(14,541,602.14)				(14,541,602.14)		
2220 Miscellaneous Current and Accrued Liabilities	0.00				0.00		
2250 Debt Retirement Charges DRC payable	(781,312.27)				(781,312.27)		
2290 Commodity Taxes	1,339,354.58				1,339,354.58		
2292 Payroll Deductions/Expenses Payable	2,124.97				2,124.97		
2425 Other Deferred Credits	(1,492,192.30)	(15,473,627.16)			(1,492,192.30)	(15,473,627.16)	
2210 Current portion of Customer deposits	(709,338.37)	(709,338.37)			(709,338.37)	(709,338.37)	
2240 Accounts Payable to Associated Companies	(6,913,021.67)	(6,913,021.67)			(6,913,021.67)	(6,913,021.67)	
2260 Current Portion of Long Term Debt	(1,869,628.01)	(1,869,628.01)	(24,965,615.21)		(1,869,628.01)	(1,869,628.01)	(24,965,615.21)
2520 Other Long Term debt	0.00				0.00		
2525 Term Bank Loans-long term Portion	(27,239,644.65)				(27,239,644.65)		
2550 Advances from Associated Companies	(25,605,089.72)	(52,844,734.37)			(25,605,089.72)	(52,844,734.37)	
2320 Other Miscellaneous Non-current liabilities	(37,334.17)				(37,334.17)		
2335 Long Term Customer Deposits	(709,338.37)	(746,672.54)			(709,338.37)	(746,672.54)	
2310 Vested Sick Leave Liability	(112,861.37)	(112,861.37)			(112,861.37)	(112,861.37)	
2306 Employee Future Benefits	(3,886,289.00)	(3,886,289.00)			(3,886,289.00)	(3,886,289.00)	
1550 Hydro One Low Voltage Variance	(50,959.88)				(50,959.88)		
1551 Smart Metering Entity Variance	36,956.23				36,956.23		
1576 Accounting Changes Under CGAAP	(3,054,565.73)				(3,054,565.73)		
1580 RSVA - WMS	(4,151,413.74)				(4,151,413.74)		
1582 RSVA - One Time	0.00				0.00		
1584 RSVA - NW	1,503,334.65				1,503,334.65		
1586 RSVA - CN	1,050,611.18				1,050,611.18		
1588 RSVA - Power	(6,474,228.04)				(6,474,228.04)		
1588 RSVA - GA Non-RPP	5,347,179.52				5,347,179.52		
1518 RCVA - Retail	138,753.23				138,753.23		
1548 RCVA - STR	178,967.35				178,967.35		
1508 Other Regulatory Assets	23,414.87				23,414.87		
1562 Deferred Payments in Lieu of taxes	0.00				0.00		
1563 Deferred PILS contra Account	823,064.91				823,064.91		
1535 Smart Grid Deferral Account	18,720.96				18,720.96		
1555 Smart Meter Capital and Recovery Variance	551,624.06				551,624.06		
1556 Smart Meter OM&A Variance	1,543,689.80				1,543,689.80		
1521 Special Purpose Charge	0.00				0.00		
1595 Disposition and Recovery of Regulatory Balances	(1,592,462.75)	(4,107,313.38)	(61,697,870.66)		(1,592,462.75)	(4,107,313.38)	(61,697,870.66)
3005 Common Shares Issued	(31,245,882.02)	(31,245,882.02)			(31,245,882.02)	(31,245,882.02)	
3010 Contributed Surplus	(18,753,902.09)			18,753,902.09	0.00		
3047 Appropriations of Retained Earnings - current	(6,705,305.00)	(25,459,207.09)			(6,705,305.00)	(6,705,305.00)	
3040 Appropriated Retained Earnings	(26,330,239.21)			(2,824,447.00)	(27,599,937.21)		
3041 Appropriated Retained Earnings				1,554,749.00			
3046 Balance Transferred from Income	(1,458,179.77)			(2,687,025.81)	(4,145,205.58)		
3049 Dividends payable - Common Shares	1,200,000.00	(26,588,418.98)	(83,293,508.09)		1,200,000.00	(30,545,142.79)	(68,496,329.81)
Balance Sheet	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

4006 Residential Energy Sales	(36,842,617.22)				(36,842,617.22)		
4010 Commercial Energy Sales	(11,645,203.82)				(11,645,203.82)		
4025 Streetlighting energy sales	(526,743.86)				(526,743.86)		
4030 Sentinel Lighting Energy Sales	(18,282.96)				(18,282.96)		

	RRR = Financial Statements December 2013	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water and PILS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
4035 General Energy Sales	(58,784,484.02)	(107,817,331.88)			(58,784,484.02)	(107,817,331.88)	
4062 Billed WMS	(7,454,786.47)				(7,454,786.47)		
4066 Billed NW	(8,975,194.40)				(8,975,194.40)		
4068 Billed CN	(5,454,831.55)				(5,454,831.55)		
4075 Billed - LV	(537,671.55)				(537,671.55)		
4076 Billed SME Charge	(320,166.15)	(22,742,650.12)			(320,166.15)	(22,742,650.12)	
4080 Distribution Services Revenue	(26,354,545.17)	(26,354,545.17)		(1,554,749.00)	(27,909,294.17)	(27,909,294.17)	
4082 Retail Services Revenue	(44,006.40)				(44,006.40)		
4084 Service Transaction Requests (STR) Revenues	(1,071.00)	(45,077.40)			(1,071.00)	(45,077.40)	
4086 SSS Admin Charge	(142,260.02)	(142,260.02)	(157,101,864.59)		(142,260.02)	(142,260.02)	(158,656,613.59)
4705 Power Purchased	107,817,331.88				107,817,331.88		
4708 Charges -WMS	7,454,786.47				7,454,786.47		
4714 Charges -NW	8,975,194.40				8,975,194.40		
4716 Charges -CN	5,454,831.55				5,454,831.55		
4751 Charges -SME	320,166.15				320,166.15		
4750 Charges - LV	537,671.55	130,559,982.00	130,559,982.00		537,671.55	130,559,982.00	130,559,982.00
4215 Other Utility Operating Income	(48,358.73)				(48,358.73)		
4225 Late Payment Charges	(353,573.62)				(353,573.62)		
4355 Gain on Disposition of Utility and Other Property	(11,121.24)				(11,121.24)		
4360 Losses from disposition of Utility and Other Property	1,135.20				1,135.20		
4362 Loss on Retirement of Utility and Other Property	66,864.73				66,864.73		
4375 Revenues from Non-Utility Operations	(2,018,308.33)				(2,018,308.33)		
4235 Miscellaneous Service Revenues	(810,536.29)				(810,536.29)		
4380 Expenses from Non-Utility Operations	1,515,822.18			355,292.01	1,871,114.19		
4390 Miscellaneous Non-Operating Income	(118,062.00)				(118,062.00)		
4405 Interest and Dividend Income	(180,173.43)	(1,956,311.53)	(1,956,311.53)		(180,173.43)	(1,601,019.52)	(1,601,019.52)
5005 Operation Supervision and Engineering	723,775.34				723,775.34		
5010 Load Dispatching	38,222.45				38,222.45		
5012 Station Buildings and fixtures expense	65,931.51				65,931.51		
5014 Transformer Station Equipment - Operation Labour	11,484.44				11,484.44		
5015 Transformer Station Equipment - Operation	141,834.38				141,834.38		
5020 Overhead Distribution Lines and Feeders -Labour	197,145.43				197,145.43		
5025 Overhead Distribution Lines and Feeders - Operation ex	14,774.82				14,774.82		
5040 Underground Distribution Lines and Feeders Labour	76,753.80				76,753.80		
5045 Underground Distribution Lines and Feeders - expenses	250,001.50				250,001.50		
5055 Underground Distribution Transformer - Operations	651.00				651.00		
5065 Meter Expense	427,571.92				427,571.92		
5085 Miscellaneous Distribution Expenses	2,062,008.09				2,062,008.09		
5105 Maintenance Supervision and Engineering	492,770.85				492,770.85		
5112 Maintenance of Transformer Station Equipment	1,115.00				1,115.00		
5114 Maintenance of Distribution Station Equipment	33,541.52				33,541.52		
5120 Maintenance of Poles, Towers and Fixtures	157,253.73				157,253.73		
5125 Maintenance of Overhead Conductors and Devices	613,407.29				613,407.29		
5130 Maintenance of Overhead Services	154,111.43				154,111.43		
5135 Overhead Distribution Lines and Feeders - Right of Way	244,449.97				244,449.97		
5145 Maintenance of Underground Conduit	25,153.29				25,153.29		
5150 Maintenance of Underground Conductors & Devices	205,312.43				205,312.43		
5155 Maintenance of Underground Services	72,639.67				72,639.67		
5160 Maintenance of Line Transformers	145,430.15				145,430.15		
5175 Maintenance of Meters	4,366.19	6,159,706.20			4,366.19	6,159,706.20	6,159,706.20
5070 Customer Premises - Operation Labour	121,019.25				121,019.25		
5410 Community Relations - Sundry	81,553.81	202,573.06			81,553.81	202,573.06	202,573.06
5605 Executive Salaries and Expenses	397,095.08				397,095.08		
5610 Management Salaries and Expenses	1,728,806.28			(55,038.20)	1,673,768.08		
5615 General Administrative Salaries and Expenses	446,357.59				446,357.59		
5620 Office Supplies and Expenses	76,250.84				76,250.84		

	RRR = Financial Statements December 2013	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water and PILS	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
5630 Outside Services Employed	40,800.00				40,800.00		
5635 Property Insurance	284,891.96				284,891.96		
5655 Regulatory Expenses	222,003.09				222,003.09		
5665 Miscellaneous General Expense	58,770.28				58,770.28		
5675 Maintenance of General Plant	556,821.56				556,821.56		
6005 Interest on Long Term Debt	810,005.58				810,005.58		
6030 Interest on Debt to Associated Companies	1,362,190.68				1,362,190.68		
6035 Other Interest Expense	273,512.14				273,512.14		
6105 Taxes other that Income Taxes	258,672.54				258,672.54		
6215 Penalties	0.00				0.00		
6205 Donations	38,906.00	6,555,083.62			38,906.00	6,500,045.42	6,500,045.42
5305 Supervision	624,637.50				624,637.50		
5310 Meter Reading Expense	154,042.91				154,042.91		
5315 Customer Billing	2,342,379.32			(282,145.81)	2,060,233.51		
5320 Collecting	429,058.48				429,058.48		
5325 Collecting - Cash Over and Short	70.32				70.32		
5335 Bad Debt Expense	223,841.58				223,841.58		
5340 Miscellaneous Customer Accounts Expense	243,807.99	4,017,838.10			243,807.99	3,735,692.29	3,735,692.29
5705 Amortization Expense - Property Plant and Equipment	5,321,040.63	5,321,040.63		(18,108.00)	5,302,932.63	5,302,932.63	5,302,932.63
5715 Amortization of Intangibles and Other Electric	1,132,276.81	1,132,276.81		(1,132,276.81)	0.00	0.00	0.00
			23,388,518.42		0.00		
4305 Regulatory Debits	3,054,565.73	3,054,565.73	3,054,565.73		3,054,565.73	3,054,565.73	3,054,565.73
6110 Income Taxes	85,936.00				85,936.00		
6115 Provision for Future Income Taxes	510,994.20	596,930.20	596,930.20		510,994.20	596,930.20	596,930.20
Income Statement total	**(1,458,179.77)**	**(1,458,179.77)**	**(1,458,179.77)**	**(2,687,025.81)**	**(4,145,205.58)**	**(4,145,205.58)**	**(4,145,205.58)**
Trial Balance Summary							
Revenues	(159,058,176.12)	(159,058,176.12)	(159,058,176.12)	(1,199,456.99)	(160,257,633.11)	(160,257,633.11)	(160,257,633.11)
Expenses	157,599,996.35	157,599,996.35	157,599,996.35	(1,487,568.82)	156,112,427.53	156,112,427.53	156,112,427.53
(Profit)/Loss	(1,458,179.77)	(1,458,179.77)	(1,458,179.77)	(2,687,025.81)	(4,145,205.58)	(4,145,205.58)	(4,145,205.58)
Net Assets	265,236,768.80	38,071,084.56	(17,998,613.72)	0.00	265,236,768.80	38,071,084.56	(17,998,613.72)
Net Liabilities and Equity	(265,236,768.80)	(38,071,084.56)	17,998,613.72	0.00	(265,236,768.80)	(38,071,084.56)	17,998,613.72
IS (Profit)/Loss	(1,458,179.77)	(1,458,179.77)	(1,458,179.77)	(2,687,025.81)	(4,145,205.58)	(4,145,205.58)	(4,145,205.58)
Balance Sheet (profit)/Loss	(1,458,179.77)	(1,458,179.77)	(1,458,179.77)	(2,687,025.81)	(4,145,205.58)	(4,145,205.58)	(4,145,205.58)

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2013
RRR Part 2
Trial Balance by Account
2.1.13

	RRR Financial Statement December 2013	Adjustment for FMV entry and Water and PILS	Filed RRR restated for FMV removal
Current Assets			
1005 Cash	11,478,494.77		11,478,494.77
1010 Cash Advance and Working Funds	2,772.16		2,772.16
1100 Custom Accounts Receivable	9,577,985.91		9,577,985.91
1104 Accounts Receivable - Recoverable Work	913,242.10		913,242.10
1110 Other Accounts Receivable	551,223.15		551,223.15
1120 Accrued Utility Revenues	16,625,609.62		16,625,609.62
1130 Accumulated Provision for Uncollectible Accts	(504,477.49)		(504,477.49)
1180 Prepayments	827,286.07		827,286.07
1200 Accounts Receivable from Associated Companies	2,100.49		2,100.49
1330 Plant Materials and Operating Supplies	1,621,583.12		1,621,583.12
1508 Other Regulatory Assets	23,414.87		23,414.87
1518 RCVA - Retail	138,753.23		138,753.23
1521 Special Purpose Charge	0.00		0.00
1535 Smart Grid Deferral Account	18,720.96		18,720.96
1548 RCVA - STR	178,967.35		178,967.35
1550 Hydro One Low Voltage Variance	(50,959.88)		(50,959.88)
1551 Smart Metering Entity Variance	36,956.23		36,956.23
1555 Smart Meter Capital and Recovery Variance	551,624.06		551,624.06
1556 Smart Meter OM&A Variance	1,543,689.80		1,543,689.80
1562 Deferred Payments in Lieu of taxes	0.00		0.00
1563 Deferred PILS contra Account	823,064.91		823,064.91
1576 Accounting Changes Under CGAAP	(3,054,565.73)		(3,054,565.73)
1580 RSVA - WMS	(4,151,413.74)		(4,151,413.74)
1584 RSVA - NW	1,503,334.65		1,503,334.65
1586 RSVA - CN	1,050,611.18		1,050,611.18
1588 RSVA - Power	(6,474,228.04)		(6,474,228.04)
1589 RSVA - GA Non-RPP	5,347,179.52		5,347,179.52
1595 Disposition and Recovery of Regulatory Balances	(1,592,462.75)		(1,592,462.75)
1606 Organization	1,926.45		1,926.45
1705 Land	82,347.02		82,347.02
1708 Buildings and Fixtures	3,693,130.15		3,693,130.15
1715 Station Equipment	2,726,687.83		2,726,687.83
1735 Underground Conduit	1,090.59		1,090.59
1740 Underground Conductors and Devices	138,793.40		138,793.40
1805 Land	424,925.77		424,925.77
1806 Land Rights	1,604,396.58		1,604,396.58
1808 Buildings and Fixtures	111,638.13		111,638.13
1815 Transformer Station Equipment - Normally Primary	75,243.58		75,243.58
1820 Distribution Station Equipment - Normally Primary	6,354,039.79		6,354,039.79
1830 Poles, Towers and Fixtures	43,552,108.21		43,552,108.21
1835 Overhead Conductors and Devices	28,184,729.14		28,184,729.14
1840 Underground Conduit	9,663,793.74		9,663,793.74
1845 Underground Conductors and Devices	66,575,037.95		66,575,037.95
1850 Line Transformers	37,356,216.71		37,356,216.71

	RRR Financial Statement December 2013	Adjustment for FMV entry and Water and PILS	Filed RRR restated for FMV removal
1855 Services	5,430,060.80		5,430,060.80
1860 Meters	6,952,486.36		6,952,486.36
1865 Other Installations on Customer's Premises	439.87		439.87
1875 Street Lighting and Signal Systems	21,835.21		21,835.21
1905 Land	508,969.83		508,969.83
1908 Buildings and Fixtures	15,117,430.20		15,117,430.20
1910 Leasehold Improvements	120,252.32		120,252.32
1915 Office Furniture and Equipment	1,493,564.37		1,493,564.37
1920 Computer Equipment-Hardware	3,777,674.42		3,777,674.42
1925 Computer Software	2,691,706.16		2,691,706.16
1930 Transportation Equipment	8,580,007.54		8,580,007.54
1935 Stores Equipment	236,413.92		236,413.92
1940 Tools, Shop and Garage Equipment	1,954,825.97		1,954,825.97
1945 Measurement and Testing Equipment	204,006.18		204,006.18
1955 Communication Equipment	846,784.65		846,784.65
1960 Miscellaneous Equipment	72,951.31		72,951.31
1980 System Supervisory Equipment	128,960.64		128,960.64
1995 Contributions and Grants - Credit	(21,516,864.10)		(21,516,864.10)
2005 Property Under Capital Leases	143,036.00		143,036.00
2060 Electric Plant Acquisition Adjustment	142,276.60		142,276.60
2065 Other Electric Plant Adjustment	45,509,515.44	(45,509,515.44)	0.00
2105 Accumulated Amortization of Electric Utility-Plant	(115,848,161.50)		(115,848,161.50)
2140 Accumulated Amortization of Electric Plant	(142,276.60)		(142,276.60)
2160 Accumulated Amortization of Other Utility Plant	(30,712,337.16)	30,712,337.16	0.00
2205 Accounts Payable	(14,541,602.14)		(14,541,602.14)
2210 Current portion of Customer deposits	(709,338.37)		(709,338.37)
2240 Accounts Payable to Associated Companies	(6,913,021.67)		(6,913,021.67)
2250 Debt Retirement Charges DRC payable	(781,312.27)		(781,312.27)
2260 Current Portion of Long Term Debt	(1,869,628.01)		(1,869,628.01)
2290 Commodity Taxes	1,339,354.58		1,339,354.58
2292 Payroll Deductions/Expenses Payable	2,124.97		2,124.97
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	1,520,859.00		1,520,859.00
2296 Future Income Taxes - Current	1,080,651.59		1,080,651.59
2306 Employee Future Benefits	(3,886,289.00)		(3,886,289.00)
2310 Vested Sick Leave Liability	(112,861.37)		(112,861.37)
2320 Other Miscellaneous Non-current liabilities	(37,334.17)		(37,334.17)
2335 Long Term Customer Deposits	(709,338.37)		(709,338.37)
2425 Other Deferred Credits	(1,492,192.30)		(1,492,192.30)
2520 Other Long Term debt	0.00		0.00
2525 Term Bank Loans-long term Portion	(27,239,644.65)		(27,239,644.65)
2550 Advances from Associated Companies	(25,605,089.72)		(25,605,089.72)
3005 Common Shares Issued	(31,245,882.02)		(31,245,882.02)
3010 Contributed Surplus	(18,753,902.09)	18,753,902.09	0.00
3040 Appropriated Retained Earnings	(26,330,239.21)	(2,824,447.00)	(27,599,937.21)
3041 Appropriated Retained Earnings	0.00	1,554,749.00	
3046 Balance Transferred from Income	(1,458,179.77)	(2,687,025.81)	(4,145,205.58)
3047 Appropriations of Retained Earnings - current	(6,705,305.00)		(6,705,305.00)
3049 Dividends payable - Common Shares	1,200,000.00		1,200,000.00
Balance Sheet	(0.00)	0.00	(0.00)

	RRR Financial Statement December 2013	Adjustment for FMV entry and Water and PILS	Filed RRR restated for FMV removal
4006 Residential Energy Sales	(36,842,617.22)		(36,842,617.22)
4010 Commercial Energy Sales	(11,645,203.82)		(11,645,203.82)
4025 Streetlighting energy sales	(526,743.86)		(526,743.86)
4030 Sentinel Lighting Energy Sales	(18,282.96)		(18,282.96)
4035 General Energy Sales	(58,784,484.02)		(58,784,484.02)
4062 Billed WMS	(7,454,786.47)		(7,454,786.47)
4066 Billed NW	(8,975,194.40)		(8,975,194.40)
4068 Billed CN	(5,454,831.55)		(5,454,831.55)
4075 Billed - LV	(537,671.55)		(537,671.55)
4076 Billed SME Charge	(320,166.15)		(320,166.15)
4080 Distribution Services Revenue	(26,354,545.17)	(1,554,749.00)	(27,909,294.17)
4082 Retail Services Revenue	(44,006.40)		(44,006.40)
4084 Service Transaction Requests (STR) Revenues	(1,071.00)		(1,071.00)
4086 SSS Admin Charge	(142,260.02)		(142,260.02)
4215 Other Utility Operating Income	(48,358.73)		(48,358.73)
4225 Late Payment Charges	(353,573.62)		(353,573.62)
4235 Miscellaneous Service Revenues	(810,536.29)		(810,536.29)
4305 Regulatory Debits	3,054,565.73		3,054,565.73
4355 Gain on Disposition of Utility and Other Property	(11,121.24)		(11,121.24)
4360 Loss on Disposition of Utility and Other Property	1,135.20		1,135.20
4362 Loss on Retirement of Utility and Other Property	66,864.73		66,864.73
4375 Revenues from Non-Utility Operations	(2,018,308.33)		(2,018,308.33)
4380 Expenses from Non-Utility Operations	1,515,822.18	355,292.01	1,871,114.19
4390 Miscellaneous Non-Operating Income	(118,062.00)		(118,062.00)
4405 Interest and Dividend Income	(180,173.43)		(180,173.43)
4705 Power Purchased	107,817,331.88		107,817,331.88
4708 Charges -WMS	7,454,786.47		7,454,786.47
4714 Charges -NW	8,975,194.40		8,975,194.40
4716 Charges -CN	5,454,831.55		5,454,831.55
4750 Charges - LV	537,671.55		537,671.55
4751 Charges - SME	320,166.15		320,166.15
5005 Operation Supervision and Engineering	723,775.34		723,775.34
5010 Load Dispatching	38,222.45		38,222.45
5012 Station Buildings and fixtures expense	65,931.51		65,931.51
5014 Transformer Station Equipment - Operation Labour	11,484.44		11,484.44
5015 Transformer Station Equipment - Operation	141,834.38		141,834.38
5020 Overhead Distribution Lines and Feeders -Labour	197,145.43		197,145.43
5025 Overhead Distribution Lines and Feeders - Operation expen:	14,774.82		14,774.82
5040 Underground Distribution Lines and Feeders Labour	76,753.80		76,753.80
5045 Underground Distribution Lines and Feeders - expenses	250,001.50		250,001.50
5055 Underground Distribution Transformers - Operation	651.00		651.00
5065 Meter Expense	427,571.92		427,571.92
5070 Customer Premises - Operation Labour	121,019.25		121,019.25
5085 Miscellaneous Distribution Expenses	2,062,008.09		2,062,008.09
5105 Maintenance Supervision and Engineering	492,770.85		492,770.85
5112 Maintenance of Transformer Station Equipment	1,115.00		1,115.00
5114 Maintenance of Distribution Station Equipment	33,541.52		33,541.52
5120 Maintenance of Poles, Towers and Fixtures	157,253.73		157,253.73
5125 Maintenance of Overhead Conductors and Devices	613,407.29		613,407.29
5130 Maintenance of Overhead Services	154,111.43		154,111.43
5135 Overhead Distribution Lines and Feeders - Right of Way	244,449.97		244,449.97

	RRR Financial Statement December 2013	Adjustment for FMV entry and Water and PILS	Filed RRR restated for FMV removal
5145 Maintenance of Underground Conduit	25,153.29		25,153.29
5150 Maintenance of Underground Conductors & Devices	205,312.43		205,312.43
5155 Maintenance of Underground Services	72,639.67		72,639.67
5160 Maintenance of Line Transformers	145,430.15		145,430.15
5175 Maintenance of Meters	4,366.19		4,366.19
5305 Supervision	624,637.50		624,637.50
5310 Meter Reading Expense	154,042.91		154,042.91
5315 Customer Billing	2,342,379.32	(282,145.81)	2,060,233.51
5320 Collecting	429,058.48		429,058.48
5325 Collecting - Cash Over and Short	70.32		70.32
5335 Bad Debt Expense	223,841.58		223,841.58
5340 Miscellaneous Customer Accounts Expense	243,807.99		243,807.99
5410 Community Relations - Sundry	81,553.81		81,553.81
5605 Executive Salaries and Expenses	397,095.08		397,095.08
5610 Management Salaries and Expenses	1,728,806.28	(55,038.20)	1,673,768.08
5615 General Administrative Salaries and Expenses	446,357.59		446,357.59
5620 Office Supplies and Expenses	76,250.84		76,250.84
5630 Outside Services Employed	40,800.00		40,800.00
5635 Property Insurance	284,891.96		284,891.96
5655 Regulatory Expenses	222,003.09		222,003.09
5665 Miscellaneous General Expense	58,770.28		58,770.28
5675 Maintenance of General Plant	556,821.56		556,821.56
5705 Amortization Expense - Property Plant and Equipment	5,321,040.63	(18,108.00)	5,302,932.63
5715 Amortization of Intangibles and Other Electric	1,132,276.81	(1,132,276.81)	0.00
6005 Interest on Long Term Debt	1,980,405.54		1,980,405.54
6030 Interest on Debt to Associated Companies	191,790.72		191,790.72
6035 Other Interest Expense	273,512.14		273,512.14
6105 Taxes other that Income Taxes	258,672.54		258,672.54
6110 Income Taxes	85,936.00		85,936.00
6115 Provision for Future Income Taxes	510,994.20		510,994.20
6205 Donations	38,906.00		38,906.00
6215 Penalties	0.00		0.00
Income Statement total	**(1,458,179.77)**	**(2,687,025.81)**	**(4,145,205.58)**

Trial Balance Summary			
Revenues	(156,003,610.39)	(1,199,456.99)	(157,203,067.38)
Expenses	154,545,430.62	(1,487,568.82)	153,057,861.80
(Profit)/Loss	(1,458,179.77)	(2,687,025.81)	(4,145,205.58)
Net Assets	265,236,768.80	0.00	265,236,768.80
Net Liabilities and Equity	(265,236,768.80)	0.00	(265,236,768.80)
IS (Profit)/Loss	(1,458,179.77)	(2,687,025.81)	(4,145,205.58)
Balance Sheet (profit)/Loss	(1,458,179.77)	(2,687,025.81)	(4,145,205.58)

Niagara Peninsula Energy Inc.
FMV Bump
2.1.13

Balance Sheet

		2007 FMV entry	Entry hits Retained Earnings	2007 FMV entry summary	2008	2009	2010	2011	2012	2013	2012 Net Adjustment on RRR to RE
1	PWU AR PWPower	(216,069.30)	216,069.30								
1	Due from PW power	1,400,000.00	(1,400,000.00)								
1	Future PILS	(5,168,552.00)	5,168,552.00								
1	Inventory	7,684.34	(7,684.34)								
	Fixed assets Total FMV Bump	45,735,559.44		45,735,559.44	45,735,559.44	45,735,559.44	45,735,559.44				
	Adjustment for PW software				-	-	(226,044.00)				
							45,509,515.44	45,509,515.44	45,509,515.44	45,509,515.44	
	Accum Deprec Total FMV Bump	(24,083,153.39)		(24,083,153.39)	(24,083,153.39)	(25,239,221.08)	(26,348,210.08)	(27,355,968)	(28,442,637)	(29,580,061)	
	Adjustment for PW software						226,044				
	Current year depreciation				(1,156,068)	(1,108,989)	(1,233,802)	(1,086,669)	(1,137,424)	(1,132,277)	
					(25,239,221)	(26,348,210)	(27,355,968)	(28,442,637)	(29,580,061)	(30,712,338)	
	Contributed Surplus	(18,753,902.09)		(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	
1	Retained Earnings	1,078,433.00	(1,078,433.00)	-							
sum of 1's	Retained Earnings net adjustment		(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	
	Cummulative impact on RE for Depreciation FMV bump				1,156,068	2,265,057	3,498,859	3,498,859	4,585,528	5,722,952	2,824,448.02
	Depreciation expense to be closed to Cummulative impact on RE							1,086,669	1,137,424	1,132,277	
	Net	(0.00)	-	-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	-	

Income Statement

	2008	2009	2010	2011	2012	2013
Depreciation expense FMV bump	1,156,068	1,111,638	1,233,802	1,086,669	1,137,424	1,132,277
Adjust depreciation expense FMV bump	0	-2649	0	0	0	
	1,156,068	1,108,989	1,233,802	1,086,669	1,137,424	1,132,277

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2012

RRR Part 1
Trial Balance Mapped to Financial Statement Grouping
2.1.13

	RRR = Financial Statements December 2012	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1005 Cash	13,351,561.45				13,351,561.45		
1010 Cash Advance and Working Funds	2,458.33	13,354,019.78			2,458.33	13,354,019.78	
1100 Custom Accounts Receivable	7,810,380.54				7,810,380.54		
1104 Accounts Receivable - Recoverable Work	1,518,847.20				1,518,847.20		
1110 Other Accounts Receivable	757,559.56				757,559.56		
1130 Accumulated Provision for Uncollectible Accts	(669,397.72)	9,417,389.58			(669,397.72)	9,417,389.58	
1120 Accrued Utility Revenues	13,218,877.65	13,218,877.65			13,218,877.65	13,218,877.65	
1200 Accounts Receivable from Associated Companies	19,839.92	19,839.92			19,839.92	19,839.92	
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	588,733.00	588,733.00			588,733.00	588,733.00	
1180 Prepayments	901,527.46				901,527.46		
1606 Organization	1,926.45	903,453.91			1,926.45	903,453.91	
1330 Plant Materials and Operating Supplies	1,457,819.72	1,457,819.72	38,960,133.56		1,457,819.72	1,457,819.72	38,960,133.56
1705 Land	82,347.02				82,347.02		
1708 Buildings and Fixtures	3,693,130.15				3,693,130.15		
1715 Station Equipment	2,726,687.83				2,726,687.83		
1735 Underground Conduit	1,090.59				1,090.59		
1740 Underground Conductors and Devices	138,793.40				138,793.40		
1805 Land	424,925.77				424,925.77		
1806 Land Rights	1,603,586.98				1,603,586.98		
1808 Buildings and Fixtures	111,638.13				111,638.13		
1815 Transformer Station Equipment - Normally Primary	58,564.58				58,564.58		
1820 Distribution Station Equipment - Normally Primary	6,450,524.96				6,450,524.96		
1830 Poles, Towers and Fixtures	33,860,858.39				33,860,858.39		
1835 Overhead Conductors and Devices	36,262,078.27				36,262,078.27		
1840 Underground Conduit	12,764,490.39				12,764,490.39		
1845 Underground Conductors and Devices	60,998,235.89				60,998,235.89		
1850 Line Transformers	33,887,619.76				33,887,619.76		
1855 Services	4,629,063.25				4,629,063.25		
1860 Meters	6,676,988.91				6,676,988.91		
1865 Other Installations on Customer's Premises	439.87				439.87		
1875 Street Lighting and Signal Systems	21,835.21				21,835.21		
1905 Land	508,969.83				508,969.83		
1908 Buildings and Fixtures	13,205,845.69				13,205,845.69		
1910 Leasehold Improvements	120,252.32				120,252.32		
1915 Office Furniture and Equipment	1,323,138.81				1,323,138.81		
1920 Computer Equipment-Hardware	3,501,321.70				3,501,321.70		
1925 Computer Software	2,576,964.23				2,576,964.23		
1930 Transportation Equipment	7,605,132.65				7,605,132.65		
1935 Stores Equipment	236,413.92				236,413.92		
1940 Tools, Shop and Garage Equipment	1,871,743.96				1,871,743.96		
1945 Measurement and Testing Equipment	204,006.18				204,006.18		
1955 Communication Equipment	502,920.61				502,920.61		
1960 Miscellaneous Equipment	72,951.31				72,951.31		
1980 System Supervisory Equipment	128,960.64				128,960.64		

	RRR = Financial Statements December 2012	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1995 Contributions and Grants - Credit	(20,525,490.62)				(20,525,490.62)		
2005 Property Under Capital Leases	143,036.00				143,036.00		
2060 Electric Plant Acquisition Adjustment	142,276.60				142,276.60		
2065 Other Electric Plant Adjustment	45,509,515.44			(45,509,515.44)	0.00		
2105 Accumulated Amortization of Electric Utility-Plant	(111,934,864.56)				(111,934,864.56)		
2140 Accumulated Amortization of Electric Plant	(142,276.60)				(142,276.60)		
2160 Accumulated Amortization of Other Utility Plant	(29,580,060.72)	119,863,656.74	119,863,656.74	29,580,060.72	0.00	103,934,202.02	103,934,202.02
2296 Future Income Taxes - Current	1,591,645.79	1,591,645.79	1,591,645.79		1,591,645.79	1,591,645.79	1,591,645.79
2205 Accounts Payable	(13,607,604.61)				(13,607,604.61)		
2220 Miscellaneous Current and Accrued Liabilities	0.00				0.00		
2250 Debt Retirement Charges DRC payable	(725,804.18)				(725,804.18)		
2290 Commodity Taxes	1,068,226.16				1,068,226.16		
2292 Payroll Deductions/Expenses Payable	(4,762.49)				(4,762.49)		
2425 Other Deferred Credits	(1,289,150.12)	(14,559,095.24)			(1,289,150.12)	(14,559,095.24)	
2210 Current portion of Customer deposits	(700,198.54)	(700,198.54)			(700,198.54)	(700,198.54)	
2240 Accounts Payable to Associated Companies	(7,513,902.18)	(7,513,902.18)			(7,513,902.18)	(7,513,902.18)	
2260 Current Portion of Long Term Debt	(2,313,484.07)	(2,313,484.07)	(25,086,680.03)		(2,313,484.07)	(2,313,484.07)	(25,086,680.03)
2520 Other Long Term debt	0.00				0.00		
2525 Term Bank Loans-long term Portion	(19,109,272.65)				(19,109,272.65)		
2550 Advances from Associated Companies	(25,605,089.72)	(44,714,362.37)			(25,605,089.72)	(44,714,362.37)	
2320 Other Miscellaneous Non-current liabilities	(37,334.17)				(37,334.17)		
2335 Long Term Customer Deposits	(700,198.54)	(737,532.71)			(700,198.54)	(737,532.71)	
2310 Vested Sick Leave Liability	(168,533.36)	(168,533.36)			(168,533.36)	(168,533.36)	
2306 Employee Future Benefits	(3,778,345.00)	(3,778,345.00)			(3,778,345.00)	(3,778,345.00)	
1550 Hydro One Low Voltage Variance	(121,768.21)				(121,768.21)		
1580 RSVA - WMS	(3,194,684.62)				(3,194,684.62)		
1582 RSVA - One Time	0.00				0.00		
1584 RSVA - NW	886,919.51				886,919.51		
1586 RSVA - CN	649,292.69				649,292.69		
1588 RSVA - Power	(4,823,801.99)				(4,823,801.99)		
1588 RSVA - GA Non-RPP	3,724,124.59				3,724,124.59		
1518 RCVA - Retail	109,056.07				109,056.07		
1548 RCVA - STR	138,377.50				138,377.50		
1508 Other Regulatory Assets	19,661.08				19,661.08		
1562 Deferred Payments in Lieu of taxes	0.00				0.00		
1563 Deferred PILS contra Account	2,377,761.42				2,377,761.42		
1535 Smart Grid Deferral Account	18,720.96				18,720.96		
1555 Smart Meter Capital and Recovery Variance	957,653.63				957,653.63		
1556 Smart Meter OM&A Variance	1,070,675.41				1,070,675.41		
1521 Special Purpose Charge	0.00				0.00		
1595 Disposition and Recovery of Regulatory Balances	(4,706,642.34)	(2,894,654.30)	(52,293,427.74)		(4,706,642.34)	(2,894,654.30)	(52,293,427.74)
3005 Common Shares Issued	(31,245,882.02)	(31,245,882.02)			(31,245,882.02)	(31,245,882.02)	
3010 Contributed Surplus	(18,753,902.09)			18,753,902.09	0.00		
3047 Appropriations of Retained Earnings - current	(6,705,305.00)	(25,459,207.09)			(6,705,305.00)	(6,705,305.00)	
3040 Appropriated Retained Earnings	(24,778,870.40)			(1,687,023.66)	(26,465,894.06)		
3046 Balance Transferred from Income	(2,751,368.81)			(1,137,423.71)	(3,888,792.52)		
3049 Dividends payable - Common Shares	1,200,000.00	(26,330,239.21)	(83,035,328.32)		1,200,000.00	(29,154,686.58)	(67,105,873.60)
Balance Sheet	**(0.00)**	**0.00**	**0.00**	**0.00**	**(0.00)**	**(0.00)**	**0.00**

	RRR = Financial Statements December 2012	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
Income Statement	**Actual December 2012**	**Income Statement**	**Income Stmt Total**	**Adjustments for FMV entry and Water**	**RRR restated for**	**Income Statement restated for Regulatory**	**Income Statement restated for Regulatory**
4006 Residential Energy Sales	(34,590,681.65)				(34,590,681.65)		
4010 Commercial Energy Sales	(11,066,913.03)				(11,066,913.03)		
4025 Streetlighting energy sales	(645,713.53)				(645,713.53)		
4030 Sentinel Lighting Energy Sales	(17,795.75)				(17,795.75)		
4035 General Energy Sales	(51,976,152.34)	(98,297,256.30)			(51,976,152.34)	(98,297,256.30)	
4062 Billed WMS	(8,186,727.76)				(8,186,727.76)		
4066 Billed NW	(8,708,519.89)				(8,708,519.89)		
4068 Billed CN	(5,502,319.90)				(5,502,319.90)		
4075 Billed - LV	(539,211.95)	(22,936,779.50)			(539,211.95)	(22,936,779.50)	
4080 Distribution Services Revenue	(27,401,547.81)	(27,401,547.81)			(27,401,547.81)	(27,401,547.81)	
4082 Retail Services Revenue	(49,124.22)				(49,124.22)		
4084 Service Transaction Requests (STR) Revenues	(1,322.75)	(50,446.97)			(1,322.75)	(50,446.97)	
4086 SSS Admin Charge	(138,403.36)	(138,403.36)	(148,824,433.94)		(138,403.36)	(138,403.36)	(148,824,433.94)
4705 Power Purchased	98,297,256.30				98,297,256.30		
4708 Charges -WMS	8,186,727.76				8,186,727.76		
4714 Charges -NW	8,708,519.89				8,708,519.89		
4716 Charges -CN	5,502,319.90				5,502,319.90		
4750 Charges - LV	539,211.95	121,234,035.80	121,234,035.80		539,211.95	121,234,035.80	121,234,035.80
4215 Other Utility Operating Income	(42,682.99)				(42,682.99)		
4225 Late Payment Charges	(372,203.04)				(372,203.04)		
4355 Gain on Disposition of Utility and Other Property	(358.85)				(358.85)		
4375 Revenues from Non-Utility Operations	(1,825,918.13)				(1,825,918.13)		
4235 Miscellaneous Service Revenues	(794,765.92)				(794,765.92)		
4380 Expenses from Non-Utility Operations	1,129,620.56			352,388.49	1,482,009.05		
4390 Miscellaneous Non-Operating Income	(118,923.00)				(118,923.00)		
4405 Interest and Dividend Income	(174,715.29)	(2,199,946.66)	(2,199,946.66)		(174,715.29)	(1,847,558.17)	(1,847,558.17)
5005 Operation Supervision and Engineering	688,629.80				688,629.80		
5010 Load Dispatching	43,296.00				43,296.00		
5012 Station Buildings and fixtures expense	127,821.79				127,821.79		
5014 Transformer Station Equipment - Operation Labour	29,298.38				29,298.38		
5015 Transformer Station Equipment - Operation	94,878.08				94,878.08		
5020 Overhead Distribution Lines and Feeders -Labour	203,079.17				203,079.17		
5025 Overhead Distribution Lines and Feeders - Operation ex	71,801.96				71,801.96		
5040 Underground Distribution Lines and Feeders Labour	82,226.49				82,226.49		
5045 Underground Distribution Lines and Feeders - expenses	276,192.13				276,192.13		
5065 Meter Expense	499,089.32				499,089.32		
5085 Miscellaneous Distribution Expenses	2,123,408.60				2,123,408.60		
5105 Maintenance Supervision and Engineering	478,493.93				478,493.93		
5112 Maintenance of Transformer Station Equipment	82,176.75				82,176.75		
5114 Maintenance of Distribution Station Equipment	28,484.59				28,484.59		
5120 Maintenance of Poles, Towers and Fixtures	166,993.54				166,993.54		
5125 Maintenance of Overhead Conductors and Devices	798,301.26				798,301.26		
5130 Maintenance of Overhead Services	160,457.73				160,457.73		
5135 Overhead Distribution Lines and Feeders - Right of Way	208,143.87				208,143.87		
5145 Maintenance of Underground Conduit	39,818.21				39,818.21		
5150 Maintenance of Underground Conductors & Devices	197,018.80				197,018.80		

	RRR = Financial Statements December 2012	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
5155 Maintenance of Underground Services	83,461.26				83,461.26		
5160 Maintenance of Line Transformers	132,651.69				132,651.69		
5175 Maintenance of Meters	5,214.45	6,620,937.80			5,214.45	6,620,937.80	6,620,937.80
5070 Customer Premises - Operation Labour	87,166.19				87,166.19		
5410 Community Relations - Sundry	79,067.93	166,234.12			79,067.93	166,234.12	166,234.12
5605 Executive Salaries and Expenses	359,989.22				359,989.22		
5610 Management Salaries and Expenses	2,174,815.32			(54,880.70)	2,119,934.62		
5615 General Administrative Salaries and Expenses	456,969.95				456,969.95		
5620 Office Supplies and Expenses	83,384.37				83,384.37		
5630 Outside Services Employed	39,600.00				39,600.00		
5635 Property Insurance	221,161.29				221,161.29		
5655 Regulatory Expenses	242,929.62				242,929.62		
5665 Miscellaneous General Expense	52,118.00				52,118.00		
5675 Maintenance of General Plant	501,708.42				501,708.42		
6005 Interest on Long Term Debt	2,045,663.26				2,045,663.26		
6030 Interest on Debt to Associated Companies	209,740.09				209,740.09		
6035 Other Interest Expense	443,767.08				443,767.08		
6105 Taxes other that Income Taxes	0.00				0.00		
6215 Penalties	167,381.05				167,381.05		
6205 Donations	38,906.00	7,038,133.67			38,906.00	6,983,252.97	6,983,252.97
5305 Supervision	576,200.30				576,200.30		
5310 Meter Reading Expense	188,961.23				188,961.23		
5315 Customer Billing	2,279,081.48			(279,399.79)	1,999,681.69		
5320 Collecting	436,346.41				436,346.41		
5325 Collecting - Cash Over and Short	0.25				0.25		
5335 Bad Debt Expense	266,257.19				266,257.19		
5340 Miscellaneous Customer Accounts Expense	230,189.78	3,977,036.64			230,189.78	3,697,636.85	3,697,636.85
5705 Amortization Expense - Property Plant and Equipment	7,421,270.34	7,421,270.34		(18,108.00)	7,403,162.34	7,403,162.34	7,403,162.34
5715 Amortization of Intangibles and Other Electric	1,137,423.71	1,137,423.71		(1,137,423.71)	0.00	0.00	0.00
			26,361,036.28		0.00		
6110 Income Taxes	637,722.83				637,722.83		
6115 Provision for Future Income Taxes	40,216.88	677,939.71	677,939.71		40,216.88	677,939.71	677,939.71
Income Statement total	**(2,751,368.81)**	**(2,751,368.81)**	**(2,751,368.81)**	**(1,137,423.71)**	**(3,888,792.52)**	**(3,888,792.52)**	**(3,888,792.52)**
Trial Balance Summary							
Revenues	(151,024,380.60)	(151,024,380.60)	(151,024,380.60)	352,388.49	(150,671,992.11)	(150,671,992.11)	(150,671,992.11)
Expenses	148,273,011.79	148,273,011.79	148,273,011.79	(1,489,812.20)	146,783,199.59	146,783,199.59	146,783,199.59
(Profit)/Loss	(2,751,368.81)	(2,751,368.81)	(2,751,368.81)	(1,137,423.71)	(3,888,792.52)	(3,888,792.52)	(3,888,792.52)
Net Assets	252,794,422.63	37,068,392.05	(11,741,648.39)	0.00	252,794,422.63	37,068,392.05	(11,741,648.39)
Net Liabilities and Equity	(252,794,422.63)	(37,068,392.05)	11,741,648.39	0.00	(252,794,422.63)	(37,068,392.05)	11,741,648.39
IS (Profit)/Loss	(2,751,368.81)	(2,751,368.81)	(2,751,368.81)	(1,137,423.71)	(3,888,792.52)	(3,888,792.52)	(3,888,792.52)
Balance Sheet (profit)/Loss	(2,751,368.81)	(2,751,368.81)	(2,751,368.81)	(1,137,423.71)	(3,888,792.52)	(3,888,792.52)	(3,888,792.52)

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2012

RRR Part 2
Trial Balance by Account
2.1.13

	RRR Financial Statement December 2012	Adjustment for FMV entry and Water	Filed RRR restated for FMV removal
Current Assets			
1005 Cash	13,351,561.45		13,351,561.45
1010 Cash Advance and Working Funds	2,458.33		2,458.33
1100 Custom Accounts Receivable	7,810,380.54		7,810,380.54
1104 Accounts Receivable - Recoverable Work	1,518,847.20		1,518,847.20
1110 Other Accounts Receivable	757,559.56		757,559.56
1120 Accrued Utility Revenues	13,218,877.65		13,218,877.65
1130 Accumulated Provision for Uncollectible Accts	(669,397.72)		(669,397.72)
1180 Prepayments	901,527.46		901,527.46
1200 Accounts Receivable from Associated Companies	19,839.92		19,839.92
1330 Plant Materials and Operating Supplies	1,457,819.72		1,457,819.72
1508 Other Regulatory Assets	19,661.08		19,661.08
1518 RCVA - Retail	109,056.07		109,056.07
1521 Special Purpose Charge	0.00		0.00
1535 Smart Grid Deferral Account	18,720.96		18,720.96
1548 RCVA - STR	138,377.50		138,377.50
1550 Hydro One Low Voltage Variance	(121,768.21)		(121,768.21)
1555 Smart Meter Capital and Recovery Variance	957,653.63		957,653.63
1556 Smart Meter OM&A Variance	1,070,675.41		1,070,675.41
1562 Deferred Payments in Lieu of taxes	0.00		0.00
1563 Deferred PILS contra Account	2,377,761.42		2,377,761.42
1580 RSVA - WMS	(3,194,684.62)		(3,194,684.62)
1584 RSVA - NW	886,919.51		886,919.51
1586 RSVA - CN	649,292.69		649,292.69
1588 RSVA - Power	(4,823,801.99)		(4,823,801.99)
1589 RSVA - GA Non-RPP	3,724,124.59		3,724,124.59
1595 Disposition and Recovery of Regulatory Balances	(4,706,642.34)		(4,706,642.34)
1606 Organization	1,926.45		1,926.45
1705 Land	82,347.02		82,347.02
1708 Buildings and Fixtures	3,693,130.15		3,693,130.15
1715 Station Equipment	2,726,687.83		2,726,687.83
1735 Underground Conduit	1,090.59		1,090.59
1740 Underground Conductors and Devices	138,793.40		138,793.40
1805 Land	424,925.77		424,925.77
1806 Land Rights	1,603,586.98		1,603,586.98
1808 Buildings and Fixtures	111,638.13		111,638.13
1815 Transformer Station Equipment - Normally Primary	58,564.58		58,564.58
1820 Distribution Station Equipment - Normally Primary	6,450,524.96		6,450,524.96
1830 Poles, Towers and Fixtures	33,860,858.39		33,860,858.39
1835 Overhead Conductors and Devices	36,262,078.27		36,262,078.27
1840 Underground Conduit	12,764,490.39		12,764,490.39
1845 Underground Conductors and Devices	60,998,235.89		60,998,235.89
1850 Line Transformers	33,887,619.76		33,887,619.76
1855 Services	4,629,063.25		4,629,063.25

	RRR Financial Statement December 2012	Adjustment for FMV entry and Water	Filed RRR restated for FMV removal
1860 Meters	6,676,988.91		6,676,988.91
1865 Other Installations on Customer's Premises	439.87		439.87
1875 Street Lighting and Signal Systems	21,835.21		21,835.21
1905 Land	508,969.83		508,969.83
1908 Buildings and Fixtures	13,205,845.69		13,205,845.69
1910 Leasehold Improvements	120,252.32		120,252.32
1915 Office Furniture and Equipment	1,323,138.81		1,323,138.81
1920 Computer Equipment-Hardware	3,501,321.70		3,501,321.70
1925 Computer Software	2,576,964.23		2,576,964.23
1930 Transportation Equipment	7,605,132.65		7,605,132.65
1935 Stores Equipment	236,413.92		236,413.92
1940 Tools, Shop and Garage Equipment	1,871,743.96		1,871,743.96
1945 Measurement and Testing Equipment	204,006.18		204,006.18
1955 Communication Equipment	502,920.61		502,920.61
1960 Miscellaneous Equipment	72,951.31		72,951.31
1980 System Supervisory Equipment	128,960.64		128,960.64
1995 Contributions and Grants - Credit	(20,525,490.62)		(20,525,490.62)
2005 Property Under Capital Leases	143,036.00		143,036.00
2060 Electric Plant Acquisition Adjustment	142,276.60		142,276.60
2065 Other Electric Plant Adjustment	45,509,515.44	(45,509,515.44)	0.00
2105 Accumulated Amortization of Electric Utility-Plant	(111,934,864.56)		(111,934,864.56)
2140 Accumulated Amortization of Electric Plant	(142,276.60)		(142,276.60)
2160 Accumulated Amortization of Other Utility Plant	(29,580,060.72)	29,580,060.72	0.00
2205 Accounts Payable	(13,607,604.61)		(13,607,604.61)
2210 Current portion of Customer deposits	(700,198.54)		(700,198.54)
2240 Accounts Payable to Associated Companies	(7,513,902.18)		(7,513,902.18)
2250 Debt Retirement Charges DRC payable	(725,804.18)		(725,804.18)
2260 Current Portion of Long Term Debt	(2,313,484.07)		(2,313,484.07)
2290 Commodity Taxes	1,068,226.16		1,068,226.16
2292 Payroll Deductions/Expenses Payable	(4,762.49)		(4,762.49)
2294 Accrual for Taxes,"Payments in Lieu"of Taxes	588,733.00		588,733.00
2296 Future Income Taxes - Current	1,591,645.79		1,591,645.79
2306 Employee Future Benefits	(3,778,345.00)		(3,778,345.00)
2310 Vested Sick Leave Liability	(168,533.36)		(168,533.36)
2320 Other Miscellaneous Non-current liabilities	(37,334.17)		(37,334.17)
2335 Long Term Customer Deposits	(700,198.54)		(700,198.54)
2425 Other Deferred Credits	(1,289,150.12)		(1,289,150.12)
2520 Other Long Term debt	0.00		0.00
2525 Term Bank Loans-long term Portion	(19,109,272.65)		(19,109,272.65)
2550 Advances from Associated Companies	(25,605,089.72)		(25,605,089.72)
3005 Common Shares Issued	(31,245,882.02)		(31,245,882.02)
3010 Contributed Surplus	(18,753,902.09)	18,753,902.09	0.00
3040 Appropriated Retained Earnings	(24,778,870.40)	(1,687,023.66)	(26,465,894.06)
3046 Balance Transferred from Income	(2,751,368.81)	(1,137,423.71)	(3,888,792.52)
3047 Appropriations of Retained Earnings - current	(6,705,305.00)		(6,705,305.00)
3049 Dividends payable - Common Shares	1,200,000.00		1,200,000.00
Balance Sheet	(0.00)	0.00	(0.00)

	RRR Financial Statement December 2012	Adjustment for FMV entry and Water	Filed RRR restated for FMV removal
Income Statement			
4006 Residential Energy Sales	(34,590,681.65)		(34,590,681.65)
4010 Commercial Energy Sales	(11,066,913.03)		(11,066,913.03)
4025 Streetlighting energy sales	(645,713.53)		(645,713.53)
4030 Sentinel Lighting Energy Sales	(17,795.75)		(17,795.75)
4035 General Energy Sales	(51,976,152.34)		(51,976,152.34)
4062 Billed WMS	(8,186,727.76)		(8,186,727.76)
4066 Billed NW	(8,708,519.89)		(8,708,519.89)
4068 Billed CN	(5,502,319.90)		(5,502,319.90)
4075 Billed - LV	(539,211.95)		(539,211.95)
4080 Distribution Services Revenue	(27,401,547.81)		(27,401,547.81)
4082 Retail Services Revenue	(49,124.22)		(49,124.22)
4084 Service Transaction Requests (STR) Revenues	(1,322.75)		(1,322.75)
4086 SSS Admin Charge	(138,403.36)		(138,403.36)
4215 Other Utility Operating Income	(42,682.99)		(42,682.99)
4225 Late Payment Charges	(372,203.04)		(372,203.04)
4235 Miscellaneous Service Revenues	(794,765.92)		(794,765.92)
4355 Gain on Disposition of Utility and Other Property	(358.85)		(358.85)
4375 Revenues from Non-Utility Operations	(1,825,918.13)		(1,825,918.13)
4380 Expenses from Non-Utility Operations	1,129,620.56	352,388.49	1,482,009.05
4390 Miscellaneous Non-Operating Income	(118,923.00)		(118,923.00)
4405 Interest and Dividend Income	(174,715.29)		(174,715.29)
4705 Power Purchased	98,297,256.30		98,297,256.30
4708 Charges -WMS	8,186,727.76		8,186,727.76
4714 Charges -NW	8,708,519.89		8,708,519.89
4716 Charges -CN	5,502,319.90		5,502,319.90
4750 Charges - LV	539,211.95		539,211.95
5005 Operation Supervision and Engineering	688,629.80		688,629.80
5010 Load Dispatching	43,296.00		43,296.00
5012 Station Buildings and fixtures expense	127,821.79		127,821.79
5014 Transformer Station Equipment - Operation Labour	29,298.38		29,298.38
5015 Transformer Station Equipment - Operation	94,878.08		94,878.08
5020 Overhead Distribution Lines and Feeders -Labour	203,079.17		203,079.17
5025 Overhead Distribution Lines and Feeders - Operation expen:	71,801.96		71,801.96
5040 Underground Distribution Lines and Feeders Labour	82,226.49		82,226.49
5045 Underground Distribution Lines and Feeders - expenses	276,192.13		276,192.13
5065 Meter Expense	499,089.32		499,089.32
5070 Customer Premises - Operation Labour	87,166.19		87,166.19
5085 Miscellaneous Distribution Expenses	2,123,408.60		2,123,408.60
5105 Maintenance Supervision and Engineering	478,493.93		478,493.93
5112 Maintenance of Transformer Station Equipment	82,176.75		82,176.75
5114 Maintenance of Distribution Station Equipment	28,484.59		28,484.59
5120 Maintenance of Poles, Towers and Fixtures	166,993.54		166,993.54
5125 Maintenance of Overhead Conductors and Devices	798,301.26		798,301.26
5130 Maintenance of Overhead Services	160,457.73		160,457.73
5135 Overhead Distribution Lines and Feeders - Right of Way	208,143.87		208,143.87
5145 Maintenance of Underground Conduit	39,818.21		39,818.21
5150 Maintenance of Underground Conductors & Devices	197,018.80		197,018.80
5155 Maintenance of Underground Services	83,461.26		83,461.26
5160 Maintenance of Line Transformers	132,651.69		132,651.69
5175 Maintenance of Meters	5,214.45		5,214.45

	RRR Financial Statement December 2012	Adjustment for FMV entry and Water	Filed RRR restated for FMV removal
5305 Supervision	576,200.30		576,200.30
5310 Meter Reading Expense	188,961.23		188,961.23
5315 Customer Billing	2,279,081.48	(279,399.79)	1,999,681.69
5320 Collecting	436,346.41		436,346.41
5325 Collecting - Cash Over and Short	0.25		0.25
5335 Bad Debt Expense	266,257.19		266,257.19
5340 Miscellaneous Customer Accounts Expense	230,189.78		230,189.78
5410 Community Relations - Sundry	79,067.93		79,067.93
5605 Executive Salaries and Expenses	359,989.22		359,989.22
5610 Management Salaries and Expenses	2,174,815.32	(54,880.70)	2,119,934.62
5615 General Administrative Salaries and Expenses	456,969.95		456,969.95
5620 Office Supplies and Expenses	83,384.37		83,384.37
5630 Outside Services Employed	39,600.00		39,600.00
5635 Property Insurance	221,161.29		221,161.29
5655 Regulatory Expenses	242,929.62		242,929.62
5665 Miscellaneous General Expense	52,118.00		52,118.00
5675 Maintenance of General Plant	501,708.42		501,708.42
5705 Amortization Expense - Property Plant and Equipment	7,421,270.34	(18,108.00)	7,403,162.34
5715 Amortization of Intangibles and Other Electric	1,137,423.71	(1,137,423.71)	0.00
6005 Interest on Long Term Debt	2,045,663.26		2,045,663.26
6030 Interest on Debt to Associated Companies	209,740.09		209,740.09
6035 Other Interest Expense	443,767.08		443,767.08
6105 Taxes other that Income Taxes	0.00		0.00
6110 Income Taxes	637,722.83		637,722.83
6115 Provision for Future Income Taxes	40,216.88		40,216.88
6205 Donations	38,906.00		38,906.00
6215 Penalties	167,381.05		167,381.05
Income Statement total	**(2,751,368.81)**	**(1,137,423.71)**	**(3,888,792.52)**

Trial Balance Summary			
Revenues	(151,024,380.60)	352,388.49	(150,671,992.11)
Expenses	148,273,011.79	(1,489,812.20)	146,783,199.59
(Profit)/Loss	(2,751,368.81)	(1,137,423.71)	(3,888,792.52)
Net Assets	252,794,422.63	0.00	252,794,422.63
Net Liabilities and Equity	(252,794,422.63)	0.00	(252,794,422.63)
IS (Profit)/Loss	(2,751,368.81)	(1,137,423.71)	(3,888,792.52)
Balance Sheet (profit)/Loss	(2,751,368.81)	(1,137,423.71)	(3,888,792.52)

Niagara Peninsula Energy Inc.
FMV Bump
2.1.13

Balance Sheet

		2007 FMV entry	Entry hits Retained Earnings	2007 FMV entry summary	2008	2009	2010	2011	2012	2012 Net Adjustment on RRR to RE
1	PWU AR PWPower	(216,069.30)	216,069.30							
1	Due from PW power	1,400,000.00	(1,400,000.00)							
1	Future PILS	(5,168,552.00)	5,168,552.00							
1	Inventory	7,684.34	(7,684.34)							
	Fixed assets Total FMV Bump	45,735,559.44		45,735,559.44	45,735,559.44	45,735,559.44	45,735,559.44			
	Adjustment for PW software				-	-	(226,044.00)			
							45,509,515.44	45,509,515.44	45,509,515.44	
	Accum Deprec Total FMV Bump	(24,083,153.39)		(24,083,153.39)	(24,083,153.39)	(25,239,221.08)	(26,348,210.08)	(27,355,968)	(28,442,637)	
	Adjustment for PW software						226,044			
	Current year depreciation				(1,156,068)	(1,108,989)	(1,233,802)	(1,086,669)	(1,137,424)	
					(25,239,221)	(26,348,210)	(27,355,968)	(28,442,637)	(29,580,061)	
	Contributed Surplus	(18,753,902.09)		(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	
1	Retained Earnings	1,078,433.00	(1,078,433.00)	-						
sum of 1's	Retained Earnings net adjustment		(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	
	Cummulative impact on RE for Depreciation FMV bump				1,156,068	2,265,057	3,498,859	3,498,859	4,585,528	1,687,024.02
	Depreciation expense to be closed to Cummulative impact on RE							1,086,669	1,137,424	
	Net	(0.00)	-	-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	

Income Statement

	2008	2009	2010	2011	2012
Depreciation expense FMV bump	1,156,068	1,111,638	1,233,802	1,086,669	1,137,424
Adjust depreciation expense FMV bump	0	-2649	0	0	0
	1,156,068	1,108,989	1,233,802	1,086,669	1,137,424

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2011

RRR Part 1
Trial Balance Mapped to Financial Statement Grouping
2.1.13

Account	Description	RRR = Financial Statements December 2011	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1005	Cash	6,613,730.78				6,613,730.78		
1010	Cash Advance and Working Funds	2,310.40	6,616,041.18			2,310.40	6,616,041.18	
1100	Custom Accounts Receivable	9,959,522.01				9,959,522.01		
1104	Accounts Receivable - Recoverable Work	1,165,828.23				1,165,828.23		
1110	Other Accounts Receivable	1,287,656.05				1,287,656.05		
1130	Accumulated Provision for Uncollectible Accts	(665,012.20)	11,747,994.09			(665,012.20)	11,747,994.09	
1120	Accrued Utility Revenues	11,521,416.73	11,521,416.73			11,521,416.73	11,521,416.73	
1200	Accounts Receivable from Associated Companies	29,885.57	29,885.57			29,885.57	29,885.57	
2294	Accrual for Taxes,"Payments in Lieu"of Taxes	1,775,399.25	1,775,399.25			1,775,399.25	1,775,399.25	
1180	Prepayments	914,130.16				914,130.16		
1606	Organization	1,926.45	916,056.61			1,926.45	916,056.61	
1330	Plant Materials and Operating Supplies	1,567,172.03	1,567,172.03	34,173,965.46		1,567,172.03	1,567,172.03	34,173,965.46
1705	Land	82,347.02				82,347.02		
1708	Buildings and Fixtures	3,693,130.15				3,693,130.15		
1715	Station Equipment	2,726,687.83				2,726,687.83		
1735	Underground Conduit	1,090.59				1,090.59		
1740	Underground Conductors and Devices	138,793.40				138,793.40		
1805	Land	424,925.77				424,925.77		
1806	Land Rights	1,598,170.68				1,598,170.68		
1808	Buildings and Fixtures	111,638.13				111,638.13		
1815	Transformer Station Equipment - Normally Primary	42,298.60				42,298.60		
1820	Distribution Station Equipment - Normally Primary	5,783,875.84				5,783,875.84		
1830	Poles, Towers and Fixtures	32,386,043.17				32,386,043.17		
1835	Overhead Conductors and Devices	34,623,385.00				34,623,385.00		
1840	Underground Conduit	11,962,394.76				11,962,394.76		
1845	Underground Conductors and Devices	58,652,494.85				58,652,494.85		
1850	Line Transformers	32,882,342.10				32,882,342.10		
1855	Services	4,191,988.92				4,191,988.92		
1860	Meters	6,609,164.31				6,609,164.31		
1865	Other Installations on Customer's Premises	439.87				439.87		
1875	Street Lighting and Signal Systems	21,835.21				21,835.21		
1905	Land	508,969.83				508,969.83		
1908	Buildings and Fixtures	12,580,150.65				12,580,150.65		
1910	Leasehold Improvements	120,252.32				120,252.32		
1915	Office Furniture and Equipment	1,211,189.44				1,211,189.44		
1920	Computer Equipment-Hardware	3,130,611.67				3,130,611.67		
1925	Computer Software	2,363,533.57				2,363,533.57		
1930	Transportation Equipment	6,444,483.98				6,444,483.98		
1935	Stores Equipment	236,413.92				236,413.92		
1940	Tools, Shop and Garage Equipment	1,738,842.83				1,738,842.83		
1945	Measurement and Testing Equipment	204,006.18				204,006.18		
1955	Communication Equipment	170,581.47				170,581.47		
1960	Miscellaneous Equipment	72,951.31				72,951.31		
1980	System Supervisory Equipment	128,960.64				128,960.64		

	RRR = Financial Statements December 2011	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
1995 Contributions and Grants - Credit	(19,052,603.13)				(19,052,603.13)		
2005 Property Under Capital Leases	143,036.00				143,036.00		
2060 Electric Plant Acquisition Adjustment	142,276.60				142,276.60		
2065 Other Electric Plant Adjustment	45,509,515.44			(45,509,515.44)	0.00		
2105 Accumulated Amortization of Electric Utility-Plant	(104,858,659.13)				(104,858,659.13)		
2140 Accumulated Amortization of Electric Plant	(142,276.60)				(142,276.60)		
2160 Accumulated Amortization of Other Utility Plant	(28,442,637.01)	118,142,646.18	118,142,646.18	28,442,637.01	0.00	101,075,767.75	101,075,767.75
2296 Future Income Taxes - Current	1,631,862.67	1,631,862.67	1,631,862.67		1,631,862.67	1,631,862.67	1,631,862.67
2205 Accounts Payable	(16,357,697.34)				(16,357,697.34)		
2220 Miscellaneous Current and Accrued Liabilities	0.00				0.00		
2250 Debt Retirement Charges DRC payable	(687,955.76)				(687,955.76)		
2290 Commodity Taxes	1,231,744.53				1,231,744.53		
2292 Payroll Deductions/Expenses Payable	(981.75)				(981.75)		
2425 Other Deferred Credits	(1,236,019.33)	(17,050,909.65)			(1,236,019.33)	(17,050,909.65)	
2210 Current portion of Customer deposits	(703,755.01)	(703,755.01)			(703,755.01)	(703,755.01)	
2240 Accounts Payable to Associated Companies	(7,057,379.57)	(7,057,379.57)			(7,057,379.57)	(7,057,379.57)	
2260 Current Portion of Long Term Debt	(2,211,518.55)	(2,211,518.55)	(27,023,562.78)		(2,211,518.55)	(2,211,518.55)	(27,023,562.78)
2520 Other Long Term debt	(22,000,000.00)				(22,000,000.00)		
2525 Term Bank Loans-long term Portion	(11,422,756.72)				(11,422,756.72)		
2550 Advances from Associated Companies	(3,605,089.72)	(37,027,846.44)			(3,605,089.72)	(37,027,846.44)	
2320 Other Miscellaneous Non-current liabilities	(37,334.17)				(37,334.17)		
2335 Long Term Customer Deposits	(703,755.01)	(741,089.18)			(703,755.01)	(741,089.18)	
2310 Vested Sick Leave Liability	(196,737.65)	(196,737.65)			(196,737.65)	(196,737.65)	
2306 Employee Future Benefits	(3,710,564.00)	(3,710,564.00)			(3,710,564.00)	(3,710,564.00)	
1550 Hydro One Low Voltage Variance	(562,200.61)				(562,200.61)		
1580 RSVA - WMS	(2,878,122.73)				(2,878,122.73)		
1582 RSVA - One Time	0.00				0.00		
1584 RSVA - NW	1,542,808.02				1,542,808.02		
1586 RSVA - CN	(570,089.47)				(570,089.47)		
1588 RSVA - Power	(1,194,482.34)				(1,194,482.34)		
1518 RCVA - Retail	75,273.55				75,273.55		
1548 RCVA - STR	98,025.00				98,025.00		
1508 Other Regulatory Assets	14,100.14				14,100.14		
1562 Deferred Payments in Lieu of taxes	(2,360,135.97)				(2,360,135.97)		
1563 Deferred PILS contra Account	2,360,135.97				2,360,135.97		
1535 Smart Grid Deferral Account	18,720.96				18,720.96		
1555 Smart Meter Capital and Recovery Variance	510,738.84				510,738.84		
1556 Smart Meter OM&A Variance	644,087.73				644,087.73		
1521 Special Purpose Charge	(51,747.68)				(51,747.68)		
1595 Disposition and Recovery of Regulatory Balances	(1,411,826.16)	(3,764,714.75)	(45,440,952.02)		(1,411,826.16)	(3,764,714.75)	(45,440,952.02)
3005 Common Shares Issued	(31,245,882.02)	(31,245,882.02)			(31,245,882.02)	(31,245,882.02)	
3010 Contributed Surplus	(18,753,902.09)			18,753,902.09	0.00		
3047 Appropriations of Retained Earnings - current	(6,705,305.00)	(25,459,207.09)			(6,705,305.00)	(6,705,305.00)	
3040 Appropriated Retained Earnings	(22,966,981.39)			(600,354.87)	(23,567,336.26)		
3046 Balance Transferred from Income	(2,311,889.01)			(1,086,668.79)	(3,398,557.80)		
3049 Dividends payable - Common Shares	500,000.00	(24,778,870.40)	(81,483,959.51)		500,000.00	(26,465,894.06)	(64,417,081.08)
Balance Sheet	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

	RRR = Financial Statements December 2011	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
Income Statement							
4006 Residential Energy Sales	(31,645,633.17)				(31,645,633.17)		
4010 Commercial Energy Sales	(10,420,511.75)				(10,420,511.75)		
4025 Streetlighting energy sales	(509,904.40)				(509,904.40)		
4030 Sentinel Lighting Energy Sales	(16,509.06)				(16,509.06)		
4035 General Energy Sales	(49,468,079.34)	(92,060,637.72)			(49,468,079.34)	(92,060,637.72)	
4062 Billed WMS	(8,462,016.27)				(8,462,016.27)		
4066 Billed NW	(7,793,522.02)				(7,793,522.02)		
4068 Billed CN	(5,675,465.08)				(5,675,465.08)		
4075 Billed - LV	(651,040.22)	(22,582,043.59)			(651,040.22)	(22,582,043.59)	
4080 Distribution Services Revenue	(27,107,094.04)	(27,107,094.04)			(27,107,094.04)	(27,107,094.04)	
4082 Retail Services Revenue	(68,150.30)				(68,150.30)		
4084 Service Transaction Requests (STR) Revenues	(1,898.00)	(70,048.30)	(141,819,823.65)		(1,898.00)	(70,048.30)	(141,819,823.65)
4705 Power Purchased	92,060,637.82				92,060,637.82		
4708 Charges -WMS	8,462,016.27				8,462,016.27		
4714 Charges -NW	7,793,522.02				7,793,522.02		
4716 Charges -CN	5,675,465.11				5,675,465.11		
4750 Charges - LV	651,040.09	114,642,681.31	114,642,681.31		651,040.09	114,642,681.31	114,642,681.31
4215 Other Utility Operating Income	(43,664.13)				(43,664.13)		
4225 Late Payment Charges	(419,155.16)				(419,155.16)		
4355 Gain on Disposition of Utility and Other Property	(16,396.90)				(16,396.90)		
4375 Revenues from Non-Utility Operations	(1,334,964.36)				(1,334,964.36)		
4235 Miscellaneous Service Revenues	(874,868.36)				(874,868.36)		
4380 Expenses from Non-Utility Operations	788,595.83			348,090.24	1,136,686.07		
4390 Miscellaneous Non-Operating Income	(58,882.00)				(58,882.00)		
4405 Interest and Dividend Income	(140,672.73)	(2,100,007.81)	(2,100,007.81)		(140,672.73)	(1,751,917.57)	(1,751,917.57)
5005 Operation Supervision and Engineering	689,564.98				689,564.98		
5010 Load Dispatching	42,648.00				42,648.00		
5012 Station Buildings and fixtures expense	69,484.02				69,484.02		
5014 Transformer Station Equipment - Operation Labour	7,209.76				7,209.76		
5015 Transformer Station Equipment - Operation	101,958.15				101,958.15		
5020 Overhead Distribution Lines and Feeders -Labour	214,469.12				214,469.12		
5025 Overhead Distribution Lines and Feeders - Operation ex	7,082.23				7,082.23		
5040 Underground Distribution Lines and Feeders Labour	86,497.56				86,497.56		
5045 Underground Distribution Lines and Feeders - expenses	247,129.85				247,129.85		
5065 Meter Expense	608,449.28				608,449.28		
5085 Miscellaneous Distribution Expenses	1,896,259.00				1,896,259.00		
5105 Maintenance Supervision and Engineering	464,601.84				464,601.84		
5114 Maintenance of Distribution Station Equipment	2,761.57				2,761.57		
5120 Maintenance of Poles, Towers and Fixtures	162,672.43				162,672.43		
5125 Maintenance of Overhead Conductors and Devices	742,311.34				742,311.34		
5130 Maintenance of Overhead Services	158,630.56				158,630.56		
5135 Overhead Distribution Lines and Feeders - Right of Way	256,403.03				256,403.03		
5145 Maintenance of Underground Conduit	31,457.19				31,457.19		
5150 Maintenance of Underground Conductors & Devices	191,439.98				191,439.98		
5155 Maintenance of Underground Services	122,745.45				122,745.45		
5160 Maintenance of Line Transformers	68,848.92				68,848.92		
5175 Maintenance of Meters	7,908.61	6,180,532.87			7,908.61	6,180,532.87	6,180,532.87

	RRR = Financial Statements December 2011	Balance Sheet	Audited Actual Balance Sheet Total	Adjustments for FMV entry and Water	RRR filed restated for Regulatory	Balance Sheet restated for Regulatory	Balance Sheet restated for Regulatory
5070 Customer Premises - Operation Labour	101,234.87				101,234.87		
5410 Community Relations - Sundry	60,687.34	161,922.21			60,687.34	161,922.21	161,922.21
5605 Executive Salaries and Expenses	370,546.22				370,546.22		
5610 Management Salaries and Expenses	1,868,449.74			(57,193.70)	1,811,256.04		
5615 General Administrative Salaries and Expenses	438,121.27				438,121.27		
5620 Office Supplies and Expenses	101,233.42				101,233.42		
5630 Outside Services Employed	39,600.00				39,600.00		
5635 Property Insurance	241,376.39				241,376.39		
5655 Regulatory Expenses	239,075.23				239,075.23		
5665 Miscellaneous General Expense	51,819.09				51,819.09		
5675 Maintenance of General Plant	556,909.52				556,909.52		
6005 Interest on Long Term Debt	2,344,250.22				2,344,250.22		
6030 Interest on Debt to Associated Companies	261,369.00				261,369.00		
6035 Other Interest Expense	262,897.75				262,897.75		
6105 Taxes other that Income Taxes	0.00				0.00		
6205 Donations	38,906.00	6,814,553.85			38,906.00	6,757,360.15	6,757,360.15
5305 Supervision	486,752.49				486,752.49		
5310 Meter Reading Expense	362,810.19				362,810.19		
5315 Customer Billing	2,276,204.06			(272,788.54)	2,003,415.52		
5320 Collecting	450,651.84				450,651.84		
5325 Collecting - Cash Over and Short	128.83				128.83		
5335 Bad Debt Expense	330,712.76				330,712.76		
5340 Miscellaneous Customer Accounts Expense	241,522.39	4,148,782.56			241,522.39	3,875,994.02	3,875,994.02
5705 Amortization Expense - Property Plant and Equipment	7,230,524.75	7,230,524.75		(18,108.00)	7,212,416.75	7,212,416.75	7,212,416.75
5715 Amortization of Intangibles and Other Electric	1,086,668.79	1,086,668.79		(1,086,668.79)	0.00	0.00	0.00
			25,622,985.03		0.00		
6110 Income Taxes	189,740.00				189,740.00		
6115 Provision for Future Income Taxes	1,152,536.11	1,342,276.11	1,342,276.11		1,152,536.11	1,342,276.11	1,342,276.11
Income Statement total	**(2,311,889.01)**	**(2,311,889.01)**	**(2,311,889.01)**	**(1,086,668.79)**	**(3,398,557.80)**	**(3,398,557.80)**	**(3,398,557.80)**
Trial Balance Summary							
Revenues	(143,919,831.46)	(143,919,831.46)	(143,919,831.46)	348,090.24	(143,571,741.22)	(143,571,741.22)	(143,571,741.22)
Expenses	141,607,942.45	141,607,942.45	141,607,942.45	(1,434,759.03)	140,173,183.42	140,173,183.42	140,173,183.42
(Profit)/Loss	(2,311,889.01)	(2,311,889.01)	(2,311,889.01)	(1,086,668.79)	(3,398,557.80)	(3,398,557.80)	(3,398,557.80)
Net Assets	236,057,105.01	30,265,714.13	(9,635,123.89)	0.00	236,057,105.01	30,265,714.13	(9,635,123.89)
Net Liabilities and Equity	(236,057,105.01)	(30,265,714.13)	9,635,123.89	0.00	(236,057,105.01)	(30,265,714.13)	9,635,123.89
IS (Profit)/Loss	(2,311,889.01)	(2,311,889.01)	(2,311,889.01)	(1,086,668.79)	(3,398,557.80)	(3,398,557.80)	(3,398,557.80)
Balance Sheet (profit)/Loss	(2,311,889.01)	(2,311,889.01)	(2,311,889.01)	(1,086,668.79)	(3,398,557.80)	(3,398,557.80)	(3,398,557.80)

Niagara Peninsula Energy Inc.
For the Twelve Months Ending December 31, 2011
RRR Part 2
Trial Balance by Account
2.1.13

	Balance Sheet Section	Balance Sheet Line Grouping	RRR Financial Statement December 2011	Adjustment for FMV entry and Water	Filed RRR restated for FMV removal
Current Assets					
1005 Cash	Current Asset	Cash	6,613,730.78		6,613,730.78
1010 Cash Advance and Working Funds	Current Asset	Cash	2,310.40		2,310.40
1100 Custom Accounts Receivable	Current Asset	Accounts Receivable	9,959,522.01		9,959,522.01
1104 Accounts Receivable - Recoverable Work	Current Asset	Accounts Receivable	1,165,828.23		1,165,828.23
1110 Other Accounts Receivable	Current Asset	Accounts Receivable	1,287,656.05		1,287,656.05
1120 Accrued Utility Revenues	Current Asset	Unbilled Revenue	11,521,416.73		11,521,416.73
1130 Accumulated Provision for Uncollectible Accts	Current Asset	Accounts Receivable	(665,012.20)		(665,012.20)
1180 Prepayments	Current Asset	Prepaids	914,130.16		914,130.16
1200 Accounts Receivable from Associated Companies	Current Asset	Due from affiliated companies	29,885.57		29,885.57
1330 Plant Materials and Operating Supplies	Current Asset	Inventory	1,567,172.03		1,567,172.03
1508 Other Regulatory Assets	Long Term Liabilities	Other Regulatory Assets	14,100.14		14,100.14
1518 RCVA - Retail	Long Term Liabilities	Retail Cost Variances	75,273.55		75,273.55
1521 Special Purpose Charge	Long Term Liabilities	Special Purpose Charge	(51,747.68)		(51,747.68)
1535 Smart Grid Deferral Account	Long Term Liabilities	Smart Grid Deferral (Green Energy Act)	18,720.96		18,720.96
1548 RCVA - STR	Long Term Liabilities	Retail Cost Variances	98,025.00		98,025.00
1550 Hydro One Low Voltage Variance	Long Term Liabilities	Retail Settlement Variances	(562,200.61)		(562,200.61)
1555 Smart Meter Capital and Recovery Variance	Long Term Liabilities	Smart Meter recovery variances	510,738.84		510,738.84
1556 Smart Meter OM&A Variance	Long Term Liabilities	Smart Meter recovery variances	644,087.73		644,087.73
1562 Deferred Payments in Lieu of taxes	Long Term Liabilities	Other Regulatory Assets	(2,360,135.97)		(2,360,135.97)
1563 Deferred PILS contra Account	Long Term Liabilities	Other Regulatory Assets	2,360,135.97		2,360,135.97
1580 RSVA - WMS	Long Term Liabilities	Retail Settlement Variances	(2,878,122.73)		(2,878,122.73)
1582 RSVA - One Time	Long Term Liabilities	Retail Settlement Variances	0.00		0.00
1584 RSVA - NW	Long Term Liabilities	Retail Settlement Variances	1,542,808.02		1,542,808.02
1586 RSVA - CN	Long Term Liabilities	Retail Settlement Variances	(570,089.47)		(570,089.47)
1588 RSVA - Power	Long Term Liabilities	Retail Settlement Variances	(1,194,482.34)		(1,194,482.34)
1595 Disposition and Recovery of Regulatory Balances	Long Term Liabilities	Retail Cost Variances	(1,411,826.16)		(1,411,826.16)
1606 Organization	Current Asset	Prepaids	1,926.45		1,926.45
1705 Land	Fixed Assets	Property and equipment	82,347.02		82,347.02
1708 Buildings and Fixtures	Fixed Assets	Property and equipment	3,693,130.15		3,693,130.15
1715 Station Equipment	Fixed Assets	Property and equipment	2,726,687.83		2,726,687.83
1735 Underground Conduit	Fixed Assets	Property and equipment	1,090.59		1,090.59
1740 Underground Conductors and Devices	Fixed Assets	Property and equipment	138,793.40		138,793.40
1805 Land	Fixed Assets	Property and equipment	424,925.77		424,925.77
1806 Land Rights	Fixed Assets	Property and equipment	1,598,170.68		1,598,170.68
1808 Buildings and Fixtures	Fixed Assets	Property and equipment	111,638.13		111,638.13
1815 Transformer Station Equipment - Normally Primary	Fixed Assets	Property and equipment	42,298.60		42,298.60
1820 Distribution Station Equipment - Normally Primary	Fixed Assets	Property and equipment	5,783,875.84		5,783,875.84
1830 Poles, Towers and Fixtures	Fixed Assets	Property and equipment	32,386,043.17		32,386,043.17
1835 Overhead Conductors and Devices	Fixed Assets	Property and equipment	34,623,385.00		34,623,385.00
1840 Underground Conduit	Fixed Assets	Property and equipment	11,962,394.76		11,962,394.76
1845 Underground Conductors and Devices	Fixed Assets	Property and equipment	58,652,494.85		58,652,494.85
1850 Line Transformers	Fixed Assets	Property and equipment	32,882,342.10		32,882,342.10
1855 Services	Fixed Assets	Property and equipment	4,191,988.92		4,191,988.92
1860 Meters	Fixed Assets	Property and equipment	6,609,164.31		6,609,164.31

1865	Other Installations on Customer's Premises	Fixed Assets	Property and equipment	439.87		439.87
1875	Street Lighting and Signal Systems	Fixed Assets	Property and equipment	21,835.21		21,835.21
1905	Land	Fixed Assets	Property and equipment	508,969.83		508,969.83
1908	Buildings and Fixtures	Fixed Assets	Property and equipment	12,580,150.65		12,580,150.65
1910	Leasehold Improvements	Fixed Assets	Property and equipment	120,252.32		120,252.32
1915	Office Furniture and Equipment	Fixed Assets	Property and equipment	1,211,189.44		1,211,189.44
1920	Computer Equipment-Hardware	Fixed Assets	Property and equipment	3,130,611.67		3,130,611.67
1925	Computer Software	Fixed Assets	Property and equipment	2,363,533.57		2,363,533.57
1930	Transportation Equipment	Fixed Assets	Property and equipment	6,444,483.98		6,444,483.98
1935	Stores Equipment	Fixed Assets	Property and equipment	236,413.92		236,413.92
1940	Tools, Shop and Garage Equipment	Fixed Assets	Property and equipment	1,738,842.83		1,738,842.83
1945	Measurement and Testing Equipment	Fixed Assets	Property and equipment	204,006.18		204,006.18
1955	Communication Equipment	Fixed Assets	Property and equipment	170,581.47		170,581.47
1960	Miscellaneous Equipment	Fixed Assets	Property and equipment	72,951.31		72,951.31
1980	System Supervisory Equipment	Fixed Assets	Property and equipment	128,960.64		128,960.64
1995	Contributions and Grants - Credit	Fixed Assets	Property and equipment	(19,052,603.13)		(19,052,603.13)
2005	Property Under Capital Leases	Fixed Assets	Property and equipment	143,036.00		143,036.00
2060	Electric Plant Acquisition Adjustment	Fixed Assets	Property and equipment	142,276.60		142,276.60
2065	Other Electric Plant Adjustment	Fixed Assets	Property and equipment	45,509,515.44	(45,509,515.44)	0.00
2105	Accumulated Amortization of Electric Utility-Plant	Fixed Assets	Property and equipment	(104,858,659.13)		(104,858,659.13)
2140	Accumulated Amortization of Electric Plant	Fixed Assets	Property and equipment	(142,276.60)		(142,276.60)
2160	Accumulated Amortization of Other Utility Plant	Fixed Assets	Property and equipment	(28,442,637.01)	28,442,637.01	0.00
2205	Accounts Payable	Current Liabilities	Accounts Payable and accrued liabilities	(16,357,697.34)		(16,357,697.34)
2210	Current portion of Customer deposits	Current Liabilities	Current portion of customer deposits	(703,755.01)		(703,755.01)
2220	Miscellaneous Current and Accrued Liabilities	Current Liabilities	Accounts Payable and accrued liabilities	0.00		0.00
2240	Accounts Payable to Associated Companies	Current Liabilities	Due to affiliated companies	(7,057,379.57)		(7,057,379.57)
2250	Debt Retirement Charges DRC payable	Current Liabilities	Accounts Payable and accrued liabilities	(687,955.76)		(687,955.76)
2260	Current Portion of Long Term Debt	Current Liabilities	Current portion of long term debt	(2,211,518.55)		(2,211,518.55)
2290	Commodity Taxes	Current Liabilities	Accounts Payable and accrued liabilities	1,231,744.53		1,231,744.53
2292	Payroll Deductions/Expenses Payable	Current Liabilities	Accounts Payable and accrued liabilities	(981.75)		(981.75)
2294	Accrual for Taxes,"Payments in Lieu"of Taxes	Current Asset	PILS income taxes receivable	1,775,399.25		1,775,399.25
2296	Future Income Taxes - Current	Future payment in lieu	Future payment in lieu of taxes	1,631,862.67		1,631,862.67
2306	Employee Future Benefits	Long Term Liabilities	Employee future benefits	(3,710,564.00)		(3,710,564.00)
2310	Vested Sick Leave Liability	Long Term Liabilities	Employees' accumulated vested sick leave	(196,737.65)		(196,737.65)
2320	Other Miscellaneous Non-current liabilities	Long Term Liabilities	Customer deposits	(37,334.17)		(37,334.17)
2335	Long Term Customer Deposits	Long Term Liabilities	Customer deposits	(703,755.01)		(703,755.01)
2425	Other Deferred Credits	Current Liabilities	Accounts Payable and accrued liabilities	(1,236,019.33)		(1,236,019.33)
2520	Other Long Term debt	Long Term Liabilities	Long term debt	(22,000,000.00)		(22,000,000.00)
2525	Term Bank Loans-long term Portion	Long Term Liabilities	Long term debt	(11,422,756.72)		(11,422,756.72)
2550	Advances from Associated Companies	Long Term Liabilities	Long term debt	(3,605,089.72)		(3,605,089.72)
3005	Common Shares Issued	Shareholders Equity	Share Capital	(31,245,882.02)		(31,245,882.02)
3010	Contributed Surplus	Shareholders Equity	Contributed surplus	(18,753,902.09)	18,753,902.09	0.00
3040	Appropriated Retained Earnings	Shareholders Equity	Contributed surplus	(22,966,981.39)	(600,354.87)	(23,567,336.26)
3046	Balance Transferred from Income	Shareholders Equity	Retained Earnings	(2,311,889.01)	(1,086,668.79)	(3,398,557.80)
3047	Appropriations of Retained Earnings - current	Shareholders Equity	Retained Earnings	(6,705,305.00)		(6,705,305.00)
3049	Dividends payable - Common Shares	Shareholders Equity	Retained Earnings	500,000.00		500,000.00
Balance Sheet				0.00	0.00	0.00

Income Statement	Income Statement Section	Income Statement Line Grouping	RRR Financial Statement December 2011	Adjustment for FMV entry and Water	Filed RRR restated for FMV removal
4006 Residential Energy Sales	Service Revenue	Standard supply charge	(31,645,633.17)		(31,645,633.17)
4010 Commercial Energy Sales	Service Revenue	Standard supply charge	(10,420,511.75)		(10,420,511.75)
4025 Streetlighting energy sales	Service Revenue	Standard supply charge	(509,904.40)		(509,904.40)
4030 Sentinel Lighting Energy Sales	Service Revenue	Standard supply charge	(16,509.06)		(16,509.06)
4035 General Energy Sales	Service Revenue	Standard supply charge	(49,468,079.34)		(49,468,079.34)
4062 Billed WMS	Service Revenue	Wholesale, network, and connection charge	(8,462,016.27)		(8,462,016.27)
4066 Billed NW	Service Revenue	Wholesale, network, and connection charge	(7,793,522.02)		(7,793,522.02)
4068 Billed CN	Service Revenue	Wholesale, network, and connection charge	(5,675,465.08)		(5,675,465.08)
4075 Billed - LV	Service Revenue	Wholesale, network, and connection charge	(651,040.22)		(651,040.22)
4080 Distribution Services Revenue	Service Revenue	Service charge,Distribution volumetric & SSS admin	(27,107,094.04)		(27,107,094.04)
4082 Retail Services Revenue	Service Revenue	Retailer Revenue	(68,150.30)		(68,150.30)
4084 Service Transaction Requests (STR) Revenues	Service Revenue	Retailer Revenue	(1,898.00)		(1,898.00)
4215 Other Utility Operating Income	Other Revenue	Other Revenue	(43,664.13)		(43,664.13)
4225 Late Payment Charges	Other Revenue	Other Revenue	(419,155.16)		(419,155.16)
4235 Miscellaneous Service Revenues	Other Revenue	Other Revenue	(874,868.36)		(874,868.36)
4355 Gain on Disposition of Utility and Other Property	Other Revenue	Other Revenue	(16,396.90)		(16,396.90)
4375 Revenues from Non-Utility Operations	Other Revenue	Other Revenue	(1,334,964.36)		(1,334,964.36)
4380 Expenses from Non-Utility Operations	Other Revenue	Other Revenue	788,595.83	348,090.24	1,136,686.07
4390 Miscellaneous Non-Operating Income	Other Revenue	Other Revenue	(58,882.00)		(58,882.00)
4405 Interest and Dividend Income	Other Revenue	Other Revenue	(140,672.73)		(140,672.73)
4705 Power Purchased	Cost of Power	Power Purchased	92,060,637.82		92,060,637.82
4708 Charges -WMS	Cost of Power	Power Purchased	8,462,016.27		8,462,016.27
4714 Charges -NW	Cost of Power	Power Purchased	7,793,522.02		7,793,522.02
4716 Charges -CN	Cost of Power	Power Purchased	5,675,465.11		5,675,465.11
4750 Charges - LV	Cost of Power	Power Purchased	651,040.09		651,040.09
5005 Operation Supervision and Engineering	Expenses	Distribution	689,564.98		689,564.98
5010 Load Dispatching	Expenses	Distribution	42,648.00		42,648.00
5012 Station Buildings and fixtures expense	Expenses	Distribution	69,484.02		69,484.02
5014 Transformer Station Equipment - Operation Labour	Expenses	Distribution	7,209.76		7,209.76
5015 Transformer Station Equipment - Operation	Expenses	Distribution	101,958.15		101,958.15
5020 Overhead Distribution Lines and Feeders -Labour	Expenses	Distribution	214,469.12		214,469.12
5025 Overhead Distribution Lines and Feeders - Operation expen:	Expenses	Distribution	7,082.23		7,082.23
5040 Underground Distribution Lines and Feeders Labour	Expenses	Distribution	86,497.56		86,497.56
5045 Underground Distribution Lines and Feeders - expenses	Expenses	Distribution	247,129.85		247,129.85
5065 Meter Expense	Expenses	Distribution	608,449.28		608,449.28
5070 Customer Premises - Operation Labour	Expenses	Utilization	101,234.87		101,234.87
5085 Miscellaneous Distribution Expenses	Expenses	Distribution	1,896,259.00		1,896,259.00
5105 Maintenance Supervision and Engineering	Expenses	Distribution	464,601.84		464,601.84
5114 Maintenance of Distribution Station Equipment	Expenses	Distribution	2,761.57		2,761.57
5120 Maintenance of Poles, Towers and Fixtures	Expenses	Distribution	162,672.43		162,672.43
5125 Maintenance of Overhead Conductors and Devices	Expenses	Distribution	742,311.34		742,311.34
5130 Maintenance of Overhead Services	Expenses	Distribution	158,630.56		158,630.56
5135 Overhead Distribution Lines and Feeders - Right of Way	Expenses	Distribution	256,403.03		256,403.03
5145 Maintenance of Underground Conduit	Expenses	Distribution	31,457.19		31,457.19
5150 Maintenance of Underground Conductors & Devices	Expenses	Distribution	191,439.98		191,439.98
5155 Maintenance of Underground Services	Expenses	Distribution	122,745.45		122,745.45
5160 Maintenance of Line Transformers	Expenses	Distribution	68,848.92		68,848.92
5175 Maintenance of Meters	Expenses	Distribution	7,908.61		7,908.61
5305 Supervision	Expenses	Billing and collecting	486,752.49		486,752.49
5310 Meter Reading Expense	Expenses	Billing and collecting	362,810.19		362,810.19
5315 Customer Billing	Expenses	Billing and collecting	2,276,204.06	(272,788.54)	2,003,415.52

5320 Collecting	Expenses	Billing and collecting	450,651.84		450,651.84
5325 Collecting - Cash Over and Short	Expenses	Billing and collecting	128.83		128.83
5335 Bad Debt Expense	Expenses	Billing and collecting	330,712.76		330,712.76
5340 Miscellaneous Customer Accounts Expense	Expenses	Billing and collecting	241,522.39		241,522.39
5410 Community Relations - Sundry	Expenses	Utilization	60,687.34		60,687.34
5605 Executive Salaries and Expenses	Expenses	Administrative and general	370,546.22		370,546.22
5610 Management Salaries and Expenses	Expenses	Administrative and general	1,868,449.74	(57,193.70)	1,811,256.04
5615 General Administrative Salaries and Expenses	Expenses	Administrative and general	438,121.27		438,121.27
5620 Office Supplies and Expenses	Expenses	Administrative and general	101,233.42		101,233.42
5630 Outside Services Employed	Expenses	Administrative and general	39,600.00		39,600.00
5635 Property Insurance	Expenses	Administrative and general	241,376.39		241,376.39
5655 Regulatory Expenses	Expenses	Administrative and general	239,075.23		239,075.23
5665 Miscellaneous General Expense	Expenses	Administrative and general	51,819.09		51,819.09
5675 Maintenance of General Plant	Expenses	Administrative and general	556,909.52		556,909.52
5705 Amortization Expense - Property Plant and Equipment	Expenses	Depreciation	7,230,524.75	(18,108.00)	7,212,416.75
5715 Amortization of Intangibles and Other Electric	Expenses	Depreciation expense on fair market value adj	1,086,668.79	(1,086,668.79)	0.00
6005 Interest on Long Term Debt	Expenses	Administrative and general	2,344,250.22		2,344,250.22
6030 Interest on Debt to Associated Companies	Expenses	Administrative and general	261,369.00		261,369.00
6035 Other Interest Expense	Expenses	Administrative and general	262,897.75		262,897.75
6105 Taxes other that Income Taxes	Expenses	Administrative and general	0.00		0.00
6110 Income Taxes	Payments in Lieu of Income Taxes	Current	189,740.00		189,740.00
6115 Provision for Future Income Taxes	Payments in Lieu of Income Taxes	Future Reduction	1,152,536.11		1,152,536.11
6205 Donations	Expenses	Administrative and general	38,906.00		38,906.00
Income Statement total			**(2,311,889.01)**	**(1,086,668.79)**	**(3,398,557.80)**

Trial Balance Summary			
Revenues	(143,919,831.46)	348,090.24	(143,571,741.22)
Expenses	141,607,942.45	(1,434,759.03)	140,173,183.42
(Profit)/Loss	(2,311,889.01)	(1,086,668.79)	(3,398,557.80)
Net Assets	236,057,105.01	0.00	236,057,105.01
Net Liabilities and Equity	(236,057,105.01)	0.00	(236,057,105.01)
IS (Profit)/Loss	(2,311,889.01)	(1,086,668.79)	(3,398,557.80)
Balance Sheet (profit)/Loss	(2,311,889.01)	(1,086,668.79)	(3,398,557.80)

Niagara Peninsula Energy Inc.
FMV Bump
2.1.13

Balance Sheet

		2007 FMV entry	Entry hits Retained Earnings	2007 FMV entry summary	2008	2009	2010	2011	2011 Net Adjustment on RRR to RE
1	PWU AR PWPower	(216,069.30)	216,069.30						
1	Due from PW power	1,400,000.00	(1,400,000.00)						
1	Future PILS	(5,168,552.00)	5,168,552.00						
1	Inventory	7,684.34	(7,684.34)						
	Fixed assets Total FMV Bump	45,735,559.44		45,735,559.44	45,735,559.44	45,735,559.44	45,735,559.44		
	Adjustment for PW software				-	-	(226,044.00)		
							45,509,515.44	45,509,515.44	
	Accum Deprec Total FMV Bump	(24,083,153.39)		(24,083,153.39)	(24,083,153.39)	(25,239,221.08)	(26,348,210.08)	(27,355,968)	
	Adjustment for PW software						226,044		
	Current year depreciation				(1,156,068)	(1,108,989)	(1,233,802)	(1,086,669)	
					(25,239,221)	(26,348,210)	(27,355,968)	(28,442,637)	
	Contributed Surplus	(18,753,902.09)		(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	(18,753,902.09)	
1	Retained Earnings	1,078,433.00	(1,078,433.00)	-					
sum of 1's	Retained Earnings net adjustment		(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	(2,898,503.96)	
	Cummulative impact on RE for Depreciation FMV bump				1,156,068	2,265,057	3,498,859	3,498,859	600,354.73
	Depreciation expense to be closed to Cummulative impact on RE							1,086,669	
	Net	(0.00)	-	-	(0.00)	(0.00)	(0.00)	(0.00)	

Income Statement

	2008	2009	2010	2011
Depreciation expense FMV bump	1,156,068	1,111,638	1,233,802	1,086,669
Adjust depreciation expense FMV bump	0	-2649	0	0
	1,156,068	1,108,989	1,233,802	1,086,669

Attachment 3 of 3

Annual Report

Annual Report

NPEI does not prepare an annual report. NPEI prepares a capital and operating budget each year which includes projected capital expenditures for the current year and a capital budget for the upcoming year. The Balance Sheet, Income Statement, Statement of Changes and Statement of Retained earnings are presented in the budget including the projections for the current year and the budget for the following year. The budget also includes a budget report and overall summary. The budget is approved first by senior management and then presented to the Finance Committee. Upon approval from the Finance Committee the budget is presented to NPEI's Board of Directors for approval.

NPEI has included as an attachment the 2014 Annual Budget for capital and operating expenditures.

Attachment 1 of 2

2014 Capital and Operating Budgets

niagara peninsula energy

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2014 BUDGET

- **2013 Projected Capital**
- **2013 Projected Financial Statements**
- **2014 Capital Budget**
- **2014 Operating Budget**

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Niagara Peninsula Energy Inc.
Budget Report 2014

This report is prepared for the purpose of reviewing the significant factors affecting the 2013 and 2014 projected and budget financial statements respectively.

Please note the presentation of the projected and budget financial statements vary from the external audited financial statements in order to provide enhanced detail.

Basis of Presentation

The 2014 Budget Balance Sheet and Budget Income Statement with 2013 comparative figures have been prepared using the Canadian Generally Accepted Accounting Principals (CGAAP). There have been no adjustments made for the International Financial Reporting Standards (IFRS).

The Accounting Standards Board (AcSB) issued an option for rate regulated entities to defer the implementation of IFRS to January 1, 2013 in March 2012. In July, the Ontario Energy Board issued a Letter of Direction stating "The Board however will require that these changes be mandatory in 2013 (i.e., effective on January 1, 2013) for those distributors that do not elect to make these accounting changes in 2012 regardless of whether the AcSB permits further deferrals beyond 2012 for the changeover to IFRS."

The most significant impact of IFRS to NPEI is the estimated useful lives of fixed assets. IFRS requires a review of an entities policy for estimating fixed asset useful lives to be in accordance with various criteria versus the OEB's policy related to fixed asset useful lives which is 25 years. As a way of achieving the OEB's letter of direction noted above without formally adopting IFRS effective January 1, 2013, many LDC's are opting to change their accounting policy for fixed assets and depreciation effective January 1, 2013 and waiting until the AcSB decides on the issue related to an interim standard for rate regulated entities with regulatory assets and liabilities so they will be eligible as a first-time adopter of this new standard.

The Board authorized a new regulatory variance account to Account for Changes in Accounting under CGAAP so LDC's will be eligible for the IFRS interim standard as first time adopters. This new variance account will record the difference in depreciation expense using the new estimated useful lives of the now componentized fixed asset balances.

The change in useful lives results in a change in Accounting Policy for Fixed Assets and Depreciation with an effective date of January 1, 2013. By adopting this change in accounting for useful lives NPEI achieves the same effect mandated by the OEB as noted above.

In 2012, NPEI completed the componentization and determination of useful lives in accordance with the Board's regulatory accounting policies as set out for modified IFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards,* EB-2008-0408, the Kinectrics Report, and the Revised 2012 *Accounting Procedures Handbook for Electricity Distributors* ("APH") with the assistance of KPMG.

In 2013, NPEI completed the segregation of the opening cost and accumulated depreciation balances due to componentization and recalculated depreciation expense using the new depreciation lives in accordance with the report identified above. The difference between the calculation of depreciation expense using the OEB's 25 year life and the new useful lives was recorded to the new variance account noted above in 2013.

For example, overhead was previously categorized between poles and wires and both were depreciated over 25 years. After componentization of overhead, poles were segregated between wooden poles and concrete poles where wood poles will now have a useful estimated life of 50 years and concrete poles will now have a useful estimated life of 60 years.

The current distribution rates are calculated using the OEB's 25 year life. As a result of componentization and changing the estimated useful lives, the depreciation expense is much lower and net income is much higher. The OEB requires LDC's to record this difference to the new variance account and dispose of its balance the next time the LDC submits its cost of service rate application. An LDC's future rate application will be prepared on the basis of the new estimated useful lives when rates are calculated.

In September 2012, the AcSB issued another option to defer the implementation of IFRS to January 1, 2014. NPEI has opted to defer the implementation of IFRS to January 2014 unless another deferral option is issued by the AcSB and change its accounting policy for fixed assets and depreciation effective January 1, 2013.

As at November 16th, 2013, the AcSB discussed recent international developments including the IASB's tentative decision to proceed with the publication of an interim standard for first-time adopters of IFRS that provides guidance on the accounting for rate-regulated activities until its comprehensive project is completed. Subject to the expected interim standard being issued early in 2014, the AcSB decided against further extending its deferral of the mandatory date for first-time adoption of IFRS by rate-regulated entities. The deferral expires at the end of 2014.

NPEI has prepared the 2013 projected financial statements and the 2014 budgeted financial statements using the new estimated useful lives for fixed assets.

2013 Highlights

2013 Projected Balance Sheet
Total assets are projected at $171M, which is up 6% or $10M from the 2012 total assets.

Cash is projected to be up by $3.0M from 2012. This is mainly due to NPEI obtaining long term financing in December of 2013 in the amount of $10M. NPEI issued a request for proposal (RFP) to five major banks and one credit union in September 2013. One of the banks did not submit a proposal. TD bank was awarded the RFP and will issue NPEI a $10M long term loan for 5 years with only interest repayments. The interest rate at the time of the RFP was 3.15% and may vary from the actual interest rate at the time of issuance in early December 2013.

Accounts receivable are projected to be up by 7% mainly due to the increase in the cost of power, network, connection, wholesale market and global adjustment charges.

Capital Additions 2013
Total gross capital expenditures excluding smart meters are projected at $13.7M, offset by capital contributions of $0.8M for a net of $12.99M. The 2013 capital budget was $14.997M which is $2.0M higher than the projected 2013 expenditures. Due to the weather in the spring of 2013, the yard excavation project was delayed, which in turn delayed the completion of the new wire building and high mast lighting. Therefore, the building workspace optimization phase of the project has been carried forward and included in the 2014 budget. Also, eight vehicles that reached their end of life and have since been replaced were disposed of from the fleet inventory.

The 2013 distribution asset additions are projected to be $32K less than budget.

Significant capital projects completed in 2013 are as follows:

Development Demand	992,081
Pole Replacement	961,365
Murray/Culp/Dunn/Main Rebuilds	714,190
Kiosk replacement program	680,830
High St-Dorchester-Stn 10 O/H	667,605
Sustainment minor projects	638,261
12-M-6 Simcoe/Buckley/Armoury	621,571
Dorchester-Garden-McMillan O/H	261,301
OH to UG Beacon Inn Jordan	260,778
U/G Development Subdivisions	256,055
K-M-2 K-M-6 Extension Montrose	211,363
Switchgear replacement	200,657
Greenlane DS replacement	198,522
July 2013 Storm Damage	180,423

Victoria Avenue Voltage Conversion	172,933
Road relocation-Kalar Road	172,920
U/G install Weightman Bridge	169,072
Metering capital costs	146,298
Stanley Avenue-Church's Lane	144,345
Demand projects	140,746
Subdivisions	135,665
U/G Replacement Marineland Parkway	106,585
Station St. LV Switchgear replacement	102,947
8-Sectionalizing Points	94,745
Maple St & Spruce St	77,464
Station 8 Transformer&Switchgear replace	67,188
Fairgrounds Rd @ Gibson	61,909
Regional Rd #20 RMN relocation	54,693
Kalar M.T.S Oil Containment	25,000
	8,517,511

Building expenditures include the excavation of the yard including stone fill and electrical services in the amount of $462K as well as the new fence and professional services related to the workspace optimization and operations department relocation project.

Office furniture additions of $188K includes the gate for the new entrance, security cameras and access hardware for the new wire storage building, the overhead crane and various ergonomic office equipment.

Computer hardware additions are projected at $443K which include a backup internet link between Niagara Falls administration building and the Smithville service centre in the amount of $150K, network related costs of $45K, servers $40K, PC replacements, monitors, laptops and mobile tablets $47K, and professional services related to hardware configuration of $84K.

Computer software additions are projected at $246K. The automation of timesheets project commenced in 2013 and is currently in the testing phase. Risk management and security costs of $60K are projected. Guying calculation software of $25K, billing system automation expenditures of $80K and customer connect automation purchases of $25K are also projected for 2013.

Vehicles < 3 tons are projected at $188K. Six small vehicles were purchased in 2013 to replace 6 small vehicles which were disposed as they had reached the end of their useful life. Vehicles > 3 tons included a 55’ double bucket for $250K, a 46’ material handling aerial man lift truck for $213K, a 55’ Radial Boom Derrick truck for $350K and a dump hook truck for $130K. Two large trucks were also disposed of in 2013 due to age, condition and maintenance costs.

NPEI began a strategic investment into the development of a smart grid. Included in communications equipment expenditures of $366K is a pilot Wi-max project. The project consists of a three-pronged approach, involving; the installation of backup DC power systems; the installation of a wireless communications network and the upgrade of archaic electromechanical equipment with modern electronics.

The backup DC power systems and communications network constitute the backbone of the smart grid. Both fundamental components will enable the continued addition of modern electronics to the distribution system for the foreseeable future. The DC systems are required to power both the communications network and modern electronics. It will also provide an uninterrupted power source during system outages.

Each electronic device added to the distribution system represents an opportunity to improve power quality, efficiency, reliability, security and safety by:

- Enhancing monitoring, control and diagnostics functionality,
- Improving NPEI's ability to identify and respond to problems more quickly,
- Introducing distribution system automation,
- Improving the quantity and quality of information available,
- Allowing greater flexibility in system configuration,
- Enabling the ability to implement condition-based maintenance,
- Establishing a communications platform capable of supporting real-time system modeling and analysis.

Added-value is achieved for the customer by:

- Improving operational efficiency,
- Reducing the duration and frequency of outages,
- Establishing a communications platform capable of supporting advanced secondary services,
- Establishing a communications platform capable of dealing with next-generation loads and substantial penetration of green energy, and
- Improving the availability and accuracy of information.

Finally, the new wire building and high mast lighting projects are anticipated to be complete by the end of 2013. Total expenditures are projected at $1.5M.

Liabilities and Share Holders Equity 2013

Accounts payable is projected to be $2.0M higher due to the timing of receiving the large vehicles being close to year end.

Regulatory Liabilities are projected to be $1.9M higher in 2013 than 2012. This increase is mainly due to the new variance account for changes to accounting policies under CGAAP which represents the difference in changing the estimated useful lives of NPEI's fixed assets. The PILS rate rider and the deferral and variance rate rider representing balances from 2011 continue to be repaid to NPEI's customers. Both of these rate riders will cease on April 30th, 2014.

NPEI filed a payment in-lieu of taxes (PILS) rate application for both former utilities, Niagara Falls Hydro (NFH) and Peninsula West Utilities (PWU) respectively. From 2001 to mid 2005 Niagara Falls Hydro was entitled to collect from its customers PILS. Peninsula West Utilities was entitled to collect PILS from December 1st 2004 to April 2005. The PILS revenue was included in distribution revenue on the income statement from 2002 to 2005 for each utility. Niagara Falls Hydro filed a scientific research and development claim related to the construction of the Kalar Road Transformer Station in both 2003 and 2004. As per the PILS rate application guidelines, scientific research and development claims are trued-up for the purposes of PILS. As a result the final balances for Niagara Falls were in refund position. PWU under collected their PILS entitlement and as a result had a final receivable balance. The final balance from both utilities was \$2.7M. This balance will be refunded/collected to/from its customers respectively from October 1, 2012 to April 30, 2014 or 19 months. Due to the original collection of PILS being included in distribution revenue, the refund/collection of PILS from October 1st to April 30th, 2014 will also be included in distribution revenue. The 2013 projected and 2014 budget income statement presents the Deferral and Variance rate rider for PILS as an extraordinary item to allow for more accurate comparisons to be made to prior years.

NPEI filed its final disposition for smart meters rate application in September 2013. NPEI also filed its 2014 IRM rate application in August 2013. The Smart meter rate application has a bill impact of \$0.69 increase per customer per month. The IRM rate application includes the disposal of the 2012 deferral and variance accounts in the amount of a refund of \$3.1M. The bill impact to a residential customer in the Niagara Falls service area is a decrease of \$0.56 per month and a decrease of \$3.73 per month per residential customer in the former Peninsula West service area.

Long-term liabilities are projected at \$52.8M which is up by \$8.1M over 2012. NPEI will obtain long-term financing in the amount of \$10M in December 2013. Principal repayments of \$1.9M related to existing debt were made in 2013.

The Ontario Provincial Government mandated all LDC's to achieve an energy savings target and a demand savings target by December 31, 2014. NPEI submitted a CDM Strategy on November 1, 2010 in accordance with the CDM code for Electricity Distributors (ED-2010-0215). NPEI's energy savings target is 58,040,000 kWh and its peak demand reduction target is 15.49 MW. The OEB regulates the CDM programs and targets for each LDC. NPEI commenced implementation of the provincial programs for Residential, Commercial, Industrial and Home Assistance customers in 2011. NPEI continued implementing CDM programs in 2013.

In 2013, NPEI paid a total dividend of \$1,200K to its shareholders proportionate to the shares held.

2013 Projected Income Statement

NPEI completed the Cost of Service Rate Application process in May of 2011 with rates effective June 1st, 2011. The final Base Revenue Requirement amounted to $29,014,020 which included a revenue deficiency of $2,064,398. The next Cost of Service rate application will be submitted to the OEB in four years, with rates effective May 1, 2015. NPEI will follow the Incentive Rate Mechanism (IRM) process for the interim period between 2012 and 2014. NPEI's IRM rate application was submitted to the OEB in August 2013 for rates effective May 1, 2014.

Projected net income after taxes is estimated at $815K, which is less than the 2011 budget, by $1,474K or 53.58%.

NPEI has presented the Deferral and Variance rate rider related to refund/collection of PILS as explained above as an Extraordinary Item. The rate rider is in effect from October 1, 2012 to April 30, 2014. Note the rate rider is calculated on consumption on or after October 1, 2012. The first full month of return is November 2012.

Regulatory Net Income does not include the depreciation expense for the FMV bump of $1,132K. Projected 2013 net income before the extraordinary item related to the deferral and variance rate rider for PILS and income tax is $3,058K.

Gross profit is projected to be 2.0% below the original budget.

Projected distribution revenues are less than budget by $0.6M. The budgeted distribution revenue equals the revenue requirement approved in the 2011 Cost of Service rate application. From 2008 to 2011, NPEI experienced a 5% increase in customer growth. The fixed service charge revenue included in the 2011 rate application anticipates 5% customer growth from 2011 to 2015. In 2013, NPEI projects to achieve the customer growth of 5% that was calculated in determining the service charge distribution revenue in the COS rate application. NPEI however, has not achieved the distribution volumetric revenue calculated in the 2011 Cost of Service rate application. Several factors such as weather, time of use rates and conservation can all be attributed to this variance. Distribution revenue is $36K higher than 2012. Distribution volumetric revenue in 2012 was grossed up by $167K for the Late Payment Penalty settlement as per a letter of direction from the OEB. General and Administrative expenses were also grossed up in the Projected 2012 as the offset. The budget revenue was not grossed up due to the net impact is zero on net income.

Other Revenue equals the budget in 2013 and is projected $0.3M less than 2012. In 2012, NPEI received $200K for its OPA peak saver and ERIP programs from 2010. Also, NPEI received $119K in apprenticeship tax credits from 2011 in 2012. No amount has been projected for the apprenticeship tax credits in 2013.

Cost of power increased over 2012 by $7.8M or 6%.

Projected Operating expenses are estimated to be below budget by $1.1M or 4% and above 2012 by $14K.
Distribution operating expenses are projected $0.6M, 9% less than budget and $0.4M, 6% less than 2012. Labour is estimated to be $175K less than 2012 due to a higher percentage of capital work versus operational expenses in 2013. Also, 2012 includes an arbitration settlement amount. In 2012, $81K was spent on maintenance for the Kalar Road Transmission Station. These expenses are cyclical in nature. Truck utilization is higher in 2013 versus 2012 by $100K. In 2012, NPEI incurred expenses of $40K related to poles removed in 2008 which were owned by Bell Canada.

As part of the stores area renovation which is budgeted for 2014, NPEI engaged a consultant in 2013 to review the current practices, processes and resources used in the purchasing, receiving, issuance and accounting of inventory. The current stores practices and processes have been the same for the last 30 years. The consulting firm was also engaged to aid with the implementation of the various changes in practices, processes and resources that were found in their initial review. Benefits include; reduced rework, increase availability of resources, greater quality assurance, enhanced productivity, strategic arrangements with suppliers, lower supplier costs, less waste, effective management reports, clear expectations, improved space design and reduced dependency on "tribal knowledge". The implementation is currently in the planning stages in the fourth quarter of 2013 and work will continue through to June 2014.

Administration and General expenses are projected $133K or 2% less than budget and $497K or 7% less than 2012. Legal fees are both lower than budget and 2012 by $72K and $96K respectively, due to a labour arbitration in 2012. Property taxes in 2012 included 3 years of property taxes related to the Clifford Street property. Only one year of property taxes was included in 2013, resulting in a decrease of $130K. The Late Payment penalty expense related to the Class Action lawsuit offset was included in 2012 in the amount of $168K. Interest expense is $76K lower in 2013 as a result of NPEI's amortizing loans. Finally, in 2012 NPEI incurred the interest related to the OMERS omission period in the amount of $190K. Twenty three former Niagara Falls Hydro employees were erroneously enrolled in OMERS during the period from 1977 to 1992. As per OMERS legislation NPEI was required to correct the enrolment start date. The decrease in the above noted expenses were offset by the Controller returning from a maternity leave in June 2013

Billing and collecting expenses are under budget by $351K or 8% and $104K or 3% higher than 2012. Labour is lower than budget by $211K due to one billing clerk retiring in 2013 and higher than budgeted sick time. The outsourcing of a systems analyst and the outsourcing of mail were both budgeted at $120K but were not completed in 2013.

Depreciation is less than budget by $110K and higher than 2012 by $808K due the 2012 and 2013 capital additions.

2014 Budget Balance Sheet

Total Assets are budgeted at $165M which is $5.5M or 3% less than projected total assets. Net capital additions total $5.9M. Cash has decreased by $10.7M which is due to the 2014 capital investment, principle repayment of existing loans in the amount of $1.9M, the repayment of the Deferral and Variance balances from 2012 in the amount of $3.1M and the repayment of the Deferral and Variance PILS balance in the amount of $0.5M.

In 2013, the City of Niagara Falls informed NPEI that the water billing, collection and cashiering functions will be returning to the City. The City of Niagara Falls' targeted date is April 1st, 2014. NPEI staff is working very closely with the City of Niagara Falls staff on converting the water billing information, preparing customer and media communication plans and aiding in the transition of workflow processes and procedures. With the target date of April 1st, 2014, the impact on the balance sheet will be a decrease in the payable due to the Niagara Falls Hydro Services company which is the affiliated company used for water billing activities. Typically, the balance represents the 4th quarter water billings less expenses and less any water receivables and deposits.

NPEI included a dividend payment of $1.2M in the 2014 budget.

Gross capital additions related to the distribution system are budgeted at $10.3M, net of capital contributions of $0.9M for a total of $9.4M.

2014 Major Capital projects include:

Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
U/G Primary Extension-Weightman Brigde Chippawa	701,810	-	701,810
Fallsview Boulevard - Ferry to Robinson	332,173	100,000	232,173
12-M-6 Replacement-Simcoe St./Buckley/Armour St.	372,632	-	372,632
Pad-mount Switchgear Replacements	110,057	-	110,057
OH to UG Primary Conversion-Rolling Acres Subdivision Phase 1	768,694	-	768,694
3-M-28,3-M-26 & 3-M-29 Feeder Replacement	417,731	-	417,731
Additional Sectionalizing Switches - 8 Units	100,000	-	100,000
Dorchester Rd.-Garden Street to McMillan Drive	362,018	-	362,018
Stanley T.S. Tie to 12-M-2	19,556	-	19,556
Crawford St. Area Rebuild	516,557	-	516,557
Replacement of Transformers with >50PPM PCB Content	566,479	-	566,479
Jordan Road- Red Maple to the QEW	397,516	-	397,516
Municipal Sub-station Rehabiliation	252,037	-	252,037
King Street- 27.6kV Extension to Martin Rd.	112,554	-	112,554
Lightning Mitigation Measures	30,000		30,000
Line Relocations due to Municipal Road Improvement requirements	520,353	125,000	395,353
Replacement of Poles identifed with limited Structural Integrity	778,702	-	778,702
Overhead line rebuilds of facilities identified by Pole Inspection Survey	516,513	-	516,513

Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
Replacement of Submersibles & Kiosks with EFD switches and posi-tects	624,457	-	624,457
System Sustainment Allowance	400,000	-	400,000
Subdivision Lot servicing of existing	200,000	200,000	-
Subdivision Connection and energizing of new subs	200,000	-	200,000
Lot connection rebates	150,000	-	150,000
Demand based system reinforcements for new commercial services	1,410,778	450,000	960,778
Wholesale Meters	300,000	-	300,000
Metering General	130,000	25,000	105,000
Totals	10,290,616	900,000	9,390,616

Detailed descriptions of these capital projects can be found in the 2014 Capital projects section.

Other Capital Additions

<u>Building</u>

In 2013, the yard excavation, new wire building, high mast lighting, workspace optimization for the operations department and meter shop as well as the renovation of the stores area was budgeted to be complete by the end of 2013. Due to inclement weather, approvals required, and resources available, the workspace optimization for the operations department and the renovation of the stores area have been deferred and re-budgeted in the capital budget for 2014.

The new operations area and meter shop will be relocated to part of the current stores area. Approximately 8,000 square feet will house 5 offices, a Lead Hand area, the Operations Assistant workstation, a planning room, record storage room, mud room, locker room, washroom facilities, line tool storage area, maintenance area, and meter shop. The remaining 6,000 square feet of the existing space will be for the small stores area.

This phase of the project is included in the Building line on the capital budget request for 2014 with details in Appendix A.

<u>General Equipment</u>

Office furniture, photocopier, security cameras and hardware for access to the new operations, meter shop and stores areas are included in the 2014 budget proposal. Ergonomic office equipment and five new defibulators are proposed in the 2014 budget to maintain our commitment to health, wellness and safety. Additional security cameras to be installed at various locations have also been proposed in the 2014 budget.

Hardware & Software

The Information Technology capital expenditures for 2014 continue to ensure that business goals are aligned to technological solutions. NPEI's network infrastructure will be optimized allowing for improved business uptime and resiliency.

The hardware and software requirements within each area allow for the following goals to be met:

- Effective and efficient business processes
- Support of risk and compliance management processes and methodology (enabling a methodology, not defining)
- Integrated, reliable, enterprise solutions
- Network integration and security
- Embedded business continuity practices, and continued update and testing of a Disaster Recovery Plan

Spending of hardware will be managed with greater emphasis on network infrastructure and disaster recovery and new business requirements.

Hardware

The following outlines the proposed 2014 costs. Costs are related to the following projects/business need:

- Improved Network Infrastructure resulting from the purchase of backup switches and servers; consultations on optimization and disaster recovery.
- Move to a hosted exchange server solution (incomplete in 2013)
- Upgrade of PC's and monitors due to age and use: 50 replacements will be completed in 2014 within Operations (purchasing, stores, metering (including meter shop test board PC upgrade and test board firmware) lead hand offices) Human Resources, Accounting, Executive Office, Billing, Customer Service, Business Application Support. The upgrade will include upgrade to Windows and Office 2007.
- Hardware server requirements in conjunction with the implementation of a bar coding software solution in the supply chain management processes
- Workforce/Outage Management Ongoing Implementation, integration and support: we will continue the pilot of replacement of aging mobile ruggedized tablets.
- Update of cell phones, current phones 3 year term ends in June 2014
- Continue the upgrade of enterprise solutions such as update and implementation of web based tools linked to the website including increased functionality of the web based tool M-care integrated with GIS tools (in-Service); this encompasses automation of workflows between customer, metering, engineering, and billing providing efficiencies, improved customer service, and long term cost savings.

Workflows impacted include New Service, Meter Changes, Reporting a problem, and Outage Management.

- Wear and malfunction of handheld meter reading devices, headsets, and signature pad when needed.
- Disaster Recovery and Business Continuity: In 2014, we will continue focus on building infrastructure to secure data and systems, while preparing for a failure. In the last three years, we have designed and build upon disaster recovery measures and infrastructure. The disaster recovery plan encompasses a multi-tier solution to ensure all core systems are recoverable with minimal downtime to the business. Each core system implemented has embedded backup procedures to tape, backup server, and off-site recovery. We are working on a solution that encompasses internal backup recovery (tape/redundant server) as well as external offsite recovery utilizing a third party and virtual management.
- Address risk management through security audits of all network infrastructure

<u>Software</u>

Software required for business process improvement projects and new requirements, which promote efficiency and reliability including the following:

- Great Plains 2013 upgrade and programming of new reports
- Optimization of stores and inventory management through implementation of bar code software solution
- Continue the integration between operations sub-systems, m-care and in-service to the CIS to improve customer relationship management (Update of workforce/outage management tools including the review and capability of the use of the other mobilized ruggedized tablets in the field.)
- Continue to incorporate automation platform within the CIS and Apollo to automate workflows and build upon business analytics used in decision making.
- Continue to update current daily, monthly, quarterly reports from Cognos 7 format to Cognos 8 format, leveraging improved functionality from a desktop automated tool
- Continue to incorporate workflow tools through the use of File Nexus in Human Resources, Engineering, and Conservation
- Address risk management through security audits of all network infrastructure including web applications
- Continue with solution of an enhanced backup solution promoting redundancy and business continuity

In review of the business requirements put forth and determination of what software is considered as part of the capital budget, key areas are reviewed. Customer engagement is of high importance.

Hardware and software solutions proposed allow for the following goals to be met:

- Effective and Efficient Business Processes enabling our business units to meet customer need and preference.
- Support of risk and compliance management processes
- Integrated, reliable, enterprise solutions: key drivers in determination of how we enable home energy management systems, making customer information available.
- Network Integration and Security: ensuring customer data is secured; however, available within a third party or web base/ mobile application. Appropriate cyber security and privacy standards must be met.
- Embedded business continuity practice: assurance of reliability

NPEI remains customer focused. Through technology, customer service surveys, customer feedback on-line forums, NPEI is prepared to undertake activities that will allow us to understand customer's preferences and to address these preferences. Whether it is data access, support of distributed generation through streamlined processes, online application support or ease of access of customer consumption data and generation, information technology investments will allow NPEI to provide information and education to customers. Customers will be able to make decisions affecting their electricity costs with the access to real time data and behind the meter services and applications. NPEI itself will have opportunities for operational efficiencies through the use of data analytic tools and automated platforms.

Vehicles

Currently NPEI has a fleet of 61 vehicles that range in age from 1992 to 2013. Of the 61 vehicles 37 are greater than 3 tons and 24 are less than 3 tons. Currently, only one small vehicle is older than eight years and five large vehicles are greater than 15 years.

In 2014, NPEI included has proposed the replacement of two large vehicles greater than 3 tons. One 55' double bucket material handling aerial man-lift truck to replace a 13 year old 46' material handler in Smithville. This vehicle has over 350,000 kilometers and has reached the end of its life. The second vehicle is a 46' material handling aerial man-lift which is 17 years old and has also reached the end of its' useful life.

Also, proposed in the 2014 budget is the purchase of an extendable trailer capable of transporting 65' poles.

Stores, Tools and Communication Equipment

Tools in the amount of $67K for the garage and fleet are detailed in Appendix G.

New inventory racks for the Niagara Falls stores have been included in the budget in the amount of $75K. The current racking is over 30 years old.

NPEI commenced the Wi-max pilot project in 2012 as noted above. The proposed 2014 Communications budget is for an expansion of this project for $228K.

Liabilities and Shareholders Equity

With the return of the water billing and collecting activities targeted by the City of Niagara Falls to return to the City by April 1st, 2014, NPEI budgeted a zero balance owing to Niagara Falls Hydro Services Inc. which this payable at year end represents the 4th quarter water billings less the water accounts receivable and deposits. As a result current liabilities are budgeted to decrease by $5.2M of which $6.5M is related to the water.

The current portion of long term debt has increased due to the smart meter loan held by Scotiabank was a five year loan with a ten year amortization period. As a result a balloon payment of $2.3M is due September 2015.

The regulatory liabilities are budgeted to increase by $4.2M from the projected 2013 balances. The Deferral Change in Accounting Policy Depreciation is budgeted to cumulatively increase by the difference in depreciation expense for the 2014 year. The Smart Meter regulatory balance is a recoverable from customers and due to the anticipated collection of these balances for 11 months in 2014, the total regulatory liabilities balance are budgeted to increase.

The last item of notation for the balance sheet is the budgeted dividend payment of $1,200K to each of the respective shareholders on a proportionate share basis which is presented on the Statement of Retained Earnings.

Budget Income Statement

<u>Revenue</u>

Distribution revenue for 2014 was budgeted using the 2013 projected balances as a guideline. Previous budgets since the last Cost of Service rate application were prepared using the rate application revenues. NPEI has not achieved the distribution volumetric revenue set out in the rate application in any year since and it has only achieved the rate application service charge revenue in 2013.

NPEI will file its next cost of service rate application in October of 2014 with rates effective May 1, 2015.

<u>Water Billing Activities</u>

The most significant highlight for the 2014 budgeted income statement is the returning of the water billing activities to the City of Niagara Falls. In 2001, the former Niagara Falls Hydro Inc. entered into an agreement with the City of Niagara Falls to process the water billings and combine the meter reading activities, collection, cashiering, customer refund and customer service activities, and issue the customers of Niagara Falls one bill. The agreement outlined that direct expenses such as labour and meter reading would be recovered by the hydro. The agreement also outlined a cost of $4.20 per water only bill would be recovered by the hydro to cover variable expenses and various allocated fixed expenses. The utility at that time hired five employees to perform these water activities.

At the same time, the hydro industry underwent de-regulation in the fourth quarter of 2001. One impact of de-regulation was the Affiliate Relationship Code "ARC" which detailed non-utility related activities must be at current market rates. The objective of ARC was to ensure hydro rates did not subsidize non-hydro related activities. In early 2013, the City of Niagara Falls decided to have all water billing activities return to the City.

The target date set by the City of Niagara Falls is April 2014. Conversion activities are currently underway.

The impact on the 2014 budgeted income statement is the loss of the revenues for nine months of $371K which is the main reason for the decrease in Other Revenues from the Projected 2013 and actual 2012 revenues.

As well the direct labour costs of $451K and allocated fixed costs net of the variable costs of $254K contained in the Billing and Collecting Expenses will no longer be recovered by the water billing activities. This is the main reason the Billing and Collecting expenses are greater than the Projected 2013 and Actual 2012 expenditures.

As a result of water processing being moved to City of Niagara Falls, four positions within Customer Service and Billing will be impacted – receptionist, cashier, customer service representative, and billing clerk. It is anticipated that Customer Service and Billing will go through a transition period beginning in the second quarter of 2014.

The use of temporary staff, re-engineering of workflow processes, and cross training will impact how resources will be utilized. Further, the upcoming absence due to maternity and retirement will facilitate a change in staffing.

Currently, the receptionist and one cashier positions are filled by outside temporary resources, with an additional contract resource backfilling for break and lunch. It is anticipated that post the move of water to the city, the temporary resources will not be required. Two full time customer service resources can be allocated to reception and cashiering; with customer service or billing full time staff managing coverage for breaks and lunch. Potentially 2 billing department personnel will be transferred to customer service as needed.

The call flow workflow is currently being reviewed. It is anticipated that changes to the call flow and how and when calls are answered will better utilize customer service and billing staff, improving overall customer service.

Currently, Business Application Support is completing the review of exception reporting on reads at that MDM/R. The purpose of the Business Application Support department is to document requirements, test, document procedures, and train. Due to resource constraints within billing, the exception based training remained with Business Application Support. Once resources become available post the movement of water, Business Application Support can transition the exception processing to billing staff.

It was anticipated that the mailroom functions may be outsourced; however, this review and decision will be postponed to the fourth quarter 2014, as billing clerks will continue to be available to work in the mailing room.

In 2013, one billing clerk retired; it is not expected to backfill this position. In the first quarter 2014, one billing clerk will begin maternity leave; it is not expected to backfill this position. Within 2-5 years, one Billing Team Lead/Lead hand and one Customer Service Lead/Lead hand will retire. It is anticipated that the lead position will be backfilled from current customer service and billing staff; the positions of the residual customer service and billing clerk positions would not be backfilled.

Within 3-5 years, two billing supervisors will become eligible to retire; it is anticipated that only one billing supervisor role will be back filled.

With the improvements to workflow and movement of resources, it is anticipated that resources will be well utilized.

Finally, NPEI will be filing its cost of service rate application in October 2014. The full impact of the water returning to the City will be more understood as transition takes place in the first quarter of 2014 and will be appropriately accounted for in the rate application.

Expenses

Total OM&A expenses excluding depreciation are budgeted at $18.377M in 2014. Depreciation at the new extended lives and the Deferred Debit related to the change in accounting policy for fixed assets and depreciation are budgeted at $8.7M and depreciation related to the fair market value bump on assets of $1.1M.

The 2014 OM&A expenses include Distribution, Utilization, Administration and General, and Billing and Collecting expenses. Total OM&A expenses budgeted in 2014 are $18.377M which is 8.0% higher than the projected 2013 OM&A expenses of $17.0M. Excluding the impact of water billing activities noted above the OM&A expenses are 3.87% above the projected 2013 OM&A.

General and administration expenses are budgeted at $6.965M which is $0.4M or 6.48% higher than 2013. Interest expense is budgeted to increase $172K. Additional financing in the amount of $10M is projected to be received in December 2013, at an estimated rate of 3.25% for a full year of $325K which has been included in interest expense in 2014. This increase has been offset by two amortizing loans where the interest expense decreases each year repayments are made and the loan related to the Kalar Road TS will be fully repaid by June 2014. The controller returned from a maternity leave in June of 2013 and has been budgeted for a full year in 2014, which accounts for $125K of the $424K increase.

A wage increase of 3.1% effective April 1, 2014 for union personnel and January 1 for management personnel was assumed for all labour expenses in both the capital and operating budgets.

Billing and collecting expenses are budgeted at $4.8M. Excluding the impact of water activities, billing and collecting expenses are $14K less than the projected 2013 expenses. This is due to one billing clerk going on maternity leave where this position will not be back-filled by temporary resources. NPEI has budgeted for a customer survey to be conducted in 2014 as well as four town hall meetings related to educating its customers.

Depreciation expense budgeted is calculated using the new estimated useful lives and the variance due to the change in accounting policy is shown separately as Deferred Debit due to change in accounting policy.

In conclusion, NPEI has continued to maintain the level of distribution expenses excluding the impact of water activities and still provide safe reliable electricity to its customers using a proactive preventive maintenance approach. Continued investments in NPEI's employees, distribution infrastructure, capital fleet and technology will contribute to the company's many future successes. NPEI has budgeted for initiatives that are customer focused both in the capital and operating budgets

Recommendation:

Senior management has reviewed the capital and operating budgets extensively and respectfully recommends approval as follows:

1. The 2014 Capital budget of $12,688,000 be approved, this is comprised of net distribution additions of $9,391,000, information technology, fleet and communication expenditures of $1,994,000, and building expenditures of $1,303,000.

2. The 2014 total operating expenditures in the amount of $28,134,000 including depreciation and depreciation related to the fair market value bump are approved.

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2013
(000's)

	Projected 2013	Actual 2012	$ Variance	% Variance
ASSETS				
Current Assets				
Cash	16,457	13,354	3,103	23%
Accounts Receivable	10,036	9,417	618	7%
Unbilled Revenue	13,241	13,219	22	0%
Due from Affiliated Companies				
Niagara Falls Hydro Holding Corporation	16	16	0	0%
Peninsula West Services	5	4	1	34%
Payments in lieu of corporate taxes refundable	402	589	(187)	-32%
Inventories	1,560	1,458	102	7%
Prepaid Expenses	909	903	6	1%
	42,625	**38,960**	**3,665**	**9%**
Fixed Assets				
Land and land rights	2,962	2,962	0	0%
Buildings	15,487	13,438	2,050	15%
Distribution Stations	9,284	8,948	337	4%
Transformer Station	6,585	6,560	25	0%
Distribution lines				
Overhead	94,867	90,155	4,712	5%
Underground	81,248	78,675	2,573	3%
Distribution transformers	36,725	35,784	941	3%
Distribution meters	7,571	7,423	148	2%
Trucks and Equipment	19,782	17,578	2,204	13%
	274,511	261,521	12,990	5%
Less: Accumulated Depreciation	(147,917)	(141,657)	(6,260)	4%
	126,594	**119,864**	**6,731**	**6%**
Future payments in lieu of taxes	**1,592**	**1,592**	-	0%
TOTAL ASSETS	**170,811**	**160,415**	**10,396**	**6%**

Niagara Peninsula Energy
Projected Balance Sheet
As at December 31, 2013
(000's)

	Projected 2013	Actual 2012	$ Variance	% Variance
LIABILITIES				
Current Liabilities				
Accounts Payable	15,186	13,270	1,916	14%
Due to Niagara Falls Hydro Services Inc.	6,539	7,514	(974)	-13%
Deferred Capital Contributions	118	0	118	200%
Deferred OPA revenues	1,385	1,275	111	100%
Deferred Standard Offer Revenue	7	14	(8)	-52%
Current Portion of long term debt	1,870	2,313	(444)	-19%
Current Portion of other liabilities	696	700	(5)	-1%
	25,801	**25,087**	**714**	**3%**
Regulatory Liabilities				
Retail Cost Variances	(315)	(247)	(67)	27%
Deferred Payment in Lieu of Taxes	(812)	(2,378)	1,566	100%
Retail Settlement Variances	3,958	2,758	1,200	43%
Low Voltage Variances	62	122	(60)	-49%
SmartGrid OMA Deferral (GEA)	(19)	(19)	0	0%
Smart Meters	(2,312)	(2,028)	(283)	14%
Other Regulatory Assets	(23)	(20)	(3)	15%
Smart Metering Entity Variance	(45)	0	(45)	100%
Deferral Change in Accounting Policy Depreciation	2,712	0	2,712	100%
Deferral & Variance Recovery 2010 IRM	107	81	25	31%
Deferral & Variance Recovery 2011 COS application	110	108	1	100%
Deferral & Variance Recovery 2012 application	541	2,139	(1,598)	100%
Deferral & Variance Recovery PILS application	812	2,378	(1,565)	200%
	4,777	**2,895**	**1,882**	**65%**
Non-Current Liabilities				
Employee Sick Leave Liability	118	169	(50)	-30%
Employee Future Benefits	3,886	3,778	108	3%
Customer Deposits	733	738	(4)	-1%
	4,738	**4,684**	**53**	**1%**
Long Term Liabilities				
Note Payable to City of Niagara Falls	22,000	22,000	0	0%
Note Payable to Niagara Falls Hydro Holding Corp.	3,605	3,605	0	0%
Long Term Bank Loan	27,240	19,109	8,130	43%
	52,845	**44,714**	**8,130**	**18%**
Shares				
Share Capital	31,246	31,246	0	0%
Contributed Surplus	25,459	25,459	(0)	0%
Retained Earnings	25,946	26,330	(385)	-1%
	82,651	**83,035**	**(385)**	**0%**
TOTAL LIABILITIES & EQUITY	**170,811**	**160,415**	**10,395**	**6%**

Niagara Peninsula Energy
Projected Statement of Operations vs Budget
For the year ending December 31, 2013
(000's)

	Projected 2013	Budget 2013	Projected vs Budget $ Variance	Projected vs Budget % Variance	Actual 2012	Projected 2013 vs Actual 2012 $ Variance	Projected 2013 vs Actual 2012 % Variance
SERVICE REVENUE							
Standard Supply Service NF	105,980	101,401	4,578	5%	98,297	7,683	8%
Wholesale, Network & Connection Charges	23,080	23,872	(792)	-3%	22,937	143	1%
Service Charge	12,777	12,778	(1)	0%	12,507	270	2%
Distribution Volumetric Charge	15,026	15,638	(612)	-4%	15,261	(235)	-2%
Standard Supply Service Admin Charge	141	138	4	3%	138	3	2%
Retailer Revenue	45	46	(1)	-1%	50	(5)	-10%
	157,049	153,873	3,177	2%	149,190	7,859	5%
Cost of Power							
Power Purchased	129,060	125,273	(3,787)	-3%	121,234	(7,826)	-6%
Gross Profit Before Other Revenue	27,989	28,600	(610)	-2%	27,956	33	0%
Other Revenue	1,878	1,879	(0)	0%	2,200	(322)	-15%
Gross Profit	29,868	30,478	(610)	-2.00%	30,156	(288)	-1%
Expenses							
Operation and maintenance							
Distribution	6,193	6,787	595	9%	6,621	428	6%
Utilization	198	162	(36)	-22%	166	(32)	-19%
Administration & general	6,541	6,674	133	2%	7,038	497	7%
Billing & Collecting	4,081	4,432	351	8%	3,977	(104)	-3%
Depreciation	5,518	5,591	73	1%	7,421	1,904	26%
Depreciation adjustment to 1576	2,712	2,748	36	1%	0	(2,712)	100%
Depreciation on FMV adjustment of fixed assets	1,132	1,132	0	100%	1,137	5	0%
TOTAL EXPENSES	26,375	27,528	1,152	4%	26,361	(14)	0%
Net Income before Extraordinary Item	3,492	2,951	542	18%	3,795	(303)	-8%
Extraordinary Item							
Deferral & Variance (Refund)/Recovery PILS	1,566	1,722	155	100%	366	(1,201)	100%
Net Income After Extraordinary Item	1,926	1,229	387	31%	3,429	(1,503)	-44%
Payments in Lieu of Income Taxes							
Income Tax expenses - current	1,111	1,350	239	18%	638	(473)	-74%
Income tax expense future reduction	0	(500)	(500)	100%	40	40	100%
Total payments in lieu of income taxes	1,111	850	(261)	-31%	678	(433)	-64%
Net Income/(Loss) After Taxes	815	379	436	115%	2,751	(1,936)	-70%

Statistics					
Cost of Power %	82.18%	81.41%	(0.76) pts	81.26%	(0.92) pts
Gross Profit % After Other Revenue	19.02%	19.81%	(0.79) pts	20.21%	(1.20) pts
Total Expenses as % of Total Revenue	16.79%	17.89%	1.10 pts	17.67%	0.88 pts
Net Income After Tax as % of Total Revenue	0.52%	0.25%	0.27 pts	1.84%	(1.33) pts
Other Revenue	1.20%	1.22%	(0.02) pts	1.47%	(0.28) pts
Distribution	3.94%	4.41%	0.47 pts	4.44%	0.49 pts
Utilization	0.13%	0.11%	(0.02) pts	0.11%	(0.01) pts
Administration & general	4.17%	4.34%	0.17 pts	4.72%	0.55 pts
Billing & Collecting	2.60%	2.88%	0.28 pts	2.67%	0.07 pts
Depreciation	3.51%	3.63%	0.12 pts	4.97%	1.46 pts

Niagara Peninsula Energy Inc.
Statement of Cash Flows
As at December 31, 2013

	Projected 2013 $	Actual 2012 $
Cash Provided By (Used In):		
Operations		
Net Income for the year	815	2,751
Items not involving cash		
Depreciation	6,650	8,559
Future payments in-lieu of taxes	0	40
Employee future benefits	108	68
	7,573	11,418
Changes in non-cash working capital components	154	(550)
	7,727	10,868
Investments		
Due to affiliated companies	1	467
Additions to property and equipment-net	(13,383)	(10,280)
Regulatory costs	1,882	(870)
	(11,500)	(10,683)
Financing		
Long-Term Deposits	(4)	(7)
Employees' accumulated vested sick leave	(50)	(28)
Long Term Bank Loan	8,130	7,788
Dividend on Common Shares	(1,200)	(1,200)
	6,876	6,553
Increase (Decrease) in Cash Position	3,103	6,738
Cash Position, Beginning of Year	13,354	6,616
Cash Position, End of Year	16,457	13,354

Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the years ending December 31, 2012 through 2013
(000's)

	Projected 2013	Actual 2012
Retained Earnings, Beginning of Year	26,330	24,779
Net Income	815	2,751
Dividends on common shares	(1,200)	(1,200)
Retained Earnings, End of Period	25,946	26,330

Niagara Peninsula Energy
Projected Capital Budget
For the year ending December 31, 2013
(000's)

	Projected 2013	Budget 2013	Projected vs Budget Variance	Actual 2012	Projected 2013 vs 2012 Variance
Land and Land Rights	0	25	25	5	(5)
Buildings & Fixtures	529	1,865	1,336	626	97
Sub Total	529	1,890	1,361	631	91
Distribution Station	337	557	219	683	345
Transformer Station	25	30	5	0	(25)
Overhead Distribution	4,938	4,163	(776)	3,663	(1,276)
Underground Distribution	2,832	2,870	38	3,148	316
Distribution Transformers	1,132	1,594	463	1,247	115
Meters	225	400	175	171	(53)
Capital Contributions	(752)	(845)	(93)	(1,585)	(833)
Sub Total before unusual contributions	8,736	8,768	32	7,327	(1,410)
Office Furniture & Equipment	188	185	(3)	112	(76)
Computer Equipment, Hardware	443	593	150	371	(73)
Computer Software	246	283	37	213	(33)
Vehicles < 3 tonnes	188	200	12	104	(84)
Vehicles > 3 tonnes	1,040	1,195	155	1,056	16
Vehicle Disposals	(355)	0	355	0	355
Stores Equipment	0	25	25	0	0
Tools, Shop & Garage Equipment	88	88	0	133	45
Measurement & Testing Equipment	0	0	0	0	0
Communication equipment	366	200	(166)	332	(33)
Miscellaneous equipment	0	0	0	0	0
Sub Total	2,204	2,769	565	2,322	118
Total Capital before non-recuring capital expenditures/(contributions)	**11,470**	**13,427**	**1,958**	**10,280**	**(1,201)**
Non-recuring Capital Expenditures					
Wire building & High mast lighting	1,520	1,570	50	0	(1,520)
Total non-recuring capital expenditures/(contributions)	1,520	1,570	50	0	(1,520)
Net Capital Expenditures	12,990	14,997	2,007	10,280	(2,721)

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2014
(000's)

	Budget 2014	Projected 2013	$ Variance	% Variance	Actual 2012	$ Variance	% Variance
ASSETS							
Current Assets							
Cash	5,738	16,457	(10,719)	-65.1%	13,354	3,103	23%
Accounts Receivable	10,236	10,036	201	2%	9,417	618	7%
Unbilled Revenue	13,506	13,241	265	2%	13,219	22	0%
Due from Affiliated Companies							
Niagara Falls Hydro Holding Corporation	0	16	(16)	-100%	16	0	0%
Peninsula West Services	5	5	(0)	0%	4	1	34%
Payments in lieu of corporate taxes refundable	0	402	(402)	0%	589	(187)	-32%
Inventories	1,404	1,560	(156)	-10%	1,458	102	7%
Prepaid Expenses	927	909	18	2%	903	6	1%
	31,816	**42,625**	**(10,809)**	**-25%**	**38,960**	**3,665**	**9%**
Fixed Assets							
Land and land rights	2,962	2,962	0	0%	2,962	0	0%
Buildings	16,790	15,487	1,303	8%	13,438	2,050	15%
Distribution Stations	9,536	9,284	252	3%	8,948	0	0%
Transformer Station	6,585	6,585	0	0%	6,560	0	0%
Distribution lines							
Overhead	98,410	94,867	3,543	4%	90,155	4,712	5%
Underground	84,661	81,248	3,413	4%	78,675	2,573	3%
Distribution transformers	38,330	36,725	1,605	4%	35,784	941	3%
Distribution meters	8,148	7,571	577	8%	7,423	148	2%
Trucks and Equipment	21,776	19,782	1,994	10%	17,578	2,204	13%
	287,199	274,511	12,688	5%	261,521	12,990	5%
Less: Accumulated Depreciation	(154,732)	(147,917)	(6,815)	5%	(141,657)	(6,260)	4%
	132,467	**126,594**	**5,873**	**5%**	**119,864**	**6,731**	**6%**
Future payments in lieu of taxes	**1,000**	**1,592**	**(592)**	**-37%**	**1,592**	**-**	**0%**
TOTAL ASSETS	**165,283**	**170,811**	**(5,528)**	**-3%**	**160,415**	**10,396**	**6%**

Niagara Peninsula Energy
Budget Balance Sheet
As at December 31, 2014
(000's)

	Budget 2014	Projected 2013	$ Variance	% Variance	Actual 2012	$ Variance	% Variance
LIABILITIES							
Current Liabilities							
Accounts Payable	15,642	15,186	456	3%	13,270	1,916	14%
Due to Niagara Falls Hydro Services Inc.	0	6,539	(6,539)	-100%	7,514	(974)	-13%
Deferred Capital Contributions	0	118	(118)	-100%	0	118	100%
Deferred Standard Offer Revenue	7	7	0	0%	1,275	(1,268)	-99%
Deferred OPA revenues	693	1,385	(692)	-50%	14	1,371	100%
Current Portion of long term debt	3,515	1,870	1,645	88%	2,313	(444)	-19%
Current Portion of other liabilities	709	696	14	2%	700	(5)	-1%
	20,566	**25,801**	**(5,235)**	**-20%**	**25,087**	**714**	**3%**
Regulatory Liabilities							
Retail Cost Variances	(387)	(315)	(72)	23%	(247)	(67)	27%
Deferred Payment in Lieu of Taxes	0	(812)	812	0%	(2,378)	1,566	0%
Retail Settlement Variances	4,116	3,958	158	4%	2,758	1,200	43%
Low Voltage Variances	65	62	2	4%	122	(60)	-49%
SmartGrid OMA Deferral (GEA)	(19)	(19)	0	0%	(19)	0	0%
Smart Meters	(604)	(2,312)	1,707	-74%	(2,028)	(283)	14%
Other Regulatory Assets	(23)	(23)	0	0%	(20)	(3)	15%
Smart Metering Entity Variance	(45)	(45)	0	0%	0	(45)	100%
Deferral Change in Accounting Policy Depreciation	5,653	2,712	2,942	100%	0	2,712	100%
Deferral & Variance Recovery 2010 IRM	74	107	(33)	-31%	81	25	31%
Deferral & Variance Recovery 2011 COS application	108	110	(2)	-1%	108	1	1%
Deferral & Variance Recovery 2012 application	100	541	(441)	-82%	2,139	(1,598)	-75%
Deferral & Variance Recovery PILS application	0	812	(812)	-100%	2,378	(1,565)	-66%
	9,039	**4,777**	**4,262**	**89%**	**2,895**	**1,882**	**65%**
Non-Current Liabilities							
Employee Sick Leave Liability	57	118	(61)	-52%	169	(50)	-30%
Employee Future Benefits	3,936	3,886	50	1%	3,778	108	3%
Customer Deposits	748	733	15	2%	738	(4)	-1%
	4,741	**4,738**	**3**	**0%**	**4,684**	**53**	**1%**
Long Term Liabilities							
Long Term Note Payable to City of Niagara Falls	22,000	22,000	0	0%	22,000	0	0%
Long Term Note Payable NF Hydro Holding	3,605	3,605	0	0%	3,605	0	0%
Long Term Bank Loan	23,725	27,240	(3,515)	-13%	19,109	8,130	43%
	49,330	**52,845**	**(3,515)**	**-7%**	**44,714**	**8,130**	**18%**
Shares							
Share Capital	31,246	31,246	0	0%	31,246	0	0%
Contributed Surplus	25,459	25,459	(0)	0%	25,459	0	0%
Retained Earnings	24,903	25,946	(1,043)	-4%	26,330	(385)	-1%
	81,608	**82,651**	**(1,043)**	**-1%**	**83,035**	**(385)**	**0%**
TOTAL LIABILITIES & EQUITY	**165,283**	**170,811**	**(5,527)**	**-3%**	**160,415**	**10,396**	**6%**

Niagara Peninsula Energy Inc.
Budgeted Statements of Operations
For the year ending December 31, 2014
(000's)

	Budget 2014	Projected 2013	2014 vs 2013 $ Variance	2014 vs 2013 % Variance	Actual 2012	2012 vs 2013 $ Variance	2012 vs 2013 % Variance
SERVICE REVENUE							
Standard Supply Service NF	114,458	105,980	8,478	8.00%	98,297	7,683	7.82%
Wholesale, Network & Connection Charges	22,779	23,080	(301)	-1.30%	22,937	143	0.62%
Service Charge	12,778	12,777	1	0.01%	12,507	270	2.16%
Distribution Volumetric Charge	15,029	15,026	3	0.02%	15,261	(235)	-1.54%
Standard Supply Service Admin Charge	141	141	0	0.00%	138	3	2.07%
Retailer Revenue	45	45	0	0.00%	50	(5)	-10.12%
	165,231	157,049	8,182	5.21%	149,190	7,859	5.27%
Cost of Power							
Power Purchased	137,237	129,060	(8,177)	-6.34%	121,234	(7,826)	-6.46%
Gross Profit Before Other Revenue	27,994	27,989	4	0.02%	27,956	33	0.12%
Other Revenue	1,513	1,878	(365)	-19.45%	2,200	(322)	-14.62%
Gross Profit	29,507	29,868	(361)	-1.21%	30,156	(288)	-0.96%
Expenses							
Operation and maintenance							
Distribution	6,457	6,193	(264)	-4.26%	6,621	428	6.47%
Utilization	184	198	14	7.25%	166	(32)	-19.07%
Administration & general	6,965	6,541	(424)	-6.48%	7,038	497	7.06%
Billing & Collecting	4,772	4,081	(690)	-16.91%	3,977	(104)	-2.62%
Depreciation at extended lives	5,715	5,518	(197)	-3.58%	7,421	1,904	25.65%
Deferred Debit due to change in lives	2,942	2,712	(230)	-8.48%	0	(2,712)	100.00%
Depreciation on FMV adjustment of fixed assets	1,100	1,132	32	2.84%	1,137	5	0.45%
TOTAL EXPENSES	28,134	26,375	(1,759)	-6.67%	26,361	(14)	-0.05%
Net Income before Extraordinary Item	1,372	3,492	(2,120)	-60.71%	3,795	(303)	-7.98%
Extraordinary Item							
Deferral & Variance Refund/Recovery PILS	508	1,566	1,058	67.55%	366	(1,201)	100.00%
Net Income After Extraordinary Item	864	1,926	(1,062)	-55.13%	3,429	(1,503)	-43.84%
Payments in Lieu of Income Taxes							
Income Tax expenses - current	707	1,111	(403)	-36%	638	(69)	-11%
Income tax expense future reduction	0	0	0	0%	40	40	100%
Total payments in lieu of income taxes	707	1,111	(403)	-36%	678	(29)	-4%
Net Income/(Loss) After Taxes	157	815	(658)	-80.75%	2,751	(1,474)	-53.58%

Statistics					
Cost of Power %	83.06%	82.18%	(0.88) pts	81.26%	(0.92) pts
Gross Profit % After Other Revenue	17.86%	19.02%	(1.16) pts	20.21%	(1.20) pts
Total Expenses as % of Total Revenue	17.03%	16.79%	(0.23) pts	17.67%	0.88 pts
Net Income After Tax as % of Total Revenue	0.09%	0.52%	(0.42) pts	1.84%	(1.75) pts
Other Revenue	0.92%	1.20%	(0.28) pts	1.47%	(0.56) pts
Distribution	3.91%	3.94%	0.04 pts	4.44%	0.49 pts
Utilization	0.11%	0.13%	0.01 pts	0.11%	(0.01) pts
Administration & general	4.22%	4.17%	(0.05) pts	4.72%	0.55 pts
Billing & Collecting	2.89%	2.60%	(0.29) pts	2.67%	0.07 pts
Depreciation	3.46%	3.51%	0.05 pts	4.97%	1.46 pts

Niagara Peninsula Energy Inc.
Statement of Cash Flows
As at December 31, 2014

	Budget 2014 $	Projected 2013 $	Actual 2012 $
Cash Provided By (Used In):			
Operations			
Net Income for the year	157	815	2,751
Items not involving cash			
Depreciation	6,815	6,650	8,559
Future payments in-lieu of taxes	592	0	40
Employee future benefits	50	108	68
	7,614	7,573	11,418
Changes in non-cash working capital components	(5,161)	154	(550)
	2,453	7,727	10,868
Investments			
Due to affiliated companies	16	1	467
Additions to property and equipment-net	(12,688)	(13,383)	(10,280)
Regulatory costs	4,262	1,882	(870)
	(8,410)	(11,500)	(10,683)
Financing			
Long-Term Deposits	15	(4)	(7)
Employees' accumulated vested sick leave	(61)	(50)	(28)
Long Term Bank Loan	(3,515)	8,130	7,788
Dividend on Common Shares	(1,200)	(1,200)	(1,200)
	(4,762)	6,876	6,553
Increase (Decrease) in Cash Position	(10,719)	3,103	6,738
Cash Position, Beginning of Year	16,457	13,354	6,616
Cash Position, End of Year	5,739	16,457	13,354

Niagara Peninsula Energy Inc.
Statement of Retained Earnings
for the years ending December 31, 2012 through 2014
(000's)

	Budget 2014	Projected 2013	Actual 2012
Retained Earnings, Beginning of Year	25,946	26,330	24,779
Net Income	157	815	2,751
Dividends on common shares	(1,200)	(1,200)	(1,200)
Retained Earnings, End of Period	24,903	25,946	26,330

Niagara Peninsula Energy Inc.
Capital Budget 2014
For the year ending December 31, 2014
(000's)

	Appendix	Budget 2014	Projected 2013	Budget 2014 vs Projected 2013 Variance	Original Budget 2013	Projected 2013 vs Budget 2013 Variance	Actual 2012
Land and Land Rights	A	0	0	0	25	25	5
Buildings & Fixtures	A	1,303	529	(774)	1,865	1,336	626
Sub Total		1,303	529	(774)	1,890	1,361	631
Distribution Station	B	252	337	85	557	219	683
Transformer Station	B	0	25	25	30	5	0
Overhead Distribution	B	3,836	4,938	1,103	4,163	(776)	3,663
Underground Distribution	B	3,782	2,832	(950)	2,870	38	3,148
Distribution Transformers	B	1,818	1,132	(687)	1,594	463	1,247
Meters	B	602	225	(378)	400	175	171
Capital Contributions	B	(900)	(752)	148	(845)	(93)	(1,585)
Sub Total before unusual contributions		9,391	8,736	(654)	8,768	32	7,327
Office Furniture & Equipment	C	157	188	31	185	(3)	112
Computer Equipment, Hardware	D	297	443	146	593	150	371
Computer Software	E	499	246	(253)	283	37	213
Vehicles < 3 tonnes	F	22	188	166	200	12	104
Vehicles > 3 tonnes	F	650	1,040	390	1,195	155	1,056
Vehicle Disposals Truck 17, 18 and 35		0	(355)	(355)	0	355	0
Stores Equipment	F	75	0	(75)	25	25	0
Tools, Shop & Garage Equipment	G	67	88	21	88	0	133
Measurement & Testing Equipment		0	0	0	0	0	0
Communication equipment	H	228	366	138	200	(166)	332
Miscellaneous equipment		0	0	0	0	0	0
Sub Total		1,994	2,204	210	2,769	565	2,322
Total Capital before non-recuring capital expenditures/(contributions)		**12,688**	**11,470**	**(1,218)**	**13,427**	**1,958**	**10,280**
Wire building & High mast lighting		0	1,520	1,520	1,570	50	0
		0	1,520	1,520	1,570	50	0
Net Capital Expenditures		**12,688**	**12,990**	**302**	**14,997**	**2,007**	**10,280**

APPENDIX A

Building 2014

	2014 Budget
Building	
Workspace optimization Operations & Inventory area	1,112,800
Pave the new entrance way from Kalar to existing building	120,000
Add 20 parking spaces on south side of building	70,000
Total	**1,302,800**

APPENDIX B

Project	Gross Capital Investment	Capital Contribution	Net Capital Investment
Crawford St.-Thorld Stone South to Sheldon	516,557	-	516,557
U/G Primary Extension-Weightman Brigde Chippawa	701,810	-	701,810
Fallsview Boulevard - Ferry to Robinson	332,173	100,000	232,173
12-M-6 Replacement-Simcoe St./Buckley/Armour St.	372,632	-	372,632
Pad-mount Switchgear Replacements	110,057	-	110,057
OH to UG Primary Conversion-Rolling Acres Subdivision Phase 1	768,694	-	768,694
3-M-28,3-M-26 & 3-M-29 Feeder Replacement	417,731	-	417,731
Additional Sectionalizing Switches - 8 Units	100,000	-	100,000
Dorchester Rd.-Garden Street to McMillan Drive	362,018	-	362,018
Stanley T.S. Tie to 12-M-2	19,556	-	19,556
Replacement of Transformers with >50PPM PCB Content	566,479	-	566,479
Jordan Road- Red Maple to the QEW	397,516	-	397,516
Municipal Sub-station Rehabiliation	252,037	-	252,037
King Street- 27.6kV Extension to Martin Rd.	112,554	-	112,554
Lightning Mitigation Measures	30,000		30,000
Line Relocations due to Municipal Road Improvement requirements	520,353	125,000	395,353
Replacement of Poles identifed with limited Structural Integrity	778,702	-	778,702
Overhead line rebuilds of facilities identified by Pole Inspection Survey	516,513	-	516,513
Replacement of Submersibles & Kiosks with EFD switches and posi-tects	624,457	-	624,457
System Sustainment Allowance	400,000	-	400,000
Subdivision Lot servicing of existing	200,000	200,000	-
Subdivision Connection and energizing of new subs	200,000	-	200,000
Lot connection rebates	150,000	-	150,000
Demand based system reinforcements for new commercial services	1,410,778	450,000	960,778
Wholesale Meters	300,000	-	300,000
Metering General	130,000	25,000	105,000
Totals	10,290,616	900,000	9,390,616

<u>PROPOSED N.P.E.I 2014 CAPITAL BUDGET PROGRAM</u>

1. **Expansions and Reinforcement of the N.P.E.I. 13.8 K.V. / 27.6 K.V. Primary Distribution System to accommodate load growth & reliability requirements.**

- **Crawford Street--Thorold Stone South to Sheldon**

This Rebuild Project targets 1.38 kilometers of urban distribution line installed in 1953, including 50 pole changes, new single (880M) & three phase (500M) primary and secondary (1790M) circuits, 10 distribution transformer replacements resulting in the upgraded supply to about 122 residential customers in the area bounded by Drummond Rd., Portage Road, Sheldon St., St James St., Longhurst Ave, Elberta ave. & Crawford St. System benefits include replacement of aging equipment, future voltage conversions opportunities, and improved equipment clearance.
Estimated cost: $ 516,556.58 ***-- NF Service Area Project #2014-0002***

- **<u>Carry-over</u>- Underground Primary Extension-Weightman Bridge Chippawa.**

Completion of the installation of approximately 230M of 600MCM Underground primary cable within an existing duct structure placed during the Bridge reconstruction in 2010. Also included are the construction of 2-primary risers, the installation of a reclosure unit to minimize feeder exposure to upstream Commercial loads, and 150 M of new trench & 600 MCM Primary on Cumming Lane between Bridgewater and Main St. with 2-primary risers to facilitate the removal of the River crossing. The project allows NPEI to deal with an existing overhead crossing over the Welland River opposite Cummings Lane, which is approaching end of life .
Estimated Cost = $ 701,809.61 ***-- NF Service Area—Project #2014-0003***

- **Fallsview Boulevard--Ferry Street to Robinson St**

Project scope involves replacement of 0.5 KM. of existing overhead 5 KV line (F-72) with an underground 15 KV single circuit 3-phase line (3-M-54) between Robinson St & Ferry St pending a City of Niagara Falls Road Reconstruction Project. The Road re-construction includes widening to 4-lanes and re-alignment of the intersection at Ferry St reducing the available boulevard required for construction of a pole line. The source will be a spare position in existing switching station #33 to a pole line north of Ferry Street. System benefits include replacement of aging equipment, conversion of an underground transformer vault at the Fairway Inn, and load reduction on the Municipal Substation #7 by conversion of the lateral to 15KV.
Estimated Cost= $ 332,173.25 ***-- NF Service Area Project #2014-0004***

- **<u>Carry-over</u>-12-M-6 Replacement—Simcoe St/Buckley Ave/Armoury St Area.**

Completion of the replacement of a PILCDSTA underground primary cable installed in 1959 with a 50’ wood pole line supporting a 556 MCM 3-phase circuit to deal with mature tree growth in the area, on Simcoe St. from Buckley Ave to Ontario Ave, and St Lawrence Ave from Armoury St to Simcoe St., constructed in the same alignment as the existing 2.4KV single phase pole line currently in service. Benefits include the elimination of 54 year old cable, which has posed reliability issues due to splice failures, providing immediate voltage conversion opportunities of several existing lateral feeds, and a source for future voltage conversions, of Stn. #3 & Stn. #6 loads, for sections previously rebuilt with 15KV rated equipment.
Estimated Cost= $ 372,632.08 ***--NF Service Area—Project #2014-0005***

- **Pad-mounted Switchgear Replacements**

The Underground Equipment Inspection Program has identified the requirement for replacement of pad-mounted switchgear units due to corrosion and contamination issues, which will continue at a rate of 3-Units per year. The scope includes the installation of applicable civil works such as manholes and duct-banks associated with the equipment replacement to current standards. Increased system reliability, safety, and functionality are some of the benefits of the program.

Estimated Cost= $ 110,057.00 ***-- NF Service Area Project #2014-0006***

- **Overhead to Underground Primary Conversion-Rolling Acres Subdivision Phase I**

Phase I project scope involves the relocation of primary facilities located on an inaccessible rear lot pole line within private property, for which easement documentation is available. Directional boring would be used to install 2.1KM of Primary duct to 7 pad-mounted transformers placed on precast pads within the Road Allowance. Secondary laterals will be directionally bored back to the rear lot easements, to source the 106 individual house services currently fed underground from existing junction boxes mounted on the poles. The streets included within this Phase include Oxford, Wiltshire, Valour, Yale, Harvard, Varsity, McGill, & Eton. The current equipment was installed in 1959 and tree growth, pool, shed and fencing installations, have made the line difficult to maintain and service. 15KV rated equipment will be installed for future voltage conversion, once all the phases have been completed.

Estimated Cost = $ 768,694.00 ***- - NF Service Area —Project #2014-0008***

- **3-M-28 3-M-26 & 3-M-29 Feeder Replacement.**

The project scope involves the installation of 2-new manhole assemblies within the Municipal R.O.W. outside of Murray Transformer Station, including the replacement of existing directly buried feeder conductors within existing duct structures installed previously, from the feeder breakers, with approximately 3.0KM of 600 MCM Underground primary cables total, and termination of 4-sets of 3 phase primary T-OP Terminations at the proposed metering units. Benefits include provisions for resolution of the expired wholesale metering points on the feeders (metering as a separate project), improved supply reliability to the tourist core, with the introduction of new supply cables.

Estimated Cost = $ 417,730.73 ***- - N.F. Service Area -—Project #2014-0009***

- **Additional Sectionalizing Switches—8-Units**

A review of existing feeder configurations, sourced by Stanley, Murray, Beamsville & Niagara West Transformer Stations , Kalar M.T.S. and Vineland D.S., utilizing system optimization software, has identified a need for additional pole mounted ganged load break switches within the system, minimizing system losses, providing improved contingency options during outage events, providing a means to minimize the area affected. The program will target the installation of 8 additional units.

Estimated Cost= $ 100,000.00 ***-- Combined Service Area Project #2014-0010***

- **<u>Carry-over</u>-Dorchester Rd. — Garden Street to McMillan Drive**

Completion of the replacement of 1.5 KM. of existing overhead single circuit 5 KV line (F-222) with a 15 KV single circuit 3-phase line (3-M-51) on 50’ poles on Dorchester Rd. between Garden St & McMillan Dr. The poles will maintain the same alignment as the existing 4.16KV pole line currently in service. System benefits include the replacement of aging equipment, improved equipment clearances, additional ties between Murray T.S & Kalar M.S. and the reduction of load on Municipal Substation #22 with conversion of some laterals to the new supply. New equipment will have the ability to add an additional 13.8 K.V. circuit in the future. 38-new 50’ poles, 1.5KM. of 556 MCM conductor. Poles & primary conductors were installed in 2013.

Estimated Cost= $ 362,018.17 ***-- NF Service Area Project #2014-0011***

- **Stanley T.S. Tie to the 12-M-2.**

The project scope involves the relocation of overhead feeder conductors which egress from an existing overhead structure to feeder breakers, within Stanley T.S. Currently the 12-M-1 & 12-M-4 breakers are backed up within the Station by alternate Feeder breakers (12-M-2, 12-M-3) which are under Hydro One control. By swapping control of either of the Hydro One controlled positions, NPEI could transfer loads between feeders under their jurisdiction, improving load transfer capabilities for maintenance and system contingencies for either party.

Estimated Cost = $ 19,555.62 - - N.F. Service Area -—Project #2014-0012

- **Replacement of Transformers with >50PPM PCB Content.**

The second phase of the three year transformer testing program has been completed within the West Service Territory resulting in the requirement to replace 50 units identified as having over the Legislated limit. The program will track these change-outs which will likely include the replacement of the pole supporting the unit with associated transfers, removals and disposal costs.
The third and final round of testing will begin in May of 2014.

Estimated Costs: $ 566,478.91 --PW Service Area --Project #2014-0014

- **Jordan Road—Red Maple to the QEW**

The Project Scope involves the rebuild of existing 3-phase 8320Volt primary line, in place, constructed to 27.6KV standards for approx 2.0 KM involving the installation of 34-new 45' poles, transfer of existing primary conductors, and installation of 2.0km of new neutral. The project was driven by the pole inspection program which has identified a high number of deteriorated cross arms supporting the primary conductors. Benefits include elimination of the identified hazard, improved equipment clearance, and provisions for future conversion to 27.6KV of the feeders supplied by Jordan M.S. for its eventual de-commissioning.

Estimated Cost = $ 397,516.10 -- West Service Area Project #2014-0015

- **Municipal Sub-station Rehabilitation**

NPEI has been de-commissioning 4.16KV Municipal Stations through voltage conversion projects since the 1990's, however , in order to support areas which are difficult to convert economically and quickly, replacement/rehabilitation of 13.8/4.16 kV Distribution Station components becomes necessary. Containing high & low voltage switchgear installed in 1971, Allendale Station #8 has been targeted for re-hab, as it is an integral link between Station #10 and Station #7. This particular installation is twinned, with 2-transformers and 2-low voltage switchgear line-ups. Scope includes removal of one side of the Station, replacement of the air insulated low voltage switchgear with new pad-mounted reclosures and switchgear, re-commissioning the existing 4000KVA Transformer, installation of an oil containment system, and a pole mounted high voltage electronic re-closure with Wi-Max capability . All equipment will be located within the present compound, existing equipment will be isolated and removed utilizing existing ties from Municipal Station #7 & #10.

Estimated Cost: $ 252,037.12 -- NF Service Area Project #2014-0017

- **King Street—27.6 K.V. Extension to Martin Rd.**

The Project Scope involves the rebuild of existing 1-phase 16KV primary line west of Martin Ave to the 3-phase dead-end, in place, and constructed to 3-phase 27.6KV for approx 280 M. Construction involves the installation of 8-new 45' poles, transfer of 1-primary riser, and installation of 165 m of new 3-phase from Rittenhouse Road to Martin Rd, and removal of 6-existing poles. Benefits include improved supply reliability and flexibility on the system during contingencies & system configuration.

Estimated Cost = $ 112,554.45 -- West Service Area Project #2014-0018

- **Lightning Mitigation Measures-**

The project scope involves the required introduction of additional lightning mitigation equipment throughout the distribution system within the Western Service Territory as identified through recent storm related equipment failure events. Benefits include improved reliability indices by reducing the amount of equipment damaged during storm events, improving outage restoration times.

Estimated Cost = $ 30,000.00 ***- - West Service Area —Project #2014-0019***

2. Line Relocations due to Municipal Road Improvement requirements.

An allowance is maintained for the construction of new distribution facilities to resolve conflicts with planned road works by such Governmental Agencies as 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. Tracking is accomplished with individual Project Numbers.

Estimated Costs: $520,352.79 (recoverable $125,000) ***-- Combined Service Area***

3. **Replacement of Poles identified with limited Structural Integrity.**

Natural degradation of wooden utility poles is an ongoing issue that is monitored through a 5-year cyclic field evaluation process and addressed by replacing subject poles through this Capital Program. In the Niagara Area pole replacements are beginning to level off as cycles begin to repeat, with a structured treatment program being implemented during the testing cycle to increase the Poles Life Cycle. The 2014 Niagara test area is bounded in the South by Thorold Stone Road, West to Thorold Town Line, North to Mountain Road, and East to Stanley Ave/Whirlpool Road. Western Service Territory testing area would be Lake Ontario to the North, south to King Street excluding Beamsville, East to Ninth Street, and West to Thirty Road. The 2013 Testing Program has identified 62-Poles in Niagara and 16-Poles within the West service area as requiring immediate replacement, and 47-poles in Niagara and 32-poles in the West as reaching the “replace within 5-years” milestone. The average cost per pole change is approximately $ 5,000.

Estimated Costs: $ 778,701.56 ***--Combined Service Area --Project #2014-1010/2010***

4. **Overhead line rebuilds of facilities identified by the Pole Inspection Survey.**

This Capital Program targets overhead distribution facilities identified at end of life, determined from results of the Pole Testing Program. Existing overhead distribution equipment at these locations, are replaced with new overhead facilities incorporating new poles, conductors and transformers to maximize efficiency, reliability and the ability for conversion to a higher distribution voltage as warranted. For 2014 this program targets 1.7 kilometers of urban distribution line installed in 1960, including 58 pole changes, new single phase primary and secondary circuits, 10 distribution transformer replacements resulting in the upgraded supply to about 125 residential customers in the area bounded by Dorchester Rd., Lundy’s Lane, Coach Drive, Clare Crescent, Brookfield Avenue & Barker Street.

Estimated cost: $ 516,512.62 ***-- NF Service Area Project #2014-0007***

5. Replacement of Submersibles & Kiosks with EFD switches and posi-tects.

This Capital Program is an integral part of the remediation of underground distribution systems, increasing longevity and reliability within the area serviced. Equipment contained within these structures include, transformers, primary sectionalizing & protection components, and secondary distribution equipment. As these legacy components are replaced, safety, reliability and service quality are significantly improved. In 1994 the kiosk replacement program was initiated with 725 locations identified for replacement and are prioritized utilizing the results of the 5-year Conditional Assessment Survey last completed in 2013. 57-Units remain on the 15KV System, 8 were converted in 2013, 74-Units remain on the 5KV System, 4 were converted in 2013, 5-Submersible units were

also converted to pad-mounts with only 4 remaining on the system. For 2013 the plan is to replace 10 to 15 units.
Estimated cost: $624,456.69 ***-- Combined Service Area Project #2014-0020***

6. System Sustainment Allowance.

This Capital Program manages an allowance for minor projects initiated by unexpected failures/deficiencies of overhead and underground distribution facilities. Replacement of underground cable experiencing repeated failures, is a major contributor covered by this allowance. Minor overhead system modifications and component replacements are also accounted for.
Estimated cost: $ 400,000 ***-- Combined Service Area-- Project #2014-1007/2007***

7. Subdivisions and new residential services

Estimated cost:	***Lot servicing of existing***	***$200,000***
	Connection and energizing of new subs	***$200,000***
	Lot connection rebates	***$150,000***
	Recoverable	***($200,000)***

8. Demand based system reinforcements for new commercial service connections.

This Capital Program manages an allowance for the construction/upgrade of distribution equipment to facilitate connection of new commercial developments. Expansions and reinforcement to the distribution system resulting from these new customer connection requirements fall under this budget allowance.
Estimated Costs: $1,410,778.00 ***–Combined Area-- Project #2014-1008/2008***
(recoverable $450,000)

7. Metering

Wholesale meters	$400,000
Metering general	$130,000
Metering recoverable	($25,000)

APPENDIX C

General Equipment

	2014 Budget
Ergonomic Office Equipment	8,500
Office furniture Operations area	70,000
Photocopier	20,000
Security cameras and access Stores and Operations Area	25,000
Security cameras front entrance	4,500
Outside Security System Upgrade Smithville Service Centre	2,500
Relocate original PTZ to a location behind the Quonset Hut	4,000
Security cameras fuel pump location Smithville Service Centre	6,000
5 Defibulators	12,500
General Equipment as needed	4,000
Total	**157,000**

APPENDIX D

Hardware

Project	Quantity	Budget 2014
LTO5 Tape Drive for HDIM Repo Backups	1	4,000
Replacement for Equallogic PS 5000 - end of life > 5 years old	1	58,000
Replacement Blade for Microsoft Dynamics (Great Plains Upgrade)	1	10,000
VM ware server in Smithville	1	10,000
Apollo Web Server	1	10,000
Upgrade RAM on ESX hosts	1	10,000
Possible Storage Upgrade to Filenexus server	1	10,000
Barcode server in NF & DR Server for Barcode	2	20,000
5 Barcode handhelds	5	5,000
Headsets	5	1,500
Signature Pads	1	600
Phones		
Phones for new office area		10,240
Cell phones	33	23,100
Network		
Data Switches for new contruction area in Stores		12,000
Avaya Swith - 5520 - Backup	2	12,000
Printers		
Lexmark T652 printer - compliance replacement	1	3,500
Fujitsu scanners (Engineering, Conservation)	2	19,600
Sue Barnes printer	1	500
Chris E printer	1	500
Bonnie printer	1	500
PC Replacement		
Niagara Fall's PC	34	34,000
Smithville PC	13	13,000
	47	
Metershop Renovations		
PC Metershop (Cliff, Scott, Metertechs)	3	3,000
Metershop Test Board PC Upgrade + Test Board Firmware	1	10,000
	4	
Replacement Monitors		
Current monitors are 10 years old.	20	6,000
Workforce Tablets	6	10,000
Total Hardware		**297,040**

APPENDIX E

Software

Project	Budget 2014
Microsoft Developer Network	7,200
Great Plains 2013 upgrade	30,000
Great Plains reports	10,000
Accellos bar code software	50,000
File Nexus conversion - Engineering, CDM, Human Resources customization	50,000
Automation Platform customization of rules	25,000
Appollo workflow form updates - account change request, request for information,	25,000
Cognos Reports resource	25,000
Network Security	
Malware Protection Appliance (Fireeye or Host Blue Cost Blade Solution)	40,000
Professional Services	
Backup A/C in NFLS	30,670
Upgrade Liebert UPS batteries in NFLS	7,340
Upgrade UPS batteries in SMTH	8,500
Dell Professional Services for SAN	3,000
Layer 227 Support Services	2,000
Forsythe Services	2,000
Exchange Migration (Inhouse or Hosted)	25,000
Bell Call Flow Revamp	3,000
Mandated customer service survey	21,000
Security Audit - Network	45,000
Security Audit - Web applications	15,000
Disaster Recovery	
VM Services - Dell/Storage Clarity - DR - building DR plan and executing	15,000
Bell-Mitel Server VM migration	3,000
VM server licenses - DR (10)	12,000
VM Backup Solution (VEEM, Hitachi, Symantec)	20,000
Other	
Bill Presentment changes	24,000
Total Software	498,710

APPENDIX F
Vehicles and Stores Equipment 2014

Description	Budget
Vehicles > 3 tonnes	
1) Purchase a 55ft. double bucket material handling aerial manlift installed on a 2014 chassis. This will replace Truck SV11 which is a 2001 Sterling Acterra Hi Ranger 46ft material handler.	350,000
2) Purchase of a 46ft. Material Handling Aerial Manlift and Fiberglass Body to be installed on a 2014 chassis. This will replace NF 43 which is a 1996 International with a aerial material handler mounted on its chassis.	300,000
Total	650,000

Transportation Equipment

Purchase of a 2014, pole carrying galvanized extendable trailer, (8300)kg with a single axle to carry 65ft poles	22,000
	22,000

Stores Equipment

Inventory Racking NF stores	75,000
Total	**75,000**

APPENDIX G

Tools Budget 2014

Tools and Equipment for Vehicles

	Total
Phasing Sticks	3,500
Trac Mats -	1,500
Hydraulic Drills	7,200
Fibre Insulating cover up	4,000
Various Duct Rollers for Underground Cable	2,200
Gator Crimping Press - battery operated	3,600
Various replacement tools for budgeted new trucks	10,000
Miscellaneous Replacement Tools	25,000
	57,000

Tools for Garage

Rolling Safety Ladder - RBD and Aerial Inspections	1,300
Pro Link IQ diagnostic tool	6,000
Porta Power Kit	700
Various other shop tools	2,000
Total cost of equipment purchase for 2014	10,000
Total Tool Budget	67,000

APPENDIX H

Communication Equipment

	2014 Budget
Wi-max pilot project communication expansion	227,500
Total	**227,500**

Niagara Peninsula Energy Inc.
Capital Budget 2010 - 2019
(000's)

	Actual 2010	Actual 2011	Actual 2012	Projected 2013	Budget 2014	Prospective Plan 2015	Prospective Plan 2016	Prospective Plan 2017	Prospective Plan 2018	Prospective Plan 2019
Land and Land Rights	0	0	5	0	0	5	5	5	5	5
Buildings & Fixtures	67	122	626	529	1,303	0	0	0	0	0
Sub Total	67	122	631	529	1,303	5	5	5	5	5
Distribution Station	509	800	683	337	252	75	77	78	79	80
Transformer Station	11	0	0	25	0	50	21	22	22	22
Overhead Distribution	3,884	3,912	3,663	4,938	3,836	4,058	4,139	4,221	4,221	4,221
Underground Distribution	3,068	2,783	3,148	2,832	3,782	3,621	3,693	3,767	3,767	3,767
Distribution Transformers	922	1,064	1,247	1,132	1,818	1,224	1,248	1,273	1,273	1,273
Meters	148	177	171	225	602	204	208	212	212	212
Capital Contributions	(625)	(1,664)	(1,585)	(752)	(900)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)
Sub Total before unusual contributions	7,917	7,072	7,327	8,736	9,391	8,232	8,386	8,573	8,574	8,575
Office Furniture & Equipment	35	69	112	188	157	35	35	35	35	35
Computer Equipment, Hardware	258	250	371	443	297	300	300	300	300	300
Computer Software	250	194	213	246	499	250	250	250	250	250
Vehicles < 3 tonnes	44	350	104	188	22	125	125	125	125	125
Vehicles > 3 tonnes	825	189	1,056	1,040	650	700	700	700	700	700
Vehicle Disposals	0	0	0	(355)	0					
Stores Equipment	26	10	0	0	75	10	10	10	10	10
Tools, Shop & Garage Equipment	95	78	133	88	67	90	90	90	90	90
Measurement & Testing Equipment	6	15	0	0	0	0	0	0	0	0
Communication equipment	10	1	332	366	228	0	0	0	0	0
Miscellaneous equipment	5	0	0	0	0	0	0	0	0	0
Sub Total	1,554	1,156	2,322	2,204	1,994	1,510	1,510	1,510	1,510	1,510
Total Capital before non-recuring capital expenditures/(contributions)	**9,538**	**8,350**	**10,280**	**11,470**	**12,688**	**9,747**	**9,901**	**10,088**	**10,089**	**10,090**
Non-recuring Capital Expenditures										
Town of Pelham	(250)	(200)	0	0	0	0	0	0	0	0
RiverRealty Development	(210)	0	0	0	0	0	0	0	0	0
Fruitbelt Development	0	(349)	0	0	0	0	0	0	0	0
City of NF Oakwood Drive	(73)	0	0	0	0	0	0	0	0	0
Wesley Gardens Extension	0	0	0	0	0	0	0	0	0	0
Wire Building & High Mass Lighting	0	0	0	1,520	0	0	0	0	0	0
	(533)	(549)	0	1,520	0	0	0	0	0	0
Net Capital Expenditures	**9,005**	**7,801**	**10,280**	**12,990**	**12,688**	**9,747**	**9,901**	**10,088**	**10,089**	**10,090**

	5 year		10 year
Average Net Capital Expenditures excluding non-recurring- 5 year	**10,465**	10 Year Averag	**10,224**
Average Net Capital Expenditures including non-recuring 5 year	**10,553**	10 Year Averag	**10,268**
Average Fixed Asset additions COS rate Application 2011 net of average $850K capital contributions	**9,345**		**9,345**

Attachment 2 of 2

Management Discussion and Analysis

Management Discussion and Analysis

NPEI does not produce a management discussion and analysis.

Attachment 1 of 1

Rating Agency Report

Rating Agency Report

NPEI does not have a rating agency report.

Attachment 1 of 1

Recent or Planned Public Debt/Equity Offering

Recent or Planned Public Debt/Equity Offering

NPEI has not had a recent public debt/equity offering and does not have a public debt/equity offering planned.

File Number: EB-2014-0096

Date Filed: September 23, 2014

Exhibit 1

Tab 5 of 6

Materiality Threshold

Materiality Threshold

NPEI's estimated distribution revenue requirement is $29,374,853. As per the OEB's chapter 2 filing requirements, dated July 17, 2013, section 2.4.4, NPEI's materiality threshold is calculated at 0.5% of distribution revenue. The table below shows a detailed calculation of the materiality threshold used in the 2015 COS rate application in the amount of $146,874.

Materiality Threshold Calculation

Service Revenue Requirement	30,971,328
(from Revenue Deficiency Calculation)	
Less Revenue Offsets	(1,596,475)
Base Revenue Requirement	**29,374,853**
Variance Calculation 0.5% of Distribution Revenue Requirement	**$ 146,874**

File Number: EB-2014-0096

Date Filed: September 23, 2014

Exhibit 1

Tab 6 of 6

Administration

Abbreviations and Defined Terms

ABBREVIATIONS

Abbreviation	Meaning
NPEI	Niagara Peninsula Energy Inc.
AMCD	Advanced Metering Communications Device
AMI	Advanced Metering Infrastructure
AMP	Asset Management Plan
APH	Accounting Procedures Handbook
ARC	Affiliate Relationships Code for Electricity Transmitters and Distributors
BRR	Base Revenue Requirement
CAIDI	Customer Average Interruption Duration Index
Canadian AcSB	Canadian Accounting Standards Board
CCA	Capital Cost Allowance
CDM	Conservation and Demand Management
CGAAP	Canadian Generally Accepted Accounting Principles
CICA	Canadian Institute of Chartered Accountants
CIS	Customer Information System
CPI	Consumer Price Index
DAMP	Distribution Asset Management Plan
DRC	Debt Retirement Charge
DSP	Distribution System Plan
EDA	Electricity Distributors Association
EDR	Electricity Distribution Rate
FAQs	Frequently Asked Questions
Filing Requirements	Update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, July 17, 2013

Abbreviation	**Meaning**
FMV	Fair Market Value
FTE	Full Time Equivalent
GA	Global Adjustment
GEA	Green Energy and Green Economy Act
GIS	Geographic Information System
GS < 50 kW	General Service Less Than 50 kW
GS > 50 kW	General Service Greater Than 50 kW
HST	Harmonized Sales Tax
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
IRM	Incentive Regulation Mechanism
IRM3	Third Generation Incentive Regulation Mechanism
IT	Information Technology
kW	KiloWatt
kWh	KiloWatt hour
LDC	Local Distribution Company
LEAP	Low-Income Energy Consumer Program
LRAM	Lost Revenue Adjustment Mechanism
LV	Low Voltage
MDM/R	Meter Data Management/Repository
MIFRS	Modified International Financial Reporting Standards
MSC	Monthly Service Charge
NBV	Net Book Value
non RPP	Non-Regulated Price Plan
O&M	Operations and Maintenance
OCEB	Ontario Clean Energy Benefit
OM&A	Operations, Maintenance and Administration
OMERS	Ontario Municipal Employees Retirement System
OMS	Outage Management System

Abbreviation	Meaning
OPA	Ontario Power Authority
PCBs	Polychlorinated Biphenyls
PILs	Payments in Lieu of Taxes
PP&E	Property, plant and equipment
RFP	Request for Proposal
ROE	Return on Equity
RPP	Regulated Price Plan
RRR	Reporting and Record Keeping Requirements
RSVA	Retail Settlement Variance Account
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SL	Streetlight Customer
SM	Smart Meters
SMDR	Smart Meter Disposition Rider
SMFA	Smart Meter Funding Adder
STRs	Service transaction requests
the Board or the OEB	Ontario Energy Board
the IESO	Independent Electricity System Operator
the OEB Act	Ontario Energy Board Act
TOU	Time of Use
UCC	Un-depreciated Capital Cost
USL	Unmetered Scattered Load
USoA	Uniform System of Accounts
WCA	Working Capital Allowance
WMP	Wholesale Market Participant

TERMS

Term	**Defined Term**
Historical Years	2011, 2012, 2013
Most Recent Board Approved Test Year	2011
Bridge Year	2014
Test Year	2015

Statement as to who is affected by application

All of Niagara Peninsula Energy's customers may be affected by this application.

Statement of publication

NPEI plans to publish the notice of application in the local paper as follows:

- Publication of the English version of the Notice of Application for an Electricity Distribution Rate Change in the Niagara Falls Review, the West Niagara News and the Lincoln Grimsby News within fourteen days of receiving the Board's Letter of Direction and Notice of Application. The Niagara Falls Review is the newspaper having the highest paid circulation in the service area, according to the best information available.

- Make a copy of the application and evidence available for public review at Niagara Peninsula Energy's offices.

- Will make a copy of the application and evidence, and any amendments thereto, available to any intervenor requesting the material.

Applicants internet access

Niagara Peninsula’s website address is www.npei.ca.

Application contact information

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Statement of Representation

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 pursuant to section 78 of the Ontario Energy Board Act, 1998 for 2015 distribution rates and related matters.

APPLICATION:

1. The Applicant is 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 is a licensed electricity distributor operating pursuant to license ED-2007-0749. NPEI carries on the business of distributing electricity to approximately 51,500 customers within the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham pursuant to a distribution license (ED-2007-0749) issued by the Ontario Energy Board (the "Board") and charges Board authorized rates (EB-2013-0154) for the distribution service it provides.

2. NPEI hereby applies to the Ontario Energy Board (the "OEB") for an order or orders made pursuant to Section 78 of the *Ontario Energy Board Act, 1998 (the "OEB Act")*, as amended, approving just and reasonable rates for the distribution of electricity based on a 2015 Test Year, effective May 1, 2015.

3. NPEI followed Chapter 2 of the OEB's Filing Requirements for Transmission and Distribution Applications dated July 18, 2014 and Chapter 5 of the OEB's Filing Requirements for the Consolidated Distribution System Plan dated March 28, 2013.

4. The 2015 distribution rates proposed by the Applicant will result in overall bill impacts for residential, GS < 50kW, GS>50kW, Unmetered Scattered Load (USL), sentinel and street light customers as detailed in Table 1-1 below. A full list of the bill impacts applicable to all customer classes is found at E8/T13/S1/Att1. The proposed schedule of rates and charges in this Application are identified in E8/T11/S1/Att.2.

Table of Bill Impacts

Monthly Bill Impacts
Summary

	Volume		Total Distribution Charges only excluding Pass through		Total Delivery Charges including Distribution		Total Bill	
Customer Class	kWh	kW	$ Change	% Change	$ Change	% Change	$ Change	% Change
Residential	800		$ 0.81	2.73%	$ 4.72	11.53%	$ 4.77	3.74%
GS<50 kw	2000		$ (4.21)	-6.06%	$ 4.77	5.13%	$ 4.77	1.54%
GS>50 kW	65000	180	$ (306.49)	-32.51%	$ (50.94)	-2.83%	$ (54.84)	-0.62%
USL	250		$ (0.04)	-0.17%	$ 1.28	4.97%	$ 1.29	2.42%
Sentinel	44	0.12	$ 2.61	17.67%	$ 3.12	20.54%	$ 3.17	15.73%
Streetlighting	50	0.13	$ (0.08)	-4.42%	$ 0.52	23.60%	$ 0.52	6.87%

5. This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on this Application.

6. The Applicant certifies that the information provided in this application is accurate at the time of this filing.

7. NPEI acknowledges that the Board will publish an update to the Rate of Return and Short Term Debt Rate and that these matters will affect the Revenue Requirement that NPEI has requested in this Application.

8. The Applicant requests that a copy of all documents filed with the Board in this proceeding be served on the Applicant.

9. NPEI requests that the OEB make its Rate Order effective May 1, 2015 in accordance with the Filing Requirements. NPEI is not seeking to align its rate year with its fiscal year in the 2015 Cost of Service rate Application.

10. NPEI applies for an Order or Orders approving the proposed distribution rates and other charges set out in the Proposed Rate Tariff in E8/T11/S1/Att.2 as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2015, or as soon as possible thereafter; and

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

DATED at: Niagara Falls, Ontario. This 23rd day of September, 2014.

All of which is respectfully submitted,

Original Signed By

Suzanne Wilson, CPA, CA
Vice-President, Finance
Niagara Peninsula Energy Inc.

Rate Order Requirement for Implementation

NPEI would require a final rate order by April 30, 2015 in order to implement rates for May 1, 2015.

Subject to timing of the approval of the Board's Decision and Order with respect to this application, NPEI respectfully request that the implementation date be May 1, 2015 and that an interim rate order be approved.

Bill Impacts for public notice of application

The 2015 distribution rates proposed by the Applicant will result in overall bill impacts for residential, GS<50kW, GS>50kW, unmetered scattered load (USL), sentinel lights and street light customer classes as detailed in Table 1-16 below. A full list of the bill impacts applicable to all customer classes is found in E8/T11/S1/Att.2.

Table 1-16 Monthly Bill Impacts Delivery and Total Bill

Customer Class	Volume kWh	Volume kW	2014 Distribution Charges	2015 Proposed Distribution Charge	Distribution Charges $ Change	Distribution Charges % Change	2014 Total Bill	2015 Proposed Total Bill	Total Bill $ Change	Total Bill % Change
Residential	800		$ 30.49	$ 34.87	$ 4.38	14.37%	$ 125.19	$ 129.95	$ 4.76	3.80%
GS<50 kw	2000		$ 92.99	$ 97.76	$ 4.77	5.13%	$ 315.05	$ 319.80	$ 4.75	1.51%
GS>50 kW	65000	180	$ 1,802.84	$ 1,751.90	$ (50.94)	-2.83%	$9,359.28	$9,304.43	$ (54.85)	-0.59%
USL	250		$ 25.78	$ 27.06	$ 1.28	4.97%	$ 51.39	$ 52.69	$ 1.30	2.53%
Sentinel	44	0.12	$ 15.18	$ 18.30	$ 3.12	20.55%	$ 19.87	$ 23.04	$ 3.17	15.95%
Streetlighting	50	0.13	$ 2.19	$ 2.71	$ 0.52	23.74%	$ 7.26	$ 7.78	$ 0.52	7.16%

A summary of bill impacts as per sub-total A of Appendix 2-W for all of NPEI's customer classes are illustrated in Table 1-17 below. Appendix 2-W is included in E8/T13/S1/Att.1.

Table 1-17 Bill impacts distribution only

Monthly Bill Impacts
As per Sub-Total A of Appendix 2-W

Customer Class	Volume kWh	Volume kW	2014 Distribution Charges $	Proposed 2015 Distribution Charges $	Total Distribution Charges only excluding Pass through $ Change	Total Distribution Charges only excluding Pass through % Change
Residential	800		29.80	30.61	$ 0.81	2.73%
GS<50 kw	2000		69.41	65.20	$ (4.21)	-6.06%
GS>50 kW	65000	180	942.78	636.29	$ (306.49)	-32.51%
USL	250		22.96	22.92	$ (0.04)	-0.17%
Sentinel	44	0.12	14.80	17.41	$ 2.61	17.67%
Streetlighting	50	0.13	1.73	1.65	$ (0.08)	-4.42%

Proposed Issues List

NPEI attended the *Orientation Session – Electricity Distributors Rebasing for 2015 Rates* at the Ontario Energy Board offices on July 24, 2014. During the "Role of the Registrar" presentation, Board Staff indicated that final issues lists for 2015 COS Applications would be established following the interrogatory phase. NPEI submits the following preliminary proposed issues list, with the understanding that the issues list will be finalized later in the proceeding.

1. **General**

   1.1 Has NPEI responded to all relevant Board directions from previous proceedings?

   1.2 What is the appropriate effective date for any new rates flowing from this Application?

2. **Rate Base**

   2.1 Is the proposed rate base for the test year appropriate?

   2.2 Is the Working Capital Allowance for the test year appropriate?

   2.3 Is the capital expenditure forecast for the test year appropriate?

   2.4 Is the capitalization policy and allocation procedure appropriate?

3. **Load Forecasting and Operating Revenue**

   3.1 Is the load forecast methodology including weather normalization appropriate?

3.2 Are the proposed customer / connections and load forecasts (both kWh and kW) for the test year appropriate?

3.3 Is the impact of CDM appropriately reflected in the load forecast?

3.4 Is the test year forecast of other revenues appropriate?

4. Operating Costs

4.1 Is the overall OM&A forecast for the test year appropriate?

4.2 Is the proposed level of depreciation/amortization expense for the test year appropriate?

4.3 Is the test year forecast of property taxes appropriate?

4.4 Is the test year forecast of PILs appropriate?

5. Capital Structure and Cost of Capital

5.1 Is the proposed capital structure, rate of return on equity and short term debt appropriate?

5.2 Is the proposed long term debt rate appropriate?

6. Calculation of Revenue Deficiency or Sufficiency

6.1 Is the calculation of revenue deficiency or sufficiency appropriate?

7. Cost Allocation

7.1 Is NPEI's cost allocation appropriate?

7.2 Are the proposed revenue-to-cost ratios for each class appropriate?

8. Rate Design

8.1 Are the fixed-variable splits for each class appropriate?

8.2 Are the proposed retail transmission service rates ("RTSR") appropriate?

8.3 Are the proposed loss factors appropriate?

9. Deferral and Variance Accounts

9.1 Are the account balances, cost allocation methodology and disposition period appropriate?

9.2 Are the proposed rate riders to dispose of the account balances appropriate?

9.3 Are the net book value and rate riders relating to Stranded Meters appropriate?

9.4 Is the proposed balance and disposition of Account 1576 – Accounting Changes Under CGAAP to be disposed appropriate?

Statement of requested hearing form

This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on the Application.

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

List of specific approvals requested

NPEI is requesting that the Board provide it with an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, as specified in this Application, to be effective May 1, 2015.

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

1. The Applicant requests that the Board approve the 2015 Schedule of Rates and Charges as found at E8/T11/S1/Att2.
2. Specifically, the Applicant hereby applies for an order or orders granting approval of:
    a. its forecasted 2015 service Revenue Requirement of $30,971,328, which leads to a base distribution Revenue Requirement of $29,374,853, net of other revenue offsets in the amount of $1,596,475;
    b. Distribution rates that allow the Applicant to recover its forecasted 2015 distribution Revenue Requirement, effective May 1, 2015;
    c. The Applicant's current distribution rates becoming interim commencing May 1, 2015 until its proposed distribution rates are implemented;
    d. The dispersal of Group 1 and 2 deferral and variance accounts as detailed at E9/T1/S1/Att.1 and additionally:
        i. The recovery of stranded meter costs of $1,283,704 collected through a rate rider over a two year period as described at E9/T3/S12.
    e. Updated Retail Transmission Service Charge rates as described at E8/T3/S1;

f. An updated loss adjustment factor based on the most recent five year average as described at E8/T9/S1;

g. Updated Low Voltage Charge rates as described at E8/T8/S1;

h. Continuation of the existing MicroFIT generator rate as described at E8/T2/S1;

i. The Specific Service Charges, as described at E8/T7/S1; and

j. The Retail Service Charges, Transformer Allowance and Primary Metering Allowance as they exist today.

Board Direction from previous EDR decisions

NPEI's last rebasing application occurred for rates effective June 1, 2011 under proceeding EB-2010-0138. The Decision and Order dated May 30, 2011, did not have any directions made by the Board.

NPEI confirms that there are no other procedural orders, accounting orders, compliance orders or other Board direction that ought to be considered in this Application.

Compliance Orders

NPEI has not received any compliance orders, nor is it aware of any areas in which it is non-compliant.

Changes in tax status

NPEI has had no changes in tax status.

Existing/proposed accounting orders

At the time of this Application, the Accounting Standard Board ("AcSB") has deferred mandatory adoption of IFRS for qualifying rate-regulated entities to January 1, 2015. However, per the Board's letter of July 17, 2012, electricity distributors electing to remain on CGAAP must implement regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. These changes are mandatory in 2013 for all distributors that have not yet made these changes, and therefore all applications for 2015 rates should reflect that these changes were made in 2012 or 2013. The 2015 Cost of Service Application is to be filed on a MIFRS accounting basis.

As such, NPEI has prepared its current application on an MIFRS basis. NPEI confirms it implemented the regulatory accounting changes for depreciation expense and capitalization policies effective January 1, 2013.

Description of applicants service area

Description of Distributor: Niagara Peninsula Energy Inc.

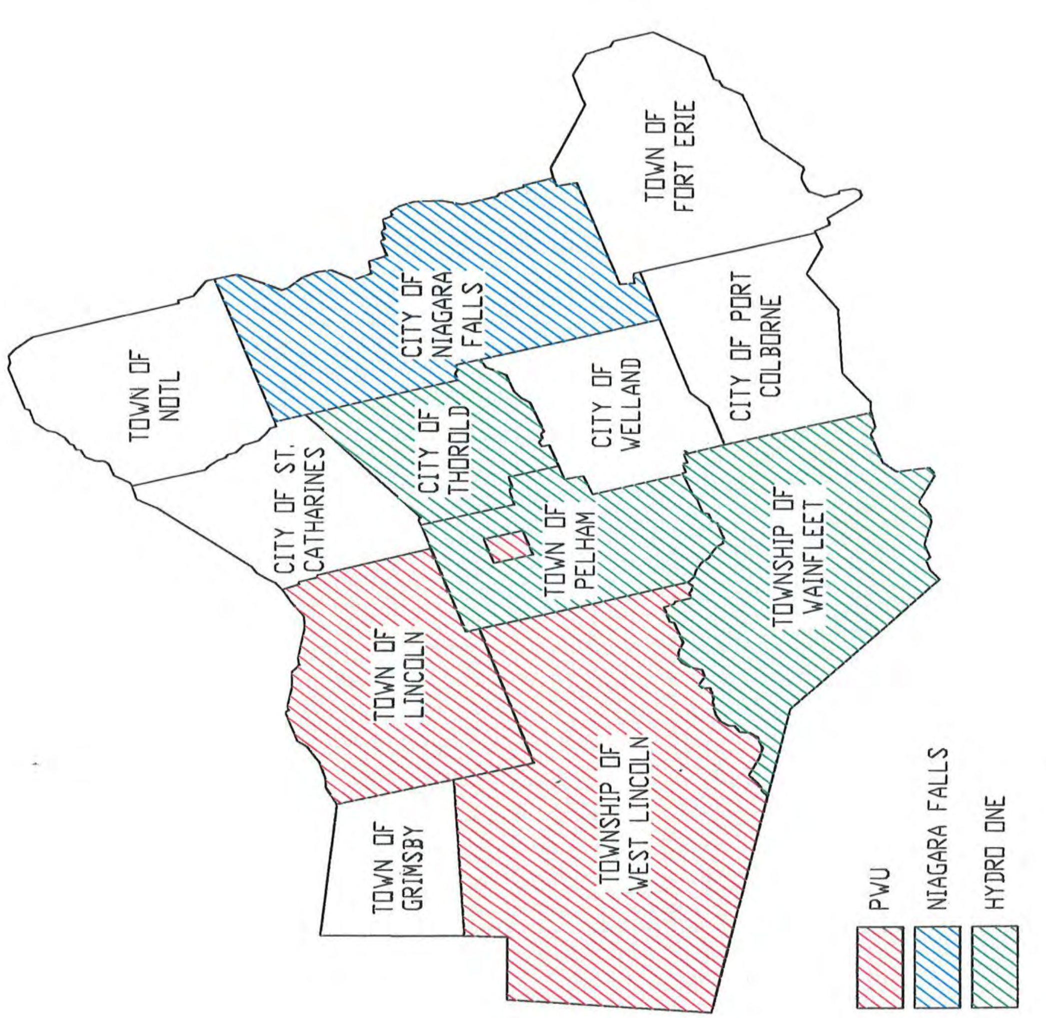
COMMUNITY SERVED:	City of Niagara Falls, Town of Lincoln Township of West Lincoln Town of Pelham
TOTAL SERVICE AREA:	827 sq km
URBAN SERVICE AREA:	68 sq km
RURAL SERVICE AREA:	759 sq km
DISTRIBUTION TYPE:	Electricity distribution
Overhead km of line	1,458
Underground km of line	519
Total km of line	1,977

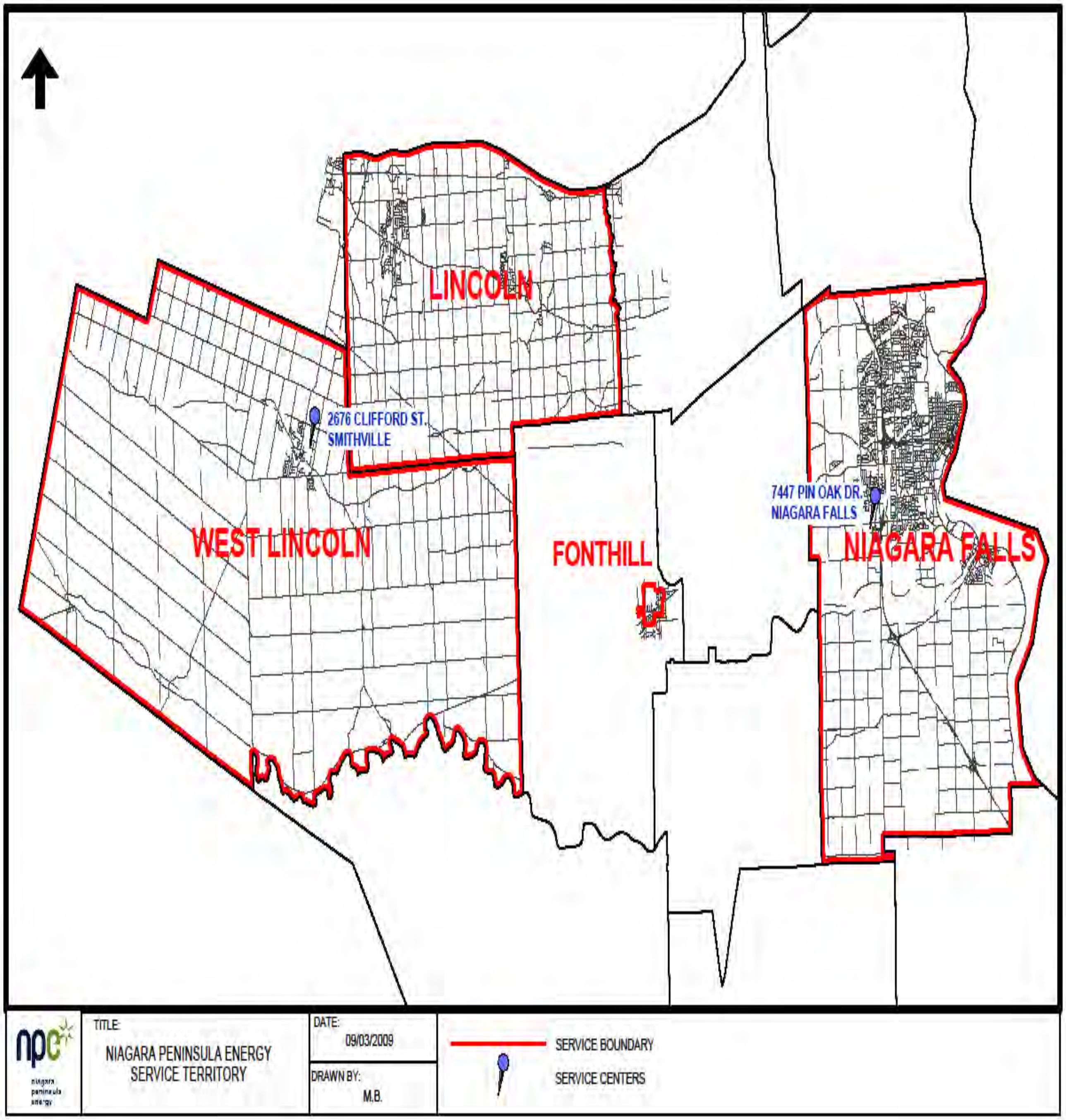
A map of the NPEI's Distribution Service Territory accompanies this Schedule as Map 1-1.

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

MAP OF DISTRIBUTION SERVICE TERRITORY

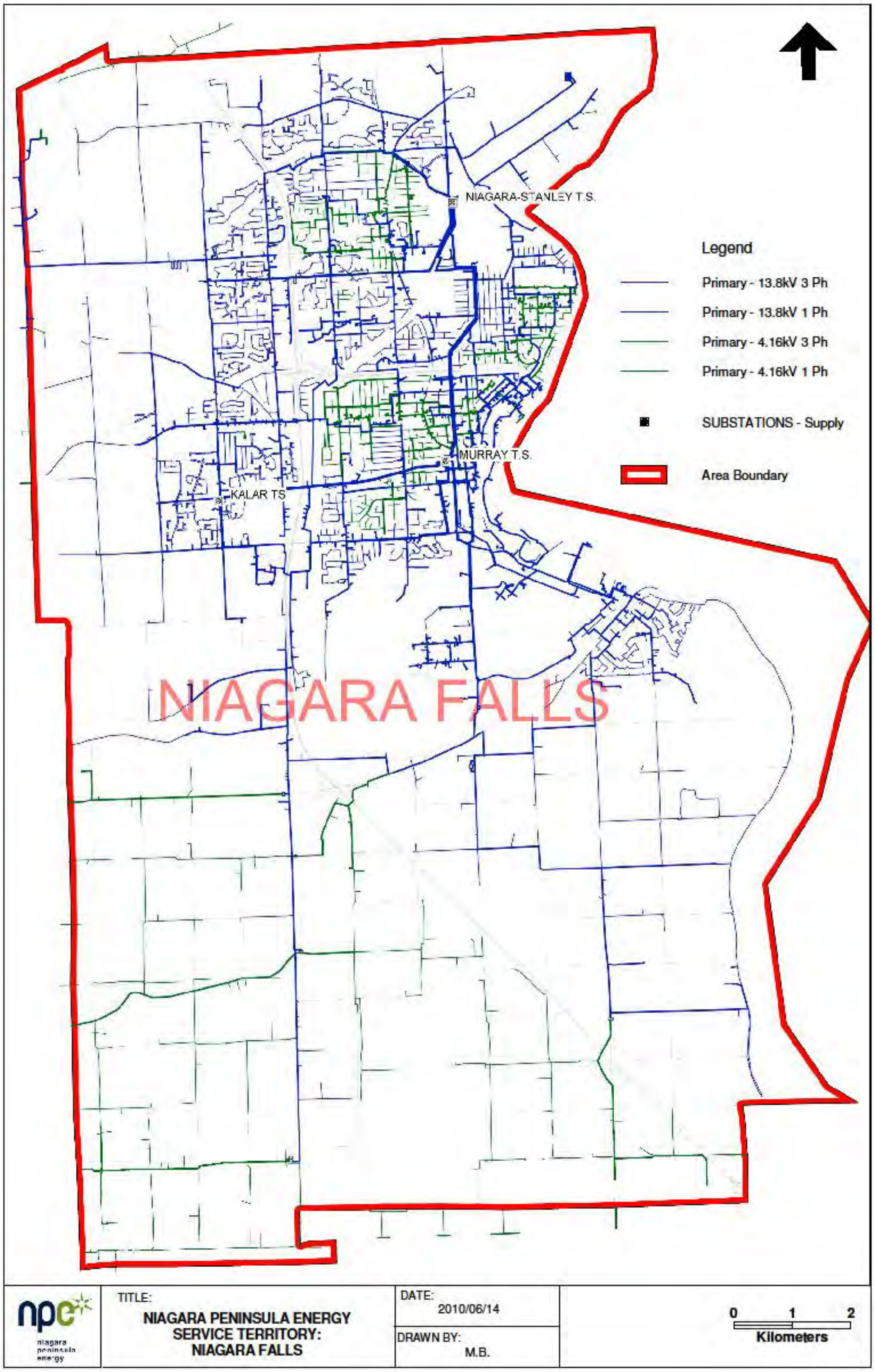
The outlined area represents the City of Niagara Falls, the Town of Lincoln, the Township of West Lincoln and the Town of Pelham. See Map 1-1 below.




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

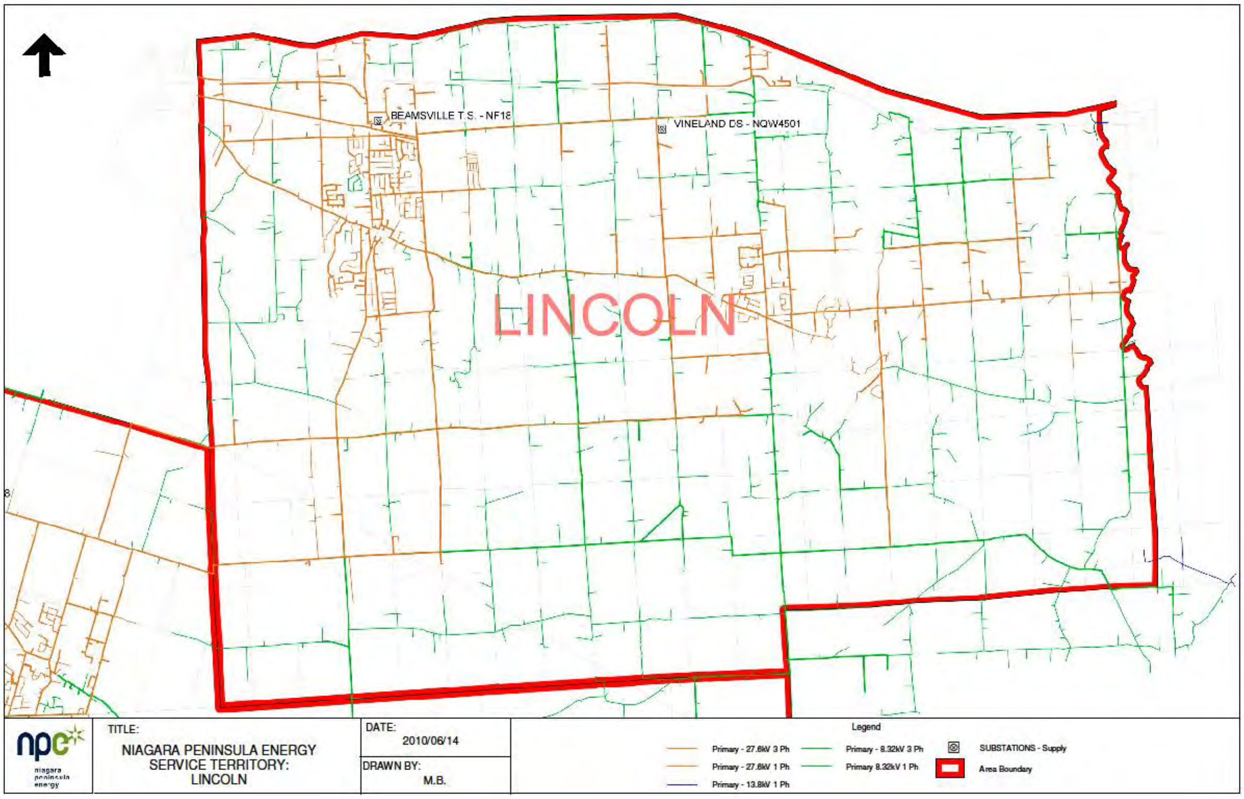
MAP 1-2 – NPEI'S DISTRIBUTION SYSTEM – NIAGARA FALLS

MAP OF DISTRIBUTION SYSTEM

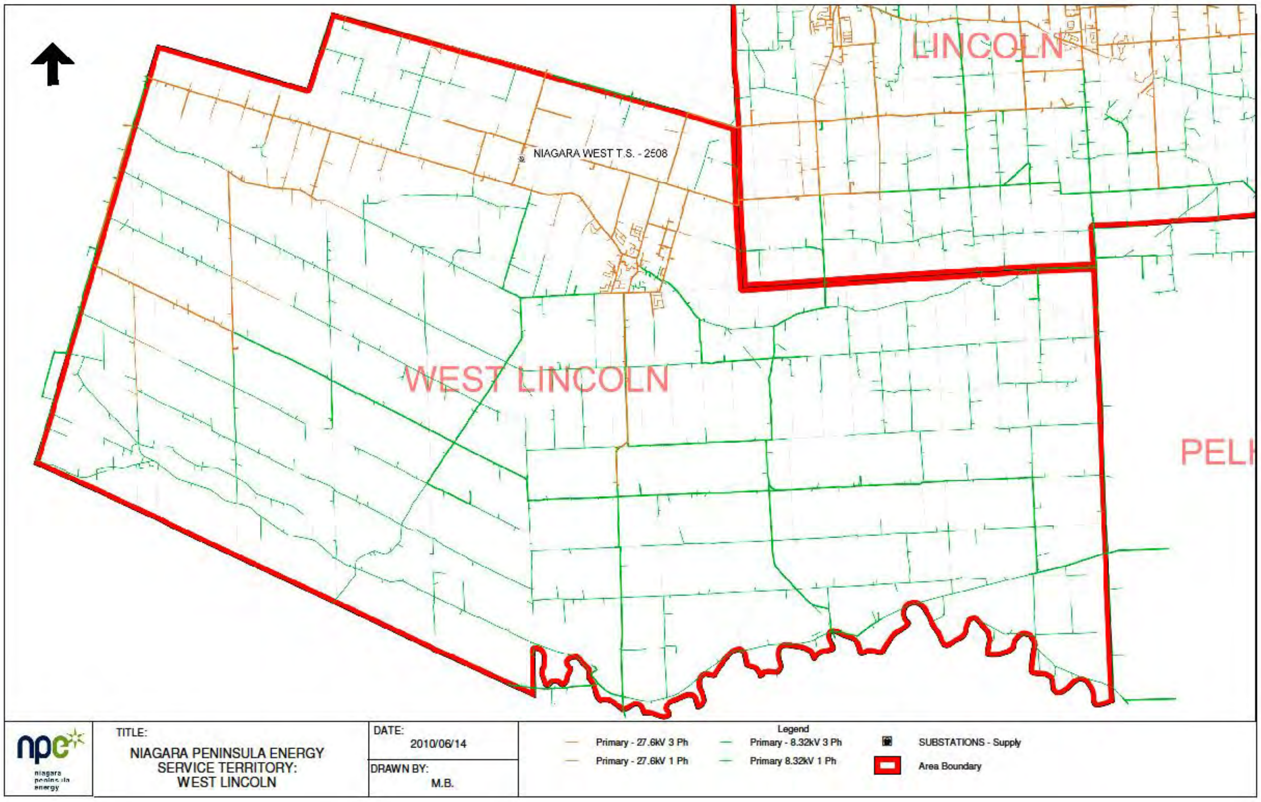

NIAGARA-STANLEY T.S.
MURRAY T.S.
KALAR TS
NIAGARA FALLS
Legend
Primary - 13.8kV 3 Ph
Primary - 13.8kV 1 Ph
Primary - 4.16kV 3 Ph
Primary - 4.16kV 1 Ph
SUBSTATIONS - Supply
Area Boundary
TITLE:
NIAGARA PENINSULA ENERGY SERVICE TERRITORY: NIAGARA FALLS
DATE: 2010/06/14
DRAWN BY: M.B.
0 1 2
Kilometers

1

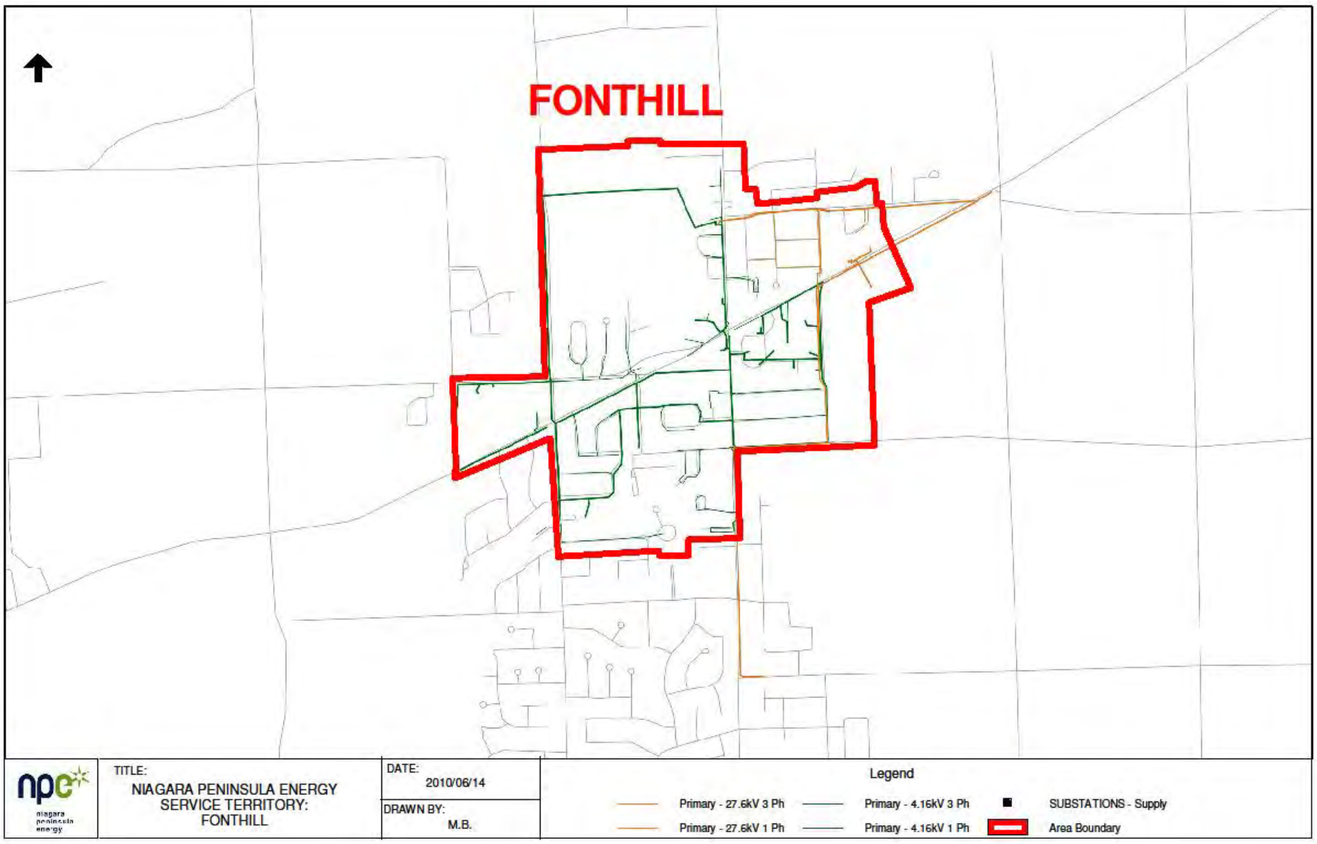
MAP 1-3 – NPEI'S DISTRIBUTION SYSTEM - LINCOLN



MAP 1-4 – NPEI'S DISTRIBUTION SYSTEM – WEST LINCOLN



1 ***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 51,500 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 519 kilometers of underground cable and 1,458 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 51,500 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 completed 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. NPEI's smart meter rate application for final disposition EB-2013-0359 was approved February 27, 2014.

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 2015 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, system configuration, and any other customer needs to determine investment needs of the system.

List of Neighboring Utilities

NPEI is bounded by the following neighboring utilities:

Canadian Niagara Power
Welland Hydro
Niagara-on-the Lake Hydro
Hydro One
Horizon Utilities
Haldimand County Hydro
Grimsby Power

Host\Embedded Distributor

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

Corporate and utility organizational structure

NPEI's Corporate Entities chart is below in Chart 1-1 and its Utility Organization chart is below in Chart 1-2. There are no planned changes to either the Corporate Entities chart or the utility organization chart.

Chart 1-1 NPEI's Corporate Entities Chart

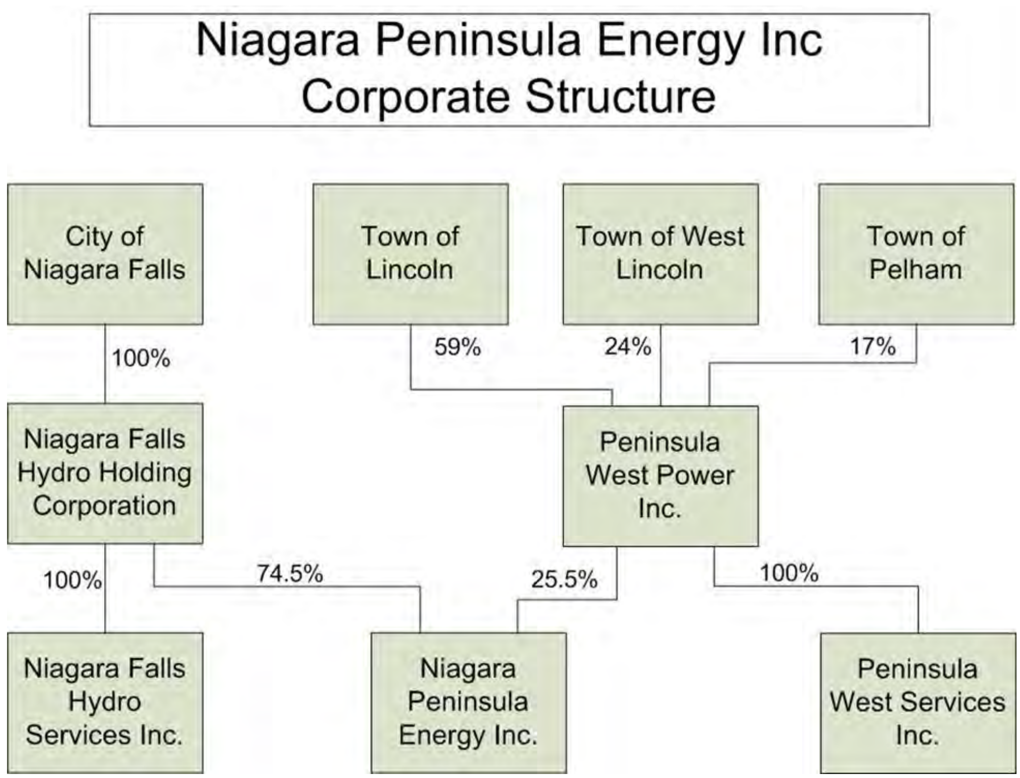
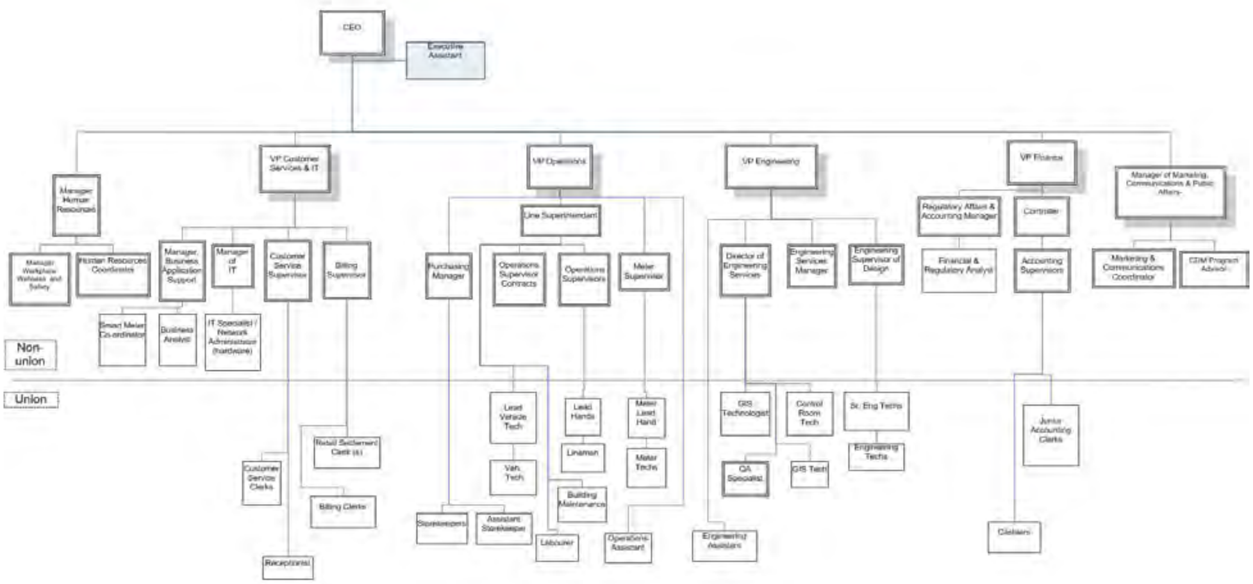
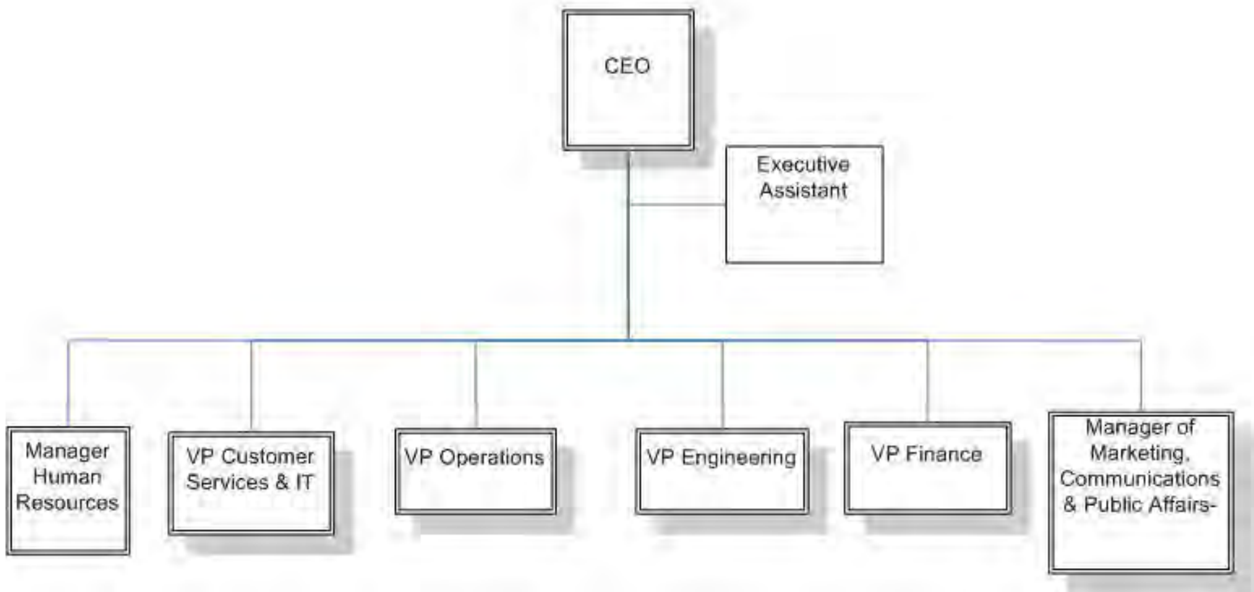


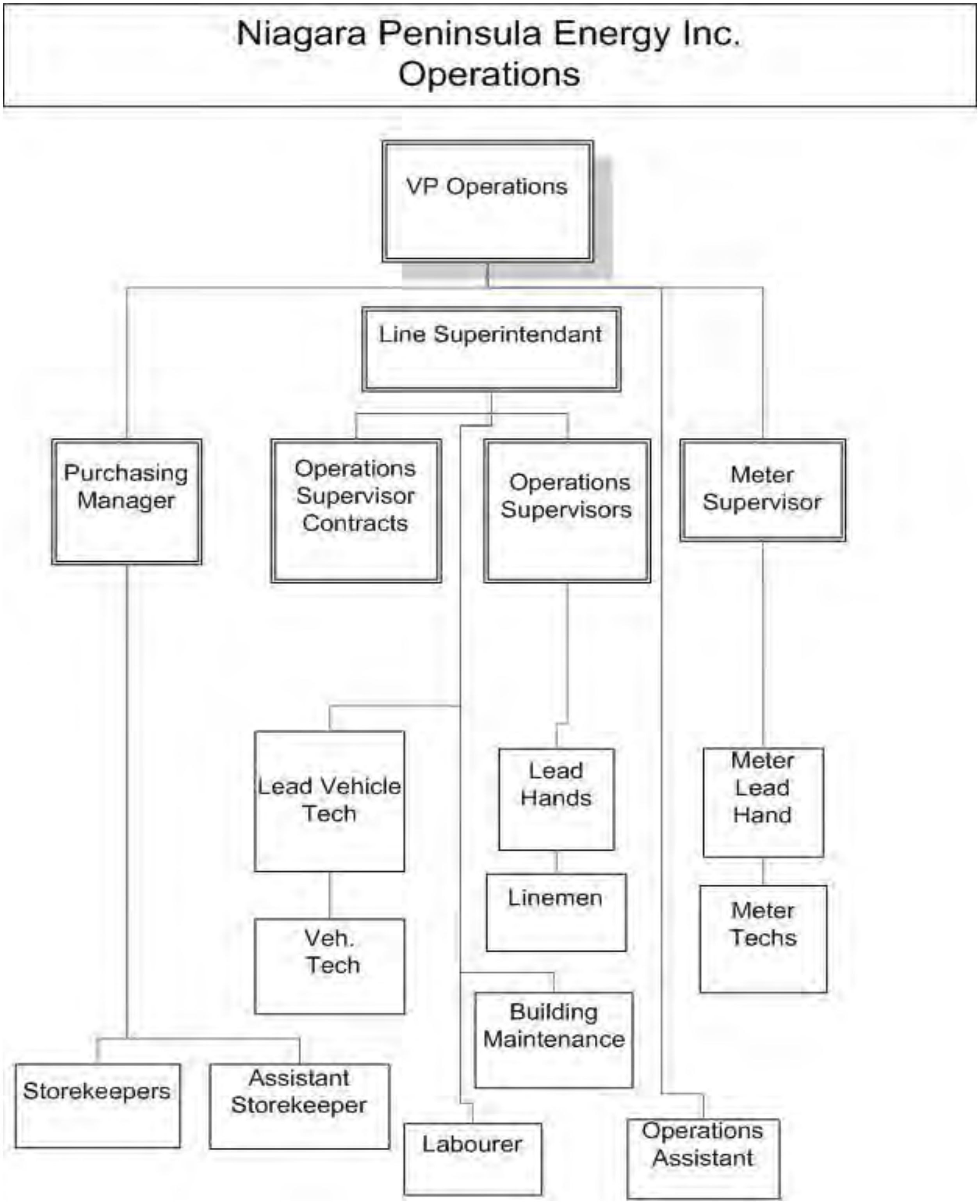
Chart 1-2 NPEI's Organization Chart

Niagara Peninsula Energy Inc

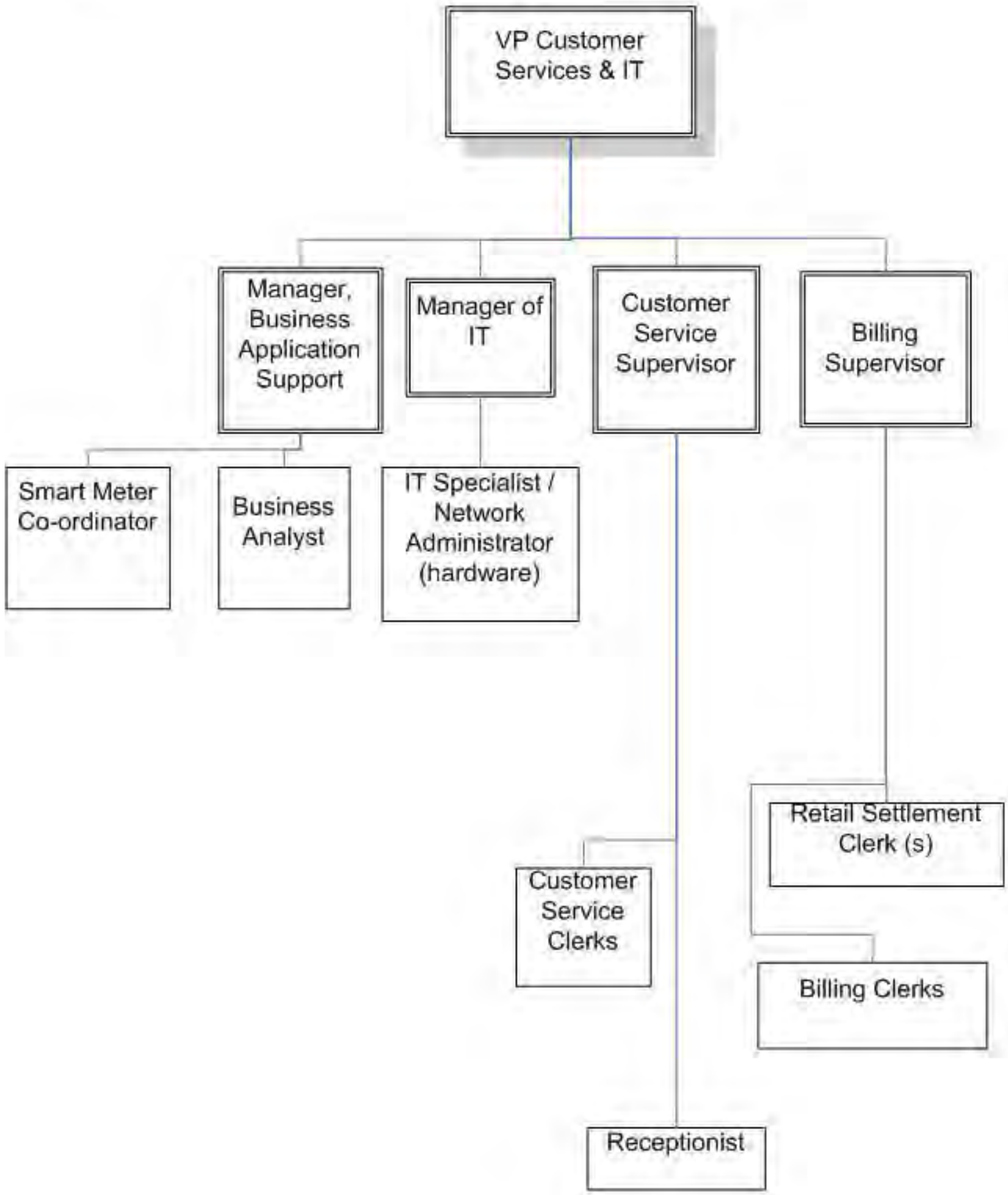


Niagara Peninsula Energy Inc.
Senior Management

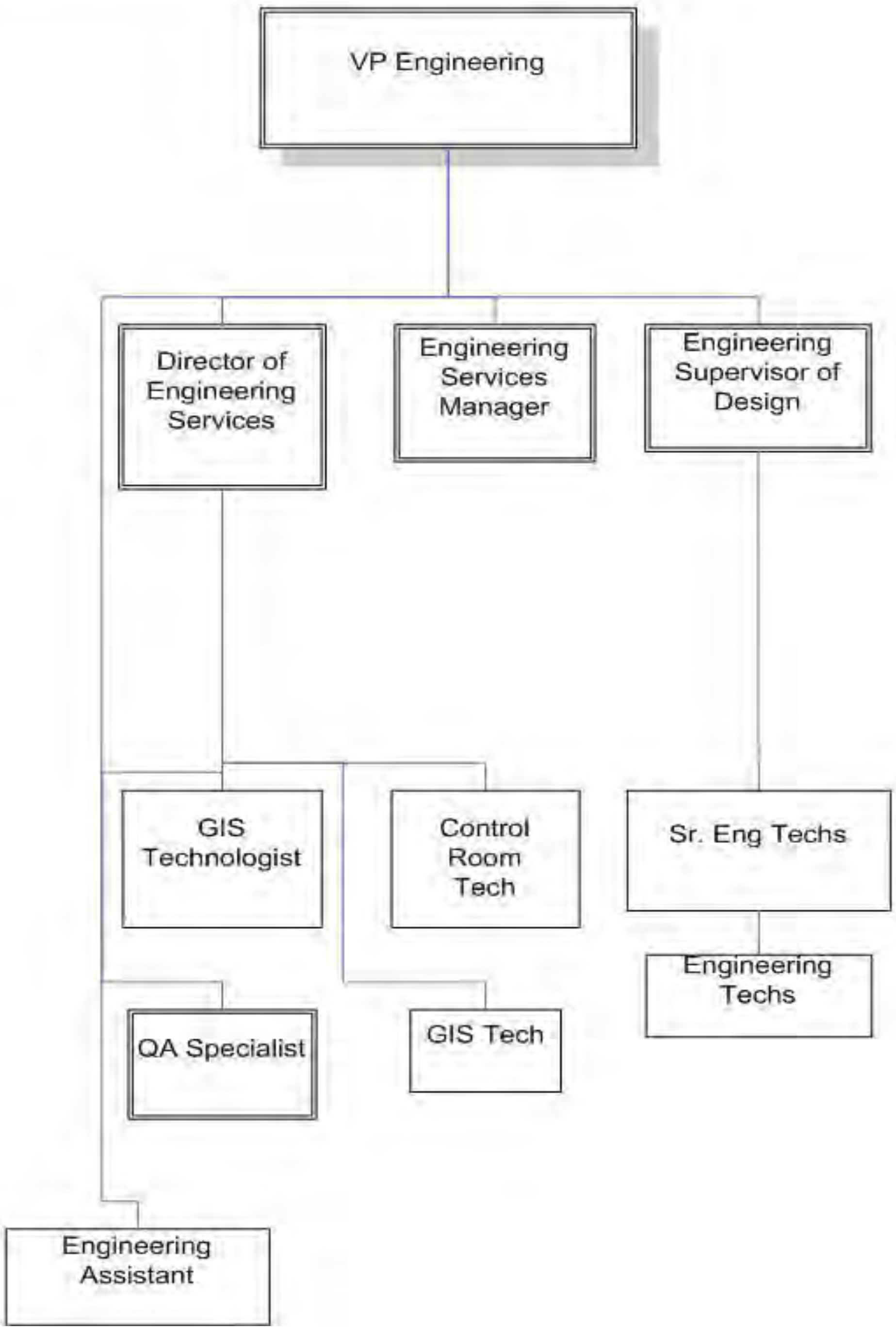


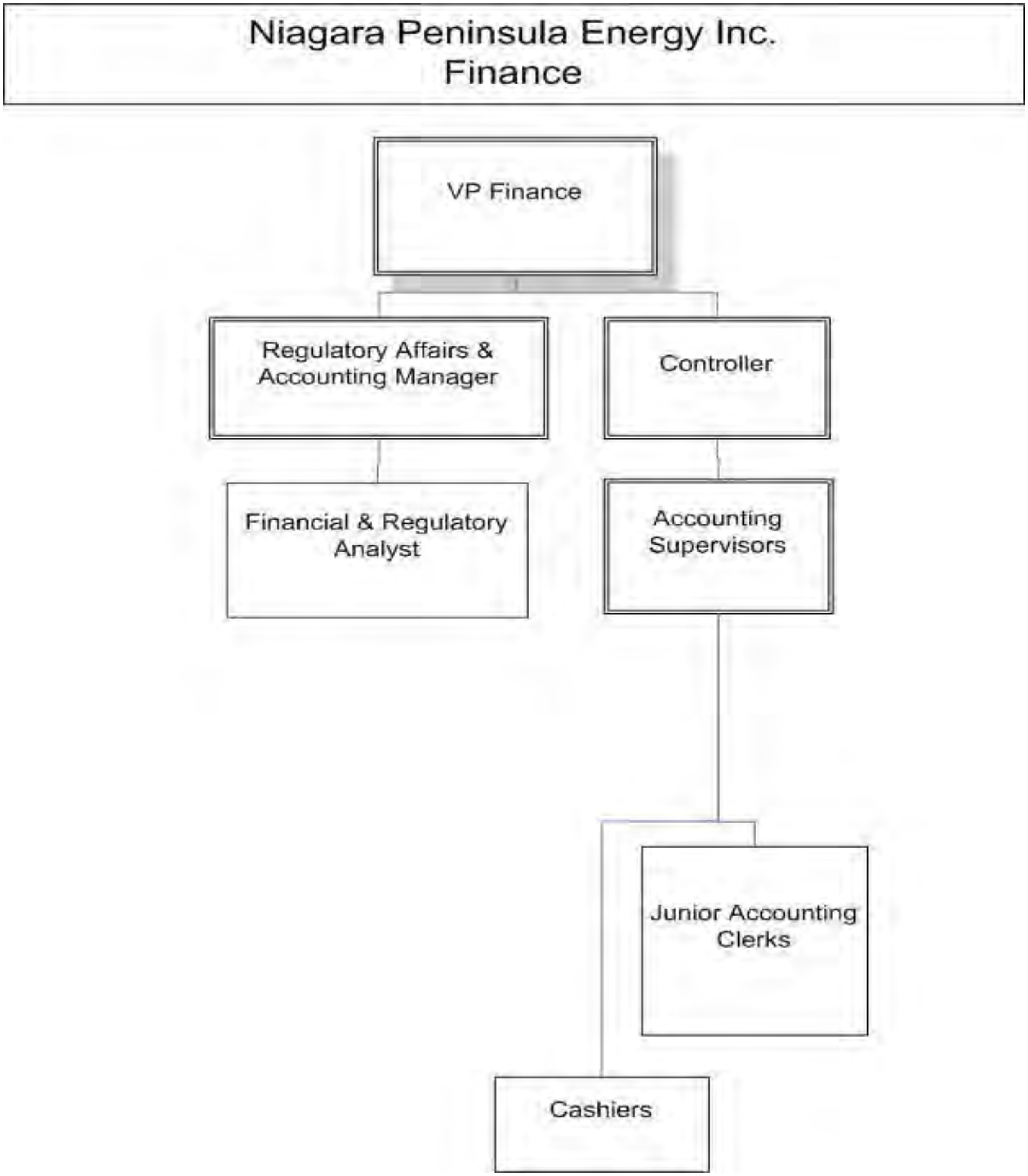
1 
Niagara Peninsula Energy Inc.
Operations
VP Operations
Line Superintendant
Purchasing Manager
Operations Supervisor Contracts
Operations Supervisors
Meter Supervisor
Lead Vehicle Tech
Lead Hands
Meter Lead Hand
Veh. Tech
Linemen
Meter Techs
Building Maintenance
Storekeepers
Assistant Storekeeper
Labourer
Operations Assistant

Niagara Peninsula Energy Inc.
Customer Service



Niagara Peninsula Energy Inc.
Engineering




Niagara Peninsula Energy Inc.
Finance
VP Finance
Regulatory Affairs & Accounting Manager
Controller
Financial & Regulatory Analyst
Accounting Supervisors
Junior Accounting Clerks
Cashiers

Corporate governance practices

Included below are the detailed governance policies as approved by NPEI's Board of Directors.

Attachment 1 of 1

Details of corporate governance practices

Board of Directors

There are eight members of NPEI's Board of Directors, four of which are independent. NPEI's composition of its Board of Directors complies with the Affiliate Relationships Code.

NPEI's governance policies, roles and responsibilities are attached in E1/T6/20/Att1/Number8 and include information relating to the Board's actions taken to facilitate its exercise of independent judgment in carrying out its responsibilities.

Board Mandate

NPEI's Board of Directors mandate is as documented in the detailed NPEI Board of Directors governance policies attached in E1/T6/S20/Att1/number 8 and as detailed in NPEI's shareholder agreement attached in E1/T6/S20/Att1/number 9.

2014 Board Meetings

NPEI's Board of Director meeting dates in 2014 are scheduled as follows:

February 4th, 2014
March 25, 2014
May 6th, 2014
July 15, 2014
September 9, 2014 (includes AGM meeting)
November 18, 2014
December 9, 2014

Orientation and continuing education

NPEI's policy for Board continuing education is as documented in the Board of Directors Governance which is attached in E1/T6/S20/Att1/number 8.

Ethical business conduct

The NPEI Code of Ethical business conduct is as documented in the Board Governance policies attached in E1/T6/S20/Att1/number 8.

Nomination of directors

NPEI's Board member recruitment is as documented in the detailed Board of Director Governance policies and in NPEI's shareholder agreement attached in E1/T6/S20/Att1 number 8 and number 9.

NPEI notes that the shareholder agreement attached at E1/T6/S20/Att1 Number 9 is marked "Privileged and Confidential." However, NPEI confirms that we are not claiming confidentiality in respect of this document.

Board committees

As per the detailed Board of Director Governance policies, NPEI has two committees which include a Governance committee and a Finance and Audit Committee.

The Governance committee consists of five Board members, three of which are independent. The Finance and Audit Committee consists of five Board members, three of which are independent. One Finance subcommittee member holds a Chartered Professional Accountant (CPA) accounting designation.

Niagara Peninsula Energy Inc.

CORPORATE GOVERNANCE

INTRODUCTION & OVERVIEW

March 2009

CONTENTS: **PAGE:**

Role of the Board of Directors

The role of the Board is to provide stewardship of the organization and to add to the long-term success of the Corporation through attending to the following key items:

- Interpret and oversee implementation of shareholder direction.
- Optimize long-term shareholder value.
- Lead a business that is strong, resilient, sustainable and financially responsible.
- Add value to the Corporation by guiding its strategic management.
- Together with the President, create, adopt, and implement a strategic agenda and policy using a disciplined planning process, periodically updated and modified from business performance feedback and external environmental (business) scans.
- Monitor the performance of the organization to ensure the success of the Corporation.
- Report on the performance of the Corporation to the Shareholder.

The Board represents the interests of the Shareholder. It complies with the Shareholder direction in force, from time to time, and it communicates events that the Board considers material to the Shareholder.

Corporate accountability rests on the principle of enhancing the economic value to the Shareholder. The Board's sole official connection to the operational organization is through the President/CEO.

Role of Directors

The Board of Directors is responsible for ensuring that the entity has a vision and a strategic plan is in place, with operating practices consistent with the ability of the organization to meet its goals and objectives.

The Board hires the President/CEO and determines his/her compensation. It holds the President/CEO accountable for achieving agreed upon goals and meeting specific performance targets.

Individual Board Members have no independent decision-making authority. The Board's only decision-making power comes from its collective authority as the duly constituted Board of the Corporation, meeting under the by-laws of the Corporation. Individual Board members may not direct management in any way, and should not purport to have any decision-making authority on behalf of the Board to outside parties, unless authorized by the Board pursuant to a Board resolution.

While individual Board members cannot direct any action by the Corporation, the Board members have an important role in providing advice to senior management at Board and committee meetings. Each member brings a unique set of skills and expertise to the Board. Both the Board and senior management should benefit from this resource.

To the extent that a Board member requests information of management, such a request, outside of Board or Committee meetings, shall be made through the Chair.

The members of the Board do not manage the organization. The Board sets broad parameters, establishes policy and controls, ensures that management is in place to achieve the organization's objectives, and it monitors management's performance against the established objectives.

The law imposes a high standard of care on Directors. They must use due diligence in discharging their duties. They must take reasonable steps to inform themselves via management of the affairs of the Corporation, and must make their own assessments of the proposals presented to them by management.

They must **always** act in the best interests of the Corporation. This obligation extends outside of Board meetings. The Directors' loyalty must be to the Corporation, and not a political or personal agenda, and the Directors must have sufficient time and capacity to stay informed about, and carefully examine, the affairs of the Corporation.

In addition to their obligations to act diligently, honestly and in the best interests of the Corporation, various statutes impose personal liabilities on Directors and it is up to each Director to make himself/herself aware of such statutes.

Conflicts of Interest

A Director or Officer of a corporation who is a party to (or is interested in), either directly or indirectly, an existing or proposed material contract or transaction with the Corporation must disclose that interest, even if the material contract or transaction is not one which, in the ordinary course of the Corporation's business, would require approval by the Directors. If the material contract or transaction is one which does require Board approval, the Director who has declared an interest is not permitted to vote on the resolution approving it.

Role of the Board Chair

The Board Chair chairs all Board meetings. The Chair serves at the pleasure of the Board.

In consultation with the President/CEO, the Chair sets the agendas for the Board meetings, ensures the meeting discussions are focused, ensures there is proper decorum at meetings, ensures good information flow and ensures decisions are clear and supported by resolutions where necessary. The Chair ensures regular and appropriate communication with the Shareholder, the Directors and the broader community.

The Chair ensures that meetings are conducted in an orderly fashion and that all Directors are encouraged to actively participate in Board deliberations. The Chair must be balanced; exercising good judgement and common sense in moving the business of the Board forward and ensuring the Board's Corporate Governance Guidelines are adhered to. By nature of the position, the Chair is frequently an informal sounding board for the President/CEO and is the conduit for the transmission to the President/CEO, on behalf of the Board, any emerging Board views or concerns so that management can address the issues in a timely fashion. The Chair is, ideally, the fulcrum upon which accountability turns. He/she must ensure a viable vision and mandate for the organization supported by good governance practices in achieving the necessary accountability of management to the Board, and the Board to the Shareholder.

The role of the Chair necessitates the Chair devoting more time for Board business than the other Directors. The Chair is a non-executive position, that is, the Chair, like the other Directors, is not part of the management team. This is necessary so that no confusion arises as to the role of the Board.

Organization of the Board

Because of the over-arching stewardship role of the Board, a Board may choose to delegate some of its more detailed review of activities to specific committees for informed discussion. This will be discussed further in section 7.

The Board and Board Committee meeting dates should be established well in advance and must be adhered to. A generally accepted practice is to establish meeting dates, as well as an Annual Meeting date for the following year, three to four months before the existing year-end.

At a minimum, four Board meetings a year are desirable. In times of unprecedented change or crisis, additional meetings are advisable in order to ensure that management is responding expeditiously to the business and organization challenges it is facing. Additional meetings would also provide management with the opportunity to draw on the collective expertise of the Board members.

Normally, materials for Board and Committee meetings should be delivered to Board members at least **5** days prior to the meeting date.

Enacting Resolutions

Most effective Boards try to manage on a consensus basis so that decisions are arrived at with something close to unanimity. When a vote is necessary a simple majority will prevail. Once a decision of the Board has been reached, and all Directors have had clear opportunity to express their respective opinions, the decision of the Board shall prevail. Board members must respect and abide by decisions of the Board.

The Directors may enact resolutions at a meeting, or may pass a resolution in the absence of a meeting in writing if all Directors sign such resolution. A quorum of Directors may call a Board of Directors meeting upon the giving of at least 5 days notice to each individual involved.

Meetings are normally held at the registered office of the Corporation, or by telephone. A majority of the number of Directors constitutes a quorum and a majority of a quorum can enact resolutions at a meeting. Alternatively, **all** of the Directors can enact a resolution without meeting by signing a written text of the resolution.

Role of Committees

Committees should act as the arms of the Board, with responsibility for monitoring assigned areas and developing policy and recommendations for the consideration of the Board as a whole. Committees should not normally be asked to act for the Board or to direct the administration. The role of committees is to:

- Assist the Board with strategy and policy development.
- Comment and advise on preliminary recommendations of management to the Board based on Board approved goals and policy statements.
- Make recommendations to the Board based on recommendations from management.

Written minutes must be kept of all Committee meetings and distributed to the whole Board. The whole Board should only deal with a report from a Committee when a specific action is proposed or if a serious problem is encountered.

Communications with Shareholder

Communications to the Shareholder on strategic and policy level issues should be in writing and that the sum and substance of these communications shall be approved by the Board prior to being communicated to the Shareholder.

Independent Advice

The Board shall be authorized to obtain, as it deems necessary for the fulfillment of its duties, any independent advice it requires (for example, legal counsel, compensation expertise etc.). This shall be authorized pursuant to a resolution passed by the Board.

Board Policies

Board policies established within these Corporate Governance Overview fall into four general groups:

A. Mission/Results-related: *what market needs are to be met and at what relative worth or cost.*

B. Executive Limitations: *the principles of prudence and ethics that limit the choice of means to achieve the Mission/Results.*

C. Board-Executive Relationship or Board-President/CEO Linkage: *how power is passed to the President and the manner in which the use of that power is assessed*

D. Board Process: *the manner in which the Board represents the Shareholder and provides strategic leadership to the organization.*

REFERENCE MATERIAL

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Niagara Peninsula Energy Inc.

CORPORATE GOVERNANCE
BOARD of DIRECTORS
POLICIES

March 2009

CONTENTS: PAGE:

NEW DIRECTOR ORIENTATION POLICY

Date:

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1. GENERAL PURPOSE AND SCOPE

This policy statement describes the orientation process provided to each new Director of Niagara Peninsula Energy Inc. and its subsidiary companies (collectively referred to as "NPEI" or the "Company") to familiarize the new Director with Board requirements, practices and standards as well as the operations of the companies within the first four weeks of appointment.

In general, this policy provides for an overview of the minimum requirements for a proper orientation process and mandates that orientation shall occur.

2. ORIENTATION POLICY

A. New Directors will be provided with an orientation program which will include written information about the duties and obligations of Directors, the business of the company, documents from recent Board meetings, opportunities for meetings and discussion with senior management and other Directors as appropriate, plus tours of the Company's facilities. The details of the orientation will be tailored to reflect that individual's needs and areas of interest as well as required components. The Chair and the President/CEO will jointly facilitate the orientation program.

B. When appointed to a Board Committee, Directors will be provided appropriate terms of reference of the committee, information and orientation to prepare them to participate effectively. The Chair of the Committee will facilitate committee orientation.

STANDARDS OF CONDUCT POLICY

Date:

1. GENERAL PURPOSE AND SCOPE

This policy statement describes the general duty of each Director of NPEI and its subsidiary companies to disclose any conflict of interest, whether actual or perceived where the Director may realize a personal benefit from the actions taken by the Company.

In general, this policy provides assurance that the Company's Directors will serve in the best interest of the company and remain independent from potential concerns of conflict. Where this cannot be achieved, the director must disclose the nature of the conflict and the potential benefit to the director.

2. GENERAL STANDARDS OF CONDUCT

Every director and every officer of a Crown corporation in exercising his/her powers and performing his/her duties shall:

(*a*) Act honestly and in good faith with a view to the best interests of the corporation; and
(*b*) Exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

3. CONFLICT OF INTEREST

Common Law

In general, common law prohibits a Director from doing business with the Company. However, a Director may from time to time be in a business which routinely provides goods and services to NPEI and similar companies. The general standard is very restrictive and the following procedures will be adhered to when it is deemed appropriate that a Director enter into a commercial contract with the Company.

i Written notice – The Director shall notify the Board in writing of his or her interest at the time the Director first becomes interested in a transaction.
ii Abstain from voting – the Director shall abstain from voting on any resolution to approve the contract or transaction in question.
iii Fair and reasonable – The final consideration is that the contract or transaction must be fair and reasonable to the Company at the time it is approved or confirmed.

STANDARDS OF CONDUCT POLICY

4. DUTY TO DISCLOSE

i Each Director has a duty to disclose any potential conflict of interest.
ii Each Director has a duty to disclose any information that he or she may have by virtue of another relationship that is of vital importance to the Board.
iii Each Director has a duty to avoid being in a position of breaching a fiduciary responsibility to NPEI by virtue of owing the same responsibility to another organization.

A Director may hold a directorship, be an officer or have another material interest in a corporation or person other than NPEI. Without affecting the operation of any rule of law,

a) A Director who holds such an interest in such other corporation or person shall disclose the same in writing to the Board forthwith upon his/her appointment and annually, afterward;
b) Where a Director acquires such an interest in such other corporation or person after his/her appointment to the Board, he/she shall disclose the same in writing to the Board forthwith after he/she acquires such an interest.

5. RESPONSIBILITY OF LOYALTY & CONFIDENTIALITY

A Director's personal interest, or the sole interest of the shareholder, should not be allowed to interfere with that Director's responsibility of loyalty to NPEI. Each proposal submitted for the consideration of the Board should be considered essentially on its merits and with a view to the best interests of NPEI.

Directors should communicate to the Chair any information that may be necessary or useful to NPEI management in the conduct of NPEI's business.

Directors should not communicate, or allow to be communicated to any person not entitled thereto any information related to the business and affairs of NPEI which has not been made available, nor allow any such person to have access to or inspect any books or documents relating to the business and affairs of NPEI made available to them as Directors, or belonging to or in the possession of NPEI.

Communications with municipal or government officials in respect of NPEI's business and affairs are the prerogative of the Chair and the President/CEO. Accordingly, Directors should not initiate such communications unless requested to do so by the Chair.

STANDARDS OF CONDUCT POLICY

6. RESPONSIBILITY OF CARE AND PRUDENCE

Generally, a Director is expected to follow the "business judgment rule" which requires the Director to act at all times in accordance with what the Director believes to be in the best interests of NPEI, relying on past experience**,** skill and applying plain common sense. Acting prudently implies acting with care and caution in trying to foresee probable consequences of his/her decisions, with a view to the best interests of NPEI. In addition, decisions must be based on the Director's informed and reasoned business judgment that is not vitiated by any conflict of interest.

7. RESPONSIBILITY OF DILIGENCE

A Director must familiarize himself/herself with the policies, businesses and affairs of NPEI so that he/she may attend meetings and be prepared to express his/her point of view on any matter put forward for consideration by the Board. In this respect a Director may rely in good faith on financial statements represented to him/her by an officer of NPEI or in a report of the auditor as fairly reflecting the financial condition of NPEI, or on a report of a lawyer, accountant, engineer, appraiser or other person whose position or profession lends credibility to a statement made by such person.

In connection with this responsibility of diligence, Directors should remember that a director of NPEI is deemed to have consented to any resolution passed or action taken at a meeting, unless (i) in the case of a Director who is present at the meeting, he/she requests that written notice of his/her dissent be entered in the minutes of the meeting, gives notice of his/her dissent to the Secretary before the meeting is adjourned or sends his/her written dissent immediately after the meeting (provided he/she did not vote in favour or consent to the resolution) and (ii) in the case of a director who is not present at the meeting, he/she causes written notice of his/her dissent to be placed with the minutes of the meeting or he/she sends written notice of his/her dissent to the head office of the corporation, within seven days after he/she becomes aware of the resolution or action taken at the meeting.

DIRECTOR'S REMOVAL POLICY

Date:

1. GENERAL PURPOSE AND SCOPE

This policy statement describes the circumstances and process under which an involuntary termination of a Director's service may be required.

In general, this policy provides for an overview of the requirements for removal of a Director of the Board should it be deemed that their continued service on the Board is no longer effective or even counter-productive.

2. REMOVAL POLICY

A. It is understood that the respected Shareholder retains the sole right, subject to recommendations of the Board, (and considering clause 3 of 'Attendance and Participation' policy), to request the replacement of a current Director of the Board with whom they have lost confidence.

B. It is a recognized practice of good governance and a policy of the Board that Directors should retain their independence of thought as well as the duty of honesty, loyalty, care, diligence, skill and prudence. However, should a circumstance arise that is determined by the majority of the Board that a Director is no longer effective or is counter-productive; the Board may recommend to the Chair that the Director be removed.

C. In the circumstance where the Chair has been requested to proceed with the replacement of a Board member, the Chair will notify the Shareholder and provide details of the circumstances surrounding the request. Should the Shareholder determine that such action is necessary; the Shareholder will proceed with appropriate notification of the Director. In all cases, the exercise of tact and diplomacy and confidentiality is required.

D. A Director who has been involuntarily removed from the Board may still retain certain liabilities of current Directors with respect to the actions of the Company prior to his or her removal from the Board.

MEETING PARTICIPATION POLICY

Date:

1. GENERAL PURPOSE AND SCOPE

This policy statement describes the general expectation of meeting participation of a Director of NPEI and its subsidiary companies (collectively referred to as the "Company").

In general, a Director is expected to make all reasonable efforts to attend the Board meetings of the Company. At Chair's discretion, other means of attendance may be available to the Director.

2. ATTENDANCE AND PARTICIPATION POLICY

A. General

1. A Director should attend all official meetings of the Board that are duly called by the chair.
2. Subject to the exception indicated below, a Board member shall resign if he or she misses more than three (3) consecutive meetings annually duly called by the chair.
3. If a Board member misses more than three (3) Board meetings annually owing to extenuating circumstances, the Board shall have right to waive the required resignation of the Director.

B. Participation at meetings

A Director is expected to participate at all meetings in order for the Company to benefit from the judgement and experience of the Director. The Director should engage in full and frank discussion on all matters before them.

BOARD MEMBER EXPENSE REIMBURSEMENT POLICY

Date:

1. GENERAL PURPOSE AND SCOPE

This policy statement describes the general expense reimbursement guidelines for a Board Director of NPEI and its subsidiary companies (collectively referred to as the "Company").

In general, a Director may incur expenses in the course of discharging his or her responsibility as a Director. Subject to the limitations outlined below, a Director shall be reimbursed for these expenses upon submission of an expense report and valid original receipts.

2. REIMBURSEMENT POLICY

General

A Director is entitled to receive reimbursement, as approved by the Board of Directors in accordance with the Shareholder per calendar year, for general expenses that he or she incurs in the course of discharging his or her duty as a Director. The Director is expected to submit an expense report with all supporting receipts. The Chair of the Board will approve the expense report. In the case of expenses incurred by the Chair of the Board, an expense report and supporting receipts will be submitted to the Chair of the Finance & Audit Committee for approval.

Continuing Education

A Director is entitled to receive reimbursement, as approved by the Board of Directors in accordance with the Shareholder per calendar year, for continuing education courses that contribute to the knowledge base of matters relating to corporate governance and Board operations. Reimbursement will include tuition or registration fees; books; meals, hotels and mileage reimbursement, in accordance with the Company travel policy rates and standards for management.

Other

If a Director is requested by the Board to represent the Company in an official capacity (i.e. a conference or meeting), as a Director of NPEI, the Director shall be reimbursed for all reasonable costs of fulfilling this duty.

DIRECTOR EDUCATION POLICY

Date:

1. GENERAL PURPOSE AND SCOPE

This policy statement describes the general duty of each Director of NPEI and its subsidiary companies (collectively referred to as "Company") to be educated on matters of current Board governance and the various business matters that are the responsibility as they occur from time to time.

2. EDUCATION POLICY

(a) The Company will provide a Director orientation and education program for all individuals recruited to the Board.

(b) The Company shall make available such resources as may be reasonably required for any industry-related or governance-related continuing education requirements of its Directors.

(c) Each Director shall have the responsibility for maintaining a sufficient knowledge base of matters relating to corporate governance.

(d) Each Director shall consider what continuing educational requirements he/she may be required on an ongoing basis in connection with discharging the Director's duty. Should additional training or courses be required in order to continue to exercise the care, diligence and skill that a reasonably prudent person would exercise in the course of serving as a member of Board of Directors, then additional training should be sought.

The training requirements should be reviewed through the Chair of the Board and the Chair of the Governance Committee. If approved, once training has been completed successfully, educational expenses will be reimbursed. (See Expense Reimbursement policy).

COMMITTEES OF THE BOARD - POLICY

Date:

1. GENERAL PURPOSE AND SCOPE

This policy statement describes the terms of reference for standing committees and provides guidelines for Director performance and rotation on committees. Special committees of the Board may be constituted from time to time to review particular interests of the business.

In general, each Director is required to participate on a minimum of one standing committee, and a maximum of three, except the Chair who may participate in standing committees except the Finance Committee.

2. COMMITTEE POLICY

Committees are responsible for monitoring assigned areas and developing strategic policy and recommendations for the consideration of the Board as a whole. Committees only have the authority delegated to them by the Board. Committees should not be involved in the day-to-day operations or administration of the business – the Board and Committee focus is on governance and stewardship, rather than on management operations, which is executing strategy and managing day-to-day operations. In general, the role of committees is to:

- Assist the Board with strategy and policy development.
- Comment and provide advice on preliminary recommendations from management to the Board within the framework of Board-approved goals and policy statements.
- To make recommendations to the Board based on information and recommendations from management.

A. It is the policy of the Board of Directors that there are 2 standing committees, namely:
   a. Governance Committee
   b. Finance and Audit Committee

B. Committees will have a minimum of three members, none of whom shall be officers of the Corporation. The members of the Committee will be appointed at the meeting of the Board of Directors immediately following each annual general meeting.

C. The schedule of meetings of each committee will be determined by its Chair, based upon the annual work plan designed to discharge the responsibilities of the committee as set out in its mandate. The Chair of the committee will develop the agenda for each committee meeting through consultation as appropriate with members of management, staff and the committee. Each committee will report to the Board on the results of each committee meeting by way of formal meeting minutes.

Niagara Peninsula Energy Inc.

BOARD of DIRECTORS
ROLES & RESPONSIBILITIES
&
COMMITTEE TERMS OF REFERENCE

March 2009

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Role of the Board of Directors

The role of the Board is to provide stewardship of the organization and to add to the long-term success of the Corporation through attending to the following key items:

- Interpret and oversee implementation of shareholder direction.
- Optimize long-term shareholder value.
- Earn a competitive profit compared to other like-sized utilities, and to ensure the Corporation avoids unacceptable risk.
- Lead a business that is strong, resilient, sustainable, and competitive with challengers, actual and potential.
- Add value to the Corporation by guiding its strategic management including setting out goals for management as well as appointing, supporting, overseeing, and monitoring the best available senior management team.
- Together with the President, create, adopt, and implement a strategic agenda and policy using a disciplined planning process. This agenda should periodically be updated and modified from business performance feedback and external environmental (business) scans.
- Monitor the performance of the organization to ensure the success of the Corporation.
- Report on the performance of the Corporation to the Shareholder.

As stated, the Board is responsible for the stewardship of the Company. This requires the Board to oversee the conduct of the business and affairs of the Company. The Board discharges some of its responsibilities directly and discharges others through committees of the Board. The Board is not responsible for the day-to-day management and operation of the Company's business, as this responsibility has been delegated to management. The Board is, however, responsible for supervising management in carrying out this responsibility.

Role of the Chair

The principal responsibilities of the Chair of the Board shall be to oversee, manage, and assist the Board in fulfilling its duties and responsibilities as a Board in an effective manner independently of management. The Chair shall be responsible, among other things,

- to chair Board meetings and annual and special meetings of shareholders;
- to organize an appropriate annual work plan and regularly scheduled meetings for the Board;
- to participate in the preparation of the agenda for each Board meeting;
- to monitor the work of the committees of the Board. Also, the Chair may attend, as a non-voting participant, all meetings of the Board committees, (in addition to those on which he/she otherwise sits);

- to arrange for an appropriate information package to be provided on a timely basis to each director in advance of the meeting;
- to assist in the Board's evaluation and self-assessment of its effectiveness and implementation of improvements;
- to provide appropriate guidance to individual Board members in discharging their duties;
- to ensure newly appointed directors receive an appropriate orientation and education program;
- to provide arrangements for members of the Board to communicate with the Chair formally and informally concerning matters of interest to Board members; and
- to promote best practices and high standards of corporate governance.

Role of the Vice Chair

The Vice Chair will facilitate the functioning of the Board independently of management of the Company, and provide independent leadership to the Board. The Vice Chair shall substitute for the Chair if the Chair is not available.

Role of the Directors

There are general duties and responsibilities of individual directors in common law and in *The Canada Business Corporations Act* ("CBCA"), as well as the Corporation's by-laws.

The relationship of the director to the Corporation is a fiduciary one. A fiduciary relationship is defined as the relationship of one person to another, where the former is bound to exercise rights and powers in good faith for the benefit of the latter (eg. as between trustee and beneficiary). A 'fiduciary' is a person in a position of authority whom the law obligates to act solely on behalf of the person he or she represents and in good faith.

The Corporation directors are "trustees" in the sense that in performance of their duties, they stand in a fiduciary relationship to the Corporation and are bound by all of the rules of fairness, morality, and honesty that the law imposes. From this fiduciary role comes the stewardship responsibility to preserve and enhance shareholder value and as such, the Board serves as trustees of the investment of the shareholders.

Directors must individually, in connection with the powers and duties of their office, exercise the care, diligence, and skill that a reasonably prudent person would exercise in comparable circumstances.

Duties of Individual Directors

The duties of a director as established by the OBCA and as interpreted by the courts may be summarized as follows:

- Duty of Honesty: In his or her dealings with fellow directors, a director must tell the whole truth and act in good faith. Secret profits are forbidden to directors;
- Duty of Loyalty: A director is required to give individual loyalty to the Corporation. Each director must exercise his or her powers honestly and for the benefit of the Corporation as a whole;
- Duty of Care: A director is required to exercise prudence and diligence. The duty of care requires prudence based on common sense;
- Duty of Diligence: A director must make those inquiries which a person of ordinary care in his or her position or in managing his or her own affairs would make;
- Duty of Skill: Every director is required to exercise the care, diligence, and skill that a reasonably prudent person would exercise in comparable circumstances; and

  Further detail regarding such duties can be found in "Guidelines for Corporate Directors in Canada" published by the Institute of Corporate Directors.

The responsibilities set out below are meant to serve as a framework to guide individual directors in their participation on the Board, with a view to enabling the Board to carry out its mandate, duties, and responsibilities. These responsibilities include:

- assuming a stewardship role, and overseeing the management of the business and affairs of the Corporation;
- maintaining a clear understanding of the Corporation, including its strategic and financial plans and objectives, emerging trends and issues, significant initiatives, and capital allocations and expenditures, management risks, internal systems, processes and controls, program for compliance with applicable regulations, and governance, audit and accounting principles and practices;
- preparing for each Board and Committee meeting by reviewing materials and requesting, where appropriate, information that will allow the director to properly participate in the Board's deliberations, make informed business judgments, and exercise oversight;
- absent a compelling reason, attending all Board and Committee meetings, actively participating in deliberations and decisions. When attendance is not possible, a director should nevertheless become familiar with the matters to be covered at such meetings;
- voting on all decisions of the Board or its Committees, except when a conflict of interest exists or may exist;
- preventing personal interests from conflicting with, or appearing to conflict with the interests of the Corporation, and disclosing details of such conflicting interests as they arise; and
- acting in the highest ethical manner and with integrity in all matters.

Director Risk Management Guidelines

Directors should:

- attend Board meetings faithfully, being absent only for compelling reasons;
- ask questions of management to gain reasonable assurance of information, due diligence on the part of management, and consistency with standards of the organization;
- record in writing any dissenting opinion;
- ensure that the Corporation's affairs are conducted according to its constitutional documents;
- keep abreast of the activities of the Corporation and be well-versed in the industry;
- be aware of the various statutes and the provisions pertaining to corporate offenses;
- refrain from voting on questions where their independence could be called into question;
- review resolutions passed and actions taken in their absence;
- retain the right to advice from outside experts where warranted;
- ensure that there is follow-up on resolutions passed by the Board;
- obtain assurance of timely payment of employee wages, source deductions, income tax instalments, GST, PST; and
- ensure that the Corporation is in compliance with all environmental legislation, has an up-to-date environmental policy, and that management makes regular reports to the Board.

Role of the Secretary

The duties and functions of the Secretary include:

- Schedules orientation, training and education for the Board of Directors;
- Disseminates the "Notice" for regular, special, or in-camera Board meetings;
- Prepares the Agenda and records the Minutes for Board and for Committee meetings;
- Creates briefing packages, whether hard or soft copy, for Directors in preparation for meetings;
- Advises the Chair on correct procedures and requirements for motions/resolutions;
- Communicates decisions and matters requiring follow-up to the Board and to appropriate people on a need to know basis;
- Ensures compliance with the By-laws or regulations governing the Board and the organization;
- Develops and maintains a schedule of meetings and any outstanding obligations for the organization;
- Drafts Minutes for approval by the Chair;
- Maintains the Minute Books;
- Organizes the AGM;
- Performs tasks at the request of and on behalf of the Chair.

Role of the Committee Chairs

The fundamental responsibility of the Chair of any committee of the Board of Directors is to be responsible for the management and effective performance of the committee, and provide leadership to the committee in fulfilling its mandate, and any other matters delegated to it by the Board.

The Chair of any committee of the Board of Directors will:

- Chair committee meetings, and ensure that the committee is properly organized, and functions effectively;
- Work with the Chairman of the Board, and Chief Executive Officer, and the Corporate Secretary, to establish the frequency of committee meetings and the agendas for meetings;
- As appropriate and in consultation with the committee, retain, oversee, and terminate independent advisers to assist the committee, or its members in fulfillment of their responsibilities;
- Report to the Board of Directors with respect to the activities of the committee and any recommendations deemed desirable by the committee;
- Lead the committee in annually reviewing and assessing the adequacy of its mandate and evaluating its effectiveness in fulfilling its mandate.

Committees of the Board – Terms of Reference

COMMITTEE TERMS OF REFERENCE

Subject to the powers and duties of the Board, the Board assigns the mandate and terms of reference (ToR), for standing committees of the Board as follows:

a. Governance Committee

Purpose

The Governance Committee's primary role is to establish process and practices to enable the Board of Directors in providing effective governance of the organization. This includes providing for governance practices to evolve with the needs of the organization and the expectations of the stakeholders. The Governance Committee is responsible for creating a framework to hold the Board accountable to the organization and its stakeholders. The Committee will also supervise the governance system of the organization to monitor that duties of the governance body are being met and regulatory requirements are being fulfilled.

The objectives of the Committee are to assist the Board in fulfilling its oversight responsibilities and to hold directors and Board committees accountable to fulfilling their duties.

Membership and Quorum

The Governance Committee will be comprised of no less than four (4) members of the Board. A quorum for meetings will be three (3) members.

Chair

The Board of Directors shall appoint the Chair of the Governance Committee.

Authority

The Governance Committee fulfills its responsibilities on behalf of the Board and makes recommendations to the Board on policies relating to governance matters as well as structural changes to the Board or the bylaws of the organization. The Committee will have authority to approve processes to be used by the Board to put the governance policies into action.

Roles and Responsibilities

- Monitor and consider trends in corporate governance generally as well as regulators' expectations for the Board and consider implications to the organization.
- Monitor the effectiveness of the organization's governance practices and make/ recommend changes on an annual basis.

- Annually consider Board committee structure, and ensure it is appropriate given the evolution of governance, structure and operations of the organization.
- Annually review NPEI policies governing Board size, composition, and candidate criteria.
- Ensure mandates are updated annually for: all Board committees, the Board itself, a director, the Chair of the Board and for the Chairs of Committees; in particular review Committee mandates to ensure there is no overlap of duties and no gaps in duties between Committees.
- Recommend to the Board the allocation of Directors to the Board committees. This should reflect the consideration of skill sets required by the committees, the interest of Directors, as well as a desire to rotate Directors around the committees. Rotation of Directors around committees will be complemented with the consideration of continuity and experience of committee membership.
- Monitor Board Committees on the fulfillment of their mandates.
- Review and make recommendations regarding remuneration for NPEI Directors, the expense reimbursement policy, and director education.
- Monitor the annual Board calendar and processes including scheduling and context of meetings and agendas.
- Facilitate the orientation for new Directors; periodically review and update content of the orientation and process.
- Review ongoing education sessions including such topics as regulatory, legal, and sector changes/issues.
- Ensure the maintenance of a Director manual and update annually.
- Review and update the communications policy for the organization.
- Establish, monitor, review, and recommend to the Board for approval the annual specific goals and objectives of the CEO and the attainment of the goals and objectives annually.
- Review and recommend succession and leadership development plans for all key management personnel for sustainability of the Corporation.

Meetings

The Committee shall meet as required. The Committee shall determine its own procedures for the conduct of the meetings.

Reporting

Minutes of all meetings of the Governance Committee will be provided to the Board. The Chair may provide an oral report to the Board on matters not yet minuted. Supporting schedules and information reviewed by the Committee will be available for examination by any Director upon request to the Corporate Secretary.

Resources

* Chief Executive Officer	*Secretary to the Board
* Other Management, as needed	*Outside advisors, as needed (legal counsel, consultants for Board assessment)

b. Finance and Audit Committee

Purpose

The Finance and Audit Committee's principal role is to ensure that due diligence is directed towards verifying that an effective risk management and control framework has been implemented by management. This framework is to provide reasonable assurance that the financial, operational and regulatory objectives of the Company are achieved and that the governance and accountability responsibilities of the Board and management are met.

The Finance and Audit Committee undertakes responsibility for the oversight of the design and implementation of internal controls to support the risk management framework, the integrity of financial reporting, and compliance with regulatory matters.

Objectives

The objectives of the Finance and Audit Committee are:

- To assist the Board to fulfill its oversight responsibilities, including accountable management of funds, efficiency and effectiveness of controls, safeguarding of assets;
- To gain assurance that the Company is in compliance with laws, regulations and policies;
- To gain assurance that there is reliability in external financial reports;
- To provide for independence of the internal audit function;
- To communicate concerns of the Board to the external auditors and have input into the overall direction of all audit efforts;
- To engage external auditors and provide appropriate oversight of their work; and to
- Promote effective and timely resolution of audit issues.

Membership and Quorum

The Board appoints members of the Finance and Audit Committee. The Finance and Audit Committee will be comprised of not less than four (4) members of the Board. The Chair shall not serve on the Audit committee. A quorum for any meeting will be three (3) members. At least one committee member must be literate with financial and audit practices which can be demonstrated through past experience on an audit committee and/or through business experience.

Chair

The Board of Directors shall appoint the Chair of the Finance and Audit Committee.

Authority

The Finance and Audit Committee fulfills its role on behalf of the Board of Directors and makes recommendations to the Board on policies and matters in the areas of financial reporting and internal controls.

It is empowered to:

- Retain outside counsel, accountants, auditors, or others to advise the committee and determine compensation for such advisors subject to prudent stewardship of resources;
- Seek any information it requires from employees and external parties and meet as necessary;
- Ensure the external auditors is given notice of every meeting of the committee;
- The Committee Chair will convene a committee meeting at the request of the auditor, an audit committee member or any director, to consider any accounting, internal control, or audit matter.

Roles and Responsibilities

The Finance and Audit Committee obtains assurance that the elements of control (resources, systems, processes, structure and tasks) are in place to support the enterprise risk framework for the Company. The Finance and Audit Committee:

- Gains assurance that the Company's activities are managed within an appropriate framework of ethics and control;
- Gains assurance that the Board has set necessary policies in compliance with legal, regulatory and ethical requirements;
- Reviews policies and procedures that safeguard the Company's assets;
- Gains assurance that the internal auditors are not restricted or impeded in the conduct of their responsibility by other personnel of the Company;
- Establishes procedures for confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters;

- Reviews and approves the Company's hiring policies regarding current and former employees and partners of the current and formal external auditors.

Financial Reporting

The Finance and Audit Committee will provide oversight to the reporting of financial results:

- Reviews and approves accounting policies used for the Company's financial reporting including any significant changes from year to year;
- Reviews management's methodology of determining provisions and adequacy thereof, where these provisions are reflected in the financial statements;
- Gains assurance that an effective process is in place, including having appropriate internal controls, to provide reasonable assurance that financial reporting has integrity and provides for reliable and fairly presented financial statements;
- Receives, reviews the annual financial audited financial statements and forwards to Board for approval;
- Reviews reports containing financial information for external distribution and approves such before distribution;
- Receives, reviews financial statements of material subsidiaries while respecting the role of the Board/Audit Committee of subsidiaries;
- Receives reports from management regarding compliance with financial regulatory requirements and other legislative compliance.

Director Qualifications

Directors serve the interests of all shareholders. This means that the Board should reflect the diversity of the shareholders. Membership on the Board should take into account individual skills; relevant business experience; geographic representation; gender and cultural representation.

The Board of Directors should contribute to its own renewal. The selection and recruitment of knowledgeable and skilled candidates to the Board is of prime importance. Although the appointment of Board members is the prerogative of the shareholder, recommendations by the Board influence the selection and the approval process. The Board's experience in setting the strategic direction and monitoring the performance of the Company, provides and ideal basis for the Board to review the suitability of its composition and the effectiveness of its performance.

The Board's self-assessment of the skills required is a useful basis for recommendations on the appointment or replacement of Directors as terms approach expiry. As such, the Governance Committee shall recommend suitable candidates for nominees for election or appointment as directors to the shareholders, based on its assessment of the results of internal and external due diligence reviews, and on the following criteria for the overall composition of the Board and characteristics of individual directors:

All candidates for consideration for nomination to the Board must:

- Be at least 18 years old;
- Be a Canadian citizen or permanent resident as defined in the Immigration and Refugee Protection Act (Canada);
- Resided in Canada for more than 183 days within the previous 365 days;
- Have no un-discharged bankruptcies;
- Board members have the capability and willingness to attend and to contribute at Board meetings and functions on a regular basis.

Selection Criteria:

The qualifications of candidates for the Board shall, where possible, include the following:

- Commercial Experience, Sensitivity and Acumen
- Time Availability
- Corporate Finance; Accounting Experience
- Corporate Governance Experience
- Market Development
- Industry Knowledge including, but not limited to, knowledge of competitive energy markets
- Independence, objective, and of sound judgment

- Knowledge of Public Policy and Government Regulation Issues relating to the Corporations and the industry
- Knowledge and Experience concerning Environmental Matters, Labour relations and occupational Health and Safety issues
- Knowledge of Local Community
- Business Expertise including marketing, product development, mergers and acquisitions and/or retail experience
- Experience on boards of significant Commercial Corporations, preferably with revenues of $10 million annually or more
- Knowledge and Experience in Risk Management
- Preference may be given to qualified candidates for the Board who are residents of the municipalities of the Shareholders.

Director Nomination Process

The appointment of Board members is the privilege of the Shareholders. Recommendations by the Board of suitable nominees may be provided to the Shareholders for consideration.

Where a vacancy occurs at any time in the membership of any Board Committee, the Committee shall recommend to the Board a member to fill such vacancy.

Terms of Office

The terms of office are subject to the Shareholder's agreement.

SHAREHOLDERS AGREEMENT

Dated as of [January 1, 2008]

NIAGARA FALLS HYDRO HOLDING CORPORATION

- and -

PENINSULA WEST POWER INC.

- and -

NIAGARA PENINSULA ENERGY INC.

- and -

SUCH OTHER PERSONS AS MAY BECOME SHAREHOLDERS IN NIAGARA PENINSULA ENERGY INC.

Borden Ladner Gervais LLP
Scotia Plaza, 40 King Street West
Toronto, Ontario
M5H 3Y4

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<u>Privileged and Confidential</u>

SHAREHOLDERS AGREEMENT

THIS AGREEMENT made as of the **[1st day of January, 2008]**.

AMONG:

NIAGARA FALLS HYDRO HOLDING CORPORATION, a corporation duly incorporated under the *Business Corporations Act* (Ontario) (hereinafter referred to as **"NFHC"**)

- and -

PENINSULA WEST POWER INC., a corporation duly incorporated under the *Business Corporations Act* (Ontario) (hereinafter referred to as **"PWPI"**)

- and -

NIAGARA PENINSULA ENERGY INC., a corporation duly amalgamated under the *Business Corporations Act* (Ontario) (hereinafter referred to as the "**Corporation**")

- and -

SUCH OTHER PERSONS AS MAY FROM TIME TO TIME BECOME SHAREHOLDERS IN THE CORPORATION AND PARTIES HERETO

RECITALS:

A. NFHC was the sole shareholder of Niagara Falls Hydro Inc. ("**NFHI**") an electricity distribution company created pursuant to Section 142 of the *Electricity Act, 1998* (Ontario) (the "**Electricity Act**");

B. PWPI was the sole shareholder of Peninsula West Utilities Limited ("**PWUL**") an electricity distribution company created pursuant to Section 142 of the Electricity Act;

C. NFHC is wholly-owned by Niagara Falls;

D. PWPI is owned by Lincoln, Pelham and West Lincoln;

E. NFHC and PWPI agreed to amalgamate NFHI and PWUL to form the Corporation (the "**Amalgamation**") pursuant to the terms of the Merger Agreement dated **[December 31, 2007]** among NFHC, NFHI, PWPI and PWUL (the "**Merger Agreement**") and the Amalgamation Agreement among NFHC, NFHI, PWPI and PWUL dated **[December 31, 2007]** and the Amalgamation was effective **[January 1, 2008]**;

F. Upon the Amalgamation, NFHC received seven hundred and forty-five (745) common shares in exchange for one hundred (100) common shares in the capital of

NFHI and PWPI received two hundred and fifty-five (255) common shares in exchange for one hundred (100) common shares in the capital of PWUL;

G. The Councils of Lincoln, Pelham and Niagara Falls approved the Amalgamation. The Council of West Lincoln did not approve the Amalgamation.

H. The shareholder agreement of PWPI requires two-thirds (2/3) of the votes cast at a duly constituted meeting of the shareholders of PWPI to approve all shareholder decisions, including amalgamations. With the approval of Lincoln and Pelham, which collectively own 76% of the voting shares of PWPI, at a duly constituted shareholders meeting, the shareholders of PWPI approved the Amalgamation. PWPI, the sole shareholder of PWUL, approved the Amalgamation. The directors of both PWPI and PWUL approved the Amalgamation.

I. The shareholders and directors of NFHC and NFHI approved the Amalgamation.

J. The authorized capital of the Corporation consists of an unlimited number of common hsares of which 1,000 are issued and outstanding.

K. At the date hereof all of the issued and outstanding shares of the Corporation are registered and beneficially owned as follows:

Shareholder	**Corporation Shares**
NFHC	745 common shares
PWPI	255 common shares

L. The parties have agreed to set out in this Agreement their respective rights and obligations with respect to the management and operation of the Corporation and the ownership of shares in the Corporation and with respect to their relationship towards each other; and

M. The operation and management of the Corporation shall be based upon the general objectives and business principles set out in Section 2.1 of this Agreement.

NOW, THEREFORE IN CONSIDERATION OF THE FOREGOING AND OF THE MUTUAL COVENANTS HEREIN CONTAINED, THE PARTIES HERETO AGREE AS FOLLOWS:

ARTICLE 1 - INTERPRETATION

1.1 **Definitions:** Whenever used in this agreement unless there is something in the subject matter or context inconsistent therewith, the following terms shall have these respective meanings:

"**Additional Shareholders**" means such Persons, other than NFHC or PWPI, as may from time to time become shareholders of the Corporation and parties to this Agreement.

"**Affiliate Relationships Code**" means the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the OEB, as amended from time to time and any replacement code or directive.

"**Agreement**" means this Shareholders Agreement, and includes any agreement which is supplementary to or an amendment or confirmation of this Agreement (and which is entered into in accordance with this Agreement) and any schedules hereto or thereto.

"**Amalgamation**" has the meaning set forth in the Recitals to this Agreement.

"**Applicable Law**" means, collectively, all applicable federal, provincial and municipal laws, statutes, ordinances, decrees, rules, regulations, by-laws, legally enforceable policies, codes, or guidelines, judicial, arbitral, administrative, ministerial, departmental or regulatory judgments, orders, decisions, directives, rulings or awards, and conditions of any grant of approval, permission, certification, consent, registration, authority or licence by any statutory body, self-regulatory authority or other Governmental Authority.

"**Articles**" means the articles of amalgamation of the Corporation in effect on the date hereof.

"**Board**" means the board of directors of the Corporation as elected by the Shareholders from time to time in accordance with the provisions of this Agreement.

"**Business**" means, with respect to the Corporation, the distribution of electricity to the customers of the Corporation and the provision of such ancillary services as may be determined from time to time and such other businesses which may be permitted to be undertaken by the Corporation pursuant to Section 2.3 of this Agreement.

"**Business Day**" means any day except Saturday, Sunday or any day which is a statutory holiday in the Province of Ontario.

"**Chair**" means the director who is appointed chair of the Board from time to time as provided in this Agreement.

"**Council**" means the municipal Council at such time of the Municipalities or of any other municipality which may become a direct or indirect shareholder of the Corporation from time to time.

"**Electricity Act**" means the *Electricity Act, 1998* (Ontario), as amended from time to time and any replacement or successor legislation.

"**Former Director**" has the meaning set forth in Section 4.13.

"**Governmental Authority**" means any government or political subdivision (including without limitation, any municipality or federal or provincial ministry) or quasi-governmental or regulatory agency, authority, board, commission, department or instrumentality of any government or political subdivision, or any court or tribunal including the IESO, OEB and OPA.

"**IESO**" means the Ontario Independent Electricity System Operator and any successor.

"**includes**" means "includes, without limitation" and "including" means "including, without limitation".

"**Information**" has the meaning set forth in Section 14.3.

"**LDC**" means an electricity distribution corporation created pursuant to Section 142 of the Electricity Act and licensed to distribute electricity pursuant to the OEB Act.

"**Lincoln**" means the Town of Lincoln.

"**Municipalities**" means Lincoln, Niagara Falls, Pelham and West Lincoln;

"**Niagara Falls**" means the City of Niagara Falls.

"**Non-Selling Shareholder**" has the meaning set forth in Section 13.5(a).

"**OBCA**" means the *Business Corporations Act* (Ontario), as amended from time to time.

"**OEB**" means the Ontario Energy Board and any successor.

"**OEB Act**" means the *Ontario Energy Board Act*, *1998*, as amended from time to time and any replacement or successor or legislation.

"**Offered Shares**" has the meaning set forth in Section 8.1(a).

"**OPA**" means the Ontario Power Authority and any successor.

"**Ordinary Course of Business**" means the conduct of the Business in the ordinary and usual course and in a manner consistent with the manner in which the Business is carried on as of the date hereof or as may be permitted pursuant to Section 2.3 hereof including as to the nature and scope of the Business and shall include the acquisition of the shares, assets or business of

LDC's and related businesses and the amalgamation of the Corporation with other LDC's.

"**Parties**" means the Shareholders and the Corporation and "Party" means any one of them.

"**Pelham**" means the Town of Pelham.

"**Permitted Transferee**" has the meaning set forth in Section 7.3(a).

"**Person**" means any individual, corporation, partnership, firm, joint venture, syndicate, association, trust, Governmental Authority and any other form of entity or organization.

"**Pro Rata**" means in the same proportion that the number of common shares owned by a Shareholder is to all of the then issued and outstanding common shares of all Shareholders of the Corporation.

"**Prospective Purchaser**" has the meaning set forth in Section 8.3.

"**Purchase Notice**" has the meaning set forth in Section 8.2.

"**Purchase Price**" has the meaning set forth in Section 8.1(a).

"**Right of First Refusal Period**" has the meaning set forth in Section 8.2.

"**Remaining Shareholders**" has the meaning set forth term in Section 8.1(b).

"**Sale Notice**" has the meaning set forth in Section 8.1(a).

"**Selling Shareholder**" has the meaning set forth in Section 8.1(a).

"**Shareholder**" means individually any, and "**Shareholders**" means collectively all, of NFHC and PWPI and any Person to whom any Shares are transferred, or issued, in accordance with the terms of this Agreement, at any time subsequent to the date of this Agreement.

"**Shares**" means common shares of the Corporation.

"**Share Purchase Price**" has the meaning set forth in Section 12.3.

"**Special Resolution**" means a resolution that is submitted to a meeting of the Shareholders called for the purpose of considering the resolution and passed, with or without amendment, at the meeting by at least two-thirds (2/3) of the votes cast.

"**Standstill Period**" means the five (5) year period from the date of this Agreement to and including **[January 1, 2013].**

"**West Lincoln**" means the Township of West Lincoln.

"**Withdrawal Date**" has the meaning set forth in Section 12.4.

"**Withdrawing Shareholder**" has the meaning set forth in Section 12.2.

1.2 **Interpretation:** Unless otherwise defined in this Agreement, words and phrases that have not been defined shall have the meaning ascribed to them in the OBCA.

1.3 **Interpretation Not Affected by Headings:** The division of this Agreement into Articles, Sections, Subsections, Paragraphs, Subparagraphs and Clauses and the insertion of headings are for the convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "this Agreement", "hereof", "herein", "hereunder" and similar expressions refer to this Agreement and not to any particular Article, Section, Subsection, Paragraph, Subparagraph or Clause or other portion hereof and include any agreement or instrument supplemental or ancillary hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to Articles and Sections are to Articles and Sections of this Agreement.

1.4 **Number and Gender:** Words importing the singular number only shall include the plural and vice versa, words importing the masculine gender shall include the feminine and neuter genders and vice versa.

1.5 **Accounting Principles:** Wherever in this Agreement reference is made to generally accepted accounting principles, such reference shall be deemed to be the generally accepted accounting principles from time to time approved by the Canadian Institute of Chartered Accountants, or any successor institute, applicable as at the date on which such calculation is made or required to be made in accordance with generally accepted accounting principles.

1.6 **Effect of this Agreement:** To the extent that this Agreement specifies that any matters relating to the Corporation may only be or shall be dealt with or approved by, or shall require action by the Shareholders, the discretion and powers of the directors of the Corporation to manage and to supervise the management of the business and affairs of the Corporation with respect to such matters are correspondingly restricted. For greater certainty, the Parties agree that Sections 5.1 and 5.2 of this Agreement are intended to operate as a unanimous shareholders agreement with respect to the Corporation, within the provisions of Section 108(2) of the OBCA.

1.7 **Statutes and Amendments:** Any reference in this Agreement to an agreement, or to a statute, regulation or rule promulgated under a statute or to any provision of an agreement, a statute, regulation or rule shall be a reference to the agreement, statute, regulation, rule or provision, as amended, restated, re-enacted or replaced from time to time.

1.8 **Schedules:** The following schedules are incorporated herein and form part of this Agreement:

Schedule A Valuation Method

ARTICLE 2 - OBJECTIVES, GUIDING PRINCIPLES AND PERMITTED BUSINESS ACTIVITIES

2.1 **Guiding Principles and Objectives:** The Parties acknowledge and recognize the following guiding principles and objectives of the Corporation and the intention of the Shareholders that the Corporation be managed in a manner consistent with these guiding principles and objectives:

(a) maintain local presence and control over the management of electricity services and rates;

(b) improve electricity distribution services to local customers;

(c) improve the utilization of existing resources;

(d) explore business options that achieve new economics of scale and avoid duplication of services and costs to the customer;

(e) pursue strategic partnerships that contribute to a strengthened corporate presence and voice – locally and provincially;

(f) improve corporate flexibility to better respond to emerging business opportunities and complexities in the electricity market; and

(g) increase corporation value to maximize Shareholder wealth.

2.2 **Financial Policies, Risk Management and Strategic Plan:** The Shareholders expect that the Board will establish policies to:

(a) Capital Structure - develop and maintain a prudent financial and capitalization structure for the Corporation consistent with industry norms and sound financial principles and established on the basis that the Corporation is a self-financing entity;

(b) Distribution Rates – ensure the establishment of just and reasonable electricity distribution rates for the regulated electricity distribution business of the Corporation which are:

(i) consistent with similar utilities in comparable growth areas and as may be permitted under the OEB Act;

(ii) intended to enhance the value of the Corporation; and

(iii) consistent with the encouragement of economic development and activity for each of the Shareholders.

It is the intention of the parties to harmonize the distribution rates of NFHI and PWUL conditional on receiving all necessary regulatory approvals;

(c) Dividends – the establishment of a dividend policy, consistent with prudent financial practices, for the Corporation, all with the intention of providing the Shareholders with a reasonable rate of return on their investment while maintaining reasonable rates for customers;

(d) Risk Management - manage all risks related to the Business conducted by the Corporation through the adoption of appropriate risk management strategies and internal controls consistent with industry norms; and

(e) Strategic Plan - develop a long range strategic plan for the Corporation which is consistent with:

(i) the guiding principles and objectives in Section 2.1;

(ii) the maintenance of a viable Business; and preservation of the value of the Business for the Shareholders.

2.3 **Permitted Business Activities:**

The Corporation may engage in the business activities which are permitted by Applicable Law from time to time, including the Electricity Act and OEB Act and as the Board may authorize. In so doing, the Corporation shall conform to all requirements of the OEB, the IESO, the OPA and all other applicable Governmental Authorities.

ARTICLE 3 - IMPLEMENTATION OF THIS AGREEMENT

3.1 **Carrying out of the Agreement:**

(a) The Shareholders shall at all times act and vote their Shares to carry out and cause the Corporation to carry out the provisions of this Agreement.

(b) To the extent that each Shareholder is permitted by Applicable Law to bind its nominees to do so, the nominee directors of the Shareholder will act and vote as directors in order that the purpose, intent and provisions of this Agreement shall be carried out.

(c) The Corporation confirms its knowledge of this Agreement and will carry out and be bound by the provisions of this Agreement to the full extent that it has the capacity and power at law to do so.

3.2 **Endorsement on Share Certificates:** Share Certificates of the Corporation shall bear the following language either as an endorsement or on the face thereof:

> "The shares represented by this certificate are subject to all the terms and conditions of an agreement made as of **[January 1, 2008]**, a copy of which is on file at the registered office of the Corporation."

ARTICLE 4 - DIRECTORS AND OFFICERS

4.1 **Number of Directors**:

(a) The Articles of the Corporation shall provide for the Board to consist of a minimum of four (4) directors and a maximum of twelve (12) directors.

(b) The initial Board shall consist of eight (8) directors.

4.2 **Nomination of the Initial Directors:** Subject to Sections 4.4, 4.6 and 4.8 , NFHC shall be entitled to nominate four (4) directors and PWPI shall be entitled to nominate four (4) directors and thereafter each of NFHC and PWPI shall be entitled to nominate an equal number of directors. Directors shall hold office until such time as their successors are elected by the Shareholders.

4.3 **Election of Directors:** The Shareholders shall at all times act and vote their Shares to elect as directors of the Corporation the individuals nominated as directors by each Shareholder, and, if required by a Shareholder, to remove such director(s). The Shareholders shall at all times act and vote their Shares to maintain the equal representation of both NFHC and PWPI on the Board.

4.4 **Changing the Number of Directors:** In the event that the Shareholders desire to increase or decrease the number of directors serving on the Board, the Shareholders shall elect such directors, as determined by the Shareholders, in order to maintain the equal representation of both NFHC and PWPI on the Board.

4.5 **Qualification of Directors:**

(a) In addition to the requirements of the OBCA, the qualifications of candidates for the Board shall, where possible, include the following:

(i) commercial experience, sensitivity and acumen;

(ii) time availability;

(iii) corporate finance; accounting experience;

(iv) corporate governance experience;

(v) market development experience;

(vi) industry knowledge including, but not limited to, knowledge of competitive energy or telecommunications markets;

(vii) independent, objective and sound of judgment;

(viii) personal integrity and honesty;

(ix) knowledge of public policy and government regulation issues relating to the Corporation and the electricity industry;

(x) knowledge and experience concerning environmental matters, labour relations and occupational health and safety issues;

(xi) knowledge of the local communities;

(xii) awareness of public policy issues related to the Corporation;

(xiii) business expertise, including marketing, product development, mergers and acquisitions and/or retail experience;

(xiv) experience on boards of significant commercial corporations, preferably with revenues of $10 million annually or more; and

(xv) knowledge and experience with risk management strategy.

(b) Preference may be given to qualified candidates for the Board who are residents of the Municipalities; however, non-residents of the Municipalities shall not be excluded from serving as members of the Board.

4.6 **Affiliate Relationships Code:** The composition of the Board shall comply with the provisions of the Affiliate Relationships Code, as applicable, unless an exemption from compliance applicable to the Corporation has been provided by the OEB and is in effect.

4.7 **Chair:** The Chair shall be selected by the Board from among the directors and shall preside at each meeting of the Board. In the absence of the Chair, the chairman of the meeting shall be selected by the directors in attendance at such meeting.

4.8 **Term of Directors:**

(a) Each director of the Corporation shall be appointed for a term which may be from one (1) to three (3) years as provided in the by-laws of the Corporation.

(b) A director may be appointed for successive terms in the discretion of the Shareholder appointing such director.

4.9 **Removal of Directors:** Section 122 of the OBCA does not apply to the removal of directors from the Board. Each Shareholder shall be entitled in its discretion to cause any of the directors nominated by it to be removed and to nominate and have an individual elect a successor or successors, as the case may be, by providing a direction in writing to the Corporation and to the other Shareholders who shall elect such replacement director or directors. Upon the resignation or removal of a director from the Board, the Shareholder that nominated such director shall use reasonable efforts to obtain and deliver to the Corporation a resignation and release from such director in a form satisfactory to the Corporation.

4.10 **Voting:**

(a) All matters to be determined by the Board shall be determined by a majority vote of directors at a duly convened meeting of the Board and, in case of an equality of votes, the matter shall not be approved and the chairman of the meeting shall not be entitled to a second or casting vote.

(b) Notwithstanding Section 4.10(a) above, in lieu of a meeting of the directors, the consent of the directors with respect to any matter may be evidenced by a resolution in writing (which may be in counterparts) signed by all of the directors.

4.11 **Meeting of Directors:**

(a) The Board shall meet at least once each financial quarter at a time and place to be determined by the Chair. Additional meetings of the Board may be called by the Chair or any other director by notice in writing to every other director of the time, place and purpose of the meeting of the Board and the matters to be considered.

(b) All meetings of the Board shall, unless held by telephone or video conference, be held within the Province of Ontario.

(c) Any one or more of the directors may participate in a meeting of the Board by any telephonic or video device which permits all participants in the meeting to communicate with each other simultaneously and instantaneously, and such participation shall be deemed to constitute attendance at the meeting of the Board for the purpose of this Section 4.11. The Chair may determine that any meeting of the Board may be held by telephone or video conference.

(d) At least seven (7) Business Days prior to each meeting, each director shall be notified in writing of the time, place and purpose of the meeting of the Board and the matters to be considered.

(e) A director may waive notice of any meeting of the Board by an instrument in writing delivered to the Secretary of the Corporation.

4.12 **Quorum – Meetings of Directors**

(a) A quorum for a meeting of the Board shall consist of a majority of the total number of elected directors, (rounded up to the next whole number) provided that, so long as NFHC and PWPI are the only Shareholders of the

Corporation, at least one (1) director who is a nominee of NFHC and at least one (1) director who is a nominee of PWPI must be present at all meetings of the Board.

(b) If a quorum of directors is not present within thirty (30) minutes after the time appointed for a meeting of the Board, the meeting shall be adjourned to a date not less than five (5) and not more than fifteen (15) Business Days subsequent to the date originally set for the meeting, as the directors present at the meeting may determine.

(c) At least two (2) Business Days prior written notice shall be provided to all of the directors of the date for the meeting adjourned pursuant to Section 4.12(b).

(d) If a quorum is not present at such adjourned meeting, the Secretary of the Corporation shall forthwith call a further adjourned meeting of the Board, to be held not later than five (5) Business Days after the previously adjourned meeting was to be held and shall provide at least two (2) Business Days prior written notice thereof to the Shareholders. The Shareholders shall cause their respective nominee directors to attend, (or shall remove their nominee directors and nominate directors to be elected as replacement directors in accordance with Section 4.9 and cause such replacement directors to attend), the further adjourned meeting.

4.13 **Vacancies:** In the event of any vacancy occurring on the Board by reason of the death, disqualification, inability to act or resignation of any director (the "**Former Director**"), the Shareholder entitled to nominate the Former Director shall nominate another individual to replace the Former Director in order to fill such vacancy as soon as reasonably possible, and the Shareholders shall vote their Shares to elect such nominee accordingly.

4.14 **Insurance:** The Corporation shall acquire and maintain insurance coverage for the directors and officers of the Corporation as the Board may determine from time to time. In the event that such insurance coverage ceases to be available to the directors for any reason, each Shareholder shall be responsible for insuring its own nominees.

4.15 **Auditor:** Crawford, Smith, and Swallow shall be appointed as the initial auditor of the Corporation and shall hold office until such time as the Shareholders select a replacement.

4.16 **Corporate Governance Matters:** Subject to the provisions of Article 5, the Board shall supervise the management of the business and affairs of the Corporation and, in so doing, shall act honestly and in good faith with a view to the best interests of the Corporation and each director shall exercise the same degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

4.17 **Initial Senior Executive Arrangements:**

(a) The Parties acknowledge and agree Brian Wilkie shall be the initial President and Chief Executive Officer of the Corporation.

(b) In addition to the senior executive arrangements provided in Section 4.17(a) the Board shall appoint such other officers of the Corporation as the Board may determine.

ARTICLE 5 - APPROVAL OF CERTAIN CORPORATE ACTIONS

5.1 **Unanimous Approval by Shareholders:** Subject to Section 5.3, unless first approved by an unanimous resolution of Shareholders, either adopted at a meeting of the Shareholders called for that purpose or evidenced by a resolution in writing signed by all of the Shareholders, no action shall be taken by the Corporation with respect to any of the following matters:

(a) Amalgamating, consolidating, reorganizing or merging the Corporation with another entity;

(b) Create new classes of shares;

(c) Issue, or enter into any agreement to issue, any shares of any class, or any securities convertible into any shares of any class, of the Corporation or grant any option or other right to purchase any shares or securities convertible into such shares;

(d) Amend the rights, restrictions or privileges of any Shares of the Corporation;

(e) Disposing of or encumbering all or substantially all of the assets of the Corporation;

(f) Changing the dividend policy for the Corporation;

(g) Any amendment to the provisions of this Agreement regarding proportional representation of the Shareholders on the Board or the rights of Shareholders to nominate members of the Board;

(h) Entering into any partnership, joint venture or other business venture that would involve the expenditure or investments of funds by the Corporation outside of the Ordinary Course of Business or that would change the status of the Corporation for taxation purposes, under the Electricity Act or the *Income Tax Act* (Canada), *Corporations Tax Act* (Ontario) or other Applicable Law;

(i) Changing the capitalization policy or the financing policy for the Corporation;

(j) Acquire any electricity distribution business outside of the municipal boundaries of the Municipalities or otherwise acquiring shares in another corporation;

(k) Making loans or providing financial support to a Shareholder, an employee or a person not at arm's length to a Shareholder; or

(l) Any amendment, assignment or termination of any agreement among the Corporation, Niagara Power Inc., Niagara West Transformation Corporation ("**NWTC**"), and/or PWPI regarding the administration and operation of NWTC and its transformation station.

5.2 **Special Resolution by Shareholders:** Subject to Section 5.3, unless first approved by a Special Resolution of the Shareholders, adopted at a meeting of the Shareholders called for that purpose, no action shall be taken by the Corporation with respect to any of the following matters:

(a) Change the name of the Corporation;

(b) Add, remove or change restrictions on the business of the Corporation;

(c) Amendment of articles or bylaws of the Corporation;

(d) Subject to Section 5.1(g) above regarding proportional representation on the Board, any change in the number of directors of the Corporation;

(e) Redeem, purchase for cancellation or otherwise retire any outstanding shares of the Corporation;

(f) Taking any action to wind-up or dissolve the Corporation;

(g) Taking any bankruptcy or insolvency related actions with respect to the Corporation;

(h) Apply to continue as a corporation in another jurisdiction;

(i) Incurring single project capital expenditures greater than $5 million;

(j) Creating a subsidiary of the Corporation;

(k) Borrowing of money in excess of $5 million;

(l) Becoming contingently liable for the debts or obligations of another person;

(m) Changing the fiscal year end of the Corporation;

(n) Changing the auditors of the Corporation;

(o) Giving security on the Corporation assets except in the ordinary course of business; or

(p) Change in the location of the head office of the Corporation.

5.3 **Additional Shareholders:** In the event that Persons become Shareholders of the Corporation in addition to NFHC and PWPI other than in accordance with Articles 7, 8, 9, 10, 11 and 12 of this Agreement, the parties acknowledge that provisions of this Agreement shall be reviewed and, if required, revised in a manner to be determined by the parties consistent with the guiding principles of the Corporation as described in Section 2.1 of this Agreement.

ARTICLE 6 - REPRESENTATIONS AND WARRANTIES

6.1 **Representations and Warranties by Shareholders.** Each Shareholder represents and warrants to each of the other Shareholders and acknowledges that each of the other Shareholders is relying on these representations and warranties in connection with entering into this Agreement:

(a) that each Shareholder owns beneficially and of record the number of issued and outstanding Shares which is set out opposite its name in Recital E to this Agreement, that those Shares are not subject to any mortgage, hypothec, lien, charge, priority, pledge, encumbrance, security interest or adverse claim, and that no Person has any rights to become a holder or possessor of any of those Shares or of the certificates representing them;

(b) that it is duly incorporated and validly existing under the laws of its jurisdiction of incorporation and that it has the corporate power and capacity to own its assets and to enter into and perform its obligations under this Agreement;

(c) that this Agreement has been duly authorized, executed and delivered by it, and (assuming due execution and delivery by the other Parties) is a legal, valid and binding obligation of it enforceable against it in accordance with its terms;

(d) that the execution, delivery and performance of this Agreement does not and will not contravene the provisions of its articles, by-laws, constating documents or other organizational documents, or the provisions of any contract, agreement or other instrument to which it is a party or by which it may be bound;

(e) that the Shareholder is not a non-resident for purposes of the *Income Tax Act* (Canada); and

(f) that all of the representations and warranties set out in Section 6.1(a) through (f) will continue to be true and correct during the term of this Agreement.

ARTICLE 7 - RESTRICTIONS ON SHARE TRANSFERS

7.1 **Standstill Period - Restricted Sales of Shares:** No Shareholder may sell all or any portion of its Shares without the prior written consent of all of the other Shareholders during the Standstill Period. After the Standstill Period has expired, a Shareholder may only sell, transfer, assign or otherwise dispose of the whole or any part of its Shares in accordance with this Agreement.

7.2 **Agreement Binding on Transferees:** No Shares of the Corporation shall be effectively issued, sold, assigned, transferred, disposed of or conveyed, by a Shareholder to any Person except in accordance with this Agreement and until the proposed transferee or purchaser executes and delivers to the Parties hereto an agreement to the same effect as this Agreement and any further agreement with respect to the Corporation to which the Shareholders are then, or are then required to be, a party. Upon the proposed transferee or purchaser so doing, such agreements shall enure to the benefit of and be binding upon all of the Parties to them as if all had executed and delivered the same agreements at the same time.

7.3 **Permitted Transferees:**

(a) Subject to the restrictions on transfer or sale in Section 7.1 and 7.2 hereof, a Shareholder may, without the consent of the other Shareholders, transfer any or all of the Shares owned by it to any Person (hereinafter in this Section 7.3 referred to as a "**Permitted Transferee**") provided that the Permitted Transferee is wholly-owned by such Shareholder or, if such Shareholder is a corporation, the Permitted Transferee is wholly-owned by the Controlling Shareholder of such Shareholder and provided that prior to any such transfer:

(i) the Permitted Transferee shall undertake in writing, by signing a counterpart of this Agreement, to be bound by the terms and conditions of this Agreement; and

(ii) the Controlling Shareholder of such Permitted Transferee represents, warrants, and undertakes in writing that it shall wholly own such Permitted Transferee for as long as such Permitted Transferee holds Shares of the Corporation.

(b) In the event that the transferee of the Shares ceases to be a Permitted Transferee for the purposes of this Section 7.3 then the Shares shall be promptly transferred back to the Shareholder.

7.4 **Pre-emptive Right**:.

(a) Except as expressly provided in this Agreement, if any additional Shares or other securities of the Corporation are approved for issue or if any other options or rights to purchase or subscribe for securities of the Corporation are approved for grant none of those Shares or other securities of the Corporation shall be issued by the Corporation, and none of those options or other rights shall be granted, at any time after the date of this Agreement, except in compliance with this Section 7.4.

(b) If the Corporation proposes to issue any Shares or other securities of the Corporation (in this Section 7.4, the "**Affected Securities**"), the Corporation shall give notice (an "**Issue Notice**") to the Shareholders of the proposed issuance. The Issue Notice shall constitute an offer for subscription by each of the Shareholders of that number of the Affected Securities (in this Section 7.4, its "**Proportionate Entitlement**") which bear the same relationship to the total number of Affected Securities as the number of issued and outstanding Shares held by each such Shareholder bears to the total number of issued and outstanding Shares (as reflected on the securities registers of the Corporation) at the date of the Issue Notices (in this Section 7.4, the "**Notice Date** ") at the subscription price determined by the Board for all those Affected Securities. Each Issue Notice shall:

(i) be made in writing by the Secretary and be made concurrently to all Shareholders in the same manner (whether by delivery, prepaid courier service or facsimile);

(ii) contain a description of the terms and conditions relating to the Affected Securities, the price at which the Affected Securities are offered and the date on which the purchase of the Affected Securities by the Shareholders is to be completed; and

(iii) state that any Shareholder that wishes to subscribe for less than its Proportionate Entitlement shall, in its notice of subscription, specify the number of Affected Securities (up to its Proportionate Entitlement) that it wishes to subscribe for.

The offer constituted by each Issue Notice shall be irrevocable and shall remain open for acceptance by the Shareholders for a period of thirty (30) days after the Notice Date.

(c) Each of the Shareholders shall have the right, exercisable by notice given to the Corporation within the period during which the offer constituted by the Issue Notice is open for acceptance under Section 7.4(b), to accept the offer constituted by the Issue Notice to subscribe for its Proportionate Entitlement of the Affected Securities or, if it wishes to subscribe for less than its Proportionate Entitlement, to indicate how many Affected Securities (up to its Proportionate Entitlement) it wishes to subscribe for. If no notice is given by a Shareholder under this Section 7.4(c), that Shareholder shall be deemed to have rejected the offer made available to it to subscribe for Affected Securities.

(d) If any of the Shareholders does not agree to purchase all of its Proportionate Entitlement of the Affected Securities or is deemed to have rejected the offer made available to it to subscribe for Affected Securities (in this Section 7.4, a

"**Declining Offeree**"), the Corporation shall forthwith so notify in writing (in this Section 7.4, the "**Additional Notice**") each of the other Shareholders which has accepted the offer to subscribe for not less than its Proportionate Entitlement of the Affected Securities (in this Section 7.4, a "**Purchasing Shareholder**"). Each of the Purchasing Shareholders shall have the right to subscribe for that number or any part thereof, of the Affected Securities that have not been accepted for subscription by the Declining Offerees (the "**Unsubscribed Securities**") which bears the same relationship to the total number of Unsubscribed Securities as the number of Shares held by each such Purchasing Shareholder bears to the total number of Shares by all Purchasing Shareholders (as reflected on the securities registers of the Corporation) at the date of the Additional Notice. Any Purchasing Shareholder that receives an Additional Notice shall have the right, exercisable by notice given to the Corporation within a period of ten (10) days after deemed receipt of that Additional Notice pursuant to Section 15.1, to agree that it will purchase the number of Unsubscribed Securities which it is entitled to purchase or any lesser number thereof specified by it in that notice. If no notice is given by a Purchasing Shareholder under this Section 7.4 within that ten (10) day period, that Purchasing Shareholder shall be deemed to have rejected the offer made available to it to purchase any Unsubscribed Securities. No Shareholder shall be obliged to purchase any Affected Securities in excess of the number indicated in its subscription.

(e) If any Affected Securities of any issue are not subscribed for prior to the expiry of the last applicable period pursuant to Sections 7.4(c) and 7.4(d), the Corporation may offer those unsubscribed for Affected Securities within a period of ninety (90) days after the expiration of the last applicable period pursuant to Sections 7.4(c) and 7.4(d) to any Person, but the price at which those Affected Securities may be issued shall not be less than the subscription price offered to the Shareholders and the terms of payment for those unsubscribed for Affected Securities shall not be more favourable to that Person than the terms of payment offered to the Shareholders.

(f) If the Corporation proposes to grant an option or other right for the purchase of or subscription for Affected Securities, that option or other right shall also be made available to Shareholders in accordance with Sections 7.4(b) through 7.4(e).

(g) The Corporation shall be entitled to issue additional Shares without complying with the provisions of this Section 7.4 when those Shares are being issued on the exercise of existing options or rights to purchase or subscribe for Shares.

ARTICLE 8 - RIGHT OF FIRST REFUSAL

8.1 **First Right of Refusal:**

(a) Any Shareholder (hereinafter in this Article 8 referred to as the "**Selling Shareholder**") who desires to transfer or sell all, but not less than all, of its Shares (hereinafter in this Article 8 referred to as the "**Offered Shares**") shall give notice of such proposed sale (hereinafter in this Article 8 referred to as the "**Sale Notice**") to the Corporation and to the other Shareholders and shall set out in the Sale Notice the terms upon which and the price at which it desires to sell the Offered Shares (such price being hereinafter in this Article 8 referred to as the "**Purchase Price**"). A Shareholder selling Shares under this Section 8.1 must sell all, and not less than all, of its Offered Shares, unless the other Shareholders otherwise agree.

(b) Upon the Sale Notice being given, the other Shareholders (hereinafter in this Article 8 referred to as the "**Remaining Shareholders**") shall have the right to purchase all, but not less than all, of the Offered Shares for the Purchase Price on a Pro Rata basis as described in Section 8.2.

8.2 <u>**Exercise of Right of First Refusal:**</u> The Remaining Shareholders shall have the option, exercisable by giving written notice of the exercise of such option (hereinafter in this Article 8 referred to as the "**Purchase Notice**") to the Selling Shareholder and the Corporation within ninety (90) days (hereinafter in this Article 8 referred to as the "**Right of First Refusal Period**") subsequent to the date of deemed receipt, pursuant to Section 15.1 hereof, by the Remaining Shareholders of the Sale Notice, to purchase all but not less than all of the Offered Shares, on a Pro Rata basis, determined on the basis of the ratio of the number of Shares owned by each Remaining Shareholder to the number of Shares owned by all Remaining Shareholders at the Purchase Price and the terms set forth in the Sale Notice. If all the Offered Shares have not been purchased by the Remaining Shareholders then the remaining Offered Shares shall be offered to those Remaining Shareholders which have purchased Offered Shares on a Pro Rata basis until all of the Offered Shares have been purchased. The closing of the sale of the Offered Shares shall occur on the first Business Day following the expiry of the sixty (60) day period following the date of deemed receipt, pursuant to Section 15.1 hereof, by the Remaining Shareholders and the Corporation of the Purchase Notice or, if the completion of such sale requires the prior approval of or notice to a third Person or Governmental Authority under Applicable Law or any instrument or agreement, within thirty (30) Business Days after receipt of such approval or required period of notice or on such later date as may be agreed by the Parties.

8.3 <u>**Sale of Shares:**</u> In the event that the Remaining Shareholders do not exercise their right of first refusal pursuant to Section 8.2, the rights of the Remaining Shareholders, subject as hereinafter provided, to purchase the Offered Shares shall forthwith terminate and the Selling Shareholder, subject to the restrictions on transfer or sale specified in Section 13.5 hereof, may sell the Offered Shares to any Person (the "**Prospective Purchaser**") within ninety (90) days after the termination of the Right of First Refusal Period, for a price not less than the Purchase Price and on other terms no more favourable to the Prospective Purchaser than those set forth in the Sale Notice, provided that the Prospective Purchaser agrees prior to such transaction to be bound by this Agreement and to become a party hereto in place of the Selling Shareholder with respect to the Offered Shares. If the Offered Shares are not sold within such ninety (90) day period, or, if the completion of such sale requires the prior approval of or notice to a third Person or Governmental Authority under Applicable Law or any instrument or agreement, within thirty (30) Business Days after receipt of such approval or any required period of notice, on such terms, the rights of the Remaining Shareholders pursuant to Sections 8.1 and 8.2 shall again take effect and so on from time to time.

8.4 **Moratorium on Sales While Purchase Offer Outstanding:** Once a Shareholder gives a Sale Notice pursuant to Section 8.1 hereof, for a period of one (1) year, no other Shareholder shall be entitled to give a Sale Notice with respect to Shares until such time as the Offered Shares are either sold to the Remaining Shareholders, or a Prospective Purchaser, as the case may be, in accordance with the terms of this Article 8 or the sale of such Shares to the Prospective Purchaser does not occur within the time limits prescribed in Section 8.3. No Shareholder may proceed with any sale of any of the Shares owned by it without complying with the relevant provisions of this Agreement.

ARTICLE 9 – TAG-ALONG/DRAG ALONG RIGHTS

9.1 **Tag-Along Rights**:

(a) In the event that a Shareholder, or Shareholders together, owning a majority of the Shares (the "Majority Shareholder") proposes to sell all of its Shares (the "**Offered Majority Shares**") to an Arm's Length third party (the "**Third Party**") pursuant to Section 8.3, then the Majority Shareholder shall, within thirty (30) days following the expiry of the ninety (90) day period referred to in Section 8.3 of the Corporation, give written notice (the "**Tag-Along Notice**") of the identity of the Third Party and the price and other material terms of the transaction (which shall be consistent with the requirements of Section 8.1) to the owners of less than fifty percent (50%) of the Shares (the "Minority Shareholders"). The Minority Shareholders (each a "Minority Selling Shareholder") may, not later than ninety (90) Business Days after receipt of the Tag-Along Notice, deliver to the Majority Shareholder a notice in writing invoking the provisions of this Section 9.1 (a "**Tag-Along Demand**"). The delivery by a Minority Selling Shareholder of a Tag-Along Demand shall be irrevocable and shall bind such Minority Selling Shareholder to sell all, but not less than all, of the Shares owned by such Minority Selling Shareholder(the "**Tag-Along Shares**"), in accordance with the provisions of this Section 9.1.

(b) If a Minority Shareholder delivers a Tag-Along Demand, then, before completing any sale, the Majority Shareholder shall cause the Third Party to deliver to each Minority Selling Shareholder a bona fide offer in writing (the "**Tag-Along Offer**") to purchase the Tag-Along Shares from such Minority

Selling Shareholder. The Tag-Along Offer will be binding upon the Third Party and shall contain only such terms and conditions as are identical to those upon which the Majority proposes to sell to the Third Party the Offered Majority Shares pursuant to Section 8.3, provided that the offer price per Share, which shall be specified in the Tag-Along Offer, shall be the same consideration as the consideration per Share at which the Majority Selling Shareholder proposes to sell to the Third Party the Offered Majority Shares pursuant to Section 8.3.

(c) The closing date and other closing arrangements for the purchase and sale transaction between the Majority Shareholder and the Third Party shall be specified in the Tag-Along Offer and shall be the same, *mutatis mutandis*, as those specified between the Third Party and the Minority Shareholder.

9.2 **Drag-Along Rights**:

(a) In the event that the Majority Shareholder proposes to sell the Offered Majority Shares to a Third Party pursuant to Section 8.3 and a Minority Shareholder (a “Non-Selling Minority Shareholder)(has not exercised its Tag Along rights under Section 9.1, then the Majority Shareholder may, by written notice to the Non-Selling Minority Shareholders delivered within thirty (30) days following the expiry of the ninety (90) day period referred to in Section 9.1, accompanied by an irrevocable offer (the "**Drag-Along Offer**") from the Third Party to the Non-Selling Minority Shareholders to purchase, for a consideration that is the same as the consideration per Share at which the Majority Shareholder proposes to sell the Offered Majority Shares to the Third Party pursuant to Section 8.3, the Shares owned by the Non-Selling Minority Shareholders (the "**Dragged Shares**"), require the Non-Selling Minority Shareholder to sell to the Third Party all such Dragged Shares at the price specified in the Drag-Along Offer.

(b) The delivery by the Majority Shareholder of an irrevocable Drag-Along Offer shall bind the Non-Selling Minority Shareholder to sell the Dragged Shares. The date on which the sale is to close and the other closing arrangements (which shall be the same, *mutatis mutandis*, as those for the purchase and sale between the Third Party and the Majority Shareholder) shall be as specified in the Drag-Along Offer. Except as specifically provided for above, the Drag-Along Offer shall contain only such terms and conditions, if any, as are identical to those pursuant to which the Majority Shareholder proposes to sell to the Third Party the Offered Shares.

ARTICLE 10- BUY-SELL RIGHTS

10.1 **Buy-Sell:**

(1) Any Shareholder (in this Section 10.1, an "**Offeror**") may give notice (a "**Purchase or Sale Notice**") to the other Shareholders (in this Section 10.1, the "**Other**

Shareholders") of a proposed purchase or sale of Shares. The Purchase or Sale Notice shall constitute an offer (the "**Purchase Offer**") by the Offeror to the Other Shareholders to purchase all but not less than all of the issued and outstanding Shares held by the Other Shareholders at the Notice Date at a specified purchase price per Share (the "**Buy-Sell Share Price**") and shall in the alternative constitute an offer (the "**Sale Offer**") by the Offeror to sell all but not less than all of the issued and outstanding Shares held by the Offeror at the date of the Purchase or Sale Notices (in this Section 10.1, the "**Affected Shares**"; and the date of the Purchase or Sale Notices, in this Section 10.1, the "**Notice Date**") at the Buy-Sell Share Price. The Purchase and Sale Notices shall:

(a) be made in writing by the Offeror and be made concurrently to all Other Shareholders in the same manner (whether by delivery, prepaid courier service or facsimile); and

(b) state the Buy-Sell Share Price.

The offers constituted by each Purchase or Sale Notice shall be irrevocable and shall remain open for acceptance by the Other Shareholders for a period of ninety (90) days after the date of the Purchase and Sale Notice.

(2) Each of the Other Shareholders shall have the right, exercisable by notice (in this Section 10.1, an "**Acceptance**") given to the Offeror within the period during which the offers constituted by the Purchase or Sale Notice is open for acceptance under Section 10.1(1) to accept the Purchase Offer and agree to sell to the Offeror all of that Other Shareholder's issued and outstanding Shares or to reject that offer and to accept the Sale Offer and agree to purchase the Affected Shares. If no Acceptance is given by an Other Shareholder under this Section 10.1(2), that Other Shareholder shall be deemed to have accepted the Purchase Offer constituted by the Purchase or Sale Notice.

(3) If one or more of the Other Shareholders accept the Sale Offer, the Purchase Offer shall be deemed to have been rejected by all of the Other Shareholders. If only one Other Shareholder accepts the Sale Offer, that Other Shareholder shall be deemed to have agreed to purchase all of the Affected Shares. If two or more Other Shareholders accept the Sale Offer (in this Section 10.1, the "**Purchasing Shareholders**"), each of such Purchasing Shareholders shall be deemed to have agreed to purchase that number of the Affected Shares which bears the same relationship to the total number of Affected Shares as the number of issued and outstanding Shares held by each such Purchasing Shareholder bears to the total number of issued and outstanding Shares held by all Purchasing Shareholders (as reflected on the securities registers of the Corporation) at the Notice Date.

(4) The completion of all purchases of Affected Shares or of the Shares held by the Other Shareholders, as the case may be, under this Section 10.1 shall occur on the thirtieth (30^{th}) day after the expiry of the period during which the offers constituted by the Purchase and Sale Notice are open for acceptance.

(5) Once a Shareholder gives a Purchase or Sale Notice, no Other Shareholder may give a Purchase or Sale Notice with respect to Shares, until such time as either the Affected Shares are sold to the Purchasing Shareholders or the Shares held by the Other Shareholders are sold to the Offeror pursuant to this Section 10.1.

ARTICLE 11 - PUT OPTION

11.1 **Put Option:**

(a) The Shareholders other than the Majority Shareholder (in this Section 11.1, the "**Other Shareholders**") shall have the irrevocable right and option (the "**Put Option**") by notice to Majority Shareholder and the Corporation with a copy to the other Shareholders, to force the purchase by the Majority Shareholder or the Corporation, of all of the Shares held by that Other Shareholder at a total purchase price equal to the Put Option Price described in Section 11.1(b) below. The closing of the Put Option shall occur on the thirtieth (30^{th}) day after the deemed receipt of notice of the exercise of the Put Option pursuant to Section 15.1 by the Majority Shareholder and the Corporation.

(b) The "**Put Option Price**" for the purposes of this Article 11 shall mean the fair market value of each Share in which the Shareholder is deemed to have exercised the Put Option. Such Put Option Price shall be determined in a manner provided in Schedule A with the sixty (60) days immediately following the date of exercise of the Put Option.

ARTICLE 12 - PURCHASE OF SHARES ON DEEMED WITHDRAWAL

12.1 **Deemed Withdrawal from the Corporation:**

(a) Subject to 12.1(b), for the purposes of this Article 12, a Shareholder shall be deemed to withdraw from the Corporation on that date (the “Withdrawal Date”) when such Shareholder,

(i) or its Controlling Shareholder: (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar Applicable Law for the protection of creditors, including, the *Bankruptcy and Insolvency Act* (Canada) and the *Companies Creditors Arrangement Act* (Canada), the *Municipal Affairs Act* (Ontario) or other statute applicable to insolvent municipalities or has such petition filed against it and such petition is not withdrawn or dismissed for sixty (60) days after such filing; (ii) otherwise becomes bankrupt or insolvent (however evidenced); or (iii) is unable to pay its debts as they fall due;

(ii) fails, refuses or neglects to conform materially to any of the terms and conditions of this Agreement, and fails to remedy any such default within thirty (30) days of the deemed receipt, pursuant to Section 15.1 hereof, of a written notice from any other Shareholder giving details of such default; or (iii) has all or any portion of its Shares of the Corporation realized upon by an encumbrancer.

(b) The Shareholders may unanimously agree to waive the provisions of this Article 12 with respect to any Shareholder that would otherwise have been deemed to withdraw from the Corporation pursuant to Section 12.1(a)

12.2 **__Purchase of Shares on a Shareholder's Withdrawal from the Corporation__:** In the event that a Shareholder is deemed to have withdrawn from the Corporation pursuant to the provisions of Section 12.1(a) hereof and the Shareholders have not agreed to waive the application of this Article 12 in accordance with Section 12.1(b), the Corporation irrevocably agrees to purchase, on the expiry of the ninety (90) day period following the occurrence of such event, all and not less than all of the Shares of the Shareholder which is deemed to have withdrawn from the Corporation (hereinafter in Section 12.2 referred to as the "**Withdrawing Shareholder**") at the Share Purchase Price. The closing of the sale of the Shares of the Withdrawing Shareholder to the Corporation shall take place at the offices of the Corporation at the address designated in Section 15.1 hereof at 10:00 in the morning (Toronto time) on the first Business Day following the expiry of the aforesaid ninety (90) day period. The Share Purchase Price, determined pursuant to Section 12.4 hereof, shall be paid at such closing in Canadian dollars. In the event that the Corporation is not, at the time of such purchase of Shares, capable of fulfilling its obligations to pay for such Shares, either because it cannot do so in compliance with the OBCA, or other Applicable Law to the same effect, the sale of such Shares to the Corporation shall be completed with the balance of the Share Purchase Price for such Shares to be paid by the Corporation as soon as it is lawfully able to do so.

12.3 **__Sale of Shares on Deemed Withdrawal from the Corporation:__**

(a) The Withdrawing Shareholder hereby irrevocably offers to sell all of its Shares to the Corporation at a price per Share (hereinafter in this Article 12 the "the Share Purchase Price") determined in the manner provided in Section 12.4 hereof and Schedule A hereto.

(b) In all of the circumstances provided in Section 12.1(a), the remaining Shareholders shall have the right to require that the Corporation assign to them the right or obligation of the Corporation to purchase any or all of the Shares of a Withdrawing Shareholder and, pursuant to such assignment, the remaining Shareholders shall have the right to purchase such Shares, provided that in the opinion of tax counsel to the Corporation, the Withdrawing Shareholder will suffer no significant prejudice from an income tax perspective as a result of such Shares being purchased by the remaining Shareholders rather than by the Corporation.

(c) In the event that the remaining Shareholders purchase such Shares, they shall be entitled to purchase them on a Pro Rata basis in proportion to their respective holdings of Shares or in any other proportion as they may choose, and the provisions of Section 12.2 of this Agreement shall apply *mutatis mutandis* provided however, that no Shareholder shall be obliged to purchase any such Shares.

12.4 **Share Purchase Price Determination:** The Share Purchase Price for the purposes of this Article 12 shall mean the fair market value of each Share as determined at the Withdrawal Date. Such Share Purchase Price shall be determined in the manner provided in Schedule A hereto within the sixty (60) days immediately following the Withdrawal Date.

12.5 **Cancellation of Shares:** Upon the acquisition of any Shares by the Corporation pursuant to this Article 12 of this Agreement, such Shares shall be cancelled and shall not be reissued.

ARTICLE 13 - PROVISIONS APPLICABLE TO SALES OF SHARES PURSUANT TO THIS AGREEMENT

13.1 **Application to All Sales:** Except as, or in addition to, what may otherwise be provided in this Agreement, this Article 13 shall apply to any sale of Shares effected pursuant to the provisions of this Agreement.

13.2 **Closing:** The closing of all sales of Shares effected pursuant to this Agreement shall take place at the offices of the Corporation at the address designated in Section 15.1 hereof, at 10:00 in the morning (Toronto time) on the date stipulated, either pursuant to the provisions hereof or pursuant to any agreement executed in connection with any such sale, as the date on which such closing is to occur.

13.3 **Cancellation of Share Certificates:** The President of the Corporation, or such other officer as may be designated by resolution of the directors of the Corporation shall attend all closings of any such sale of Shares and shall deliver to the Corporation for cancellation share certificates evidencing Shares which are to be sold and shall take custody of new share certificates, if any, issued in replacement of such cancelled share certificates so that at all times the Corporation shall have custody of share certificates representing all of the Shares.

13.4 **Resignation of Seller's Nominees:** At the closing of any sale of Shares, the Shareholder selling its Shares shall cause to be delivered to the Corporation signed resignations of its nominees as directors of the Corporation, and shall assign and transfer to the purchaser of such Shares, all of its right, title and interest in such Shares.

13.5 **Transfer Taxes and Other Tax Impacts of a Proposed Sale:**

(a) In the event that any proposed sale or transfer of Shares would result or results in tax or an amount in respect of payments in lieu of tax being exigible from the Corporation or any Shareholder other than the Shareholder selling its Shares (the "**Non-Selling Shareholder(s)**"), whether transfer tax, income tax, capital tax or other tax (and including any taxes or related expenses resulting from the Corporation no longer being tax exempt pursuant to Section 149(1)(d.6) of the *Income Tax Act* (Canada)), all such tax and expenses shall be an expense to the purchaser which shall indemnify the Corporation with respect thereto, and notwithstanding any other provision of this Agreement to the contrary, the proposed sale or transfer shall not be completed unless all such tax and expenses of the Corporation or any Non-Selling Shareholder are first paid in full by the purchaser ; provided that if a proposed sale or transfer is pursuant to the Article 11 Put Option or the Article 12 Deemed Withdrawal, any eligible tax is payable by the Selling Shareholder and the provisions above shall apply *mutatis mutandis*.

(b) A Shareholder selling Shares to any Person shall, as required by the Electricity Act or any other Applicable Law, pay all transfer taxes payable under the Electricity Act in respect of such sale such that the sale shall not be void.

13.6 **Additional Provisions: Loans, Guarantees:** In conjunction with any sale of all Shares:

(a) if the Shareholder selling all of its Shares is indebted to the Corporation, the Corporation may, at its option, require such Shareholder to repay in full all indebtedness which it owes to the Corporation on or before the closing of such sale of Shares;

(b) if the Corporation is indebted to the Shareholder selling all of its Shares, the Shareholder selling Shares may, at its option, require the Corporation to repay in full all indebtedness which it owes to such Shareholder on or before the closing of such sale of Shares; and

(c) if the Shareholder selling all of its Shares has provided a guarantee, letter of credit, security or other financial assistance to the Corporation, the Corporation shall use its commercially reasonable efforts to replace or release such guarantee, letter of credit, security or other financial assistance within ninety (90) days after the closing of such sale of Shares.

ARTICLE 14 - NON-COMPETITION AND CONFIDENTIALITY

14.1 **Non-Competition:** During the period commencing as of the date of this Agreement and terminating on the expiry of the twelve (12) months following the date on which a Shareholder:

(a) is deemed to withdraw from the Corporation, pursuant to Section 14.1 of this Agreement; or

(b) sells all of its Shares in accordance with this Agreement,

such Shareholder shall not, and shall use its commercially reasonable efforts to ensure that its shareholders do not, individually or in partnership or in conjunction with any Person, as principal, agent, shareholder, consultant or otherwise, directly or indirectly, carry on or be engaged in, or advise, acquire an interest in, or permit its name or any part thereof to be used or employed by an association, syndicate or corporation engaged in or concerned with or interested in, the business of distributing electricity as regulated by the OEB unless the consent of the other Shareholders has first been obtained.

14.2 **Necessary Covenants:** Each Shareholder hereby confirms that all restrictions in this Article 14 are reasonable and valid, that they are necessary for the protection of the Corporation's legitimate interests and that they do not unduly affect their earning capacity, and waive all defences to the strict enforcement thereof.

14.3 **Confidential Information:** The Shareholders hereby acknowledge that they have had and will have access to confidential information and trade secrets concerning the Business, the Corporation, and the Corporation's Affiliates (as defined in the OBCA), if any, and their customers and suppliers (hereinafter in this Article 14 referred to as the "**Information**") and they each undertake and agree that they shall not, and their Controlling Shareholder shall not, directly or indirectly, use, disclose or divulge to any Person or other entity any of the Information otherwise than in the Ordinary Course of Business of the Corporation, and its Affiliated Bodies Corporate and as may be required by Applicable Law or order of any Governmental Authority.

14.4 **Survival of Obligations:** The obligations and covenants in this Article 14 shall survive the termination of this Agreement.

ARTICLE 15 - NOTICES

15.1 **Notices:** Any notice or other communication required or permitted to be given under this Agreement shall be in writing and shall be given by facsimile or other means of electronic communication or by hand-delivery as provided below. Any such notice or other communication, if sent by facsimile or other means of electronic communication, shall be deemed to have been received on the Business Day following the sending, or if delivered by hand, shall be deemed to have been received at the time it is delivered to the applicable address noted below either to the individual designated below or to an individual at such address having apparent authority to accept deliveries on behalf of the addressee. Notice of change of address shall also be governed by this Section 11.1. Notices and other communications shall be addressed as follows:

(a) in the case of PWPI:

4548 Ontario Street
Unit 2
Beamsville, ON L0R 1B5

Attention: President
Fax No.: 905-563-0838

(b) in the case of NFHC:

7447 Pin Oak Drive
P.O. Box 120
Niagara Falls, ON L2E 6S9

Attention: President
Fax No.: 905-356-0118

(c) in the case of the Corporation:

7447 Pin Oak Drive
P.O. Box 120
Niagara Falls, ON L2E 6S9

Attention: President
Fax No.: 905-356-0118

Notwithstanding the foregoing, any notice of arbitration permitted to be given by any party pursuant to or in connection with any arbitration procedures in Section 16.2 may only be delivered by hand. Normal communications during the arbitration process itself may be delivered by facsimile, regular mail or by hand-delivery. The failure to send or deliver a copy of a notice to counsel shall not invalidate any notice given under this Section 15.

ARTICLE 16- DISPUTE RESOLUTION

16.1 **Disputes:** Each Shareholder shall appoint one or more representatives who shall be responsible for administering this Agreement on its behalf and for representing its respective interests in disputes relating to this Agreement. Any dispute between Shareholders relating to this Agreement that is not resolved between such representatives within ten (10) Business Days of a date that a Party notifies the other Party of such dispute shall be referred by the Parties' representatives in writing to the senior management of each Shareholder for resolution. Such senior management shall use good faith efforts to resolve the dispute for a period of up to ten (10) Business Days.

16.2 **Arbitration:** If a dispute is not resolved by the procedure set forth in Section 16.1 above, such dispute may, by any Party, be referred to and resolved by arbitration by a single arbitrator in accordance with the provisions of the *Arbitration Act, 1991* (Ontario), subject to the following modifications and additions:

(a) The arbitration shall take place in the Province of Ontario, and shall be conducted in English;

(b) The arbitration shall be conducted by a single arbitrator having no financial, business or personal interest in the outcome of the arbitration. The arbitrator shall be appointed jointly by agreement of the parties to such dispute. In the event the parties to such dispute are unable to agree on the appointment of the arbitrator within ten (10) days after notice of a demand for arbitration is given by a party and agreed to by the other parties to such dispute, then the arbitrator shall be selected pursuant to the provisions of the *Arbitration Act, 1991* (Ontario).

(c) The arbitrator shall have the authority to award any remedy or relief that a court could order or grant in accordance with this Agreement including, without limitation, specific performance of any obligation, the issuance of an interim, interlocutory or permanent injunction, or the imposition of sanctions for abuse or frustration of the arbitration process.

(d) The arbitrator shall have sole and exclusive jurisdiction to examine into, hear and determine all matters and questions of fact and law in respect of which any powers or authority has been conferred upon the arbitrator, including questions of jurisdiction. The arbitral award shall be in writing, stating the reasons for the award and shall be final and conclusive and is not open to appeal, question or review in any court and any determination by the arbitrator made under this Article is hereby ratified and confirmed and is binding upon all persons. No proceedings by or before the arbitrator shall be restrained by injunction, prohibition or other process or proceeding in any court, or are removable by certiorari or otherwise into any court.

ARTICLE 17 - MISCELLANEOUS

17.1 **Termination:** This Agreement shall terminate upon (a) the written agreement of all the Parties hereto to this effect, (b) the bankruptcy, receivership or dissolution of the Corporation, or (c) the ownership of all the Shares of the Corporation by one Shareholder.

17.2 **Successors and Assigns:** This Agreement shall be binding upon, and enure to the benefit of, the Parties hereto and their respective successors and permitted assigns.

17.3 **Assignment:** Except as specifically provided in this Agreement, none of the Parties hereto may assign its rights or obligations under this Agreement without the prior written consent of all of the other Parties hereto.

17.4 **Time is of the Essence:** Time shall be the essence of this Agreement in all respects.

17.5 **Further Assurances:** Each Party hereto shall promptly do, execute, deliver or cause to be done, executed and delivered all further acts, documents and matters in connection with this Agreement that the other Parties may reasonably require, for the purposes of giving effect to this Agreement.

17.6 **Counterparts:** This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original and all of which taken together shall be deemed to constitute one and the same instrument. Counterparts may be executed either in original or telecopied form and the Parties shall accept any signatures received by a receiving telecopy machine as original signatures of the Parties; provided, however, that any Party providing its signature in such manner shall promptly forward to the other Parties an original of the signed copy of this Agreement which was so telecopied.

17.7 **Governing Law:** This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein. The Parties agree that the courts of Ontario shall have exclusive jurisdiction to determine all disputes and claims arising under or pursuant to this Agreement.

17.8 **Amendments and Waivers:**

(a) No amendment to this Agreement shall be valid or binding unless set forth in writing and duly executed by all of the Parties hereto.

(b) No waiver of any breach of any provision of this Agreement shall be effective or binding unless made in writing and signed by the Party purporting to give the same and, unless otherwise provided in the written waiver, shall be limited to the specific breach waived.

17.9 **Severability:** If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision or part thereof and the remaining part of such provision and all other provisions hereof shall continue in full force and effect.

[EXECUTION PAGE FOLLOWS]

IN WITNESS WHEREOF the Parties hereto have executed this Agreement as of the day first above written.

NIAGARA FALLS HYDRO HOLDING CORPORATION

By: ______________________________
Name:
Title:

By: ______________________________
Name:
Title:

PENINSULA WEST POWER INC.

By: ______________________________
Name:
Title:

By: ______________________________
Name:
Title:

NIAGARA PENINSULA ENERGY INC.

By: ______________________________
Name:
Title:

By: ______________________________
Name:
Title:

[EXECUTION PAGE TO SHAREHOLDERS AGREEMENT]

SCHEDULE A

VALUATION METHOD

In this Schedule, the vendor and the purchaser of the Shares being sold pursuant to Article 11 or Article 12 of this Agreement are called the "Vendor" and the "Purchaser", respectively.

Negotiation. If the value of the Shares must be established pursuant to any provision of this Agreement, then the Vendor and the Purchaser shall negotiate honestly and in good faith to agree upon the fair market value of the Shares and such value as the parties may agree upon shall be deemed to be the fair market value of these shares for all purposes of this Agreement.

Failure to Agree. If the Vendor and the Purchaser do not agree upon the fair market value of the Shares on or before the 20th Business Day after the date on which the obligation to sell or purchase Shares arises under this Agreement, then the value of the Shares shall be determined in accordance with the following provisions:

(a) the Vendor and Purchaser shall agree on the choice of an independent business valuator who deals at Arm's Length with both the Vendor and Purchaser and has experience in valuing businesses similar to the business carried on by the Corporation ("Valuator") with in a further ten (10) days; provided that if the Vendor and Purchaser do not agree on the choice of a Valuator as specified above, either party may apply to a single Judge of the Ontario Superior Court of Justice who will appoint a Valuator;

(b) the business valuator so selected shall be the "Valuator" for the purposes of this Agreement and shall proceed to determine the fair market value of all of the Shares being sold in accordance with the provisions of this Schedule A.

Valuation by Valuator. The Valuator agreed upon or selected in accordance with this Schedule A to determine the fair market value of the Shares being sold shall act as a business valuator and not as an arbitrator or umpire. The Valuator shall apply such business valuation principles as the Valuator deems appropriate. The Valuator may consult such other expert valuators as it considers advisable. The fair market value of the Shares shall be determined without regard for any restrictions applying to the transfer of Shares. The fees and disbursements of the Valuator shall be borne equally by the Vendor and the Purchaser.

Valuation Conclusive. The determination of the value of the Shares being sold pursuant to this Agreement in accordance with this Schedule A, whether based upon the agreement of the Vendor and the Purchaser or the determination by the Valuator, shall be conclusive and binding upon the Vendor and the Purchaser, and there shall be no appeal from the determination.

Statement of deemed transmission assets

NPEI confirms that it does have transmission assets (i.e. assets operating at greater than 50 kV) in its distribution system that had previously been deemed by the Board as distribution assets. NPEI constructed a transformer station on Kalar Road in Niagara Falls 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 was included in the 2011 Cost of Service rate application. This transformer station was approved to be a deemed distribution asset in the 2006 EDR rate application. NPEI does not have any other transmission assets being requested to be deemed distribution assets in this Application.

Accounting standard used in application

Historical financial results are presented using the CGAAP method of presentation. As directed by the Board, NPEI has provided 2014BY on both a CGAAP basis and a MIFRS basis. 2015TY is presented on a MIFRS basis only.

The main area impacted by the change in presentation is to amortization of Capital Assets. No other substantial change affecting capitalization of overhead costs is expected to be required for NPEI on the conversion to MIFRS.

NPEI changed its capitalization policy related to capitalization of the stores and garage departments and the capitalization of training costs effective January 1, 2011. Therefore, there is no impact on the 2015 revenue requirement related to a change in capitalization policy. Appendix 2-Y is not applicable to NPEI.

Statement of deviation from Filing Requirements

There are no deviations from the filing requirements.

Statement of change in methodologies

The pro-forma projections for the 2015TY were prepared in accordance with NPEI's usual process, including the directives and assumptions described in E1/T2/S3, with the following exceptions:

1) Rates for Distribution and Sales of Electricity are assumed to be constant for the entire calendar year.
2) Amortization reflects the half-year rule for capital additions.
3) No amount for Provincial Sales Tax ("PST") was included in the 2015TY. NPEI will cease deferral of PST amounts actually paid.
4) Regulatory costs have been normalized over a five year period.
5) Indirect capital costs were expensed effective January 1, 2011 due to the transition to International Financial Reporting Standard

Accounting treatment of non-utility business

NPEI has not included any non-regulated operations in this application.

Previous Board directives

NPEI has not received any other utility-specific directions from the Board since submitting its last cost of service rate application for 2011, and no such directions are outstanding presently.

Conditions of service

The current version of NPEI's Conditions of Service is available on NPEI's website as www.npei.ca. Rates and charges which are the subject of this rate application are not contained in the Conditions of Service.

Attachment 1 of 1

2015 COS checklist

2015 Cost of Service Checklist

NIAGARA PENINSULA ENERGY INC.

EB-2014-0096

Date: August 29, 2014

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
GENERAL			
Ch 1 p3 & 4	Confidential Information - Practice Direction has been followed	Yes	E1/T2/S1
2 & 3	In advance of scheduled application - meet threshold established in Board letter (April 20, 2010)	Yes	E1/T2/S1
3	Align rate year with fiscal year - request for proposed alignment	Yes	E1/T2/S1
4	Text searchable and bookmarked PDF documents	Yes	E1/T2/S1
Accounting Standards and Modified IFRS Applications			
6	State accounting standard(s) used in historical, bridge and test years	Yes	E1/T6/S22
6	Summary of changes to accounting policies and quantification of revenue requirement impact (Appendix 2-Y)	Yes	E1/T6/S22
7	Identify all material changes, quantify and explain the changes in the adoption of IFRS, if none state that and explain why it would not be material	Yes	E1/T6/S22
Performance Evaluation			
8	Discuss performance for each of the Board's performance outcomes over the last five years, and current performance	Yes	E1/T2/S2
8	Discuss how self-assessment has informed the utility's business plan and the application, and what measures are planned to achieve continuous improvement	Yes	E1/T2/S2
EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS			
Management Discussion and Analysis			
9 & 10	Overall business strategy past and expected performance including narrative of how they align with the four objectives of the RRFE	Yes	E1/T4/S1
Executive Summary			
10	Revenue Requirement - service RR, increase from previously approved, main drivers	Yes	E1/T2/S4
10	Budgeting Assumptions - economic overview and identification of accounting standard used for test year and brief explanation of impacts arising from any change in standards	Yes	E1/T2/S5
10	Load Forecast Summary - load and customer growth, change in kWh and customer numbers, methodology description	Yes	E1/T2/S6
10 &11	Rate Base and Capital Plan - major drivers of DSP, rate base for test year, change from last approved, capex for test year, change from last approved, costs for any REG-related capital investments	Yes	E1/T2,S7
11	OM&A for test year and change from last approved, summary of drivers, inflation assumed, total compensation for test year and change from last approved.	Yes	E1/T2/S8
11	Statement regarding use of Board's cost of capital parameters; summary of any deviations	Yes	E1/T2/S9
11	Cost Allocation & Rate Design - summary of any deviations from Board methodologies, significant changes and summary of proposed mitigation plans	Yes	E1/T2/S10
11	Deferral and Variance Accounts - total disposition (RPP and non-RPP), disposition period, new accounts requested	Yes	E1/T2/S11
11	Bill Impacts - total impacts ($ and %)for all classes for typical customers	Yes	E1/T2/S12
Customer Engagement			
11 & 12	Overview of customer engagement activities; description of plans and how customer needs have been reflected in the application.	Yes	E1/T3/S1
12	Discuss how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates	Yes	E1/T3/S1
12	Discuss any feedback provided by customers and how the feedback shaped the final application	Yes	E1/T3/S1
12	Reference any other communication sent to customers about the application i.e. bill inserts, town hall meetings or other forms of out reach and the feedback received from customers through these engagement activities	Yes	E1/T3/S1
12	Explanation if no customer engagement done and whether any is planned for the future	N/A	
12	Complete Appendix 2-AC Customer Engagement Activities Summary	Yes	E1/T3/S1/ATT1
Financial Information			
12 & 40	Non-consolidated Audited Financial Statements for 2 most recent years (i.e. 3 years of historical actuals)	Yes	E1/T4/S1
12	Detailed reconciliation of AFS with regulatory financial results filed in the application, with identification of any deviations that are being proposed	Yes	E1/T4/S1
13	Annual Report and MD&A for most recent year of parent company, if applicable	Yes	E1/T4/S1
13	Rating Agency Reports, if available; Prospectuses, etc. for recent and planned public issuances	Yes	E1/T4/S1
13	Any change in tax status	Yes	E1/T6/S14
13	Existing accounting orders and departures from USoA including references to the accounting orders	Yes	E1/T6/S15

2015 Cost of Service Checklist

NIAGARA PENINSULA ENERGY INC.

EB-2014-0096

Date: August 29, 2014

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
13	Accounting Standards used for financial statements and when adopted	Yes	E1/T6/S22
13	Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities	Yes	E1/T6/S25
Materiality Thresholds			
13 & 14	Materiality threshold; additional details beyond the threshold if necessary	Yes	E1/T5/S1
Administration			
Ch 1 p2	Certification that evidence is accurate, consistent and complete	Yes	E1/T2/S1
14	Table of Contents	Yes	E1/T1/S1
14	Primary contact information (name, address, phone, fax, email)	Yes	E1/T6/S5
14	Identification of legal (or other) representation	Yes	E1/T6/S6
14	Applicant's internet address for viewing of application and any social media accounts used by the applicant to communicate with customers	Yes	E1/T6/S4
14	Statement of who will be affected by application	Yes	E1/T6/S2
14	Bill impacts - distribution only impacts for 800 kWh residential and 2000 kWh GS<50 (sub-total A of Appendix 2-W)	Yes	E1/T6/S8
14	Form of hearing requested and why	Yes	E1/T6/S10
14	Requested effective date	Yes	E1/T6/S7
14	List of approvals requested (and relevant section of legislation), including accounting orders	Yes	E1/T6/S11 E1/T6/S15
14	Statement identifying all deviations from Filing Requirements	Yes	E1/T6/S23
15	Statement identifying and describing any changes to methodologies used vs previous applications	Yes	E1/T6/S24
15	Identification of Board Directives from previous Board Decisions, and how addressed	Yes	E1/T6/S26
15	Reference to Conditions of Service - LDC does not need to file Conditions of Service, but must provide reference to website and confirm version is current; identify if there are changes to Conditions of Service as a result of application	Yes	E1/T6/S27
15	Description of Operating Environment (including map, list of neighbouring utilities)	Yes	E1/T6/S16/ATT1
15	Identification of embedded and/or host distributors	Yes	E1/T6/S18
15	Statement as to whether or not the distributor has had any transmission or high voltage assets deemed by the Board as distribution assets and whether or not there are any such assets the distributor is seeking approval for in this application	Yes	E1/T6/S21
15, 16 & 17	Corporate Governance: Number of Directors on Board, number of independent directors, how independent judgement is facilitated - Board Mandate; Schedule of Board Meetings - Orientation and Continuing Education for directors - Ethical Business Conduct - written code where available - Process for Nomination of Directors - Committees - function and charter for each committee - Audit Committee - number of independent members, whether members are financially literate	Yes	E1/T6/S20
17	Responses to matters raised in letters of comment filed	Yes	E1/T6
EXHIBIT 2 - RATE BASE			
Overview			
17	Completed Fixed Asset Continuity Schedule (Appendix 2-BA)	Yes	E2/T1/S1/ATT1
17 & 18	Opening and closing balances, average of opening and closing balances for gross assets and accumulated depreciation; working capital allowance (historical actuals, bridge and test year forecast)	Yes	E2/T1/S2 E2/T1/S3
18	Continuity statements (year end balance, including interest during construction and overheads). Year over year variance analysis; explanation where variance greater than materiality threshold Hist. Brd-Approved vs Hist. Actual Hist. Act. Vs previous Hist. Act. Bridge vs. Test	Yes	E2/T1/S1
18 & 19	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation must be provided (eg. WIP, ARO, smart meter balances). Reconciliation must be between YE 2014 and YE 2015 net book value balances reported on Appendix 2-BA and balances included in rate base calculation	Yes	E2/T1/S1
Gross Assets - PP&E and Accumulated Depreciation			
19	Breakdown by function and by major plant account; description of major plant items for test year	Yes	E2/T2/S1

2015 Cost of Service Checklist

NIAGARA PENINSULA ENERGY INC.

EB-2014-0096

Date: August 29, 2014

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
19	Summary of approved and actual costs for any ICM(s) approved in previous IRM applications	Yes	E2/T1/S1
19 & 40	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	Yes	E2/T1/S1/ATT1
Allowance for Working Capital			
19	Working Capital - 13% allowance or Lead/Lag Study or Previous Board Direction	Yes	E2/T1/S3
20	Cost of Power must be determined by split between RPP and non-RPP customers based on actual data, use most current RPP price, use current UTR. Should include SME charge.	Yes	E2/T1/S3
20	Lead/Lag Study - leads and lags measured in days, dollar-weighted	Yes	E2/T1/S3
Treatment of Stranded Assets Related to Smart Meter Deployment			
20 & 21	Stranded Meters - if the recovery of stranded conventional meters replaced by smart meters has not been reviewed and approved, a proposal for a Stranded Meter Rate Rider must be made Explanation for approaches that are not the Board approach Completed Appendix 2-S.	Yes	E2/T1/S4
Planning			
22	As applicable - file evidence that demonstrates that regional issues have been appropriately considered and where applicable addressed in developing the applicant's proposed capital expenditure plan. As part of its planning an applicant should consider municipal planning, including any plans for expansion of boundaries from a regional perspective to demonstrate the most cost effective solutions are being considered.	Yes	E2/T2/S7
Capital Expenditures/Distribution System Plan			
23	DSP filed as a stand-alone document	Yes	E2/T2/S1/ATT1
Ch 5 p9	Where applicable, explanation for section headings other than Chapter 5 headings; cross reference table	Yes	E2/T2/S1/ATT1/TABLE OF CONTENTS-NPEI used the same section headings as detailed in Chapter 5
Ch 5 p9-10	Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies	Yes	E2/T2/S1/ATT1/SECTION 5.2.1
Ch 5 p10-11	Coordinated Planning with 3rd parties - description of consultations - deliverables of the Regional Planning Process, or status of deliverables - OPA letter in relation to REG investments (Ch 5 p8&9) and Dx response letter	Yes	E2/T2/S1/ATT1/SECTION 5.2.2
Ch 5 p11	Performance Measurement - identify and define methods and measures used to monitor DSP performance - summary of performance and trends over historical period. Must include SAIFI and SAIDI for all interruptions and all interruptions excluding loss of supply - explain how information has affected DSP	Yes	E2/T2/S1/ATT1/SECTION 5.2.3
Ch5 p12	Asset Management Process Overview - description of AM objectives/corporate goals and how Dx ranks objectives for prioritizing investments	Yes	E2/T2/S1/ATT1/SECTION 5.3
Ch5 p12	Inputs/Outputs of the AM process and information flow for investments; flowchart recommended	Yes	E2/T2/S1/ATT1/SECTION 5.3.1.1
Ch 5 p13	Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP), - description of system configuration - service profile and condition by asset type (tables and/or figures) - date data compiled - assessment of degree the capacity of system assets is utilized	Yes	E2/T2/S1/ATT1/SECTION 5.3.2
Ch 5 p13-14	Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions - description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation	Yes	E2/T2/S1/ATT1/SECTION 5.3.3
Ch 5 p14-15	Capital Expenditure Plan Summary for significant projects and activities to be undertaken - capability to connect new load or Gx customers, total annual capex over forecast period by investment category, description of how AMP and Capex planning have affected capital expenditures for each category - list, description and total capital cost of material capital expenditures sorted by category (table recommended) - information related to Regional Planning Process (Needs Assessment Report, Regional Planning Status Letter, Regional Infrastructure Plan - as appropriate) - description of customer engagement - Dx expectations of system development over next 5 years - list, description and total capital cost of projects planned in response to customer preferences, to take advantage of technology based opportunities, to study innovative processes (table recommended)	Yes	E2/T2/S1/ATT1/SECTION 5.4

2015 Cost of Service Checklist

NIAGARA PENINSULA ENERGY INC.

EB-2014-0096

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Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
Ch 5 p15	Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/ assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to prioritise REG investments	Yes	E2/T2/S1/ATT1/SECTION 5.4.2
Ch 5 p16	System Capability Assessment for REG - REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints	Yes	E2/T2/S1/ATT1/SECTION 5.4.3
Ch 5 p16-18 Ch 2 p23	Capital Expenditure Summary by Investment Category - completed Table 2 of Ch 5 for historical and forecast period, explanation of markedly different variances plan vs actual, explanation of markedly different variances year over year Table 2 of Ch 5 is provided in Excel format in Appendix 2-AB	Yes	E2/T2/S1/ATT1/SECTION 5.4.4
Ch5 p19	Overall Plan - comparative expenditures by category over historical period, forecast impact of system investment on O&M, drivers of investments by category, information related to Dx system capability assessment	Yes	E2/T2/S1/ATT1/SECTION 5.4.5.1
Ch 5 p19-25	Material Investments - For each project that meets materiality threshold set in Ch 2 p10 - general information - total capital, customer attachments, dates, risks, variances, REG investments - evaluation criteria - may include: efficiency, customer value, reliability, etc. - category specific requirements for each project - system access, system renewal, system service, general plant (as applicable)	Yes	E2/T2/S1/ATT1/SECTION 5.4.5.2
23 & 24	Capital Expenditures - completed Appendix 2-AA showing capex on a project specific basis for 4 historical years, bridge and test; explanation of variances, accounting treatment for projects with life cycle greater than one year	Yes	E2/T2/S1/ATT3
24	Non-distribution activities - capital expenditures and reconciliation to total capital budget	Yes	E2/T1/S1
7 & 24	Capitalization policy, changes to capitalization since previous rebasing - explanations must be provided. The changes must be identified and the causes of the changes must also be identified.	Yes	E2/T2/S2
24	Capitalization of overhead - Completed Appendix 2-D regarding overhead costs on self-constructed assets Burden rates must be identified; changes from last rebasing must be identified; LDC must identify burden rates prior to and after the change	Yes	E2/T2/S3/ATT1
Costs of Eligible Investments for Connection of Qualifying Generation Facilities			
25	For Eligible Investments - proposal to divide costs per O.Reg. 330/09	Yes	E2/T2/S7
25	Where applicable, file a draft accounting order to establish variance account tracking IESO payment revenues against actual spending	Yes	E2/T2/S7
25	As Applicable appendices 2-FA through 2-FC must be filed identifying eligible investments, as applicable	Yes	E2/T2/S7
25	Ensure that Capital Costs of the Distributor are entered into the Rate Base for the Test Year	Yes	E2/T2/S7
New Policy Options for the Funding of Capital			
25	Policy Options - can propose an approach for the funding of capital based on the proposed policy options	N/A	
Addition of ICM Assets to Rate Base			
25 & 26	Distributor with previously approved ICM(s) - schedule of ICM amounts, variances and explanation	N/A	
26	Balances in Account 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue	N/A	
Service Quality and Reliability			
26	5 historical years of ESQRs, explanation for any under-performance and actions taken	Yes	E2/T3/S1
26	5 historical years of SAIDI and SAIFI - for all interruptions and all interruptions excluding loss of supply, explanation for any under-performance and actions taken	Yes	E2/T3/S1
26	Completed Appendix 2-G	Yes	E2/T3/S1/ATT1
EXHIBIT 3 - OPERATING REVENUE			
Load and Revenue Forecasts			
27 & 30	Customer, volume and revenue forecast methodologies and data	Yes	E3/T1/S1
27	Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts	Yes	E3/T1/S1
27	Completed Appendix 2-IA	Yes	E3/T1/S1/ATT3

2015 Cost of Service Checklist

NIAGARA PENINSULA ENERGY INC.

EB-2014-0096

Date: August 29, 2014

Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
28	Regression Model - rationale for choice, regression statistics, explanation for any unintuitive relationships, explanation of modeling approaches and alternative models tested, explanation of weather normalization methodology, sources of data for endogenous and exogenous variables, explanation of any constructed variables; data used in load forecast must be provided in Excel format, including derivation of constructed variables	Yes	E3/T1/S1
29	NAC Model - rationale for choice, data supporting NAC variables, description of accounting for CDM including licence conditions, discussion of weather normalization considerations	Yes	E3/T1/S1 E3/T1/S1/ATT1
29 & 30	CDM Adjustment - 2014 and 2015 CDM reductions must take into account 2011 - 2013 CDM program results reported by OPA. CDM adjustment should take into account historical CDM results factored into base load forecast before CDM adjustment	Yes	E3/T1/S1
29	CDM savings for 2015 LRAMVA balance and adjustment to 2015 load forecast; data by customer class	Yes	E3/T1/S1
29 & 30	Completed Appendix 2-I, or alternative with explanation	Yes	E3/T1/S1/ATT2
Accuracy of Load Forecast and Variance Analyses			
30	Schedule of volumes, revenues, customer/connection count by class and total system load: 5 years historical, Board approved, 5 years historical weather normalized, bridge year and test year.	Yes	E3/T2/S1
30	Customer count increases or decreases for test year - explanation by class; confirmation of year end or average format	Yes	E3/T2/S1
31	Explanation for any changes in definition or composition of class	Yes	E3/T2/S1
31	Weather normalized average consumption per customer for historical 5 years, bridge and test	Yes	E3/T2/S1
31	Explanation of net change in average consumption from last Board approved, and actual historical, bridge and test - for each rate class	Yes	E3/T2/S1
31	Details of development of billed kW	Yes	E3/T2/S1
31	Revenues on existing and proposed rates for the test year	Yes	E3/T2/S1
31	Variance analysis of volumes, revenues, customer/connection count and total system load: Historical Board approved vs Historical Actual (and Historical Actual weather normalized) Year over year historical weather normalized variance, weather normalized bridge, test year	Yes	E3/T2/S1
31	Data used to determine forecast should be filed as live Excel spreadsheet	Yes	E3/T2/S1
Other Revenue			
31	Breakdown of other distribution revenue accounts; completed Appendix 2-H	Yes	E3/T3/S1/ATT1
31	Variance analysis - year over year, historical, bridge and test	Yes	E3/T3/S1
31	Any new proposed specific service charges, or proposed changes to rates or application of existing specific service charges	Yes	E3/T3/S1
31	Revenue from affiliate transactions, shared services, corporate cost allocation	Yes	E3/T3/S1
EXHIBIT 4 - OPERATING COSTS			
Overview			
33	Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes	Yes	E4/T1/S1
Summary and Cost Driver Tables			
33	Summary of recoverable OM&A expenses; Appendix 2-JA	Yes	E4/T2/S1/ATT1
33	OM&A cost drivers; Appendix 2-JB	Yes	E4/T2/S1/ATT2
33	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	Yes	E4/T2/S1/ATT3
33	Identification of change in OM&A in test year in relation to change in capitalized overhead.	Yes	E4/T2/S1
33	OM&A variance analysis for test year with respect to bridge and historical years; Appendix 2-D	Yes	E4/T2/S1/ATT4
Program Delivery Costs with Variance Analysis			
33 &34	Completed Appendix 2-JC OM&A Programs Table - completed by program or major functions; include variance analysis limited to variances that are outliers, between test year and last Board approved and most recent actuals, including an explanation for each significant change whether the change was within or outside the applicant's control and explanation of why.	Yes	E4/T3/S1/ E4/T3/S1/ATT1
34	For each significant change within the applicant's control describe business decision that was made to manage the cost increase/decrease and the alternatives	Yes	E4/T3/S1
34	Employee Compensation - completed Appendix 2-K	Yes	E4//T3/S2/ATT1
34	Description of compensation strategy	Yes	E4/T3/S2
34 & 35	Explanation for material changes to head count and compensation: year over year variances, inflation, plans for new employees, details on collective agreements, basis for performance pay, filing of any relevant studies	Yes	E4/T3/S2

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35	Details of employee benefit programs including pensions for last Board approved, historical, bridge and test; must agree with tax section	Yes	E4/T3/S2
35	Most recent actuarial report on employee benefits, pension and OPEBs	Yes	E4/T3/S2/ATT2
35	Identification of all shared services among affiliates and parent company	Yes	E4/T3/S3
35	Allocation methodology for corporate and shared services, list of costs and allocators, including any third party review	Yes	E4/T3/S3
36	Completed Appendix 2-N for service provided or received for historical, bridge and test; including reconciliation with revenue included in Other Revenue	Yes	E4/T3/S3/ATT1
36	Identification of any Board of Director costs for affiliates included in LDC costs	Yes	E4/T3/S3/ATT1
36	Shared Service and Corporate Cost Variance analysis - test year vs last Board approved and most recent actual	Yes	E4/T3/S4
36	Purchased Non-Affiliated Services - file a copy of procurement policy (signing authority, tendering process, non-affiliate service purchase compliance)	Yes	E4/T3/S4/ATT1
36	Explanation for procurements above materiality threshold without competitive tender	Yes	E4/T3/S4
36	Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test (or future years)	Yes	E4/T3/S5
37	Regulatory costs - breakdown of actual and forecast, supporting information related to CoS application, proposed recovery (ie amortized?). Completed Appendix 2-M	Yes	E4/T3/S6
37	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes	Yes	E4/T3/S7
37	Statement whether test year revenue requirement includes legacy low income energy assistance programs. If yes, identify programs	Yes	E4/T3/S7
38	Charitable Donations - amounts paid from last Board approved up to test year	Yes	E4/T3/S8
38	Detailed information for any proposal to recover charitable donations (outside of assistance for payment of electricity bills)	Yes	E4/T3/S8
38	Any non-recoverable contributions identified and removed from revenue requirement. Confirm that no political contributions have been included for recovery	Yes	E4/T3/S8
Depreciation, Amortization and Depletion			
38	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	Yes	E4/T4/S1
18 & 38	Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must agree to accumulated depreciation in Appendix 2-BA under rate base.	Yes	E4/T4/S1
38	Identify any Asset Retirement Obligations and associated depreciation	Yes	E4/T4/S1
38 & 39	May propose an approach that differs from Board's general policy of capital additions attracting six months of depreciation expense when they enter service in the test year, based on the Board's proposed new policy options for the Board's consideration	Yes	E4/T4/S1
39	Identify historical depreciation practice and proposal for test year. Variances from half year rule must be documented and with supporting rationale	Yes	E4/T4/S1
39	Copy of depreciation/amortization policy, or equivalent written description; summary of changes to depreciation/amortization policy since last CoS	Yes	E4/T4/S1/ATT1
39	Explanation of any deviations from the practice of significant parts or components of PP&E being depreciated separately	Yes	E4/T4/S1
39 & Appendices	Regulatory Accounting changes for depreciation - use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA, detail differences in TUL from Kinetrics and explain differences outside of minimum and maximum TUL range from Kinectrics - Appendix 2-BB - recalculation to determine average remaining service life of opening balance on date of making depreciation changes - If further depreciation expense policy changes or changes in asset service lives are made they must be identified and provide a detailed explanation of the changes -File applicable depreciation appendices as provided in Chapter 2 MIFRS Appendices (Appendix 2-CA to 2-CI)	Yes	E4/T4/S1/ATT2 E4/T4/S1/ATT3
PILs and Property Taxes			
40	Completed version of the PILs model (PDF and Excel); derivation of adjustments for historical, bridge, test years	Yes	E4/T5/S1

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40	Supporting schedules and calculations identifying reconciling items	Yes	E4/T5/S2
40	Most recent federal and provincial tax returns	Yes	E4/T5/S2/ATT1
12 & 40	Financial Statements included with tax returns if different from those filed with application	Yes	E1/T4/S1
40	Calculation of Tax Credits	Yes	E4/T5/S3
40	Supporting schedules, calculations and explanations for other additions and deductions	Yes	E4/T5/S4
40	Explanation of how property tax amounts are derived	Yes	E4/T5/S7
40 & 41	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	Yes	E4/T5/S5
41	Completion of Integrity checks listed on p.41; statement confirming completion	Yes	E4/T5/S6
Conservation and Demand Management			
43	LRAM and LRAMVA - disposition of balance(s) for any pre-2011 and 2011-2014 account balances - statement indicating use of most recent input assumptions when calculating lost revenue - statement indicating reliance on most recent CDM evaluation report from OPA; copy of report - Tables for each rate class showing lost revenue by year - lost revenue calculations - energy savings by class and Board approved variable charge - statement that indicates if carrying charges are requested - Third party report for any Board-approved programs	Yes	E4/T6/S1 E4/T6/S2 E4/T6/S3
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE			
Capital Structure			
44	Statement that LDC adopting Board's guidelines for cost of capital and confirming updates will be done. Alternatively - utility specific cost of capital with supporting evidence	Yes	E5/T1/S1
4 & 44 Appendices	Completed Appendix 2-OA for last Board approved and test year; total capitalization (debt and equity) must equate to total rate base	Yes	E5/T1/S1/ATT1
44	Completed Appendix 2-OB for historical, bridge and test years	Yes	E5/T1/S1/ATT2
44	Explanation for any changes in capital structure	Yes	E5/T1/S1
44	Calculation of cost for each capital component	Yes	E5/T1/S1
44	Profit or loss on redemption of debt	Yes	E5/T2/S1
45	Copies of promissory notes or other debt arrangements with affiliates	Yes	E5/T2/S1/ATT2 & ATT3
45	Explanation of debt rate for each existing debt instrument	Yes	E5/T2/S1
45	Forecast of new debt in bridge and test year - details including estimate of rate	Yes	E5/T2/S1
Not-for-Profit Corporations			
45	Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves	N/A	
45	Detailed calculation for its test year revenue requirement based on its Reserve Requirement	N/A	
45	The proposed reserves and rationale for the need to establish each reserve, the time period of building up the reserves, and the procedure and policy of each reserve	N/A	
46	Description of the governance of the not-for-profit corporation -policy on Reserve Requirement -roles and responsibilities of the Board of Directors and management with regards to the need for types of reserves -authorization and approval process for access and use -investment objectives and policies for the reserve funds -reporting requirements and monitoring	N/A	
46	If there are approved reserves from previous Board decisions provide the following: -any changes to the reserve policies and rationale for the changes since last CoS -limits of any capital and/or operating reserves as approved by the Board and identify decisions -current balances of any established capital and/or operating reserves -list withdrawals from capital and operating reserves, identify amounts and purpose of withdrawal -if limits on capital and operating reserves achieved provide a proposal for utilization of amounts -if limits on reserves not achieved provide rationale and the detail for its forecast of the Reserve Requirement for the test year	N/A	
EXHIBIT 6 - REVENUE DEFICIENCY/SUFFICIENCY			
47	Calculation of delivery-related Revenue Deficiency/Sufficiency (excluding cost of power and associated costs): net utility income, rate base, actual return on rate base, indicated rate of return, requested rate of return, deficiency/sufficiency, gross deficiency/sufficiency. Deficiency/sufficiency must also be net of other costs (e.g. LV costs, RSVAs, smart meter and other DVA balances).	Yes	E6/T1/S1

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47	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	Yes	E6/T1/S1
47	Impacts of any changes in methodologies to deficiency/sufficiency	Yes	
Revenue Requirement Work Form			
48	RRWF - in PDF and Excel. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	Yes	E6/T1/S1
EXHIBIT 7 - COST ALLOCATION			
Cost Allocation Study Requirements			
48	Completed cost allocation study reflecting test year loads and costs. Excel version of 2015 cost allocation model (updated load profiles or scaled version of HONI CAIF). Appendix 2-P completed as well.	Yes	E7/T1/S1 E7/T1/S3/ATT1 E7/T1/S4/ATT1
48	Description of weighting factors, and rationale for use of default values (if applicable)	Yes	E7/T1/S1
48	Hard copy of sheets I-6, I-8, O-1 and O-2 (first page)	Yes	E7/T1/S2/ATT1
49	Host Distributor - evidence of consultation with embedded Dx - Statement regarding embedded Dx support for approach to allocation of costs - If embedded Dx is separate class - class in cost allocation study and Appendix 2-P - If new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges); include in cost allocation study and Appendix 2-P - If embedded Dx billed as GS customer - , include with the GS class in cost allocation model and Appendix 2-P. Provide cost of serving, load served, asset ownership information, distribution charges, appropriateness of rate class. LDC may choose to file Appendix 2-Q.	Yes	E7/T1/S4
Unmetered Load			
50	Confirmation of communication with unmetered load customers when proposing changes to the level of the rates and charges or the introduction of new rates and charges	Yes	E7/T1/S4
50	New customer class or eliminated customer class - rationale and restatement of revenue requirement from previous CoS	Yes	E7/T1/S4
Class Revenue Requirements and Revenue to Cost Ratios			
51	Completed Appendix 2-P; supporting information for any proposal to re-balance rates	Yes	E7/T1/S4/ATT1
52	Proposal to re-balance to bring R:C ratio within Board policy ranges; any proposal to for further re-balancing beyond test year.	Yes	E7/T1/S4
52	If Cost Allocation Model other than Board model used - exclude LV, exclude DVA such as smart meters	Yes	E7/T1/S1
EXHIBIT 8 - RATE DESIGN			
52	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places	Yes	E8/T11/S1/ATT2
53	Current and Proposed F/V proportion with explanation for any changes	Yes	E8/T11/S1/ATT1 & ATT2
53	Table comparing current and proposed fixed charge with floor and ceiling from cost allocation study. Explanation for Monthly Fixed Charge(s) that exceed the ceiling; analysis must be net of adders and riders	Yes	E8/T1/S1
53	Policy Options - can propose fixed monthly charge based on the proposed policy options	Yes	E8/T1/S1
53	Explanation of the method used to design the fixed charge for distribution service (if applicable)	Yes	E8/T1/S1
RTSRs and Other Charges			
53	Retail Transmission Service Rate Work Form - PDF and Excel	Yes	E8/T3/S1/ATT1
53	RTSR information must be consistent with working capital allowance calculation	Yes	E8/T3/S1
54	If proposing changes to Retail Service Charge - evidence of consultation and notice	Yes	E8/T4/S1
54	Wholesale Market Service Rate - reflect $0.0057 in application or justify otherwise	Yes	E8/T5/S1
54 & 55	Smart Metering Charge - reflect $0.79 in application for Residential and GS<50	Yes	E8/T6/S1
55	Specific Service Charge description/purpose/reason for new and revised SSC; calculations to support charges	Yes	E8/T7/S1
55	Identify any rates and charges in Conditions of Service that do not appear on tariff sheet Explain nature of costs, schedule outlining revenues 2010-2013, bridge and test Whether these charges are included on tariff sheet	Yes	E8/T7/S1
55	Ensure revenue from SSCs corresponds with Operating Revenue evidence	Yes	E8/T7/S1
55	Can propose activities or initiatives that will reduce cost of transition to monthly billing	N/A	
56	Forecast of LV cost, sum of host distributors charges	Yes	E8/T8/S1
56	Low Voltage Cost (historical, bridge, test), variances and explanations for substantive changes	Yes	E8/T8/S1
56	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	Yes	E8/T8/S1
56	Allocation of LV cost to customer classes (typically proportional to Tx connection revenue)	Yes	E8/T8/S1

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56	Proposed LV rates by customer class	Yes	E8/T8/S1

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Loss Factors			
56	Proposed SFLF and Total Loss Factor for test year	Yes	E8/T9/S1
56	Statement as to whether LDC is embedded including whether fully or partially	Yes	E8/T9/S1
56	Study of losses if required by previous decision	N/A	
56	3-5 years of historical loss factor data - Completed Appendix 2-R	Yes	E8/T9/S1/ATT1
56	Explanation of losses >5%	Yes	E8/T9/S1
56	If proposed loss factor >5%, action plan to reduce losses going forward	Yes	E8/T9/S1
56	Explanation of SFLF if not standard	Yes	E8/T9/S1
Rates and Bill Impacts			
57	Current Tariff of Rates and Charges	Yes	E8/T11/S1/ATT1
57	Proposed Tariff of Rates - Appendix 2-Z	Yes	E8/T11/S1/ATT3
57	Explanation of changes to terms and conditions of service if changes affect application of rates	Yes	E8/T11/S1
57	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement	Yes	E8/T12/S1
57	Completed Appendix 2-V (Revenue Reconciliation)	Yes	E8/T12/S1/ATT1
57	Bill Impacts - completed Appendix 2-W for all classes for representative samples of end-users. Must provide residential 800 kWh and GS<50 2,000 kWh. Commodity and regulatory charges held constant	Yes	E8/T13/S1/ATT1
58 & 59	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification, revised impact calculation	Yes	E8/T14/S1
59	Rate Harmonization Plans, if applicable - including impact analysis	N/A	
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS			
59	List of all outstanding DVA and sub-accounts; provide description of DVAs that were used differently than as described in the APH	Yes	E9/T1/S1
59	Completed DVA continuity schedule for period following last disposition to present - Excel format	Yes	E9/T1/S1/ATT1
59	Interest rates applied to calculate carrying charges (month or quarter)	Yes	E9/T1/S2
59	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS	Yes	E9/T1/S3
60	Identification of Group 2 accounts that will continue/discontinue going forward, with explanation	Yes	E9/T3/S1
60	Statement as to any new accounts, and justification.	Yes	E9/T1/S5
60	Statement whether any adjustments made to DVA balances previously approved by Board on final basis; explanation, amount of adjustment and supporting documents	Yes	E9/T1/S6
60	Breakdown of energy sales and cost of power by USoA - as reported in AFS mapped and reconciled to USoA. Provide explanation if making a profit or loss on commodity.	Yes	E9/T2/S2
60	Statement confirming that IESO GA charge is pro-rated into RPP and non-RPP; provide explanation if not pro-rated.	Yes	E9/T2/S3
60	If not addressed previously, disposition of Account 1592 - Completed Appendix 2-TA	Yes	E9/T3/S2/ATT1
61	If not addressed previously, disposition of Account 1592 sub-account HST/OVAT ITC - analysis that supports conformity with Dec 2010 APH FAQ (particularly #4) Applicant must state the period that the account covers (i.e. Jul 1-2010 up to start of new rate year (year of rebasing))	Yes	E9/T3/S3
61 & 62	Request for disposition of Account 1508 sub-account IFRS transition costs - completed Appendix 2-U - statement whether any one time IFRS transition costs are embedded in 2015 revenue requirement, where and why it is embedded, and the quantum - explanation for each category of cost recorded in 1508 sub-account, how it meets criteria of one time IFRS admin incremental costs - explanation for material variances in Account 1508 sub-account IFRS Transition Costs Variance - statement that no capital costs, ongoing IFRS compliance costs are recorded in 1508 sub-account; provide explanation if this is not the case	Yes	E9/T3/S6/ATT1

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Filing Requirement Page # Reference		Yes/No/N/A	Evidence Reference, Notes
62 & 63	1575 IFRS-CGAAP PP&E account - Account 1575 and 1576 can't be used interchangeably - breakdown of balance, Appendix 2-EA - listing and quantification of drivers - a breakdown for quantification of any accounting changes arising from IFRS in relation to PP&E - volumetric rate rider to clear 1575; - rate of return component is to be applied to 1575 but not recorded in 1575 - statement confirming no carrying charges applied to 1575 - explanation for the basis of the proposed disposition period to clear Account 1575 rate rider - show the balance in DVA continuity schedule	Yes	E9/T3/S7
63, 64 & 65	Changes to depreciation and capitalization in 2012 or 2013 - 1576 IFRS-CGAAP PP&E account - Appendix 2-BA must not be adjusted for 1576 - breakdown of balance related to 1576, Appendix 2-EB or 2-EC - volumetric rate rider to clear 1576; - rate of return component is to be applied to 1576 but not recorded in 1576 - statement confirming no carrying charges applied to 1576 - explanation for the basis of the proposed disposition period to clear Account 1576 rate rider - show the balance in DVA continuity schedule	Yes	E9/T3/S8
65	Retail Service Charges - material balance in 1518 or 1548 - confirm variances are incremental costs of providing retail services - identify drivers - provide schedule identifying all revenues and expenses listed by USoA for 2013, actual/forecast for bridge and test year - state whether Article 490 of APH has been followed; explanation if not followed	Yes	E9/T3/S9
65	Retail Service Charges - zero balance in 1518 or 1548 - state whether Article 490 of APH has been followed; explanation if not followed	Yes	E9/T3/S9
5 & 65	Identify all accounts for which LDC is seeking disposition; identify DVA for which LDC is not proposing disposition and the reasons why Proposal for disposition of deferral accounts for renewable generation connection and smart grid as set out in FR "Distribution System Plans - Filing Under Deemed Conditions of Licence"	Yes	E9/T1/S1
59 & 65	Statement whether DVA balances before forecasted interest match the last AFS	Yes	E9/T1/S3
65	Provide an explanation of variance > 5% between amounts proposed for disposition and amounts reported in RRR for each account. Provide explanations even if such variances are < 5% threshold if the variances in question relate to: (1) matters of principle (i.e. conformance with the APH or prior Board decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts totaling to a material difference between what is proposed for disposition in total before forecasted interest and what is recorded in the RRR filings	Yes	E9/T1/S1
66	Show relevant calculations: rationale for allocation of each account, proposed billing determinants and length of disposition period.	Yes	E9/T1/S4
66	If applicant is proposing to allocate an account which the Board has not established an approved allocator for the applicant must: -propose and allocator based on the cost driver(s) -propose the charge type (fixed or variable) for recovery purposes -include this in the continuity schedule	Yes	E9/T1/S4
66	Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period must provide explanation.	Yes	E9/T3/S12
66	Establish separate rate riders to recover balances in the RSVA's from Market Participants who must not be allocated the RSVA balances related to charges for which the MP's settle directly with the IESO.	N/A	
66	Establish separate rate riders to recover the balance of account 1589. Distributors who serve class A customers per O.Reg 429/04 must propose an appropriate allocation for their recovery of the global adjustment variance balance based on their settlement process with the IESO.	N/A	
66	New DVA - must meet causation, materiality, prudence criteria; include draft accounting order	N/A	
	TOTAL "NO"	0	