PETERBOROUGH DISTRIBUTION INC.

1867 Ashburnham Drive, PO Box 4125, Station Main
Peterborough ON K9J 6Z5

May 27, 2013

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

Dear: Ms. Walli

Re: Peterborough Distribution Inc. (PDI) 2013 Cost of Service Electricity Distribution Rate Application EB-2012-0160
Written Responses to Interrogatories

Please find enclosed PDI's written responses to Interrogatories as filed by Board Staff, Energy Probe, School Energy Coalition and the Vulnerable Energy Consumers Coalition.

These responses are being filed pursuant to the Board's e-Filing Services. Two hard copies of the responses will be delivered to the Board via courier. In addition, electronic copies and hard copies, as required, will be forwarded to all intervenors listed above.

Also attached please find the following:

- PDI_APPL_2013 EDDVAR Continuity Schedule_20130523.xlsm
- 2013_Rev_Reqt_Work_Form_UEBV9_PDI IRR.xlsm
- PDI_APPL_2013 CostAllocationModel_xlsm_20130225_Separate Meter Reading.xlsm
- 2006 - 2010 Final OPA CDM Results Peterborough Distribution Inc.xls
- 2011 OPA CDM Results Peterborough Distribution Inc.xls
- RTSR Model_V3_20120628_PDI data updated April 29 2013.xlsm
- Various Appendices including updated Bill Impacts

An electronic version of these responses has been submitted though the e-Filing Services.

If you require any further information, please contact the undersigned.

Sincerely,

Byron Thompson
Chief Financial Officer
Peterborough Distribution Inc.
Peterborough, Ontario
Email: bthompson@peterboroughutilities.ca
Phone: 705-748-9301 x 1283

PETERBOROUGH DISTRIBUTION INC.

2013 COST OF SERVICE RATE APPLICATION

RESPONSE TO INTERROGATORIES

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

EB-2012-0160

FILED: MAY 27, 2013

1-Energy Probe-1

Ref: Exhibit 1, Tab 1, Schedule 4

Please explain what PDI means that it is requesting that the OEB issue an Interim Order "approving the current distribution rates and other charges, effective May 1, 2013". Does PDI believe that it needs an interim rate order in order to continue with the current Board approved rates?

PDI Response

Yes, PDI believes that it needs an interim rate order in order to continue with the current Board approved rates. On April 23, 2013, the Board issued a Procedural Order declaring PDI's currently approved rates interim as of **May 1, 2013** and until such time as a final rate order is issued by the Board.

1-Energy Probe-2

Ref: Exhibit 1, Tab 1, Schedule 14

a) Does the revenue requirement for the 2013 test year include any costs associated with the Board of Directors of any of the corporations shown in Chart 1-1 other than that of PDI itself? If yes, please provide the amount included in the revenue requirement associated with each of the other corporations and indicate how this amount has been allocated to PDI.

b) Is the operation of the Peterborough Utilities Group of companies unchanged in relation to PDI from its last cost of service proceeding? If not, please explain any changes made since the last cost of service proceeding for PDI.

PDI Response

a) PDI has been allocated 33% of the CoPHI board fee which amounts to $33,000. The allocation is based on time the CoPHI board spends on PDI related matters.

b) Since 2009, Peterborough Utilities Group now includes new entities Lily Lake Solar Inc., Trent Energy Inc., LFG Power Corporation, and Peterborough Utilities Solar Inc.

1-Energy Probe-3

<u>Ref: Exhibit 1, Tab 2, Schedule 1</u>

a) Please provide the amount of funding provided by PDI to Peterborough Green Up for each of 2009 through 2012 and the forecast for 2013. Has PDI included the 2013 forecast in the revenue requirement, or is this amount funded through funds received from the OPA?

b) Please provide the amount of funding provided by PDI to the Housing Resource Centre for each of 2009 through 2012 and the forecast for 2013. Has PDI included the 2013 forecast in the revenue requirement? What is the amount of LEAP funding that has been included in the 2013 revenue requirement?

PDI Response

a) PDI has provided the following conservation program support to Peterborough Green Up:

2009	$34,894
2010	$24,577
2011	$23,000
2012	$35,000
2013 forecast	$23,000

The $23,000 forecast for 2013 is included in the revenue requirement and is not funded by the OPA.

b) PDI has provided the following funding to the Housing Resource Centre:

	LEAP	Other	Total
2009	$0	$40,000	$40,000
2010	$0	$40,000	$40,000
2011	$19,505	$0	$19,505
2012	$19,505	$0	$19,505
2013 forecast	$20,000	$0	$20,000

The amount of LEAP funding forecast for 2013 is $20,000 and it is included in the revenue requirement.

1-Energy Probe-4

Ref: Exhibit 1, Tab 2, Schedule 1 & Exhibit 1, Tab 1, Schedule 4

Please reconcile the deficiency of $658,809 shown under the Purpose and Need section of Exhibit 1, Tab 2, Schedule 1 with the figure of $604,748 shown on page 1-9 of Exhibit 1, Tab 1, Schedule 4. Please confirm which figure is the correct figure and, if necessary, please provided a revised Revenue Requirement Work Form that shows the derivation of the gross deficiency.

PDI Response

The revenue deficiency stated in Exhibit 1, Tab 2, Schedule 1 (page 1-42) is an error. The correct figure is $604,748 as is consistent with the Revenue Requirement Work Form.

1-Energy Probe-5

Ref: Exhibit 1, Tab 2, Schedule 3

How many months of actual data has been used for each of capital expenditures, OM&A expenses and the revenue forecast, including the customer and volume forecasts?

PDI Response

The 2012 Bridge Year forecast is based on actual expenses as of September 30, 2012 plus expected expenditures for the remaining 3 months.

1-SEC-1

Ref: Exhibit 1

Please confirm that there are 34 schools in the Applicant's franchise area. Please advise the number of schools in each of the GS<50 and GS>50 classes.

PDI Response

There are 34 schools in PDI's franchise area. 20 schools are GS>50, and 14 are GS<50.

1-SEC-2

Ref: Exhibit 1

Please refer to the attached table entitled "2011 Comparisons of Distributor Data – Peterborough":

a) Please confirm that the figures are accurate to the best of the Applicant's knowledge.

b) Please advise if there are any material facts known to the Applicant that make any of the comparisons misleading or invalid.

c) Please provide copies of any internal comparisons with other distributors, including but limited to any performance benchmarking by the Applicant using data from other utilities.

PDI Response

a) While PDI cannot confirm the accuracy of other distributor data provided in the OEB yearbook, PDI confirms the accuracy of the figures for PDI in this table for Lines 1-3, and 5-10. PDI confirms the OM&A/Customer of $198.57 on page 78 of the 2011 OEB yearbook, and not the amount included on the report for OM&A/Customer of $212.07.

b) As PDI cannot confirm the accuracy of other distributor data provided in the yearbook, PDI cannot advise as to whether there are material facts that make any of the comparisons misleading or invalid.

PDI notes that the schedule contains FTE information without a reference or metric that considers the size of the LDC. With out this reference FTE information may be misleading. Furthermore, FTE information may not be comparable in situations where one LDC utilizes more of their own employees for capital work relative to an LDC who contracts out most of their capital work.

c) PDI has provided internal benchmarking in Exhibit 4, Tab 1, Schedule 1 Tables 4-6 and Tables 4-7. The source of information for Table 4-6 is the OEB 2011 yearbook. The data presented in Table 4-7 is based on the OM&A per customer as filed by each of the applicants listed in their original submission for their 2013 Cost of Service applications in Appendix 2-L.

In response to 4-Energy Probe-19 part a), PDI notes that the 2011 customers were recorded in the table for each of Welland, Westario, and Bluewater in error.

Additionally, a comparison of Residential Customer Bill's at 800kWh was included in PDI's parent company annual report as provided in Appendix B of the application.

This data was based on the "Estimated Bill Impacts – 800kWh" report published by the OEB.

1-SEC-3

Ref: Exhibit 1, Tab 1, Schedule 10

Please provide details of the reallocation of administrative costs from affiliates to 5615, including the dollar impact for each year from 2009 through 2013.

PDI Response

PDI has provided the dollar impacts between O&M and A&G in the table below. PDI notes that there is no impact to total OM&A as a result of the mapping change.

Table 1-SEC-3- Reallocation of Administrative Costs Impact to OM&A

	2009A	2010A	2011A	2012A	2013B
Operations	(271,539)	(326,859)	(283,933)	(245,554)	(450,648)
Maintenance	(199,710)	(234,564)	(288,357)	(217,755)	(399,631)
Administrative	471,249	561,423	572,290	463,309	850,279
Total OM&A Impact	-	-	-	-	-

1-SEC-4

Ref: Exhibit 1, Tab 1, Schedule 14

Please provide the 2012 financial statements (audited when available) for each of PDI, PUI, PUC, and PUSI.

PDI Response

PDI has provided the audited 2012 financial statements for each of PDI, PUC, and PUSI in Appendix 1-1, 1-2, and 1-3.

Peterborough Utilities Inc. (PUI) is a corporation engaged in competitive businesses. The public disclosure of its financial statements could reasonably be expected to prejudice the economic interest of, significantly prejudice the competitive position of, cause undue financial loss to, and be injurious to the financial interest of each of these consultants since it would enable its competitors and potential customers and suppliers to ascertain the financial condition of the company.

The Board's *Practice Direction on Confidential Filings* (the "Practice Direction") recognizes that these are among the factors that the Board will take into consideration when addressing the confidentiality of filings. They are also addressed in section 17(1) of the *Freedom of Information and Protection of Privacy Act* ("FIPPA"), and the Practice Direction notes (at Appendix B of the Practice Direction) that third party information as described in subsection 17(1) of FIPPA is among the types of information previously assessed or maintained by the OEB as confidential. PDI has requested the company's consent to the placement of the financial statements on the public record and it has requested that the document be kept in confidence. Accordingly, PDI requests that the PUI financial statements be kept confidential. PDI is prepared to provide copies of the PUI's financial statements to parties' counsel and experts or consultants provided that they have executed the OEB's form of Declaration and Undertaking with respect to confidentiality and that they comply with the Practice Direction, subject to PDI's right to object to the OEB's acceptance of a Declaration and Undertaking from any person.

In keeping with the Practice Direction, PDI is filing a confidential unredacted version of the PUI financial statements. The unredacted version of the document has been placed in a sealed envelope marked "Confidential".

1-SEC-5

Ref: Exhibit 1, Tab 1, Schedule 16

Please provide a detailed calculation of the impact on January 31, 2013 rate base of applying the half year rule in 2012.

PDI Response

The ending 2012 rate base, and opening 2013 rate base, would be $150,175 lower if the half year rule had not been applied in 2012.

	2011 Actual	2012 Actual half-year rule	2012 no half-year rule	2012 Variance half-year rule vs no half-year rule
Gross Fixed Assets	79,001,224	91,374,101	91,374,101	-
Accumulated Depreciation	33,043,912	38,737,884	39,039,373	(301,489)
Net Book Value	45,957,312	52,636,217	52,334,728	301,489
Average Net Book Value	45,240,916	49,296,765	49,146,020	150,745
Working Capital Expenses	75,911,382	82,286,185	82,286,185	-
Working Capital Allowance (15%)	11,386,707	12,342,928	12,342,928	-
Rate Base	**56,627,623**	**61,639,693**	**61,488,948**	**150,745**

1-SEC-6

Ref: Exhibit 1, Tab 2, Schedule 2, p 1-47 and Exhibit 1, Tab 2, Schedule 4

Please confirm that, but for the accounting changes totalling $1,350,856, the deficiency in the test year would be $1,955,604, requiring a 13.6% weighted average rate increase. Please confirm that, but for the reduction in interest rates from 2009 Board Approved to forecast 2013 costs, the deficiency would be a further $1,000,000 higher, or approximately $2,950,000, requiring a 20.5% weighted average rate increase.

PDI Response

As noted on page 1-48, PDI has estimated the impact of accounting changes to the 2013 revenue requirement to be a reduction of $1,350,856. If this amount was added to the revenue requirement for 2013, the increase in Distribution revenue based on rates established in 2009 and incrementally adjusted through the IRM process would total 13.6%.

Further to the questions concerning interest rates, in 2012, PDI restructured its higher-interest affiliate debt in an effort to reduce interest expense and more closely align with OEB-prescribed rates. When PDI applied the 2009 Board Approved long-term debt rate of 6.59% and short-term debt rate of 1.33% the resulting increase to the 2013 revenue requirement was approximately $835,000.

1-SEC-7

Ref: Exhibit 1, Appendix A p 15

With respect to the 2010 Financial Statements of PDI:

a) Please explain in detail how capital expenditures are incurred by affiliates for the account of PDI, including the need for affiliate involvement, the nature of the payments, and the cash flow and working capital implications.

b) Please provide a copy of the current Unanimous Shareholders Declaration for any of the companies in the Peterborough Utilities Group.

PDI Response

a) PUSI supplies labour expense to PDI. PDI uses the labour for both operating and capital activities. At the beginning of each month PDI pays PUSI for operating and capital work performed in the prior month.

b) PDI has provided a copy of the Unanimous Shareholders Declaration for City of Peterborough Holdings Inc. in Appendix 1-4.

1-SEC-8

Ref: Exhibit 1, Appendix B

With respect to the 2011 Annual Report of PDI:

a) First page (pages are not numbered). Please provide the document comparing rates that shows that the Applicant's "rates are some of the lowest in the region".

b) Third page. Please confirm that PUI does not charge less for MDMA/MSP Metering services to any third party than it does to PDI.

c) Sixth page. Please provide details of any drop in costs from 2011 to 2012 and 2013 as a result of the "four severe thunderstorms" in 2011.

d) Tenth page. For each of the individuals listed on this page, please provide their most recent time allocation estimates for each of the entities in PUG, and the resulting percentage allocation of their costs to each of those entities for the Test Year.

PDI Response

a) On the Sixth Page of the 2011 Annual Report, PDI has illustrated the typical residential customer bill based on 800 kWh for other utilities in the Peterborough region. This data was gathered from the Estimated Bill Impacts for 2011 as published on the OEB website, and included in Appendix 1-5.

b) PDI has made an inquiry of PUI and is advised that PUI does not charge less for MDMA/MSP Metering services to any third party than it does to PDI for comparable services.

c) PDI has illustrated the storm damage impact from 2011 to the 2013 test year in response to 4-VECC-20.

d) PDI has provided the requested details for Executive Leadership time and cost allocations in the table below.

Table 1-SEC-8 – 2013 Time and Cost Allocations of ELT

Name	Title	PDI Time/Cost Allocation	PUC Time/Cost Allocation	PUI Time/Cost Allocation	PUSI Time/Cost Allocation	Outside PUG Time/Cost Allocation
John Stephenson	President & CEO	30%	30%	30%	5%	5%
Byron Thompson	CFO	30%	30%	30%	5%	5%
Larry Franks	VP Information Technology	26%	14%	5%	0%	55%
Jeff Guilbeault	VP Electric Utility	100%	0%	0%	0%	0%
Carrissa McCaw	Director, Human Resource & Safety	35%	41%	12%	12%	0%
Wayne Stiver	VP Water Utility	0%	100%	0%	0%	0%
David Whitehouse	Director, Customer & Corporate Services	69%	28%	3%	1%	0%
John Wynsma	VP Generation & Retail Services	0%	0%	100%	0%	0%

1-VECC- 1

Reference: Exhibits All

PDI filed its application in February 2013. Is PDI seeking to have new rates applied retroactively to May 1, 2013 or is the Utility seeking new rates only on a prospective basis and after the date of Board approval?

PDI Response

PDI is not seeking to have new rates applied retroactively to May 1, 2013.

1-VECC- 2

Reference: Exhibits All

a) Please provide a tracking sheet (table) showing all adjustments arising from the interrogatories (include Reference IR #.; Item description; area of change, i.e. return on capital/rate base/working capital allowance/amortization/PILS/OM&A/ etc.).

b) Please update the RRWF Excel spreadsheet for these adjustments.

PDI Response

a) PDI has provided the tracking sheet as requested on the following page.

b) PDI has provided the RRWF in Excel format as requested.

Table 1-VECC-2 – Summary of Changes

Peterborough Distribution Inc.
Summary of Changes

	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital Allowance %	Working Capital	Working Capital Allowance	Amortization	PILs	OM&A (including Taxes other than Income Tax)	Service Revenue Requirement	Base Revenue Requirement	Gross Revenue Deficiency
Original Submission	$4,016,755	6.06%	$66,310,232	13%	$92,858,402	$12,071,592	$2,673,856	$257,435	$9,238,791	$16,291,837	$15,028,837	$604,748
6-Energy Probe-23 Updated Cost of Capital Parameters	$4,029,752	6.08%	$66,310,232	13%	$92,858,402	$12,071,592	$2,673,856	$257,435	$9,238,791	$16,308,693	$15,045,693	$621,604
Change	$12,997	0%	$0	0%	$0	$0	$0	$0	$0	$16,856	$16,856	$16,856
3-VECC-17 Revised Test Year for Specific Service Charges	$4,029,752	6.08%	$66,310,232	13%	$92,858,402	$12,071,592	$2,673,856	$257,435	$9,238,791	$16,308,693	$14,995,693	$571,604
Change	$0	0%	$0	0%	$0	$0	$0	$0	$0	$0	($50,000)	($50,000)
2-Energy Probe-12 Updated Cost of Power for 2013 rates	$4,027,370	6.08%	$66,271,035	13%	$92,556,885	$12,032,395	$2,673,856	$257,435	$9,238,791	$16,305,902	$14,992,902	$568,813
Change	($2,382)	0%	($39,197)	0%	($301,517)	($39,197)	$0	$0	$0	($2,791)	($2,791)	($2,791)
2-Energy Probe-6 Updated 2013 Opening Balance Fixed Assets	$3,988,075	6.08%	$65,624,434	13%	$92,556,885	$12,032,395	$2,673,856	$257,435	$9,238,791	$16,259,847	$14,946,847	$522,758
Change	($39,295)	0%	($646,601)	0%	$0	$0	$0	$0	$0	($46,055)	($46,055)	($46,055)
3-Energy Probe-17 Revise Test Year for SSS Admin	$3,988,075	$0	$65,624,434	$0	$92,556,885	$12,032,395	$2,673,856	$257,435	$9,238,791	$16,259,847	$14,941,047	$516,958
Change	$0	0%	$0	0%	$0	$0	$0	$0	$0	$0	($5,800)	($5,800)
Change between Initial Filing and IRR	-1%	0%	-1%		0%	0%	0%	0%	0%	0%	-1%	-15%
	($28,680)	0%	($685,798)		($301,517)	($39,197)	$0	$0	$0	($31,990)	($87,790)	($87,790)

PETERBOROUGH DISTRIBUTION INC.

2013 COST OF SERVICE RATE APPLICATION

RESPONSE TO INTERROGATORIES

EXHIBIT 2 – RATE BASE

EB-2012-0160

FILED: MAY 27, 2013

PETERBOROUGH DISTRIBUTION INC.

2013 COST OF SERVICE RATE APPLICATION

RESPONSE TO INTERROGATORIES

EXHIBIT 2 – RATE BASE

EB-2012-0160

FILED: MAY 27, 2013

2-Preliminary-1

Ref: Exhibit 2, Tab 3, Schedule 2, Table 2-17

Update Exhibit 2, Tab 3, Schedule 2, Table 2-17 for 2011, 2012, and 2013 capital projects, providing in-service dates for each project.

PDI Response

Table 2-17 has been updated with 2012 actual expenditures and is provided in the response to 2-Energy Probe-9.

The column headings in this table reflect the year that the assets were placed in service.

2-Staff-1

Ref: Exhibit 2, Tab 3, Schedule 2, Capital Expenditures
Ref: Exhibit 2, Tab 3, Schedule 3, Asset Management Plan Summary
Ref: Appendix C, s 2.4.2 Operation and Maintenance Strategy
Ref: Exhibit 4, Tab 2, Schedule 2, OM&A Detailed Cost Tables

a) With respect to the management of PDI's assets, please discuss the trade-off between capital and OM&A expenditures.

b) Please provide percentage figures for capital and OM&A expenditures linked to the following categories: Planned/Internal Sustainment & Development; Unplanned Customer Driven Sustainment and Development

c) Where applicable, please identify all significant instances of life-extending maintenance expenditures.

PDI Response

a) With regard to the management of PDI assets, OM&A expenditures are for the most part focused on diagnostics, inspection and some preventative maintenance. For example, infra inspection and annual patrol inspection to identify assets that may need repair or replacement prior to potential failure. Tree trimming is a maintenance activity that provides for reliability and preventative damage to existing assets. Substation assets are maintained on a more regular basis due to the age of the assets. Capital for sustainment is focused on the replacement of older assets typically exhibiting lower reliability and/or in end of life condition. Capital for development and system enhancement is focused on load growth and new development.

b) The table is provided below:

		% of Total Annual Expenditures						
		2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Test
CAPITAL								
Planned/internal	Sustainment	57%	56%	52%	54%	33%	48%	55%
	Development	17%	7%	16%	14%	24%	12%	16%
OM&A								
Planned/internal	Sustainment	66%	62%	83%	85%	79%	80%	84%
	Development	0%	0%	0%	0%	0%	0%	0%

		% of Total Annual Expenditures						
		2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Test
CAPITAL								
Unplanned/	Sustainment	8%	0%	10%	13%	37%	11%	18%
Customer driven	Development	18%	36%	22%	19%	5%	28%	12%
OM&A								
Unplanned/	Sustainment	34%	38%	17%	15%	21%	20%	16%
Customer driven	Development	0%	0%	0%	0%	0%	0%	0%

c) There are no significant instances of life-extending maintenance expenditures.

2-Staff-2

<u>Ref: Exhibit 2, Tab 3, Schedule 2, Table 2-17</u>

Table 2-17 provides a breakdown of PDI's capital projects from 2007 to 2013. Board staff notes that for 2012 PDI has categorized certain amounts in each of the programs as "Other" as follows:

Program	Total Program Cost	Categorized as "Other"	% of Total Program
Overhead Distribution Renewal	1,390,507	515,983	37%
Substations	217,075	217,075	100%
Underground Distribution Renewal	1,313,920	699,190	53%
OH Distribution Lines - Customer Demand	351,099	351,099	100%
Relocations requested by Municipality	308,795	221,620	72%

a) Please provide a breakdown of the category of "Other" for each of the programs listed above.

b) Please identify capital expenses in the "Other" entries that are onetime costs and those that are recurring or cyclical.

PDI Response

The table prepared by Board staff was based on the 2012 forecast. PDI has updated the table based on 2012 actual expenditures and the revised Table 2-17 included in the response to 2-Energy Probe-9.

Program	Total Program Cost	Categorized as "Other"	% of Total Program
Overhead Distribution Renewal	864,847	423,559	49%
Substations	165,545	165,545	100%
Underground Distribution Renewal	790,338	108,361	14%
OH Distribution - Customer Demand	184,165	184,165	100%
OH Distribution Lines - Customer Demand	262,237	165,146	63%
Relocations requested by Municipality	317,578	139,167	44%

The breakdown of the "Other" category is provided below:

Overhead Distribution Renewal			
Replacement of defective insulators		84,858	recurring
M10-M11 Feeder Tie, Switch Installation, Otonabee TS		51,448	one-time
King George St 27.6 kV conversion		50,833	one-time
Guying improvements O'Brien/Neal Dr poles		48,955	one-time
Otonabee Dr 27.6 kV conversion		42,246	one-time
Primary electric rehabilition - Victory Cr/Armstrong Dr area		38,150	one-time
Annual capital program OH lines		32,680	recurring
Parkhill Rd E. canal crossing improvements		25,650	one-time
Goodfellow Rd - Install LIS at Goodfellow NO of M11/M8		22,948	one-time
Cottonwood Dr - 2400 V OH distribution pole change out		14,808	one-time
Replace missing ground wires		7,639	recurring
Woodbine Ave		3,244	one-time
		423,459	
Substations			
MS #18 - 44 kV U/G Supply		54,853	one-time
MS 21 Transformer Bushing Replacement		33,097	one-time
Wholesale Meters Replacement		25,394	recurring
MS #8 - Replace Ceiling		22,766	one-time
BS#4 & BX#11 Replace isolating switches		15,786	one-time
MS #7 Replace Brick		13,651	one-time
		165,547	
Underground Distribution Renewal			
Ungava Ave		48,436	recurring
Highland Court		28,229	recurring
Webber Ave		20,122	recurring
Cottonwood Drive		11,574	recurring
		108,361	
Overhead Distribution - Customer Demand			
280 Perry St - Service Replacement		55,332	one-time
OH Distribution - Customers Misc		36,712	one-time
Joint use make ready - Concession St		25,586	one-time
1111 Royal Drive - Transformer Bank		16,404	one-time
965 Crawford - Cell Tower OH Primary Pole Line Work		13,300	one-time
Joint use make ready - George St N.		13,115	one-time
33 Greenhill Dr - New OH line		10,668	one-time
Joint use make ready - Nassau Mills Rd		6,167	one-time
207-209 MurraySt - OH Distribution Lines Re-worked		5,631	one-time
Joint use make ready - McDonnel St		1,250	one-time
		184,165	
Overhead Distribution Lines - Customer Demand			
1901 Fisher Drive		64,073	one-time
1293 Clonsilla Ave - New OH Lines		32,112	one-time
890 Chemong Rd - New Overhead Lines		30,321	one-time
900 Major Bennett Drive		17,560	one-time
Trent Student Residence OH Primary		15,941	one-time
Miscellaneous capital work new 27.6kV		5,139	one-time
		165,146	
Relocations			
Edward St Lakefield		68,008	one-time
Hunter/Burnham		61,500	one-time
Park St N		4,722	one-time
1066 Ford St		4,643	one-time
Geraldine Ave		294	one-time
		139,167	

2-Staff-3

Ref: Exhibit 2, Tab 3, Schedule 2, Table 2-17

Table 2-17 provides a breakdown of PDI's capital projects from 2007 to 2013. Board staff notes that for 2013 PDI has categorized certain amounts in each of the programs as "Other" as follows:

Program	Total Program Cost	Categorized as "Other"	% of Total Program
Substations	245,000	115,000	47%
Underground Distribution Renewal	645,000	570,000	88%
OH Distribution Lines - Customer Demand	225,000	225,000	100%

a) Please provide a breakdown of the category of "Other" for each of the programs listed above.

b) Please identify capital expenses in the "Other" entries that are one-time costs and those that are recurring or cyclical.

PDI Response

The breakdown of the "Other" category is provided below:

Substations			
MS #29 - brick & block work		25,000	one-time
MS #8 - door upgrade		10,000	one-time
MS #7 - brick & block work		5,000	one-time
MS #1 - backup SCADA		15,000	one-time
Scout RTU/modem (2)		10,000	one-time
MS #2 - station grid		35,000	one-time
MS #8 - batteries		15,000	one-time
		115,000	
Underground Distribution Renewal			
150 King St		40,000	one-time
U/G primary conversion to Holiday Inn		20,000	one-time
Fault indicators		10,000	recurring
U/G rehabilitation - Chamberlain St, Applewood Cres, Champlain Cres, Highland Crt, Foresthill Blvd		500,000	recurring
		570,000	
Overhead Distribution Lines - Customer Demand			
Aylmer/King St OH Distribution Rework		10,000	one-time
Misc Extensions/Rebuilds		25,000	one-time
Misc Capital/Customers		15,000	one-time
Misc Capital Line Projects		175,000	one-time
		225,000	

2-Staff-4

<u>Ref: Exhibit 2, Tab 3, Schedule 2, Capital Expenditures – 2012</u>

For 2012, the totals shown at table 2-17 for “Overhead Distribution Renewal” and “44 kV Switches Upgrades/SCADA” do not coincide with the amounts provided at the reference above. Please reconcile and/or explain the discrepancy described above.

PDI Response

The figure in Table 2-17 is the correct figure for the bridge year. The figure in the description in the Capital Expenditures – 2012 project summary is a typographical error.

2-Staff-5

<u>Ref: Exhibit 2, Tab 3, Schedule 2, Table 2-17</u>

a) Has the “Miscellaneous” category been integrated into the “Other” entries?

b) What did “Miscellaneous” encompass in the 2007-2011 period?

PDI Response

a) Yes. The Miscellaneous category was used previously and is now divided into all of the major category headings.

b) The Miscellaneous category was used for all types of projects that were of small value or were under the materiality threshold limit of $75,000.

2-Staff-6

Ref: EB-2008-0247, Exhibit 2, Tab 3, Schedule 2, Table 2-17

PDI has provided total Contributions and Grants for 2012 and 2013 of $1,319,000 and $1,180,000, respectively.

a) Please provide actual contributions for 2012.

b) Please provide a breakdown of contributions by project for each of 2012 and 2013.

PDI Response

a) Actual contributions for 2012 were $1,671,900.

b) Contributions by project for 2012 and 2013 are shown below:

Contributions and Grants - 2012 Actual	
Project Description	Contribution Amount
Otonabee TS M10-M11 feeder tie	43,391
U/G Subdivisions assumed from developers - Jackson Creek	753,776
U/G Subdivisions - Developer Capital Contribution Rebates	(95,589)
Ground rod installation - Stewart Drive	1,058
Joint Use Make Ready	9,700
Crawford Drive cell tower	14,685
Trent University student residence	15,941
27.6 kV expansion - Major Bennett	9,447
Relocation - Peterborough Regional Health Centre	58,094
Relocation - Hunter/Burnham	17,306
Relocation - Edward St, Lakefield	14,972
Relocate guys for City sidewalks	1,915
Overhead Services	12,830
Underground Services - Primary - Walmart	89,582
Underground Services - Primary - other	331,452
Underground Services - Secondary	145,593
Underground Services - Residential	185,505
U/G transformer - 33 Hunter St E.	31,439
Overhead transformer - 708 Lansdowne St W.	500
Meters - MicroFIT	5,797
Meters - other	2,200
FIT/MicroFIT generation connections	22,306
	1,671,900

Contributions and Grants - 2013 Test Year	
Project Description	Contribution Amount
U/G Subdivisions assumed from developers	360,000
Relocation - Chemong Road	27,000
Relocation - Parkhill Road/Brealey Drive	60,000
Relocation - other	30,000
Overhead Services	10,000
Underground Services - Primary - other	400,000
Underground Services - Secondary	200,000
Underground Services - Residential	93,000
	1,180,000

2-Staff-7

Ref: Exhibit 2, Appendix D
Ref: Report of the Board, *Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09*
Ref*: Filing Requirements*: Distribution System Plans – Filing under Deemed Condition of Licence, revised May 17, 2012

a) Please provide a schedule of capital and initial OM&A expenditures associated with the Green Energy projects to 2017 as discussed in the Green Energy Plan.

b) Please break out the expenditures as renewable enabling improvements or expansion costs in accordance with the DSC classification.

c) In accordance with the Direct Benefits methodology outlined in the Framework, please provide an estimate of the direct benefits accruing to PDI's ratepayers.

d) Please provide the amount of Green Energy Plan capital expenditures which have been included in PDI's rate base.

PDI Response

The response to the above questions has been provided in the table below:

Year	OM&A	Capital Enabling	Capital Expansion	Benefit to PDI Ratepayers	Incl. Rate Base
2013			$207,000	100%	$160,000
2014	$15,000	$50,000	$125,000	100%	$175,000
2015	$15,000			100%	
2016	$15,000			100%	
2017	$15,000			100%	

2-Staff-8

Ref: Exhibit 2, Appendix D, s. 3.0
Ref: Filing Requirements: Distribution System Plans – Filing under Deemed Condition of Licence, revised May 17, 2012, s. 2.4.1

Please indicate what these educational costs amount to and whether they have been assigned to the appropriate deferral accounts as described in section 7.0 of the *Filing Requirements*.

PDI Response

The educational costs for smart grid are included in normal education activities carried out by technical staff and are deemed to be immaterial at this time. No costs have been assigned to deferral accounts.

2-Energy Probe-6

Ref: Exhibit 2, Tab 1, Schedule 2

Please update Tables 2-5 and 2-6 to reflect actual capital expenditures closed to rate base for 2012. Please also indicate if there is any change to the 2013 figures as a result of the actual closures to rate base in 2012.

PDI Response

The tables have been updated:

Table 2-5: 2012 Actual vs. 2011 Actual

	2011 Actual	2012 CGAAP Actual	Variance
Gross Fixed Assets	79,001,224	91,374,101	12,372,877
Accumulated Depreciation	33,043,912	38,737,884	5,693,972
Net Book Value	45,957,312	52,636,217	6,678,905
Average Net Book Value	45,240,916	49,296,765	4,055,849
Working Capital Expenses	75,911,382	82,286,185	6,374,803
Working Capital Allowance (15%)	11,386,707	12,342,928	956,221
Rate Base	**56,627,623**	**61,639,693**	**5,012,070**

Table 2-6: 2013 Test Year vs. 2012 Actual

	2012 Actual	Revised 2013 Test	Variance	2013 Test per Original Application
Gross Fixed Assets	91,374,101	95,959,601	4,585,500	95,959,601
Accumulated Depreciation	38,737,884	41,411,740	2,673,856	41,411,740
Net Book Value	52,636,217	54,547,861	1,911,644	54,547,861
Average Net Book Value	49,296,765	53,592,039	4,295,274	54,238,640
Working Capital Expenses	82,286,185	92,556,885	10,270,700	92,858,402
Working Capital Allowance (15%)	12,342,928			
Working Capital Allowance (13%)		12,032,395	(310,533)	12,071,592
Rate Base	**61,639,693**	**65,624,434**	**3,984,741**	**66,310,232**
2013 Test Year revised				**65,624,434**
Change from Original Application				**(685,798)**

In the above table, 2013 working capital expenses include revised cost of power as requested in 2-Energy Probe-12.

2-Energy Probe-7

Ref: Exhibit 2, Tab 2, Schedule 1

Please update Table 2012 to reflect actual data for 2012.

PDI Response

The continuity schedule for 2012 has been updated with actual results.

Table 2-12 Fixed Asset Continuity Schedule – 2012 Actual

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 509,711	$ 666,078		$ 1,175,789	-$ 361,883	-$ 137,002		-$ 498,885	$ 676,904
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 134,968			$ 134,968	$ -			$ -	$ 134,968
47	1808	Buildings	$ 444,815	$ 91,270		$ 536,085	-$ 74,207	-$ 11,683		-$ 85,890	$ 450,195
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 3,466,251	$ 74,277		$ 3,540,528	-$ 1,160,249	-$ 132,664		-$ 1,292,913	$ 2,247,615
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 22,740,550	$ 1,033,419		$ 23,773,969	-$ 9,955,005	-$ 999,841		-$ 10,954,846	$ 12,819,123
47	1835	Overhead Conductors & Devices	$ 9,165,810	$ 1,134,725		$ 10,300,535	-$ 2,209,535	-$ 362,770		-$ 2,572,305	$ 7,728,230
47	1840	Underground Conduit	$ 15,031,740	$ 900,206		$ 15,931,946	-$ 5,646,864	-$ 633,917		-$ 6,280,781	$ 9,651,165
47	1845	Underground Conductors & Devices	$ 5,158,092	$ 511,530		$ 5,669,622	-$ 719,303	-$ 138,997		-$ 858,300	$ 4,811,322
47	1850	Line Transformers	$ 18,572,095	$ 1,419,018		$ 19,991,113	-$ 7,449,418	-$ 839,154		-$ 8,288,572	$ 11,702,541
47	1855	Services (Overhead & Underground)	$ 13,546,399	$ 1,527,873		$ 15,074,272	-$ 3,759,848	-$ 435,403		-$ 4,195,251	$ 10,879,021
47	1860	Meters	$ 911,264	$ 487,068		$ 1,398,332	-$ 358,370	-$ 46,542		-$ 404,912	$ 993,420
47	1860	Meters (Smart Meters)	$ 5,702,472			$ 5,702,472	-$ 1,221,004	-$ 380,164		-$ 1,601,168	$ 4,101,304
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 44,877			$ 44,877	-$ 25,984	-$ 8,976		-$ 34,960	$ 9,917
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 82,385			$ 82,385	-$ 82,385			-$ 82,385	$ -
	1970	Load Management Controls Customer Premises	$ 1,633,219			$ 1,633,219	-$ 1,570,981	-$ 15,735		-$ 1,586,716	$ 46,503
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 11,944,111	-$ 1,671,900		-$ 13,616,011	$ -			$ -	-$ 13,616,011
		Sub-total	**$ 85,200,537**	**$ 6,173,564**	**$ -**	**$ 91,374,101**	**-$ 34,595,036**	**-$ 4,142,848**	**$ -**	**-$ 38,737,884**	**$ 52,636,217**
	2055	Contract work in progress-electric	$ 3,416,629	$ 2,043,052	-$ 3,416,629	$ 2,043,052				$ -	$ 2,043,052
		Total	**$ 88,617,166**	**$ 8,216,616**	**-$ 3,416,629**	**$ 93,417,153**	**-$ 34,595,036**	**-$ 4,142,848**	**$ -**	**-$ 38,737,884**	**$ 54,679,269**

2-Energy Probe-8

Ref: Exhibit 2, Tab 2, Schedule 1

Please explain how the disposals for the account 2055 - Contract work in progress - electric can be higher than the opening balance in the account, as was the case for both 2010 and 2011 (Tables 2-10 and 2-11). Does this mean that some of the work in progress shown in the additions column was added to work in progress and then closed to rate base within the same year?

PDI Response

In 2010 and 2011 disposals for account 2055 exceeded the opening balance because some additions to work in progress were closed to rate base within the same year.

2-Energy Probe-9

Ref: Exhibit 2, Tab 3, Schedule 2

Please update Table 2-17 to reflect actual data for 2012 and any impact the difference between the forecasted and actual data for 2012 is forecast to have on 2013.

PDI Response

Table 2-17 has been updated to reflect actual data for 2012.

Impact on 2013

The Cumberland 27.6 kV and the Parkhill Rd W 27.6 kV extension projects will not proceed in 2013. We have two development driven projects that will (may) proceed instead: Aylmer St Reconstruction (not listed but will proceed) and Charlotte Street U/G (not listed and not confirmed yet). Both projects were recent additions due to developer requirements and City requests.

The Aylmer St Project will be approximately $350,000 and covered by PDI. The Charlotte St project will be approximately $750,000 will be recoverable from the City.

The City has also expanded the scope of its Parkhill Rd W relocation project essentially doubling the scope although Chemong Road relocation is now delayed.

Trent University GS connection extension will be higher than forecast.

Table 2-17: Capital Projects 2007 to 2013

Projects	2007 Actual CGAAP	2008 Actual CGAAP	2009 Actual CGAAP	2010 Actual CGAAP	2011 Actual CGAAP	2012 Actual CGAAP	2013 Test MIFRS
Overhead Distribution Renewal							
Springbrook/Daleview area	190,146						
Hunter St. - Belmont to Park	106,580						
Juliet Avenue	139,420						
Sherbrooke St.- Goodfellow to Wallis	229,431						
Ashburnham/Neal Drive area		391,415					
Romaine Street		210,167					
Erskine Avenue			129,136				
Hilliard Street and Hedonics Road			128,599				
Brealey Drive/Kawartha Heights			166,976				
Water Street North				120,862			
Insulator Replacement Program				88,611			
Ford Street/Brunswick Avenue area					103,813		
Cumberland Avenue OH line conversion						142,674	
Cumberland Avenue 27.6 kV extension							
Parkhill Road West 27.6 kV extension							225,000
Parkhill Road West Feeder							525,000
44kV OH River Crossing							136,000
44 kV Switches Upgrades/SCADA						298,614	50,000
other	132,325	84,733	151,986	160,700	45,123	423,559	126,000
	797,902	**686,315**	**576,697**	**370,173**	**148,936**	**864,847**	**1,062,000**
Pole Replacement Program				**787,323**	**612,201**	**755,684**	**550,000**
New 27.6 kV Feeder (M9)	**390,684**						
New 27.6 kV Feeder (M8)				**553,658**	**390,633**		
Substations							
MS1	88,783						
MS19				138,165			
MS65							130,000
other			53,340	120,366	43,578	165,545	115,000
	88,783	**-**	**53,340**	**258,531**	**43,578**	**165,545**	**245,000**
New Underground Subdivisions	**508,996**	**263,747**	**562,718**	**203,362**	**780,762**	**760,470**	**600,000**
New Underground Lines - Cumberland							
				271,489			
Underground Distribution Renewal:							
Cumberland Avenue feeder	947,599						
Cumberland Avenue 27.6 kV line	81,181						
Ashburnham by the Lake Subdivision	445,632						
Cherryhill Road area	262,834	898,942					
Marsdale, Maria, Walker	146,308						
Garside Road area		141,137					
Hilltop, Cottonwood, Ashdale, Bayleaf, Stocker, Whitefield			725,876				
St. Paul's Street/Herbert Street area				187,950			
George Street Vault Reconstruction				87,493			
University Heights					476,892	448,381	
Cameron Street/Orpington Road						143,552	
Stewart Drive						90,044	
Downtown underground vault rebuild							75,000
other	168,762		33,631	369,438		108,361	570,000
	2,052,316	**1,040,079**	**759,507**	**644,881**	**476,892**	**790,338**	**645,000**

Capital Projects 2007 to 2013 – continued

Projects	2007 Actual CGAAP	2008 Actual CGAAP	2009 Actual CGAAP	2010 Actual CGAAP	2011 Actual CGAAP	2012 Actual CGAAP	2013 Test MIFRS
Overhead Distribution - Customer Demand							
Major Bennett Drive						-	
other	105,825	240,432	188,239	192,072	102,194	184,165	
	105,825	**240,432**	**188,239**	**192,072**	**102,194**	**184,165**	**-**
OH Distribution Lines - Customer Demand							
Line extension to new YMCA - Aylmer Street	201,753						
Line extension to new subdivision - Maria St.	95,257						
George Street/Argyle Street			158,793				
Carnegie Avenue				184,483			
Cumberland Avenue				167,157			
Heritage Trail				80,354			
Major Bennett line extension						97,091	
other	213,181	298,296	127,917	152,176		165,146	225,000
	510,191	**298,296**	**286,710**	**584,170**	**-**	**262,237**	**225,000**
Relocations requested by Municipality							
Highway 7/Highway 115 intersection			341,986				
Lansdowne Street/Borden Avenue				243,340			
Borden Avenue/Erskine Avenue				211,350			
Romaine Street				116,467			
Lansdowne Street West					1,210,702		
Water Street North					183,199		
Hilliard Street/Towerhill Road					182,913		
Peterborough Regional Health Centre						178,411	
Parkhill Road West							242,000
Parkhill Road/Brealey Drive							361,000
Chemong Road							90,000
other	168,012			12,013	39,675	139,167	109,500
	168,012	**-**	**341,986**	**583,170**	**1,616,489**	**317,578**	**802,500**
Services							
Overhead Services	249,665	280,957	129,046	282,403	219,312	484,297	320,000
Overhead Services - Sherwood Drive						105,897	
Overhead Services - Market Plaza						149,892	
Underground Services - Primary	373,106	391,578	263,976	218,379	506,545	720,150	455,000
Underground Services - Secondary		222,475	147,884	81,148	200,161	346,651	220,000
Underground Services - Residential	323,392	332,151	270,942	332,199	267,422	222,120	221,000
600V service upgrades					204,349	277,334	
	946,163	**1,227,161**	**811,848**	**914,129**	**1,397,789**	**2,306,341**	**1,216,000**
Transformers	**163,769**	**228,183**	**357,224**	**639,091**	**136,884**	**260,556**	**130,000**
Meters	**159,914**	**78,634**	**402,177**	**155,039**	**379,911**	**487,068**	**205,000**
Generation Connection							
Trent Rapids Power				595,310			
Trent University							75,000
other						24,557	10,000
	-	**-**	**-**	**595,310**	**-**	**24,557**	**85,000**
MDMR Integration						**666,078**	
Load Control							
Miscellaneous	**216,086**	**40,273**	**117,500**	**42,577**	**181,795**	**-**	**-**
Contributions and Grants	**(738,434)**	**(555,079)**	**(900,355)**	**(1,448,545)**	**(1,410,810)**	**(1,671,900)**	**(1,180,000)**
Total	**5,370,207**	**3,548,041**	**3,557,591**	**5,346,430**	**4,857,254**	**6,173,564**	**4,585,500**

2-Energy Probe-10

Ref: Exhibit 2, Tab 3, Schedule 2

Please update the projects shown for 2012 starting at page 2-55 to reflect actual 2012 costs closed to rate base.

PDI Response

Actual 2012 projects closed to rate base are described below.

Capital Expenditures - 2012 Actual

MDM/R - $666,078

This project is to integrate the smart meter infrastructure with the IESO meter data management repository and prepare for the implementation of TOU billing for customers. The project was initiated in late 2009 and was completed in 2012.

Overhead Distribution Renewal - $566,233

This project area includes 9 overhead line renewal projects started in 2011. Only one of the projects exceeded the materiality threshold, Cumberland Ave overhead line conversion ($142,674) completed for an underground conversion and renewal in an existing underground residential subdivision in 2012 and conversion of a newer subdivision completed in a prior year.

44 kV Switches Upgrades/SCADA - $231,175

This 2012 project is the completion of a multi-year project started in 2010 to renew the SCADA controls and communication for remote controlled 44 kV switches and an upgrade to a 27.6 kV re-closer.

Switch Upgrades - $67,439

Expenditures in 2012 to upgrade or replace major 44 and 27.6 kV switches on the distribution system. None of the projects exceed the materiality threshold.

<u>Pole Replacement Program - $755,684</u>

The 2012 expenditure for the ongoing pole replacement program determined from the pole testing completed in 2011 and prior years as described in the Asset Management Plan.

<u>Substations Building Upgrades - $36,417</u>

The project area includes substation upgrades in 2012 for two municipal substation buildings. None of the projects exceed the materiality threshold.

<u>MS #18 44 kV Upgrade- $54,853</u>

This project area was to install new underground 44 kV supply to an existing municipal substation. This was a safety related upgrade for employee safety. The project was started in 2011 and completed in 2012.

<u>Substation Equipment Upgrades - $74,276</u>

Project area covers the upgrade to 44 kV bushings at MS #21 to remove existing PCB contaminated circuit breaker bushings and replacement of isolating switches at two breaker stations completed in 2012.

<u>New Underground Subdivisions - $760,470</u>

The project area includes the installation and assumption of a new underground residential subdivision.

<u>Underground Rehabilitation Program - $790,338</u>

This the annual program for rehabilitating underground lines and transformers as described in the Asset Management Plan. The program covered several different areas and was started in 2011 and completed in 2012.

<u>Joint Use Make Ready - $46,118</u>

Make ready work on the distribution system for third party joint use attachments.

<u>Overhead Distribution – Customer Demands - $138,047</u>

This area includes a total of six larger customer demand projects completed in 2012 for new or upgraded overhead customer services. Several smaller projects were completed as well but none of the projects exceeded the materiality threshold.

<u>Overhead Distribution Line Extensions – Customer Demands - $262,237</u>

This project area includes fourteen overhead line completed in 2012 for new customer service requests. One project exceeded the materiality threshold:

- Major Bennett Road Line Extension ($97,091) for Peterborough Movers service.

<u>Relocations Municipality - $317,578</u>

This area includes customer demand projects with eight municipality road relocations completed. One project, the Hospital Access Road ($178,411) exceeded the materiality threshold. This project was started late in 2011 and was completed in 2012.

<u>Overhead Services - $343,876</u>

The project area includes customer demand for new and upgraded overhead services. More than 26 projects were completed in 2012. Some projects were started in 2011 and completed in 2012. None of the projects exceeded the materiality threshold.

<u>Overhead Services Renewal - $396,210</u>

Seven projects were completed in 2012. Two backyard overhead service renewal projects were started in 2010 and completed in 2012. The following projects exceeded the materiality threshold:

- Market Plaza ($149,892), overhead primary and transformer bank replaced due to safety concerns for the existing service.

- Sherwood Dr. ($105,897), the project was initiated as the result of damage during a wind storm.

<u>600 V Service Replacement Program - $277,334</u>

This is phase II of a combined renewal project to replace obsolete 600 V services, replace PCB contaminated transformers (also near end of life), replace Primary Metering Units (PMU) and install new smart meters. A total of twelve projects were completed in 2012. None of the projects exceeded the materiality threshold.

<u>New Underground Primary Services - $720,150</u>

This a customer demand project area for new underground high voltage services with a total of 23 projects. Some projects started in 2011 and completed in 2012. The following projects exceeded the materiality threshold:

- The Brick ($109,991), replacement of a PCB contaminated transformer and conversion to 27.6 kV.
- Walmart Expansion ($84, 521), transformer and service upgrade.
- Hunter St E. #211 ($72,928), service upgrade.

<u>New Underground Secondary Services - $346,651</u>

A customer demand area for approximately 28 new general service underground low voltage services completed in 2012.

None of the new customer services projects in this area exceeded the materiality threshold.

<u>New Underground Residential Secondary Services - $222,120</u>

A customer demand area for new underground residential low voltage services completed in 2012. No projects in this area exceeded the materiality threshold.

<u>Transformers - $260,556</u>

This project area is for the replacement of overhead and underground ($126,516) transformers in 2012 due to failure, car accidents, leaks, or condition, etc.

Some transformers were replaced for upgraded or new customer services.

Meters - $487,068

This project area includes expenditures to install new or replace failed or damaged revenue or seal expired meters and upgrades for 600 V services. Two areas exceeded the materiality threshold:

- Smart Meter Replacement (GS>50kW) ($340,373), Phase I of a project to install smart meters and upgrade the installation (3 element) for larger customer class on meters that are seal expired. Phase I of the project began in 2010 and completed in 2012. Phase II to be completed in 2013.

- General Service Meters ($86,956), new or replacement meters for general service class customers.

Generation Connections – $24,557

This area relates to activity to connect Micro-FIT generators and FIT generators.

2-Energy Probe-11

Ref: Exhibit 2, Tab 3, Schedule 2

a) Please explain why PDI has closed the land purchase associated with the MS #65 substation to rate base in 2013 despite the fact that construction on the substation will not begin until 2014.

b) Are any of the projects listed for 2013 likely to be carried forward for completion in 2014, similar to a number of projects that began in 2012 but are forecasted to be completed in 2013? If not, why not? If yes, please identify and quantify.

PDI Response

a) PDI has forecast to close the land purchase in 2013 because it is considered to be a distinct component that will be complete in 2013 and is not a depreciable asset. The station will be under construction in 2013 but will not be closed to capital and amortized until it is in service, expected in 2014.

b) The projects listed in Exhibit 2, Tab 3, Schedule 2 are those that are expected to be completed in 2013 and closed to rate base. As described in part a) construction will begin on MS #65 in 2013 but it will not be completed until 2014. 2013 expenditures for this project are forecast at $1,271,000 in addition to the land purchase of $130,000.

2-Energy Probe-12

Ref: Exhibit 2, Tab 4, Schedule 1

a) Please update Tables 2-21, 2-24 and 2-25 using the cost of power based on the October 17, 2012 Regulated Price Plan Price Report for November 1, 2012 to October 31, 2013. Please also update these tables to reflect the current transmission rates, rural rate assistance, low voltage and wholesale market service rates.

b) What billing frequency does PDI use for each of its rate classes? Is this unchanged from the 2009 cost of service application? If not, when did the billing frequency change?

PDI Response

a) The tables have been updated as requested:

Table 2-21 – Working Capital Calculation

	2013 Test Year
Operations	1,939,510
Maintenance	1,440,822
Billing & Collecting	2,474,467
Administration & General	3,383,992
Taxes other than Income Taxes	105,000
Total Operating Expenses for Working Capital Allowance	9,343,791
Cost of Power	83,213,094
Total Base for Working Capital Allowance	92,556,885
Working Capital Allowance (13%)	**12,032,395**

Table 2-24 Cost of Power Calculation 2013

2013 Load Foreacst	kWh	kW	2011 %RPP
Residential	294,240,107		91%
General Service < 50 kW	112,158,205		85%
General Service 50 to 4,999 kW	350,715,605	862,025	10%
Large User	53,896,862	113,561	0%
Street Lighting	5,413,675	14,877	0%
Sentinel Lighting	697,744	1,993	24%
Unmetered Scattered Load	1,632,744		9%
TOTAL	**818,754,942**	**992,456**	

Electricity - Commodity RPP	2013	2013 Loss			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2013**	
Residential	267,758,497	1.0550	282,485,215	$0.07932	$22,406,727
General Service < 50 kW	95,334,474	1.0550	100,577,870	$0.07932	$7,977,837
General Service 50 to 4,999 kW	35,071,561	1.0550	37,000,496	$0.07932	$2,934,879
Large User	0	1.0171	0	$0.07932	$0
Street Lighting	0	1.0550	0	$0.07932	$0
Sentinel Lighting	167,459	1.0550	176,669	$0.07932	$14,013
Unmetered Scattered Load	146,947	1.0550	155,029	$0.07932	$12,297
TOTAL	**398,478,938**		**420,395,279**		**$33,345,754**

Electricity - Commodity Non-RPP	2013	2013 Loss			
Class per Load Forecast	**Forecasted**	**Factor**		**2013**	
Residential	26,481,610	1.0550	27,938,098	$0.07877	$2,200,684
General Service < 50 kW	16,823,731	1.0550	17,749,036	$0.07877	$1,398,092
General Service 50 to 4,999 kW	315,644,045	1.0550	333,004,467	$0.07877	$26,230,762
Large User	53,896,862	1.0171	54,818,498	$0.07877	$4,318,053
Street Lighting	5,413,675	1.0550	5,711,427	$0.07877	$449,889
Sentinel Lighting	530,285	1.0550	559,451	$0.07877	$44,068
Unmetered Scattered Load	1,485,797	1.0550	1,567,516	$0.07877	$123,473
TOTAL	**420,276,004**		**441,348,494**		**$34,765,021**

Transmission - Network		Volume			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	310,423,313	$0.0068	$2,110,879
General Service < 50 kW		kWh	118,326,906	$0.0062	$733,627
General Service 50 to 4,999 kW		kW	862,025	$2.5134	$2,166,614
Large User		kW	113,561	$2.9613	$336,288
Street Lighting		kW	14,877	$1.8945	$28,184
Sentinel Lighting		kW	1,993	$1.9086	$3,804
Unmetered Scattered Load		kWh	1,722,545	$0.0062	$10,680
TOTAL					**$5,390,075**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	310,423,313	$0.0046	$1,427,947
General Service < 50 kW		kWh	118,326,906	$0.0042	$496,973
General Service 50 to 4,999 kW		kW	862,025	$1.6362	$1,410,445
Large User		kW	113,561	$2.0045	$227,633
Street Lighting		kW	14,877	$1.2690	$18,879
Sentinel Lighting		kW	1,993	$1.2992	$2,589
Unmetered Scattered Load		kWh	1,722,545	$0.0042	$7,235
TOTAL					**$3,591,701**

Wholesale Market Service					
Class per Load Forecast				**2013**	
Residential			310,423,313	$0.0052	$1,614,201
General Service < 50 kW			118,326,906	$0.0052	$615,300
General Service 50 to 4,999 kW			370,004,963	$0.0052	$1,924,026
Large User			54,818,498	$0.0052	$285,056
Street Lighting			5,711,427	$0.0052	$29,699
Sentinel Lighting			736,120	$0.0052	$3,828
Unmetered Scattered Load			1,722,545	$0.0052	$8,957
TOTAL			**861,743,773**		**$4,481,068**

Rural Rate Assistance					
Class per Load Forecast				**2013**	
Residential			310,423,313	$0.0011	$341,466
General Service < 50 kW			118,326,906	$0.0011	$130,160
General Service 50 to 4,999 kW			370,004,963	$0.0011	$407,005
Large User			54,818,498	$0.0011	$60,300
Street Lighting			5,711,427	$0.0011	$6,283
Sentinel Lighting			736,120	$0.0011	$810
Unmetered Scattered Load			1,722,545	$0.0011	$1,895
TOTAL			**861,743,773**		**$947,918**

Low Voltage					
Class per Load Forecast				**2013**	
Residential			294,240,107	$0.0009	$274,941
General Service < 50 kW			112,158,205	$0.0009	$95,689
General Service 50 to 4,999 kW			862,025	$0.3150	$271,571
Large User			113,561	$0.3860	$43,829
Street Lighting			14,877	$0.2443	$3,635
Sentinel Lighting			1,993	$0.2502	$499
Unmetered Scattered Load			1,632,744	$0.0009	$1,393
TOTAL			**409,023,512**		**$691,557**

Table 2-25 – Summary of Cost of Power Calculation 2013

	2013
4705-Power Purchased	$68,110,774
4708-Charges-WMS	$4,481,068
4714-Charges-NW	$5,390,075
4716-Charges-CN	$3,591,701
4730-Rural Rate Assistance	$947,918
4750-Low Voltage	$691,557
TOTAL	**83,213,094**

b) PDI bills all rate classes monthly. This is unchanged from the 2009 cost of service application.

2-Energy Probe-13

Ref: Exhibit 2, Tab 5, Schedule 1

Please confirm that the $207,000 noted in the schedule has not been included in rate base for revenue requirement purposes.

PDI Response

Capital expenditures of $160,000 have been included in the rate base for revenue requirement purposes. This was understated by $47,000 as the capital expenditure forecast should have used the same estimate as the Green Energy Plan.

2-Energy Probe-14

Ref: Exhibit 2, Appendix C

a) Was the asset management plan prepared by PDI management only, or was there input from any affiliate companies and/or third parties? If there was input provided beyond PDI management, please identify the companies that provided the input.

b) Was the asset management plan reviewed by any independent third party? If not, why not?

PDI Response

a) The Asset Management Plan was primarily completed by PDI Management. There was input from our affiliate PUSI from the Engineering and Operations staff. There was no external third party input.

b) The Asset Management Plan was not reviewed by an independent third party. PDI believes that Management and PUSI staff have significant experience in the industry and are in the best position to have intricate knowledge and understand the Peterborough distribution system the best and did not believe the additional cost of a third party review would be warranted and add significant value to the current plan. In the future as the plan matures and is implemented, PDI may seek a third party opinion on its merit.

2-SEC-9

<u>Ref: Exhibit 2, Tab 1, Schedule 1 p 2-4</u>

Please provide the "analysis of what measures…indices" referred to.

PDI Response

There is an ongoing and annual review of reliability indices by Engineering and Operations staff to determine emerging trends or areas where there may be an increased level of interruptions. Unscheduled patrols may take place and measures such as additional tree trimming, insulator replacement, animal guard replacement and arrester installation may be undertaken.

2-SEC-10

Ref: Exhibit 2, Tab 2, Schedule 1 p 2-5

Please provide any long term system plan currently in use by the Applicant (other than the Asset Management Plan).

PDI Response

The overall system plan is included in Asset Management Plan. Specific projects are created and integrated into the annual capital forecast as required in support of the asset management and overall system plan.

2-SEC-11

Ref: Exhibit 2, Tab 1, Schedule 1 p 2-6

Please provide the "departmental Budget Plans" referred to.

PDI Response

The departmental budget plan for the 2013 test year is provided in Exhibit 4, Tab 2, Schedule 5 Table 4-23.

2-SEC-12

Ref: Exhibit 2, Tab 2, Schedule 4 p 2-28

Please explain why there is no negative amortization for 1995 Contributions and Grants.

PDI Response

The negative amortization for 1995 Contributions and Grants is included in amortization for the corresponding asset accounts on the continuity schedule.

2-SEC-13

Ref: Exhibit 2, Tab 3, Schedule 2 p 2-46

Please explain how pole replacement was handled prior to the new program started in 2008.

PDI Response

Prior to the formal annual program initiated in 2008, ad hoc testing was done in specific areas identified by annual patrols or as result of a capital project in the immediate area that may have been initiated by system expansion, enhancement or a customer request for service. Deteriorated poles were also replaced along with other assets within specific capital projects initiated for other reasons. Additional poles were replaced due to inspections or as result of car accidents.

2-SEC-14

Ref: Exhibit 2, Tab 3, Schedule 2 p 2-46 and following

Please confirm that the cost per pole in 2010 was $16,752, and in 2011 was over $21,000. Please provide a table for each year from 2009 through 2013 showing the total costs for pole replacement, the total number of poles replaced, and the cost per pole. Please reconcile those figures with the cost of $7,436 per pole forecast by Hydro One for 2013 (EB-2012-0136, Ex. B/2/3, p. 9) and the Applicant's own estimate of $5,000 per pole (Ex. 2/App. C, p. 9).

PDI Response

Annual pole replacement program:

Year	# of Poles Replaced	Total Cost	Cost per Pole
2009	0	$0	$0
2010	49	$783,323	$15,986
2011	32	$612,201	$19,131

2012	26	$622,194	$23,931
2013	24 (ytd)	$274,488 (ytd)	$11,437

The cost per pole shown in the table is a full cost accounting of replacing the pole including engineering design (if necessary), switching costs to isolate the pole, additional guying if required and if a transformer and/or switch located on the pole is replaced at the same time. The cost per pole can be affected by the height, number of circuits attached, voltage level and joint use attachments on the specific pole to be replaced.

The figure used as an estimate in the Asset Management Plan is a component cost representing only the material and labour cost associated with the pole only and does not include the other costs as noted above. The other asset costs are accounted in other asset categories in the Asset Management Plan.

2-SEC-15

Ref: Exhibit 2, Appendix C

With respect to the Asset Management Plan:

a) Please advise the circumstances in which this document was prepared. Please confirm whether it is an operating document, or solely for regulatory compliance purposes.

b) Please advise what external advisors, if any, were used in the production of the Plan, and their role in its development.

c) P. 3. Please advise in whose franchise area is the bulk of the growth in the Peterborough metropolitan area. If it is possible to provide a map, that would be optimal.

d) P. 5. Please provide a list of all asset categories that are currently operated on a run to failure basis. If that policy has changed in the last five years, please provide the previous list before the change in policy. Please relate each of these lists to Table 11 on page 23.

e) P. 8. Please advise whether conversion of MS#19 to 44-27.6 kV was considered instead of building the new MS#65. If it was, please explain briefly why that option was not chosen, and the cost implications of that result.

f) P. 9 and 25. Please explain why the Applicant is not using 60 years as the TUL for wood poles. Please provide any reports, memoranda, or other documents dealing with the condition of the wood poles, and the expected useful lives of the poles that have been tested. Please provide details of any other asset categories in which the TUL in the Kinectrics Report is inconsistent with the Applicant's data on its own assets.

PDI Response

a) The document is an operating document primarily for staff. It was utilized for compliance for the rate application and an executive summary for senior management and the PDI Board of Directors.

b) There were no external advisors used in the preparation of the document.

c) The bulk of the growth has been in PDI's franchise territory since the annexation by the City in 2008. Future growth is expected to be in all of the growth areas noted on the map. Within Hydro One Network's territory, the first major subdivision (500 units in the Jackson area) was granted to PDI through a Service Area Amendment in 2011. There are still significant areas remaining in PDI's franchise area that may develop before areas in Hydro One's franchise territory. Referring to the attached Peterborough Growth Map, the following areas are inside PDI's franchise territory: Auburn North, Carnegie, Chemong, Jackson (part of northern half), Coldsprings (north half), Liftlock (except north east quadrant). Areas in Hydro One's franchise territory: Lily Lake, Jackson (part of northern half above Parkhill Rd W.), Coldsprings (south half), Liftlock (north east quadrant). PDI has provided a City of Peterborough Growth Map in Appendix 2-1.

d) The run to failure approach applies to a smaller group of assets such as in-line switches, cutout switch and fuses, arresters and some conductor. Some substation assets are being treated that way as the conversion of 4.16 kV to the 27.6 kV progresses. Typically, individual customer services and some low voltage lines are treated this way unless there is some safety or other operational issue that overrides this approach.

e) The conversion of MS #19 is the second phase of the new 27.6 kV network source plan. The MS #19 location does not address the north end load growth issue underway at the moment, the conversion around MS #19 is not progressed sufficiently to allow for the 4.16 kV station to be converted at this time. Additionally, there are some physical and technical constraints at the station (smaller property and inside station) that have not been solved yet.

   The land for MS #65 has been acquired at a nominal cost in the course of negotiations with the sub-divider and the City of Peterborough. The only additional cost potentially is the civil preparation of the site and the fencing and camouflage issues that may be raised by the neighbours in the area. Equipment costs for the new station would be the same in either case with exception of the aforementioned physical and technical constraints at the MS#19 location that have not been solved.

f) The reference to TUL for wood poles in the Asset Management Plan is preliminary and is not yet supported by enough empirical evidence. Our experience has been that some poles have remained in service for longer than 45 years but there are others that have failed and deteriorated much earlier than 45 years. Our current age is 32 years but PDI believes that is a result of advanced construction of the 27.6 kV network during the past 25 years. As our pole testing program progresses and we monitor results there may be stronger evidence in the future to support the use of 60 years. However, since the Kinectrics Report provides a broader industry wide study, PDI has calculated amortization expense based on the average TUL of 60 years as suggested by the OEB.

2-VECC-3

<u>Reference: Exhibit 2, Tab 3, Schedule 2, Table 2-16</u>

a) Please describe the methodology used for calculating 2013 capital contributions.

b) Please explain the difference between the capital contribution forecast of $1,180,000 and the past three year average of approximately $1.4 million.

c) Please provide the actual 2012 capital contributions.

d) Please provide a table showing the capital projects most associated with capital contributions in the years 2009 through 2013 along with the associated contributions.

PDI Response

a) Capital contributions are based on 25% of estimated municipality relocations, 60% of subdivision assumptions, 100% of new customer services and projects where appropriate.

b) Please refer to the response to part d) which shows capital contributions by project.

c) Actual 2012 capital contributions were $1,671,900.

d) The list of projects most associated with capital contributions is provided below:

Contributions and Grants - 2009 Actual

Project Description	Contribution Amount	Total Project Cost
U/G Subdivisions assumed from developers - Fairview Estates	254,571	254,571
U/G Subdivisions assumed from developers - Heritage Park	208,126	208,126
U/G Subdivisions assumed from developers- Loggerhead Meadows	98,125	98,125
U/G Subdivisions - Developer Capital Contribution Rebates	(253,593)	(253,593)
Relocation - Lansdowne St E., Hwy 7	98,858	341,986
U/G Services - Primary - Costco	97,008	97,008
U/G Services - Primary - other	153,260	166,968
U/G Services - Secondary	32,757	147,884
U/G Services - Residential	208,077	270,942
Miscellaneous	3,166	
	900,355	

Contributions and Grants - 2010 Actual

Project Description	Contribution Amount	Total Project Cost
OH Distribution Lines - Visitor Center, The Parkway	93,375	76,177
Relocation - Borden Ave & High Street	211,350	211,350
Relocation - Lansdowne St & Borden Ave	243,340	243,340
Relocation - Romaine St	34,128	116,467
Generation Connection - Trent Rapids Power Corporation	595,310	595,310
U/G Services - Primary	204,679	218,379
U/G Services - Secondary	56,388	81,148
Miscellaneous	9,975	
	1,448,545	

Contributions and Grants - 2011 Actual

Project Description	Contribution Amount	Total Project Cost
U/G Subdivisions assumed from developers - Heritage Park	240,309	240,309
U/G Subdivisions assumed from developers - Foxmeadow Estates	215,230	215,230
U/G Subdivisions assumed from developers - Loggerhead Meadows	70,926	70,926
U/G Subdivisions - Foxmeadow and Marsdale	85,881	95,255
U/G Subdivisions - Wentworth Street	50,042	58,610
U/G Subdivisions - Summerhill Village	41,987	51,022
U/G Subdivisions - Ireland Drive	17,293	18,462
U/G Subdivisions - Developer Capital Contribution Rebates	(191,842)	(191,842)
Relocation - Lansdowne St W.	295,789	1,210,702
Relocation - Water St N.	39,319	183,199
Relocation - Hillard St	49,647	182,913
U/G Services - Primary	181,050	506,545
U/G Services - Secondary	90,530	200,161
U/G Services - Residential	182,808	267,422
Miscellaneous	41,841	
	1,410,810	

Contributions and Grants - 2012 Actual

Project Description	Contribution Amount	Total Project Cost
Otonabee TS M10-M11 feeder tie	43,391	51,448
U/G Subdivisions assumed from developers - Jackson Creek Meadows	753,776	753,776
U/G Subdivisions - Developer Capital Contribution Rebates	(95,589)	(95,589)
Crawford Drive cell tower	14,685	14,685
Trent University student residence	15,941	15,941
Relocation - Peterborough Regional Health Centre	58,094	178,411
Relocation - Hunter/Burnham	17,306	61,500
Relocation - Edward St, Lakefield	14,972	68,008
Overhead Services	12,830	152,449
Underground Services - Primary - Walmart	89,582	84,522
Underground Services - Primary - other	331,452	635,628
Underground Services - Secondary	145,593	346,651
Underground Services - Residential	185,505	222,120
U/G transformer - 33 Hunter St E.	31,439	14,921
FIT/MicroFIT generation connections	22,306	24,557
Miscellaneous	30,617	
	1,671,900	

Contributions and Grants - 2013 Test Year

Project Description	Contribution Amount	Total Project Cost
U/G Subdivisions assumed from developers	360,000	360,000
Relocation - Chemong Road	27,000	90,000
Relocation - Parkhill Road/Brealey Drive	60,000	361,000
Relocation - other	30,000	100,000
Overhead Services	10,000	10,000
Underground Services - Primary - other	400,000	455,000
Underground Services - Secondary	200,000	220,000
Underground Services - Residential	93,000	221,000
	1,180,000	

2-VECC-4

<u>Reference: Exhibit 2, Tab 2, Schedule 2, pgs. 2-60 to 2-63</u>

Please provide the forecast in-service dates for the 2013 capital projects listed at pages 2-60 to 2-63.

PDI Response

At the time the forecast was prepared all projects were expected to be in service in 2013, except for MS#65 which will not be placed into service until 2014.

As stated in the response to 2-Energy Probe-9 the Cumberland 27.6 kV and the Parkhill Rd W 27.6 kV extension projects will not proceed in 2013. We have two development driven projects that will (may) proceed instead: Aylmer St Reconstruction (not listed but will proceed) and Charlotte Street U/G (not listed and not confirmed yet). Both projects were recent additions due to developer requirements and City requests.

2-VECC-5

Reference: Exhibit 2, Tab 3, Schedule 2, Table 2-17

Please provide update Table 2-17 (Capital Expenditures) to show the actual 2012 spending and, if necessary, any changes to the 2013 capital budget.

PDI Response

The information requested has been provided in the response to 2-Energy Probe-9.

2-VECC-6

Reference: Exhibit 2, Tab 3, Schedule 2

a) What is PDI's policy with respect to underground vs. overhead plant installation? Specifically, what is the expected capital contribution when existing overhead plant is replaced by underground conduit?

b) For each year 2009 through 2013 please provide the total capital expenditure for overhead plant that was replaced by underground plant. Please provide the capital contributions for these same projects.

PDI Response

a) Relocation of existing overhead plant to underground is normally recovered at 100% from the requesting party. In some cases there may be an allowance for depreciation of existing assets or safety clearance improvement to a maximum of 5% of the project cost.

b) There were no overhead lines replaced by underground lines for the years 2009 to 2012. One project in 2013 is in the discussion phase with the City of Peterborough. Estimated cost of this project is $750k.

2-VECC-7

Reference: Exhibit 2, Tab 3 Schedule 2, pg.4, 2-63

Please clarify the meter expenditures of $205k in 2013, in particular indicate what amount, if any, is being spent to replace existing newly installed smart meters in the residential and gs <50 class. Please comment on whether these expenditures are comparable to the maintenance/ failure costs of the previous generation of mechanical meters.

PDI Response

There is $5,000 allocated for replacement of existing smart meters in residential or GS<50 kW rate classes. Only meters that fail or are damaged will be replaced if necessary. Current experience is that smart meter failure rate is approximately less than 0.2%. This is better than previous generation of electromechanical meters where the failure rate was approximately 0.9%. Data on this is preliminary as the majority of smart meters have only been in service for less than four years.

2-VECC-8

Reference: Exhibit 2, Tab 3, Schedule 3, Table 2-18

Between 2007 and 2013 the average capital expenditure was just under $4.8 million. The average forecast expenditure in 2014 through 2016 is approximately 4.0 million. The forecast for 2015 and 2016 is around $3.5 million. Please explain why there is a significant drop in capital expenditures during the incentive rate period.

PDI Response

After the construction of the new substation and completion of two larger municipal road relocations in the next two years, it is expected that customer demand project activity would stabilize given the higher rate of activity experienced in City of Peterborough in recent years.

2-VECC-9

Reference: Exhibit 2, Tab 3, Schedule 4

Please update Table 2-19 to show SAIDI/SAIFI/CAIDI statistics excluding and including loss of supply for 2009 and 2012.

PDI Response

Table 2-19 has been updated as requested:

Year	SAIDI	SAIFI	CAIDI
Including Loss of Supply			
2009	4.60	1.77	2.60
2010	2.22	1.59	1.39
2011	5.16	2.73	1.89
2012	2.49	2.16	1.15
Excluding Loss of Supply			
2009	4.29	1.48	2.9
2010	2.11	1.51	1.40
2011	5.01	2.67	1.88
2012	2.43	2.12	1.15

2-VECC-10

Reference: Exhibit 2, Appendix C, Asset Management Plan

a) Please convert Tables 10 and 11 (Outage Statistics) to show the cause of outages by year for 2009 through 2012.

b) Please clarify whether the Table 9 – Service Reliability shows SAIDI (etc.) statistics with or without loss of supply.

PDI Response

a) Outage statistics have been provided in the tables below.

Table 10

PDI Outage Statistics 2009 - 2012						
Interruption Type	**Frequency**	**% of Total**	**No. of Customers**	**% of Total**	**Customer Outages Hrs**	**% of Total**
0-Unknown/Other	171	8.6%	464,569	22.6%	3,973	0.8%
1-Schedule Outage	831	42.0%	18,107	0.9%	54,564	10.4%
2-Hydro One Outage	56	2.8%	136,282	6.6%	23,467	4.5%
3-Tree Contacts	75	3.8%	99,195	4.8%	66,432	12.7%
4-Lightning	41	2.1%	98,401	4.8%	128,918	24.6%
5-Defective Equipment	341	17.2%	289,521	14.1%	58,111	11.1%
6-Adverse Weather	207	10.5%	419,202	20.4%	129,423	24.7%
7-Adverse Environment	4	0.2%	5,002	0.2%	7	0.0%
8-Human Element	18	0.9%	25,607	1.2%	4,118	0.8%
9-Foreign Interference	235	11.9%	500,532	24.3%	55,461	10.6%
Total	1979	100.0%	2,056,418	100.0%	524,474	100.0%

Table 11

PDI Equipment Outage Statistics 2009 - 2012						
Equipment Type	Frequency	% of Total	No. of Customers	% of Total	Customer Outages Hrs	% of Total
Connectors	19	5.6%	9,844	3.4%	7,731	13.3%
Customer Equipment	33	9.7%	46,908	16.2%	8,726	15.0%
Fuse / Protection	68	19.9%	95,708	33.1%	11,166	19.2%
O/H Conductor	21	6.2%	19,833	6.9%	478	0.8%
O/H Transformer	60	17.6%	44,724	15.4%	4,520	7.8%
Pole	21	6.2%	14,663	5.1%	6,123	10.5%
Switch	26	7.6%	29,152	10.1%	16,010	27.6%
U/G Cable	58	17.0%	11,687	4.0%	2,058	3.5%
U/G Transformer	35	10.3%	17,002	5.9%	1,299	2.2%
Total	341	100.0%	289,521	100.0%	58,111	100.0%

b) Table 9 includes all cause codes.

2-VECC-11

Reference: Exhibit 2, Appendix C

Was the Asset Management Plan completed by PDI (or affiliate) staff? If yes was any external review of the plan completed. If yes, please provide that review.

PDI Response

The Asset Management Plan was completed by PDI and affiliate staff. There was no external review.

2-VECC-12

Reference: Exhibit 2, Appendix D

a) Please provide OM&A and capital budget, if any, for 2012 through 2016 for the GEA Plan.

PDI Response

Please refer to the response provided in 2-Staff-7.

PETERBOROUGH DISTRIBUTION INC.

2013 COST OF SERVICE RATE APPLICATION

RESPONSE TO INTERROGATORIES

EXHIBIT 3 – OPERATING REVENUE

EB-2012-0160

FILED: MAY 27, 2013

3-Preliminary-4

Ref: Exhibit 3, Tab 1, Schedule 3, Table 3-27

Update Table 3-27 to include 2012 Actual kWh Purchases and 2012 and 2013 CDM adjustments in Predicted Purchases.

PDI Response

The revised table is provided on the following page:

Table 3-27: Summary of Forecast – Includes 2012 Actual kWh Purchases and 2012 and 2013 CDM Adjustments in Predicted Purchases

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Weather Normalized Bridge	2013 Weather Normalized Test
ACTUAL AND PREDICTED KWH PURCHASES						
Actual kWh Purchases		834,049,383	838,046,263	848,819,242	834,306,527	
Predicted kWh Purchases		838,345,001	842,918,314	852,551,620	859,746,440	866,587,550
% Difference of actual and predicted purchases		0.5%	0.6%	0.4%		
CDM Adjustment (kWj)					7,780,901	15,561,802
Predicted kWh Purchases after CDM Adjustment (kWh)					851,965,539	851,025,748
BILLING DETERMINANTS BY CLASS						
Residential						
Customers	30,883	30,524	30,791	31,135	31,445	31,758
kWh	301,495,708	284,464,847	287,709,082	293,541,684	294,333,518	294,240,107
General Service < 50 kW						
Customers	3,638	3,619	3,600	3,570	3,558	3,547
kWh	121,412,816	117,206,107	117,506,264	114,708,317	113,597,004	112,158,205
General Service > 50 kW						
Customers	368	363	372	389	389	390
kWh	297,624,170	327,169,221	331,296,296	345,543,415	348,573,781	350,715,605
kW	731,891	819,801	825,019	848,381	856,760	862,025
Large User	2	2	2	2	2	2
Customers	63,699,061	58,518,018	55,529,141	56,661,879	55,262,516	53,896,862
kWh	128,427	126,985	121,689	121,779	116,439	113,561
kW						
Sentinel Lighting						
Connections	401	425	423	416	387	361
kWh	659,151	796,438	788,608	768,502	732,275	697,744
kW	1,795	1,916	2,174	2,129	2,092	1,993
Street Lighting						
Connections	8,540	8,002	8,064	8,131	8,140	8,150
kWh	6,261,525	5,539,999	5,582,044	5,614,216	5,513,077	5,413,675
kW	17,527	16,284	16,388	16,448	15,150	14,877
Unmetered Scattered Loads						
Connections	9	383	383	384	384	384
kWh	1,909,385	1,601,817	1,565,650	1,661,205	1,646,926	1,632,744
Customer/Connections	43,841	43,319	43,634	44,026	44,306	44,592
kWh	793,061,816	795,296,447	799,977,085	818,499,218	819,659,096	818,754,942
kW from applicable classes	879,640	964,986	965,270	988,737	990,441	992,456

3-Staff-9

Ref: Exhibit 3, Tab 1, Schedule 2
Ref: Exhibit 3/Tab 1/Schedule 3

Please clarify and provide further explanation of the drivers for the decline in forecasted USL revenues.

PDI Response

The decline in forecasted USL revenues is due to an error in the 2009 cost allocation model which overstated the number of connections. The number of USL connections used in the 2009 cost allocation model was 4,190. This was incorrect because it was based on the light bulb count for traffic lights, rather than the number of connections to the distribution system. PDI confirms that this error has been corrected in the 2013 cost allocation model. The number of USL connections in the 2013 cost allocation model is 384. A more detailed description is provided in response to 3-VECC-13.

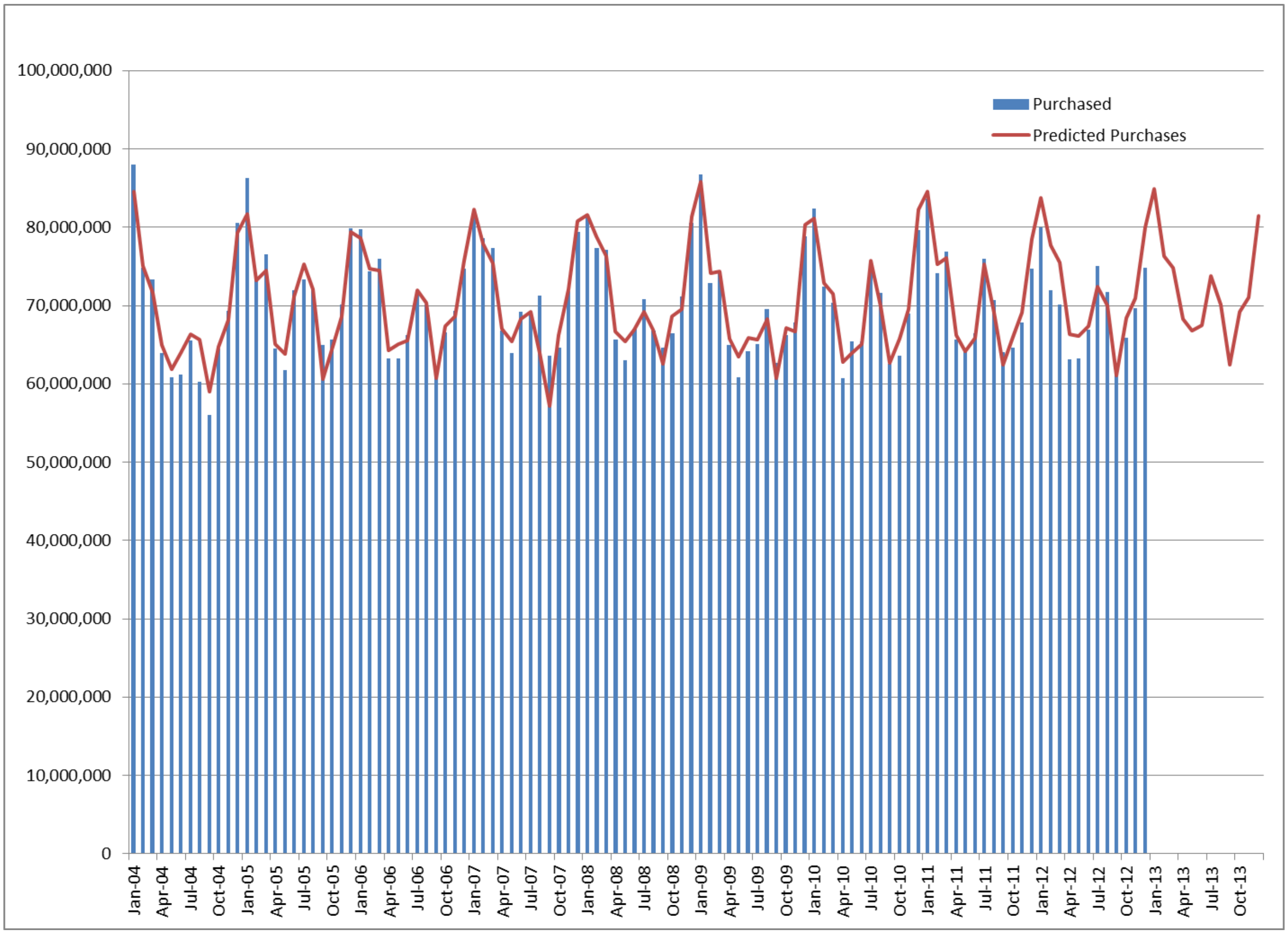
3-Staff-10

Ref: Exhibit 3, Tab 1, Schedule 3, Chart 3-1

Please provide Table 3-1 on the basis of the monthly actuals and forecasted amounts per the following (example) format. Please include forecasted values for 2012 and 2013 and actual values for 2012. If PDI has updated its load forecast, the provided chart should reflect the update.

PDI Response

Chart 3-1 has been provided in the requested format on the basis of the monthly actuals and forecasted amounts including forecasted values for 2012 and 2013 and actual values for 2012.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3-Staff-11

Ref: Exhibit 3, Tab 1, Schedule 3, Table 3-15

Please explain the decrease in the average consumption per streetlighting connection from over 750 kWh per annum prior to 2008 to about 690 kWh per annum for 2008 and later.

PDI Response

PDI attributes the decline in consumption to a newer photo cell used to measure the hours of darkness and estimate consumption more accurately.

3-Staff-12

Ref: Exhibit 3, Tab 1, Schedule 3, Table 3-21

a) Please verify the inputs and results of the model.

b) Please input the "net" and "gross" CDM savings from 2006 to 2011 as reported in the OPA-issued 2006-2010 and 2011 CDM reports for PDI into cells E26 and D26 respectively of the model provided.

c) Please derive the class CDM kWh and kW savings that would correspond with the "net" CDM savings above.

d) Please provide PDI's comments on the methodology above to develop the CDM savings that will underlie the 2013 CDM amount for the LRAMVA and the corresponding CDM adjustment for the 2013 test year load forecast. What refinements to this approach should be considered? In particular, should the 2011 amount be also adjusted by 50% for the load forecast CDM adjustment to reflect the fact that 2011 CDM impacts are also reflected in the 2011 data as a "first year" basis, and hence influence the regression results that underlie the base forecast before the CDM adjustment?

PDI Response

a) PDI has verified the inputs and results of the model.
b) The "gross" and "net" cumulative kWh CDM savings from all CDM programs from 2006 to 2011 on 2013 as measured in the final OPA reports have been entered, respectively, into cells D26 and E26 and provided in the live spreadsheet titled "BdStaff_IR_3-Staff-12_xlsx_20130503_Completed"
c) The class CDM kWh and kW savings that would correspond with the "net" CDM savings of 11,967,098 kWh is provided in Exhibit 3, Tab 1, Schedule 3, Table 3-22 of the Application.
d) PDI agrees with the methodology used to determine the CDM savings that will underlie the 2013 CDM amount for the LRAMVA. With regards to the manual CDM adjustment for the 2013 test year load forecast, PDI agrees it should be a value that represents the gross level. However, the 2011 value should not be included in the manual CDM adjustment. The results of the 2011 programs and how they persist into 2013 have impacted the actual 2011 power purchases used in the regression analysis. In PDI's view to include the 2011 value in the manual CDM adjustment would be a double count. With regards to the 2013 value used in the manual CDM adjustment, PDI is concerned with using the "half year rule" since it is PDI's understanding that there should be consistent treatment on how the load forecast is adjusted and how the LRAMVA threshold is determined. Since a full year amount is used in the LRAMVA threshold calculation for 2013 then a full year for 2013 should be used in the manual CDM adjustment. To do otherwise could cause confusion when the LRAMVA is trued-up by those who may not have been part of this proceeding and notice an inconsistency in the LRAMVA amount compared to the amount the load forecast was adjusted for CDM.

3-Staff-13

Ref: March 26, 2013 Additional Information
Ref: Exhibit 9, Appendix P

a) Please provide the full final 2011 CDM result report for PDI issued by the OPA in Excel format.

b) Please provide the final 2006-2011 CDM results report for PDI issued by the OPA in Excel format.

PDI Response

PDI has provided the CDM results requested in a) and b) as requested.

3-Energy Probe-15

Ref: Exhibit 3, Tab 1, Schedule 3

a) Please update Table 3-8 to reflect actual data for 2012.

c) Please update Table 3-15 to reflect actual data for 2012.

d) Please update Table 3-24 to reflect actual data for 2012.

e) Table 3-25 appears to be missing from the original evidence. Please provide Table 3-25.

PDI Response

a) The updated Table 3-8 to reflect actual data for 2012 is provided below:

Table 3-8: Billed Energy and Number of Customers/Connections by Rate Class – updated for 2012 actual data

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large User	Street Lighting	Sentinel Lighting	Unmetered Scattered Loads	Total
Billed Energy (GWh)								
2009 Board Approved	301.5	121.4	297.6	63.7	6.3	0.7	1.9	793.1
2004 Actual	285.7	121.8	320.0	63.3	6.0	1.0	0.0	797.9
2005 Actual	296.4	126.3	330.7	66.5	6.0	1.0	0.0	827.0
2006 Actual	290.2	124.4	327.0	65.1	6.3	1.1	1.2	815.3
2007 Actual	285.4	124.7	333.1	63.5	6.6	1.3	2.2	816.7
2008 Actual	288.2	121.6	339.0	63.3	5.6	0.6	1.4	819.7
2009 Actual	284.5	117.2	327.2	58.5	5.5	0.8	1.6	795.3
2010 Actual	287.7	117.5	331.3	55.5	5.6	0.8	1.6	800.0
2011 Actual	293.5	114.7	345.5	56.7	5.6	0.8	1.7	818.5
2012 Actual	**285.7**	**111.9**	**334.7**	**54.1**	**5.7**	**0.8**	**1.7**	**794.4**
2013 Test	**294.2**	**112.2**	**350.7**	**53.9**	**5.4**	**0.7**	**1.6**	**818.8**
Number of Customers/Connections								
2009 Board Approved	30,883	3,638	368	2	8,540	401	9	43,841
2004 Actual	29,047	3,650	384	2	8,065	681	0	41,830
2005 Actual	29,322	3,642	385	2	8,182	675	0	42,208
2006 Actual	29,576	3,612	377	2	8,255	685	383	42,890
2007 Actual	29,947	3,618	375	2	8,284	565	383	43,174
2008 Actual	30,249	3,633	369	2	8,148	451	383	43,235
2009 Actual	30,524	3,619	363	2	8,002	425	383	43,319
2010 Actual	30,791	3,600	372	2	8,064	423	383	43,634
2011 Actual	31,135	3,570	389	2	8,131	416	384	44,026
2012 Actual	**31,345**	**3,564**	**393**	**2**	**8,180**	**406**	**390**	**44,279**
2013 Test	**31,758**	**3,547**	**390**	**2**	**8,150**	**361**	**384**	**44,592**

b) Question b) is missing in the sequence. No response required.

c) The updated Table 3-15 to reflect actual data for 2012 is provided below:

Table 3-15: Historical Annual Usage by Customer – updated for 2012 actual data

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large User	Street Lighting	Sentinel Lighting	Unmetered Scattered Loads
Annual kWh Usage Per Customer/Connection							
2004	9,837	33,370	833,067	31,655,809	742	1,485	0
2005	10,110	34,680	860,191	33,260,358	732	1,433	0
2006	9,811	34,430	866,489	32,550,079	761	1,595	3,185
2007	9,530	34,460	887,786	31,725,050	795	2,316	5,775
2008	9,527	33,465	917,661	31,640,233	692	1,405	3,724
2009	9,319	32,386	901,293	29,259,009	692	1,873	4,182
2010	9,344	32,644	890,581	27,764,571	692	1,867	4,087
2011	9,428	32,135	888,858	28,330,940	690	1,850	4,326
2012	9,113	31,391	852,588	27,051,274	693	1,855	4,309

d) The updated Table 3-24 to reflect actual data for 2012 is provided below:

Table 3-24: Historical Annual kW per Applicable Rate Class – updated for 2012 actual data

Year	General Service > 50 kW	Large User	Street Lighting	Sentinel Lighting	Total
Billed Annual kW					
2004	786,950	133,227	16,548	2,630	939,355
2005	764,330	136,079	16,365	2,721	919,495
2006	805,126	133,042	16,568	4,030	958,766
2007	830,729	128,681	13,932	2,574	975,916
2008	842,747	134,390	16,513	2,437	996,087
2009	819,801	126,985	16,284	1,916	964,986
2010	825,019	121,689	16,388	2,174	965,270
2011	848,381	121,779	16,448	2,129	988,737
2012	826,732	122,199	16,590	2,122	967,643

e) Table 3-25 was omitted in error on page 3-25. Table 3-25 - Historical kW/kWh Ratio per Applicable Rate Class appears below.

Table 3-25 – Historical kW/kWh Ratio per Applicable Rate Class

Year	General Service > 50 kW	Large User	Street Lighting	Sentinel Lighting
Ratio of kW to kWh				
2004	0.2459%	0.2104%	0.2767%	0.2602%
2005	0.2311%	0.2046%	0.2734%	0.2814%
2006	0.2462%	0.2044%	0.2637%	0.3687%
2007	0.2494%	0.2028%	0.2114%	0.1967%
2008	0.2486%	0.2124%	0.2927%	0.3848%
2009	0.2506%	0.2170%	0.2939%	0.2406%
2010	0.2490%	0.2191%	0.2936%	0.2757%
2011	0.2455%	0.2149%	0.2930%	0.2770%
Average 2004 to 2011	**0.2458%**	**0.2107%**	**0.2748%**	**0.2856%**

3-Energy Probe-16

Ref: Exhibit 3, Tab 1, Schedule 3

a) Please calculate the distribution revenues at current (2012) rates assuming that the CDM adjustment is based on net basis, with the adjustment in 2013 equal to 50% of the 2011 CDM figure of 2,577,438 kWh, 100% of the 2012 CDM target of 4,694,830 kWh and 50% of the 2013 CDM target of 4,694,830 kWh shown in Table 3-21 for a total CDM adjustment in 2013 of 8,330,964 kWh.

b) Please provide versions of Tables 3-22, 3-23 3-26 and 3-27 that are consistent with the CDM adjustment for 2013 consistent with that proposed in part (a) above.

PDI Response

a) The distribution revenue at current (2012) rates assuming that the CDM adjustment is 8,330,964 kWh in 2013 is $14,481,474.

b) Revised versions of Tables 3-23 3-26 and 3-27 that are consistent with the CDM adjustment for 2013 consistent with that proposed in part (a) above are provided below. Table 3-22 is not impacted by this change.

Table 3-23: Alignment of Non-normal to Weather Normal Forecast – revised 2013 CDM Adjustment

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large User	Street Lighting	Sentinel Lighting	Unmetered Scattered Loads	Total
Non-normalized Weather Billed Energy Forecast (GWh)								
2012 Non-Normalized Bridge	294.7	113.7	349.3	55.8	5.6	0.7	1.7	821.5
2013 Non-Normalized Test	295.8	112.8	353.2	54.9	5.5	0.7	1.7	824.5
Weather Adjustment (GWh)								
2012	2.3	0.9	2.4	0.0	0.0	0.0	0.0	5.7
2013	3.8	1.5	3.9	0.0	0.0	0.0	0.0	9.2
CDM Adjustment (GWh)								
2012	(2.7)	(1.0)	(3.2)	(0.5)	(0.1)	(0.0)	(0.0)	(7.5)
2013	(3.0)	(1.1)	(3.6)	(0.6)	(0.1)	(0.0)	(0.0)	(8.3)
Weather Normalized Billed Energy Forecast (GWh)								
2012 Normalized Bridge	294.3	113.6	348.6	55.3	5.5	0.7	1.6	819.7
2013 Normalized Test	296.6	113.1	353.5	54.3	5.5	0.7	1.6	825.4

Table 3-26: kW Forecast by Applicable Rate Class – revised 2013 CDM adjustment

Year	General Service > 50 kW	Large User	Street Lighting	Sentinel Lighting	Total
Predicted Billed kW					
2012 Normalized Bridge	856,760	116,439	15,150	2,092	990,441
2013 Normalized Test	869,016	114,493	14,999	2,009	1,000,518

Table 3-27: Summary of Forecast – revised CDM adjustment

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Weather Normalized Bridge	2013 Weather Normalized Test
ACTUAL AND PREDICTED KWH PURCHASES						
Actual kWh Purchases		834,049,383	838,046,263	848,819,242		
Predicted kWh Purchases		838,345,001	842,918,314	852,551,620	859,746,440	866,587,550
% Difference of actual and predicted purchases		0.5%	0.6%	0.4%		
BILLING DETERMINANTS BY CLASS						
Residential						
Customers	30,883	30,524	30,791	31,135	31,445	31,758
kWh	301,495,708	284,464,847	287,709,082	293,541,684	294,333,518	296,622,495
General Service < 50 kW						
Customers	3,638	3,619	3,600	3,570	3,558	3,547
kWh	121,412,816	117,206,107	117,506,264	114,708,317	113,597,004	113,066,322
General Service > 50 kW						
Customers	368	363	372	389	389	390
kWh	297,624,170	327,169,221	331,296,296	345,543,415	348,573,781	353,560,208
kW	731,891	819,801	825,019	848,381	856,760	869,016
Large User	2	2	2	2	2	2
Customers	63,699,061	58,518,018	55,529,141	56,661,879	55,262,516	54,338,967
kWh	128,427	126,985	121,689	121,779	116,439	114,493
kW						
Sentinel Lighting						
Connections	401	425	423	416	387	361
kWh	659,151	796,438	788,608	768,502	732,275	703,468
kW	1,795	1,916	2,174	2,129	2,092	2,009
Street Lighting						
Connections	8,540	8,002	8,064	8,131	8,140	8,150
kWh	6,261,525	5,539,999	5,582,044	5,614,216	5,513,077	5,458,082
kW	17,527	16,284	16,388	16,448	15,150	14,999
Unmetered Scattered Loads						
Connections	9	383	383	384	384	384
kWh	1,909,385	1,601,817	1,565,650	1,661,205	1,646,926	1,646,137
Customer/Connections	43,841	43,319	43,634	44,026	44,306	44,592
kWh	793,061,816	795,296,447	799,977,085	818,499,218	819,659,096	825,395,678
kW from applicable classes	879,640	964,986	965,270	988,737	990,441	1,000,518

3-Energy Probe-17

Ref: Exhibit 3, Tab 1, Schedule 4

a) Please update Table 3-28 to reflect actual data for 2012.

b) Please confirm that Table 3-28 does NOT include interest associated with deferral and variance accounts or any regulatory asset/liability accounts. If this is not confirmed, please update the response to part (a) to exclude this interest.

c) Please confirm that Table 3-28 does NOT include any revenues or expenses associated with OPA funded CDM programs. If this cannot be confirmed, please update the response to part (a) to exclude such revenues and expenses.

d) What is the actual revenue recorded in account 4220 in 2012?

e) Please explain the decrease in late payment charges in 2012 and 2013 relative to 2011 despite a significant increase in bad debt costs forecast for both 2012 and 2013 relative to 2013.

f) Please explain the drop in retail services revenues in 2012 and 2013 relative to 2011. How has the movement of customers away from retailers and to the regulated price plan been reflected in the SSS Administration revenue forecast for these years?

g) How has the growth in the number of customers in the bridge and test years been reflected in the SSS Administration revenue forecast for the test year?

h) The increase in interest and dividend income in 2010 is said to be related to the higher levels of regulatory assets due to the smart meter initiative. Appendix 2-F shows that the majority of the interest is bank deposit interest. Please reconcile.

i) Where are revenues from microfit customers recorded? Please show the actual microfit revenues for each of 2009 through 2012 on an actual basis and the forecast for 2013.

PDI Response

a) Table 3-28 has been updated:

Table 3-28 Other Operating Revenue

USoA #	USoA Description	2009 Actual	2010 Actual	2011 Actual[2]	2012 Actual	2013 Test Year
4235	Specific Service Charges	731,535	712,961	620,946	699,723	650,000
4225	Late Payment Charges	203,845	203,072	207,858	197,951	200,000
4082	Retail Services Revenues	34,566	34,326	27,299	21,030	22,000
4084	STR Revenue	19,532	20,769	15,678	10,605	11,000
4086	SSS Administration Revenue	89,560	91,279	95,183	99,140	95,000
4210	Rent from Electric Property	216,325	204,294	210,681	211,206	210,000
4405	Interest & Dividend Income	10,836	82,940	75,551	80,172	75,000
Specific Service Charges		731,535	712,961	620,946	699,723	650,000
Late Payment Charges		203,845	203,072	207,858	197,951	200,000
Other Operating Revenues		359,983	350,668	348,841	341,981	338,000
Other Income or Deductions		10,836	82,940	75,551	80,172	75,000
Total		$ 1,306,199	$ 1,349,641	$ 1,253,196	$ 1,319,827	$ 1,263,000

b) Table 3-28 does NOT include interest associated with deferral and variance accounts or any regulatory asset/liability accounts.

c) Table 3-28 does NOT include any revenues or expenses associated with OPA funded CDM programs.

d) The actual revenue recorded in account 4220 in 2012 was $0.

e) Actual late payment charges billed in 2012 were $197,951. The 2013 forecast of $200,000 is a reasonable estimate compared to 2012 actual results.

f) The movement of customers away from retailers has not been reflected in the SSS Administration revenue forecast. Based on 2012 actual results, the 2013 SSS Administration revenue may be understated by approximately $4,000.

g) The growth in the number of customers in the bridge and test years was not reflected in the SSS Administration revenue forecast for the test year. PDI estimates that the additional revenue in 2013 would be approximately $1,800.

h) The increase in interest and dividend income in 2010 was primarily bank interest. PDI obtained $10 million of debt financing in December 2009 resulting in increased cash balances and interest income in 2010.

i) Revenues from Microfit customers are recorded in account 4235 Miscellaneous Service Revenues. Actual revenues recorded and forecast are as follows:

2009	$0
2010	$179
2011	$1,207
2012	$2,645
2013	$0

PDI did not include any Microfit revenue in its test year revenue. There are currently 53 Microfit generators in PDI service territory which would result in annual revenue of $3,434 at the proposed rate of $5.40 per month.

3-SEC-16

Reference: Exhibit 3, Tab 1, Schedule 1 Tables 3-1 and 3-2

Please reconcile the Board-approved revenues for 2009 in each of these two tables.

PDI Response

The 2009 Board-approved revenues were incorrect in both of these tables. Revised tables are provided below:

Table 3-1 Summary of Operating Revenue

USoA #	Description	Board Approved	Actual	Actual	Actual	Bridge Year	Test Year - Current Rates	Test Year - Proposed Rates
		2009	2009	2010	2011	2012	2013	2013
Distribution Throughput Revenue								
4080	Residential	8,174,965	7,694,772	7,715,800	7,664,766	7,843,713	7,952,109	8,811,682
4080	General Service < 50 kW	2,371,648	2,138,280	2,308,025	2,242,628	2,274,315	2,282,022	2,377,699
4080	General Service > 50 kW	2,801,369	2,696,428	2,922,838	2,948,693	3,026,916	3,107,588	2,982,566
4080	Large User	176,391	132,682	210,817	234,809	239,998	235,212	245,073
4080	Street Lighting	344,931	205,099	435,750	516,612	523,687	505,234	523,393
4080	Sentinel Lighting	35,240	25,449	49,841	54,823	53,405	51,688	32,338
4080	Unmetered Scattered Loads	174,416	74,857	219,285	290,404	294,760	290,236	56,086
Total Distribution Throughput Revenue		**14,078,960**	**12,967,566**	**13,862,355**	**13,952,736**	**14,256,794**	**14,424,089**	**15,028,837**
% of Total Revenue		**90%**	**91%**	**91%**	**92%**	**92%**	**92%**	**92%**
Other Revenue								
4082	Retail Services Revenues	30,000	34,566	34,326	27,299	22,000	22,000	22,000
4084	STR Revenue	20,000	19,532	20,769	15,678	11,000	11,000	11,000
4086	SSS Administration Revenue	88,000	89,560	91,279	95,183	95,000	95,000	95,000
4210	Rent from Electric Property	211,851	216,325	204,294	210,681	210,000	210,000	210,000
4225	Late Payment Charges	190,000	203,845	203,072	207,858	200,000	200,000	200,000
4235	Specific Service Charges	630,000	731,535	712,961	620,946	644,000	650,000	650,000
4405	Interest & Dividend Income	449,000	10,836	82,940	75,551	82,000	75,000	75,000
Total Other Revenue		**1,618,851**	**1,306,199**	**1,349,641**	**1,253,196**	**1,264,000**	**1,263,000**	**1,263,000**
% of Total Revenue		**10%**	**9%**	**9%**	**8%**	**8%**	**8%**	**8%**
TOTAL REVENUE		**15,697,811**	**14,273,765**	**15,211,996**	**15,205,932**	**15,520,794**	**15,687,089**	**16,291,837**

Table 3-2 2009 Board Approved vs 2009 Actual Revenue by Class

USoA #	USoA Description	Board Approved	Actual	Difference	Difference
		2009	2009	$	%
Throughput Revenue					
4080	Residential	8,174,965	7,694,772	(480,193)	-6%
4080	General Service < 50 kW	2,371,648	2,138,280	(233,368)	-10%
4080	General Service > 50 kW	2,801,369	2,696,428	(104,941)	-4%
4080	Large User	176,391	132,682	(43,709)	-25%
4080	Street Lighting	344,931	205,099	(139,832)	-41%
4080	Sentinel Lighting	35,240	25,449	(9,791)	-28%
4080	Unmetered Scattered Loads	174,416	74,857	(99,559)	-57%
Total Distribution Throughput Revenue		**$ 14,078,960**	**$ 12,967,566**	**-$ 1,111,394**	**-8%**

The variance explanation provided on page 3-3 of the application still applies.

3-VECC–13

<u>Reference: Exhibit 3, Tab 1, Schedule 2, page 3-7 and Table 3-8</u>

a) The statement on page 3-7 claims that USL connections have declined from the 2009 Board Approved to the 2013 forecast. However, Table 3-8 shows a material increase. Please reconcile this inconsistency.

b) Please confirm that the forecast revenue for 2012 (per Table 3-6) is based on the forecast 2012 customer/connection count for each class. If this is the case, please explain the role the number of connections used in the 2009 cost allocation model has in determining the 2012 revenues for Sentinel Lights and USL – as discussed on page 3-7.

PDI Response

a) Table 3-8 shows USL number of customers/connections as 9 for the 2009 Board Approved and 384 for the 2013 forecast. The number shown for 2009 Board Approved is the number of customers (9) whereas the number shown for the 2013 forecast is the number of connections (384).

The number of USL connections used in the 2009 cost allocation model was 4,190. The number of USL connections in the 2013 cost allocation model is 384. As discussed in response to IR#3-Staff-9 and below, PDI has determined that there was an error in the number of USL connections used in the 2009 cost allocation model. The proposed 2013 cost allocation corrects the 2009 error.

The statement on page 3-7 refers to the decline in the number of USL connections from 4,190 in the 2009 cost allocation model to 384 in the updated 2013 cost allocation model.

b) The forecast revenue for 2012 (per Table 3-6) is based on the forecast 2012 customer/connection count for each class. The rates for each class are based on the 2009 cost allocation model which assumed a higher connection count.

<u>Unmetered Scattered Load</u>

The revenue requirement allocated to the USL class in the 2009 Cost of Service Application was based on 4,190 connections. This count was incorrect because it treated each traffic light bulb as a separate connection. The resulting revenue was divided by the revised connection count of 404 to determine the monthly service charge. The revenue requirement that was based on 4,190 connections is being billed based 404 connections. The 2012 forecast revenue was calculated on this basis.

The 2013 cost allocation model uses a USL connection count of 384 instead of 4,190 and results in less revenue being allocated to the USL class.

<u>Sentinel Lighting</u>

The number of sentinel light connections used in the 2009 cost allocation model was 689. This assumed that each light was a connection to the distribution system. The revenue requirement allocated to the sentinel lighting class in the 2009 Cost of Service Application was based on 689 connections.

PDI has continued to use this definition of sentinel lighting connection for billing purposes – one light equals one connection. The 2012 revenue forecast was calculated on this basis.

The 2013 cost allocation model recognizes that a connection to the distribution system may have more than one light. PDI proposes to revise the method it uses to bill the monthly service charge: each connection to the distribution system will be considered a "connection" for billing purposes, rather than each individual light. On this basis, the sentinel lighting connection count used in the updated 2013 cost allocation model is 148, compared to 689 in the 2009 model. The decline in revenue for the sentinel lighting class from 2012 to 2013 is due to fewer connections in the 2013 cost allocation model (the basis of the 2013 rates) compared to the 2009 cost allocation model (the basis of the 2012 rates).

3-VECC–14

<u>Reference: Exhibit 3, Tab 1, Schedule 3, page 3-14</u>

a) The 2009-2013 GDP data used to estimate the model was taken from the 2011 Fall Update of the Ontario Economic Outlook and Review. Does this mean that the values used for 2011 monthly GDP were not the actual GDP values for 2011?

b) If there are more recent versions of the Ontario Economic Outlook and Review available please undertake the following:

- Re-estimate the model using the actual 2011 GDP (if not used in the Application).
- Update the forecast for the more current GDP forecast for 2013.

PDI Response

a) According to the 2013 Ontario Budget the actual 2011 GDP value is 1.8% which is equal to the 2011 forecasted value from the 2011 Fall Update of the Ontario Economic Outlook and Review.

b) The 2013 Ontario Budget also included the actual 2012 GDP value of 1.6% and 2013 forecasted value of 1.5%. When these values are included in the forecast formula for 2013 the resulted billed forecast is 816,056,242 kWh for 2013.

3-VECC–15

Reference: Exhibit 3, Tab 1, Schedule 3, pages 3-21 to 3-22

Please provide a copy of the OPA's final CDM Report for 2011 – for PDI.

PDI Response

PDI has provided this report in PDF form as part of the Additional Information request, and also in Excel format.

3-VECC–16

Reference: Exhibit 3, Tab 1, Schedule 3, pages 3-22 to 3-23

a) Please confirm that the difference between the gross and net CDM savings represents those savings that would have occurred even if there were no CDM programs. If not, please explain why not.

b) Please confirm that, for any given year, the difference between gross and net OPA reported savings does not reflect all of the CDM activity that will take place without any incentive being provided. If not confirmed, please explain why.

c) Does PDI agree that the historical consumption values for each customer class will have been impacted by the total CDM activity that has occurred each year without any incentive being provided (and not just that associated with OPA CDM programs)?

d) Please explain why the difference between the gross and net CDM impacts is not already reflected in the forecast values for 2012 and 2013.

PDI Response

a) There are numerous factors that collectively define the difference between the gross and net CDM results. One should refer to the Ontario Power Authority for the factors that they use within each program. In general terms, it is PDI's understanding that the net-to-gross ratio is derived from factors such as free ridership and free drivers (spill over) but these factors are associated with the programs.

b) It is PDI understands that for any given year, the difference between gross and net OPA reported savings does not reflect all of the CDM activity that will take place in PDI's service area.

c) PDI agrees that the historical consumption values for each customer class will have been impacted by the total CDM activity that has occurred each year.

d) The difference between the gross and net CDM impacts is not reflected in the forecast values for 2012 and 2013 since the regression analysis used to support the forecast is based on actual data up to and including 2011. This means any CDM activity up to the end of 2011 has been included in the regression analysis and is reflected in the prediction formula for 2012 and 2013.

However, any 2012 or 2013 CDM activity whether at the gross or net associated with the 2012 and 2013 CDM programs level has not been reflected since such activity is not included in the actual data supporting the regression analysis. It is PDI's view that the gross savings are associated with the net results of the CDM programs. In other words, if the CDM programs have not occurred the net or the gross results would also not occur.

3-VECC–17

Reference: Exhibit 3, Tab 1, Schedule 4, page 3-29 (Table 3-28) and Energy Probe #17 a)

For any accounts where the 2012 actual is 5% or more greater than the 2012 forecast in the original Application, please explain why this higher Revenue amount should not be assumed to continue in 2013.

PDI Response

The only account in Table 3-28 where the 2012 actual amount exceeds the 2012 forecast amount by more than 5% is account 4235 Specific Service Charges where the forecast amount was $644,000 and the actual amount was $699,723. The 2013 test year was forecast at $650,000. It would be reasonable to expect that 2013 should be similar to 2012.

PETERBOROUGH DISTRIBUTION INC.

2013 COST OF SERVICE RATE APPLICATION

RESPONSE TO INTERROGATORIES

EXHIBIT 4 – OPERATING COSTS

EB-2012-0160

FILED: MAY 27, 2013

4-Preliminary-5

<u>Ref: Exhibit 4, Appendix G</u>

Provide Appendix 1 to the third party cost allocation review letter provided in the evidence at Exhibit 4, Appendix G.

PDI Response

Appendix 1 of the cost allocation review has been provided in Appendix 4-1.

4-Staff-14

<u>Ref: Exhibit 4, Tab 2, Schedule 2, Table 4-12</u>

Board staff notes that PDI has not recorded Meter Reading Expense for 2009 to 2013 in Account 5310.

a) Please explain where this expense has been recorded.

b) Please provide actual Meter Reading Expense for 2009 to 2012, and the amount budgeted for 2013.

c) Please verify the impact of this accounting treatment on the Cost Allocation model and make any adjustments required.

PDI Response

a) Meter reading expense was recorded in Account 5315 Billing.

b) The amounts are as follows:

- 2009 actual $320,787
- 2010 actual $300,706
- 2011 actual $187,194
- 2012 actual $184,764
- 2013 test year $191,000

c) The following outlines how the change in accounting treatment for Meter Reading Expense has impacted the results of the Cost Allocation Model.

Rate Class	Cost Allocated in the 2013 Study - Application	Cost Allocated in the 2013 Study - Application with Meter Reading Separated	Change
Residential	$10,471,540	$10,468,853	($2,687)
General Service < 50 kW	$2,395,636	$2,399,221	$3,586
General Service > 50 kW	$2,614,948	$2,615,144	$197
Large User	$261,368	$261,372	$4
Street Lighting	$469,886	$469,865	($21)
Sentinel Lighting	$29,022	$27,999	($1,023)
Unmetered Scattered Load	$49,437	$49,382	($55)
Total	$16,291,837	$16,291,837	$0
Rate Class	**Revenue to Cost Ratio in the 2013 Study - Application**	**Revenue to Cost in the 2013 Study - Application with Meter Reading Separated**	**Change**
Residential	87.5%	87.6%	0.0%
General Service < 50 kW	106.0%	105.9%	(0.1%)
General Service > 50 kW	129.8%	129.8%	(0.0%)
Large User	101.0%	101.0%	(0.0%)
Street Lighting	120.6%	120.6%	0.0%
Sentinel Lighting	194.1%	201.0%	6.9%
Unmetered Scattered Load	618.2%	618.9%	0.7%

4-Staff-15

Ref: Exhibit 4, Tab 2, Schedule 2, Table 4-13
Ref: Exhibit 4, Tab 2, Schedule 4, Table 4-19

Board staff notes that PDI has not recorded pension expense for 2009 to 2013 in either Account 5645 or Account 5646, although pension expenses are shown in Table 4-19.

a) Please explain where this expense has been recorded.

b) Please verify the impact of this accounting treatment on the Cost Allocation model and make any adjustments required.

PDI Response

a) Since PDI has only one employee, the pension expenses have been included in 5605 – Executive Salaries and Expenses. As PDI is under a shared services arrangement, PUSI charges a total salaries, wages, and benefits to PDI which is recorded in 5615 – General Administrative Salaries and Expenses.

b) The following outlines how the change in accounting treatment for Pension Expense has impacted the results of the Cost Allocation Model assuming the change for Metering Reading Expense has also been made. Please note the change in Pension Expense does not impact on the results of the Cost Allocation model since account 5645 and 5605 (i.e. the account that Pension Expense was recorded in the Application) are allocated to each rate class in the cost allocation model with the same allocator.

Rate Class	Cost Allocated in the 2013 Study - Application with Meter Reading Separated	Cost Allocated in the 2013 Study - Application with Meter Reading and Pension Expense Separated	Change
Residential	$10,468,853	$10,468,853	$0
General Service < 50 kW	$2,399,221	$2,399,221	$0
General Service > 50 kW	$2,615,144	$2,615,144	$0
Large User	$261,372	$261,372	$0
Street Lighting	$469,865	$469,865	$0
Sentinel Lighting	$27,999	$27,999	$0
Unmetered Scattered Load	$49,382	$49,382	$0
Total	$16,291,837	$16,291,837	$0

Rate Class	Revenue to Cost Ratio in the 2013 Study - Application	Revenue to Cost Ratio in the 2013 Study - Application with Meter Reading and Pension Expense Separated	Change
Residential	87.6%	87.6%	0.0%
General Service < 50 kW	105.9%	105.9%	0.0%
General Service > 50 kW	129.8%	129.8%	0.0%
Large User	101.0%	101.0%	0.0%
Street Lighting	120.6%	120.6%	0.0%
Sentinel Lighting	201.0%	201.0%	0.0%
Unmetered Scattered Load	618.9%	618.9%	0.0%

4-Staff-16

Ref: Exhibit 4, Tab 2, Schedule 2, Table 4-11

Board staff notes that PDI has not recorded costs for 2009 to 2013 in certain Maintenance accounts in Table 4-19, which would appear to be applicable to PDI’s system. Specifically, PDI has not recorded costs in the following accounts:

- Account 5114 – Maintenance of Distribution Station Equipment
- Account 5120 – Maintenance of Poles, Towers and Fixtures
- Account 5165 – Maintenance of Street Lighting and Signal Systems
- Account 5170 – Sentinel Lights – Labour
- Account 5172 – Sentinel Lights – Materials and expenses

a) Please explain where these expenses have been recorded.

b) Please verify the impact of this accounting treatment on the Cost Allocation model and make any adjustments required.

PDI Response

a) Expenses have been recorded as follows:

- Account 5114 – the expenses recorded in Account 5110 Maintenance of Buildings & Fixtures should have been recorded in Account 5114. Account 5110 should be $0 as PDI records all expenses associated with Buildings & Fixtures in Account 5012 Station Buildings & Fixtures Expense.

- Account 5120 – PDI does not record any maintenance expenses for poles. Defective poles are replaced and charged to capital.

- Account 5165 – PDI does not own any street lighting assets.

- Account 5170 and 5172 – PDI does not own any sentinel lighting assets.

b) The following outlines how the change in accounting treatment for 5114 Maintenance of Distribution Station Equipment has impacted the results of the Cost Allocation Model assuming the change for Metering Reading and Pension Expense has also been made.

Rate Class	Cost Allocated in the 2013 Study - Application with Meter Reading and Pension Expense Separated	Cost Allocated in the 2013 Study - Application with Meter Reading and Pension Expense Separated with movement in Maintenance Expense	Change
Residential	$10,468,853	$10,467,314	($1,539)
General Service < 50 kW	$2,399,221	$2,401,199	$1,978
General Service > 50 kW	$2,615,144	$2,614,797	($348)
Large User	$261,372	$261,563	$191
Street Lighting	$469,865	$469,524	($341)
Sentinel Lighting	$27,999	$28,012	$12
Unmetered Scattered Load	$49,382	$49,429	$46
Total	$16,291,837	$16,291,837	$0
Rate Class	**Revenue to Cost Ratio in the 2013 Study - Application with Meter Reading and Pension Expense Separated**	**Revenue to Cost Ratio in the 2013 Study - Application with Meter Reading and Pension Expense Separated with movement in Maintenance Expense**	**Change**
Residential	87.6%	87.6%	0.0%
General Service < 50 kW	105.9%	105.8%	(0.1%)
General Service > 50 kW	129.8%	129.8%	0.0%
Large User	101.0%	100.9%	(0.1%)
Street Lighting	120.6%	120.7%	0.1%
Sentinel Lighting	201.0%	200.9%	(0.1%)
Unmetered Scattered Load	618.9%	618.4%	(0.6%)

4-Staff-17

Ref: Exhibit 4, Tab 2, Schedule 5

The above referenced exhibit describes the cost allocation methodology by which PDI receives services from its affiliates.

a) How often is the cost allocation methodology reviewed?

b) What, if any, changes have taken place since 2009 as a result of reviews of the methodology?

PDI Response

a) The cost allocation methodology is reviewed annually to ensure fair allocation of costs from affiliates.

b) There has been no change to the cost drivers that form the basis of allocation for each activity. The cost drivers for each activity are reviewed and updated accordingly with actual data at the end of each year.

4-Staff-18

<u>Ref: Exhibit 4, Tab 1, Schedule 1, page 4-7</u>

The above referenced exhibit describes the OM&A budget process as being prepared by PUSI Managers and approved by the Board of Directors. Board staff notes that the budget is prepared by "department".

a) Does PDI represent a separate department? If not, how many separate departments encompass PDI?

b) If PDI is represented by more than one departmental budget within the PUSI budget process, please describe the process by which the overall PDI budget is reviewed for reasonableness and approved.

PDI Response

a) PDI does not represent a separate department. Please refer to Tables 4-25 through 4-29 on pages 4-50 through 4-52 of the application which lists the PUSI departments in the "Service Offered" column and shows the percentage of costs allocated to PDI.

b) The overall budget is reviewed for reasonableness by management by comparing the proposed budget to previous budgets and prior year actuals, and analyzing the variances. After the management review process is complete the budget is presented to the PDI Board of Directors for approval.

4-Staff-19

Ref: Exhibit 4/Tab 1/Schedule 1, page 4-9
Ref: Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued June 28, 2012, s. 2.1.7

Please identify where PDI has applied increases, for the 2013 test year, for non-labour components of OM&A expenses and where it has not. Where PDI has applied a non-labour expense increase, please explain the increase and its supporting rationale.

PDI Response

PDI has summarized the labour and non-labour increases in the variance analysis presented in pages 4-24 through 4-28. A noted example of a non-labour increase is in Account 5135 where tree trimming has increased by $80,000 as a result of known increases from the contractor and increased activity due to growth in cycles in the city of Peterborough.

4-Staff-20

Ref: Exhibit 4, Tab 2, Schedule 4

PDI states that there is only one employee in the LDC and that employee costs are allocated to affiliates by PUSI.

a) Please describe the decision-making process in determining the requirement for additional headcount, including:

(i) Which entity determines the need for additional headcount;

(ii) Who approves the request;

(iii) What support documentation is required by the decision-maker?

b) Please describe the relationship between PDI's capital budget and its headcount budget. Specifically, is the capital plan determined based on the resources available, or are the resources acquired and assigned to support the capital plan?

c) Similar to b), above, please describe the budget process relationship between non-recurring OM&A projects and resource availability. Specifically, are large or non-recurring projects undertaken in years where resources are available, or are resources acquired and assigned to complete these projects?

PDI Response

a) PUSI will determine the headcount need based on the workload requirements and service agreement established by PDI. PDI has ultimate approval authority on head count and expenditures through the budget approval process. Support documentation includes budget plan including OM&A requirements and capital forecast.

b) PDI determines the capital requirements based on its asset management, system requirements and customer demand inputs. Resources both from the affiliate or contractors are acquired and assigned to support the capital plan.

c) Large or non-recurring OM&A projects may be undertaken when customer demand in a particular year is lower with available resources depending on the urgency of the project. If the project is urgent and resources internally are not available, then external resources would be acquired and assigned to complete these projects.

4-Staff-21

Ref: Exhibit 4, Tab 2, Schedule 4

a) Please provide the total actual overtime pay charged to PDI by PUSI for unionized employees for 2009, 2010, 2011 and 2012, as well as budgeted overtime pay for 2013.

b) Please provide the percentage amount of total PUSI overtime pay for unionized employees that has been allocated to PDI in each of the years outlined in part a), above.

c) Please provide the number of non-union employees eligible for overtime.

d) Please provide the total actual overtime pay for non-union employees for 2009, 2010, 2011 and 2012, as well as budgeted overtime pay for 2013.

e) Please provide the percentage amount of total PUSI overtime pay for non-union employees that has been allocated to PDI in each of the years outlined in part d), above.

PDI Response

a) PDI has provided the overtime pay charged to PDI in the table below.

Table 4-Staff-21 – Overtime Charged to PDI

	2009A	2010A	2011A	2012A	2013B
Overtime	383,658	316,477	500,185	340,695	289,355
% of PUSI to PDI	63%	55%	61%	61%	60%

b) PDI has provided the percentage amount of PUSI overtime pay allocated to PDI in the table above.

c) There are no non-union employees eligible for overtime.

d) Amount is $0 for each year – see response in c).

e) Amount is 0% for each year – see response in c).

4-Staff-22

Ref: Exhibit 4, Tab 2, Schedule 4, page 4-29

PDI states that PUSI non-union staff increases are based on performance and an inflationary adjustment. What inflationary adjustments were applied in 2010, 2011, 2012 and 2013?

PDI Response

The inflationary adjustments were as follows: 2010 – 2.5%, 2011 – 2.7%, 2012 – 2.5%, 2013 – 2.6%.

4-Staff-23

Ref: Exhibit 4, Tab 2, Schedule 4, page 4-29

a) Please provide the total actual incentive payouts for unionized employees for 2009, 2010, 2011 and 2012, as well as the amount budgeted for 2013, which have been allocated to PDI by PUSI.

b) Please provide the percentage of total PUSI incentive payouts for unionized employees that has been allocated to PDI.

c) Please provide the total actual incentive payouts for each of the Executive, Management and Supervisory employee categories for 2009, 2010, 2011 and 2012, as well as the amount budgeted for 2013, which have been allocated to PDI by PUSI.

d) Please provide the percentage of total PUSI incentive payouts for each of the Executive, Management and Supervisory employee categories that has been allocated to PDI.

PDI Response

a) PDI has provided the incentive payouts to union employees that are shared by PDI and other affiliates in the table below.

Table 4-Staff-23a – Incentive Payouts

	2009A	2010A	2011A	2012A	2013B
Incentive - Union	12,074	240	21,977	-	-
% of PUSI to PDI	62%	64%	65%	-	-

b) PDI has provided the percentage of PUSI incentive for union employees in the above table. It should be noted that where an employee has not provided services to PDI, their incentive has not been included

c) PDI has provided the incentive payouts to non-union employees as requested in the table below:

Table 4-Staff-23c – Incentive Payouts

	2009A	2010A	2011A	2012A	2013B
Incentive - Executive	25,742	41,157	45,698	32,964	24,000
% of PUSI to PDI	50%	48%	46%	44%	48%
Incentive - Management	14,323	23,983	22,207	27,742	29,000
% of PUSI to PDI	65%	67%	64%	63%	69%
Incentive - Non Union	4,142	2,354	3,228	3,629	3,000
% of PUSI to PDI	48%	45%	38%	38%	48%

d) PDI has provided the percentage of PUSI incentive for non-union employees in the above table. It should be noted that where an employee has not provided services to PDI, their incentive has not been included

4-Staff-24

Ref: Exhibit 4, Tab 2, Schedule 4, pages 4-42, 4-43
Ref: Exhibit 4, Tab 2, Schedule 4, Tables 4-25 to 4-29

Please describe the services provided to PUSI's other affiliates by the Electrical Operations and Field Technical Operations departments.

PDI Response

The Electrical Operations Department provides streetlight maintenance services to the City of Peterborough and sentinel lighting services to PUI. Both departments will provide high voltage and metering services to PUI upon request.

4-Staff-25

Ref: Exhibit 4, Tab 2, Schedule 4, pages 4-48, 4-49
Ref: Exhibit 4, Tab 2, Schedule 4, Tables 4-25 to 4-29

a) When did PDI implement time of use billing?

b) Please explain why there has been no change in service levels from PUI as a result of PDI's implementation of smart meters and transition to time of use billing over the period.

PDI Response

a) PDI implemented time of use billing in July 2012.

b) Services provided by PUI relate to wholesale meters and interval meters. Neither are affected by the transition to time of use billing.

4-Staff-26

Ref: Exhibit 4, Tab 2, Schedule 4, pages 4-48, 4-49
Ref: Exhibit 4, Tab 2, Schedule 4, Tables 4-25 to 4-29

a) Does PUSI track the number and length of calls as an allocator?

b) Has there been any increase in call centre activity as a result of implementing smart meters and transitioning to time of use billing?

PDI Response

a) PUSI does not use the number and length of calls as an allocator.

b) There has not been an increase in call centre activity as a result of implementing smart meters and transitioning to time of use billing.

4-Staff-27

Ref: Exhibit 4, Tab 2, Schedule 5, page 4-44

Board staff notes that costs for the Administration department are allocated to the companies based partially on the following basis:

Labour hours from support departments allocated to the associated companies using the specific cost drivers for each support department.

Please explain the above statement and provide an example.

PDI Response

Direct labour hours are applied to each company where possible, and the remaining Administration department costs are allocated to companies based on a weighted average of the allocation of all other support departments. In the case where there is $50,000 of PUSI Administration department costs not allocated based on direct labour hours, PDI would receive a share of this $50,000 based on their weighted average allocation of Customer Service, Corporate Services, Finance, Technology Services, Human Resources and Purchasing. Using this simple example, if PDI was allocated 50% of each of the aforementioned support functions, it would receive a 50% allocation of the $50,000.

4-Staff-28

Ref: Exhibit 4, Tab 2, Schedule 5, page 4-44

Board staff notes that Software and Equipment Rental is allocated partially on the following basis:

Remaining costs are allocated using the percentage allocations derived for the Administrative Department.

Please explain the rationale for using the same percentage allocations for software and equipment as are used for the Administration Department.

PDI Response

The remaining rental costs referred to above cover a range of items including office equipment, telephone equipment, small tools, computer equipment, and software excluding the software related to the customer billing system.

The Administration Department percentage allocations are an appropriate allocator for these costs because the Administration percentages are a blended rate based on broad base of activities: direct labour hours charged to operating activities, and labour hours from support departments allocated to the associated companies using the specific cost drivers for each support department.

4-Energy Probe-18

Ref: Exhibit 4, Tab 1, Schedule 1

Please update Tables 4-2, 4-3, 4-4 and 4-5 to reflect actual data for 2012.

PDI Response

As requested, PDI has updated Tables 4-2, 4-3, 4-4, and 4-5 below with 2012 actual data.

Table 4-2 Summary of Recoverable OM&A Expenses

Description	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2012 Actuals	2013 Test Year
Operations	$ 1,220,786	$ 1,484,675	$ 1,361,253	$ 1,464,706	$ 1,649,704	$ 1,536,913	$ 1,939,510
Maintenance	$ 1,014,319	$ 1,091,936	$ 976,884	$ 1,487,519	$ 1,245,627	$ 1,424,501	$ 1,440,823
Billing and Collecting	$ 2,026,703	$ 2,132,552	$ 1,859,141	$ 1,900,286	$ 2,287,891	$ 2,286,152	$ 2,474,467
Administrative and General	$ 2,412,298	$ 1,853,270	$ 1,981,314	$ 2,040,523	$ 2,192,806	$ 1,824,635	$ 2,433,629
Administrative - Previously Capitalized							$ 950,363
Total	**$ 6,674,106**	**$ 6,562,433**	**$ 6,178,592**	**$ 6,893,034**	**$ 7,376,028**	**$ 7,072,201**	**$ 9,238,792**
%Change (year over year)			-5.8%	11.6%	7.0%	2.6%	30.6%
CAGR from 2009 Approved							8.5%
CAGR from 2009 Approved excl Capitalized Administration							5.6%
CAGR from 2009 Actual							8.9%
GDP-IPI		2.3%	1.3%	1.3%		1.6%	

Table 4-3 Summary of Recoverable OM&A Expenses 2009 Board Approved to 2013

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2012 Actuals	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP		CGAAP
Operations	$ 1,220,786	$ 1,484,675	$ 1,361,253	$ 1,464,706	$ 1,649,704	$ 1,536,913	$ 1,939,510
Maintenance	$ 1,014,319	$ 1,091,936	$ 976,884	$ 1,487,519	$ 1,245,627	$ 1,424,501	$ 1,440,823
SubTotal	**$ 2,235,105**	**$ 2,576,611**	**$ 2,338,137**	**$ 2,952,225**	**$ 2,895,331**	**$ 2,961,414**	**$ 3,380,333**
%Change (year over year)			-9.3%	26.3%	-1.9%	0.3%	
%Change (Test Year vs Last Rebasing Year - Actual)							31.2%
Billing and Collecting	$ 2,026,703	$ 2,132,552	$ 1,859,141	$ 1,900,286	$ 2,287,891	$ 2,286,152	$ 2,474,467
Community Relations							
Administrative and General	$ 2,412,298	$ 1,853,270	$ 1,981,314	$ 2,040,524	$ 2,192,806	$ 1,824,635	$ 2,433,629
Administrative - Previously Capitalized							$ 950,363
SubTotal	**$ 4,439,001**	**$ 3,985,822**	**$ 3,840,455**	**$ 3,940,810**	**$ 4,480,697**	**$ 4,110,787**	**$ 5,858,459**
%Change (year over year)			-3.6%	2.6%	13.7%	4.3%	
%Change (Test Year vs Last Rebasing Year - Actual)							47.0%
%Change (Test Year vs							23.1%
Total	$ 6,674,106	$ 6,562,433	$ 6,118,592	$ 6,893,035	$ 7,376,028	$ 7,072,201	$ 9,238,792
%Change (year over year)			-5.8%	11.6%	7.0%	2.6%	

Table 4-4 Summary OM&A Expense Variances 2009 Board Approved to 2013 Test Year

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	Variance 2009 BA – 2009 Actuals	2010 Actuals	Variance 2010 Actuals vs. 2009 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Bridge Year	Variance 2012 Bridge vs. 2011 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013 Test Year	Variance 2013 Test vs. 2012 Actuals
Operations	$ 1,220,786	$ 1,484,675	-$ 263,889	$ 1,361,253	-$ 123,422	$ 1,464,706	$ 103,453	$1,649,704	$ 184,998	$ 1,536,913	$ 72,207	$ 1,939,510	$ 402,597
Maintenance	$ 1,014,319	$ 1,091,936	-$ 77,617	$ 976,884	-$ 115,052	$ 1,487,519	$ 510,635	$1,245,627	-$ 241,892	$ 1,424,501	-$ 63,018	$ 1,440,823	$ 16,322
Billing and Collecting	$ 2,026,703	$ 2,132,552	-$ 105,849	$ 1,859,141	-$ 273,411	$ 1,900,286	$ 41,145	$2,287,891	$ 387,605	$ 2,286,152	$ 385,866	$ 2,474,467	$ 188,315
Administrative and General	$ 2,412,298	$ 1,853,270	$ 559,028	$ 1,981,314	$ 128,044	$ 2,040,524	$ 59,210	$2,192,806	$ 152,282	$ 1,824,635	-$ 215,889	$ 2,433,629	$ 608,994
Administrative - Previously Capitalized												$ 950,363	$ 950,363
Total OM&A Expenses	$ 6,674,106	$ 6,562,433	$ 111,673	$ 6,178,592	-$ 383,841	$ 6,893,035	$ 714,443	$7,376,028	$ 482,993	$ 7,072,201	$ 179,166	$ 9,238,792	$ 2,166,591
Variance from previous year				-$ 383,841		$ 714,443		$ 482,993		$ 179,166		$ 2,166,591	
Percent change (year over year)				-6%		12%		7%		3%		31%	
Percent Change: Test year vs. Most Current Actual												31%	
Percent Change: Test year vs. Most Current Actual - excluding Capitalized Administration												17%	
Simple average of % variance for all years													9.2%
Compound Annual Growth Rate for all years													8.9%
Compound Annual Growth Rate for all years - excluding Capitalized Administration													6.0%
Compound Growth Rate (2011 Actuals vs. 2009 Actuals)						5.04%				7.77%			

Table 4-5 OM&A per Customer and FTE

	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Actuals	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Number of Customers	34,890	34,508	34,764	35,095	35,303	35,697
Total Recoverable OM&A from Appendix 2-I	$ 6,674,106	$ 6,562,433	$ 6,178,592	$ 6,893,035	$ 7,072,201	$ 9,238,792
OM&A cost per customer	$ 191.29	$ 190.17	$ 177.73	$ 196.41	$ 200.33	$ 258.81
Number of FTEEs	64.6	64.6	64.4	63.29	61.7	70.6
Customers/FTEEs	540	534	540	555	572	506
OM&A Cost per FTEE	103,314	101,586	95,941	108,912	114,622	130,861

4-Energy Probe-19

Ref: Exhibit 4, Tab 1, Schedule 1

a) With respect to Table 4-7, please indicate why the number of customers shown for each of Welland, Westario and Bluewater is less than the number used in their OM&A cost per customer tables in their prefiled evidence, even though the OM&A cost per customer is the same as that shown in Table 4-7.

b) Please provide a revised Table 4-7 that reflects the same number of customers as used by each of the three distributors in their OM&A per customer calculations in their evidence.

PDI Response

a) In Table 4-7, the 2011 customers was included in error. The 2013 projected customers is included in the table in part b).

b) Table 4-7 has been revised for the 2013 customers as filed in Welland, Westario, and Bluewater's pre-filed evidence.

Table 4-7 – Revised - 2013 OM&A Per Customer as Filed in 2013 Cost of Service Application

	Customers	2013 Filed[2]
Westario Power Inc.	22,876	$ 226.94
Peterborough Distribution Inc.	**35,697**	**$ 258.81**
Welland Hydro Electric System Corp.	23,098	$ 287.34
Bluewater Power Distribution Corp.	36,578	$ 357.56
COLLUS Power Corp.	15,723	N/A

4-Energy Probe-20

Ref: Exhibit 4, Tab 2, Schedule 2

a) Please update Tables 4-10, 4-11, 4-12, 4-13 and 4-14 to reflect actual data for 2012.

b) Please explain why there is a reduction of only $40,000 in 2012 for storm damage when there was an increase in costs of $271,000 shown for 2011. Does this mean that there is an additional cost in both 2012 and 2013 of approximately $230,000 per year compared to 2010 for storm damage that occurred in 2011?

PDI Response

a) As requested, PDI has updated Tables 4-10, 4-11, 4-12, 4-13 and 4-14 to reflect actual data for 2012.

Table 4-10 – Detailed Account by Account Operations Expenses

Account Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	Bridge Year 2012[3]	2012 Actual	Test Year 2013 - MIFRS Asset policies under
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Operations						
5005 Operation Supervision and Engineering	$ 44,039	$ 25,430	$ 85,050	$ 121,478	$ 109,131	$ 121,247
5010 Load Dispatching	$ 270,056	$ 366,423	$ 328,055	$ 275,876	$ 333,966	$ 332,563
5012 Station Buildings and Fixtures Expense	$ 124,527	$ 124,582	$ 97,716	$ 76,420	$ 143,796	$ 73,504
5014 Transformer Station Equipment - Operation Labour	$ -	$ -	$ -	$ -	$ -	$ -
5015 Transformer Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -	$ -	$ -
5016 Distribution Station Equipment - Operation Labour	$ 61,221	$ 101,742	$ 118,330	$ 122,933	$ 132,893	$ 181,492
5017 Distribution Station Equipment - Operation Supplies and Expenses	$ 110,009	$ 112,921	$ 124,859	$ 104,320	$ 108,271	$ 141,100
5020 Overhead Distribution Lines and Feeders - Operation Labour	$ 20,622	$ 17,056	$ 25,972	$ 68,926	$ 46,181	$ 51,767
5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 10,659	$ 7,511	$ 19,854	$ 24,300	$ 17,155	$ 23,800
5030 Overhead Sub-transmission Feeders - Operation	$ 16,389	$ 20,576	$ 16,471	$ 28,548	$ 21,608	$ 28,684
5035 Overhead Distribution Transformers - Operation	$ 79,239	$ 1,852	$ 1,103	$ 11,241	$ 193	$ 9,685
5040 Underground Distribution Lines and Feeders - Operation Labour	$ 85,020	$ 129,882	$ 164,292	$ 157,669	$ 140,460	$ 166,303
5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 20,576	$ 19,997	$ 58,971	$ 42,500	$ 33,111	$ 67,500
5050 Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -
5055 Underground Distribution Transformers - Operation	$ 17,766	$ 730	$ 1,669	$ 40,426	$ 141	$ 12,060
5060 Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -	$ -	$ -
5065 Meter Expense	$ 148,257	$ 193,889	$ 200,185	$ 296,153	$ 220,009	$ 335,758
5070 Customer Premises - Operation Labour	$ 1,064	$ 620	$ -	$ -	$ -	$ -
5075 Customer Premises - Operation Materials and Expenses	$ 1,866	$ -	$ -	$ -	$ -	$ -
5085 Miscellaneous Distribution Expenses	$ 473,363	$ 238,042	$ 222,179	$ 278,914	$ 229,998	$ 394,047
5090 Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -	$ -
5095 Overhead Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -	$ -
5096 Other Rent	$ -	$ -	$ -	$ -	$ -	$ -
Total - Operations	$ 1,484,675	$ 1,361,253	$ 1,464,706	$ 1,649,704	$ 1,536,913	$ 1,939,510

Table 4-11 – Detailed Account by Account Maintenance Expenses

Account Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	Bridge Year 2012[3]	2012 Actual	Test Year 2013 - MIFRS Asset policies under
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Maintenance						
5105 Maintenance Supervision and Engineering	$ -	$ -	$ -	$ -	$ -	$ -
5110 Maintenance of Buildings and Fixtures - Distribution Stations	$ 4,346	$ 12,485	$ 34,717	$ 40,843	$ 26,561	$ 37,833
5112 Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -	$ -	$ -
5114 Maintenance of Distribution Station Equipment	$ -	$ -	$ -	$ -	$ -	$ -
5120 Maintenance of Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -
5125 Maintenance of Overhead Conductors and Devices	$ 363,560	$ 323,021	$ 628,345	$ 444,531	$ 505,057	$ 480,690
5130 Maintenance of Overhead Services	$ 140,532	$ 227,515	$ 251,086	$ 180,377	$ 228,873	$ 209,982
5135 Overhead Distribution Lines and Feeders - Right of Way	$ 233,413	$ 74,990	$ 175,650	$ 253,255	$ 328,593	$ 260,938
5145 Maintenance of Underground Conduit	$ -	$ -	$ -	$ -	$ -	$ -
5150 Maintenance of Underground Conductors and Devices	$ 100,921	$ 79,095	$ 54,381	$ 106,987	$ 61,649	$ 123,877
5155 Maintenance of Underground Services	$ 125,491	$ 130,531	$ 197,492	$ 149,572	$ 180,666	$ 193,237
5160 Maintenance of Line Transformers	$ 121,268	$ 129,247	$ 145,848	$ 68,104	$ 93,102	$ 132,485
5165 Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -	$ -	$ -
5170 Sentinel Lights - Labour	$ -	$ -	$ -	$ -	$ -	$ -
5172 Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -	$ -	$ -
5175 Maintenance of Meters	$ 2,405	$ -	$ -	$ 1,958	$ -	$ 1,781
5178 Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -	$ -	$ -
5195 Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -
Total - Maintenance	$ 1,091,936	$ 976,884	$ 1,487,519	$ 1,245,627	$ 1,424,501	$ 1,440,823

Table 4-12 – Detailed Account by Account Billing & Collecting Expenses

Account Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	Bridge Year 2012[3]	2012 Actual	Test Year 2013 - MIFRS Asset policies under
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Billing and Collecting						
5305 Supervision	$ 240,914	$ 251,449	$ 273,856	$ 271,543	$ 270,977	$ 253,267
5310 Meter Reading Expense						
5315 Customer Billing	$ 879,119	$ 764,253	$ 789,587	$ 946,764	$ 1,186,363	$ 1,080,326
5320 Collecting	$ 779,596	$ 677,734	$ 681,754	$ 839,584	$ 666,380	$ 880,874
5325 Collecting - Cash Over and Short	-$ 37	-$ 55	-$ 8		-$ 27	
5330 Collection Charges						
5335 Bad Debt Expense	$ 232,960	$ 165,760	$ 155,097	$ 230,000	$ 162,459	$ 260,000
5340 Miscellaneous Customer Accounts Expenses						
Total - Billing and Collecting	$ 2,132,552	$ 1,859,141	$ 1,900,286	$ 2,287,891	$ 2,286,152	$ 2,474,467

Table 4-13 – Detailed Account by Account General & Administrative Expenses

Account Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	Bridge Year 2012[3]	2012 Actual	Test Year 2013 - MIFRS Asset policies under
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Administrative and General Expenses						
5605 Executive Salaries and Expenses	$ 174,457	$ 221,186	$ 229,546	$ 233,219	$ 213,014	$ 221,609
5610 Management Salaries and Expenses			$ -			$ -
5615 General Administrative Salaries and Expenses	$ 471,249	$ 561,423	$ 572,290	$ 628,115	$ 463,309	$ 1,800,642
5620 Office Supplies and Expenses			$ -			$ -
5625 Administrative Expense Transferred - Credit						
5630 Outside Services Employed	$ 163,250	$ 162,461	$ 178,731	$ 196,939	$ 169,387	$ 190,689
5635 Property Insurance	$ 82,362	$ 67,448	$ 91,294	$ 96,000	$ 89,864	$ 110,000
5640 Injuries and Damages			$ -			$ -
5645 OMERS Pensions and Benefits			$ -			$ -
5646 Employee Pensions and OPEB			$ -			$ -
5647 Employee Sick Leave			$ -			$ -
5650 Franchise Requirements			$ -			$ -
5655 Regulatory Expenses	$ 93,936	$ 93,227	$ 115,143	$ 120,000	$ 105,506	$ 121,250
5660 General Advertising Expenses	$ 107,382	$ 108,432	$ 72,655	$ 59,733	$ 63,368	$ 62,000
5665 Miscellaneous General Expenses	$ 78,657	$ 69,291	$ 78,868	$ 88,800	$ 58,758	$ 103,802
5670 Rent	$ 681,977	$ 683,293	$ 667,651	$ 735,000	$ 626,595	$ 739,000
5672 Lease Payment Charge			$ -			$ -
5675 Maintenance of General Plant			$ -			$ -
5680 Electrical Safety Authority Fees	$ -	$ 14,553	$ 14,841	$ 15,000	$ 15,329	$ 15,000
5681 Special Purpose Charge Expense	$ -	$ 187,168	$ 130,179	$ -		$ -
5685 Independent Electricity System Operator Fees and Penalties			$ -			$ -
5695 OM&A Contra Account			$ -			$ -
6205 Donations			$ -			$ -
6205 Donations, Sub-account LEAP Funding	$ -	$ -	$ 19,505	$ 20,000	$ 19,505	$ 20,000
Total - Administrative and General Expenses	$ 1,853,270	$ 2,168,482	$ 2,170,703	$ 2,192,806	$ 1,824,635	$ 3,383,992

Table 4-14 – Cost Driver Table

OM&A	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Actuals	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Opening Balance	$ 6,711,606	$ 6,562,432	$ 6,178,591	$ 6,893,034	$ 7,072,201
A) Payroll and Benefits					
Net Change in FTE's		($100,000)	($72,000)	$116,000	$440,400
Progression and Cost of Living changes	$150,000	$150,000	$199,000	$202,000	$237,000
Benefit Increases attributed to payroll changes					
OMERS/Green Shield rates less than anticipated	($144,000)				
OMERS rate increase			$83,000	$56,000	$118,000
B) Operating and Maintenance					
Meter maintenance	($43,000)				
Breakdown costs		$84,000	$123,000		
Tree trimming		($162,000)	$101,000		
Storm damage		($45,000)	$271,000	($100,000)	$60,000
PCB testing		($91,000)			
Control center costs		$96,000			
Substations		$50,000			
Meter reading costs		($109,000)			
Asset Management			$42,000		
Downtown Vaults			$58,000		
C) Billing and Collecting					
Bad debt expense	$103,000	($67,000)	($11,000)	$7,000	$98,000
D) Administration					
Software/Equipment Rentals	($41,011)			($41,000)	$41,000
Outside Services	($97,000)				
Systems support/maintenance					$50,000
Change to capitalization of overhead					$950,363
Allocation of Admin labour to capital projects	($63,000)	($68,280)	($44,000)		
E) Other					
Changes in PDI's Share of PUSI costs	($24,573)	($118,000)	($76,000)	($68,000)	$181,800
Other	$10,411	($3,560)	$40,443	$7,167	($9,972)
Closing Balance	$ 6,562,433	$ 6,178,592	$ 6,893,034	$ 7,072,201	$ 9,238,792

b) The 2010 year brought unusually low levels of storm damage. PDI anticipated that both 2012 and 2013 would have higher levels of storm damage versus 2010, however lower than the 2011 year. The storm damage trend is illustrated in the above cost driver table.

4-Energy Probe-21

<u>Ref: Exhibit 4, Tab 2, Schedule 4</u>

a) What would be the impact on the 2012 revenue requirement if the unionized staff had received 2% increases in both 2012 and 2013 (rather than 2.9% in 2012 and 2.6% in 2013)?

b) What was the average annual increase in each of 2009 through 2012 and forecast for 2013 for non-union employees?

c) What is the impact on the 2013 revenue requirement if the inflationary increase for 2012 and 2013 was 2.0%?

d) Please explain why PDI has aggregated the executive, management and non-union employees together in Table 4-19. In particular, are there less than 3 employees in each of the executive and management category? Are there less than 3 employees in the combined executive and management categories? If no, please provide a revised Table 4-19 that provides a break out of all of the categories that have more than 3 FTEs.

e) Please update Table 4-19 (or the revised version requested in (d) above, if applicable) to reflect actual data for 2012.

f) Please provide a table that shows for each of the union and non-union categories, the total FTE's of PUSI and the allocation to PDI and each of the other affiliates that are allocated FTE's over the 2009 through 2012 period on an actual basis and the forecast for 2013.

PDI Response

a) The impact to the 2013 revenue requirement would be a reduction of $18,371.

b) The average increases are as follows: 2009 – 2.8%, 2010 – 2.5%, 2011 – 2.7%, 2012 – 2.5%, 2013 – 2.6%.

c) The impact to the 2013 revenue requirement would be a reduction of $43,087.

d) PDI has updated Table 4-19 with a more detailed breakout of the non-union category in response to 4-SEC-21.

e) PDI has updated Table 4-19 with 2012 actual data in response to 4-SEC-21.

f) PDI has provided the relevant FTEs allocated from PUSI to PDI and affiliates in the table below.

Table 4-Energy Probe-21 – PDI and Affiliate FTE's

Union FTE	2009A	2010A	2011A	2012A	2013B
PUSI Total	73.0	69	70	72	75
PDI	45.6	44.5	45.33	44.4	50.1
PUC	10.4	9	9.2	9	8
PUI	2.6	2	2.0	2.4	1.7
PUSI	1.1	1.5	1.0	2.4	1.4
Outside PUG	13.3	12	12.5	13.8	13.8
Exec FTE					
PUSI Total	5.0	5	5	5	5
PDI	2.5	2.4	2.3	2.20	2.40
PUC	1.2	1.3	1.3	1.3	1.2
PUI	0.4	0.5	0.5	0.7	0.7
PUSI	0.3	0.2	0.3	0.2	0.1
Outside PUG	0.6	0.6	0.6	0.6	0.6
Mgmt FTE					
PUSI Total	18.0	18	18	18	18
PDI	11.7	12.1	11.5	11.3	12.4
PUC	3.2	2.5	2.9	3	2.5
PUI	0.8	0.5	0.6	0.7	0.5
PUSI	0.3	0.4	0.5	0.5	0.3
Outside PUG	2.0	2.5	2.5	2.5	2.3
Non Union FTE					
PUSI Total	10.0	12.0	11.0	10.0	12.0
PDI	4.8	5.4	4.2	3.8	5.7
PUC	3.8	4.8	4.8	4	4
PUI	0.8	1.4	1.5	1.5	1.6
PUSI	0.6	0.4	0.5	0.5	0.5
Outside PUG	0.0	0	0	0.2	0.2

4-Energy Probe-22

Ref: Exhibit 4, Tab 2, Schedule 5

a) Please update Table 4-23 to reflect actual data for 2012.

b) Please confirm that Table 4-23 are PUSI costs and not the portion of PUSI costs allocated to PDI. If this cannot be confirmed, please explain why the costs in Table 4-23 are higher than those shown in Table 4-3.

c) Do the 2013 figures shown in Table 4-23 reflect the capitalization change proposed for 2013? If yes, please provide a version of Table 4-23, including 2012 actuals, that maintains the 2012 capitalization policy (i.e. reflects the continuation of old CGAAP in 2013).

PDI Response

a) PDI has provided Table 4-23 with 2012 actual data below.

Table 4-23 Summary of Shared Services and Corporate Cost Allocation

ACTIVITY	2009 BAP	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2012 Actual	2013 Test Year
Electric Distribution Operations	$1,959,758	$2,043,804	$2,141,338	$2,177,301	$2,087,315	$2,212,494	$2,233,297
Engineering Services	$999,360	$887,422	$715,392	$797,583	$1,070,469	$853,794	$1,246,516
Field Technical Operations	$605,051	$551,098	$588,294	$527,963	$643,950	$625,091	$898,940
Vehicles	$401,350	$502,616	$497,567	$512,120	$522,110	$524,280	$553,540
Stores	$201,923	$184,301	$141,989	$138,850	$136,108	$166,470	$120,220
Operating Activities	**$4,167,442**	**$4,169,241**	**$4,084,580**	**$4,153,817**	**$4,459,952**	**$4,382,129**	**$5,052,513**
Customer Service	$1,378,550	$1,387,816	$1,213,090	$1,274,143	$1,467,295	$1,264,572	$1,456,261
Administration	$522,250	$519,762	$580,116	$538,872	$504,335	$515,865	$561,394
Corporate Services	$303,051	$301,682	$280,039	$269,083	$321,168	$261,190	$348,701
Finance	$180,294	$198,243	$127,861	$142,979	$164,040	$151,242	$311,570
Peterborough Technology Services	$636,026	$639,718	$600,363	$600,329	$692,261	$565,611	$894,940
Human Resources	$299,247	$249,640	$283,163	$303,800	$326,825	$306,967	$318,633
Purchasing	$71,965	$74,613	$61,122	$110,324	$112,008	$116,899	$123,610
Facilities Management	$513,122	$514,062	$503,276	$513,860	$524,000	$489,000	$531,000
Software & Equipment Rent	$219,285	$167,915	$180,017	$153,791	$211,000	$137,595	$208,000
Support Activities	**$4,123,790**	**$4,053,452**	**$3,829,047**	**$3,907,181**	**$4,322,932**	**$3,808,941**	**$4,754,109**
TOTAL	**$8,291,232**	**$8,222,693**	**$7,913,627**	**$8,060,998**	**$8,782,884**	**$8,191,070**	**$9,806,622**

b) The data in Table 4-23 represents PUSI's allocation of costs to PDI. The Operating and Support Activities charged to PDI include a portion of costs that PDI has allocated to capital. Table 4-3 includes only charges to OM&A.

c) Because PDI has included both operating and capital costs in Table 4-23, the table would be the same under both the historical and revised capitalization policies.

4-SEC-17

Reference: Exhibit 4, Tab 1, Schedule 1 p 4-2

Please provide details of any changes in accounting methods or policies between 2009 and 2010 that would cause A&G to increase but the other three categories to decrease.

PDI Response

Administrative and General expenses increased in 2010 relative to 2009 as a result of moving the VP Electric Utility to Executive Salaries and Expenses (Account 5605). Previously, the VP Electric Utility was distributed to Operations and Maintenance Accounts 5000-5999.

4-SEC-18

Reference: Exhibit 4, Tab 1, Schedule 1 p 4-2

Please reconcile the 2011 OM&A Cost per Customer of $196.41 with the $201.07 listed in the 2011 Yearbook.

PDI Response

PDI notes that the 2011 OEB Yearbook states that OM&A Cost per Customer is $198.57. PDI notes that the $196.41 is based on a customer count of 35,095 which represents the average for 2011 and includes only Recoverable OM&A of $6,893,035. The OEB Yearbook uses a customer count of 35,270 which is the customer count as of the end of 2011 and Total OM&A which includes the non-recoverable Special Purpose Charge recorded in 5681.

4-SEC-19

Reference: Exhibit 4, Tab 1, Schedule 1 p 4-7

Please provide the document referred to as the “total labour budget by department” for the Test Year.

PDI Response

The labour budget by department is an Excel spreadsheet containing confidential salary and benefit information for identifiable individuals. PDI is not prepared to release it in that form. Under section 4.3.1 of the Board's *Practice Direction on Confidential Filings* (the "Practice Direction"), the Board is prohibited from releasing personal information, as that phrase is defined in FIPPA. While PDI is not able to present this confidential information, an aggregated summary of PUSI's labour budget by department for the 2013 Test Year has been provided in the table below. Departments with fewer than 3 employees have been grouped accordingly.

Table 4-SEC-19 – PUSI Labour Budget by Department

Department	2013 Labour Budget
Electric Operations	2,187,202
Engineering Services	1,780,042
Field Technical Operations	740,412
Customer Service	966,468
Administration	571,757
Corporate Services	356,025
Finance	482,148
Technology Services	2,581,421
Human Resources	406,108
Purchasing & Stores	518,790

4-SEC-20

<u>Reference: Exhibit 4, Tab 2, Schedule 3 p 4-23</u>

Please explain why moving the VP Electric Utility into PDI resulted in a change in cost to PDI. How did the basis of allocation of responsibility for that person's costs change as a result of that move?

PDI Response

Moving the VP Electric Utility into PDI did not result in a change in cost to PDI. The increase to account 5605 – Executive Salaries and Expenses is offset against a reduction in Operating & Maintenance accounts 5000 through 5199 as this was where the VP Electric Utility was accounted for in the 2009 Budget. Please refer to Exhibit 1, Tab 1, Schedule 10 for further details regarding the realignment of administrative costs to OEB accounts.

4-SEC-21

Reference: Exhibit 4, Tab 2, Schedule 4 p 4-31

With respect to Appendix 2-K:

a) Please refile with Executive, Management and Non-Union separately identified in all areas of the table.

b) Please confirm that this is electric only. If so, please provide a similar table, for all years and with full breakdowns, for PUSI.

PDI Response

a) PDI has updated the table as requested.

Table 4-SEC-21a – Appendix 2-K Employee Costs Revised

	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Actuals	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Number of Employees (FTEs including Part-Time)[1]						
Executive	2.2	2.5	2.4	2.3	2.20	2.40
Management	11.7	11.7	12.1	11.5	11.30	12.40
Non-Union	5.6	4.8	5.4	4.2	3.8	5.7
Union	45.1	45.6	44.5	45.3	44.4	50.1
Total	**64.6**	**64.6**	**64.4**	**63.3**	**61.7**	**70.6**
Number of Part-Time Employees (Headcount)						
Executive						
Management						
Non-Union						
Union	2.7	1.2	2.5	3.2	1.0	1.6
Total	**2.7**	**1.2**	**2.5**	**3.2**	**1.0**	**1.6**
Total Salary and Wages						
Executive	$ 254,833	$ 334,004	$ 347,795	$ 364,880	$ 336,844	$ 365,857
Management	$ 1,064,973	$ 1,035,364	$ 1,118,910	$ 1,059,581	$ 1,093,226	$ 1,189,826
Non-Union	$ 311,031	$ 316,589	$ 329,258	$ 219,358	$ 208,120	$ 340,466
Union	$ 2,909,600	$ 3,105,612	$ 3,046,591	$ 3,283,156	$ 3,115,925	$ 3,696,641
Total	**$ 4,540,437**	**$ 4,791,569**	**$ 4,842,554**	**$ 4,926,974**	**$ 4,754,115**	**$ 5,592,790**
Current Benefits						
Executive	$ 61,160	$ 46,786	$ 51,802	$ 62,841	$ 72,468	$ 78,776
Management	$ 255,594	$ 196,069	$ 210,239	$ 224,634	$ 245,150	$ 233,374
Non-Union	$ 74,647	$ 64,649	$ 72,241	$ 45,733	$ 45,759	$ 113,055
Union	$ 698,304	$ 638,198	$ 625,563	$ 702,474	$ 750,858	$ 918,594
Total	**$ 1,089,705**	**$ 945,702**	**$ 959,845**	**$ 1,035,682**	**$ 1,114,235**	**$ 1,343,799**
Accrued Pension and Post-Retirement Benefits						
Executive						
Management						
Non-Union	$ 39,255	$ 33,828	$ 41,138	$ 34,052	$ 49,213	$ 36,233
Union	$ 90,790	$ 81,187	$ 91,993	$ 87,561	$ 126,548	$ 88,549
Total	**$ 130,046**	**$ 115,015**	**$ 133,131**	**$ 121,613**	**$ 175,761**	**$ 124,782**
Total Benefits (Current + Accrued)						
Executive	$ 61,160	$ 46,786	$ 51,802	$ 62,841	$ 72,468	$ 78,776
Management	$ 255,594	$ 196,069	$ 210,239	$ 224,634	$ 245,150	$ 233,374
Non-Union	$ 113,903	$ 98,477	$ 113,379	$ 79,785	$ 94,972	$ 149,288
Union	$ 789,094	$ 719,385	$ 717,556	$ 790,035	$ 877,406	$ 1,007,143
Total	**$ 1,219,750**	**$ 1,060,717**	**$ 1,092,976**	**$ 1,157,295**	**$ 1,289,996**	**$ 1,468,580**
Total Compensation (Salary, Wages, & Benefits)						
Executive	$ 315,993	$ 380,790	$ 399,597	$ 427,720	$ 409,312	$ 444,633
Management	$ 1,320,567	$ 1,231,433	$ 1,329,149	$ 1,284,215	$ 1,338,376	$ 1,423,200
Non-Union	$ 424,933	$ 415,066	$ 442,637	$ 299,143	$ 303,092	$ 489,754
Union	$ 3,698,694	$ 3,824,997	$ 3,764,147	$ 4,073,191	$ 3,993,331	$ 4,703,784
Total	**$ 5,760,187**	**$ 5,852,286**	**$ 5,935,530**	**$ 6,084,269**	**$ 6,044,112**	**$ 7,061,370**
Compensation - Average Yearly Base Wages						
Executive	$ 110,424	$ 123,305	$ 127,766	$ 138,774	$ 138,127	$ 142,440
Management	$ 90,254	$ 87,268	$ 90,490	$ 90,206	$ 94,291	$ 93,615
Non-Union	$ 55,273	$ 65,093	$ 60,538	$ 51,459	$ 53,814	$ 59,205
Union	$ 57,312	$ 60,995	$ 61,308	$ 63,795	$ 62,505	$ 66,739
Total	**$ 64,910**	**$ 68,469**	**$ 69,203**	**$ 70,496**	**$ 70,488**	**$ 73,425**
Compensation - Average Yearly Overtime						
Executive						
Management						
Non-Union						
Union	$ 5,826	$ 8,414	$ 7,112	$ 11,034	$ 7,673	$ 5,776
Total						
Compensation - Average Yearly Incentive Pay						
Executive	$ 5,409	$ 10,297	$ 17,149	$ 19,869	$ 14,984	$ 10,000
Management	$ 769	$ 1,224	$ 1,982	$ 1,931	$ 2,455	$ 2,339
Non-Union	$ 268	$ 863	$ 436	$ 769	$ 955	$ 526
Union	$ -	$ 265	$ 5	$ 485	$ -	$ -
Total	**$ 2,013**	**$ 1,780**	**$ 2,067**	**$ 1,920**	**$ 2,849**	**$ 1,767**
Compensation - Average Yearly Benefits						
Executive	$ 27,800	$ 18,714	$ 21,584	$ 27,322	$ 32,940	$ 32,823
Management	$ 21,846	$ 16,758	$ 17,375	$ 19,533	$ 21,695	$ 18,820
Non-Union	$ 20,340	$ 20,516	$ 20,996	$ 18,996	$ 24,993	$ 26,191
Union	$ 17,497	$ 15,776	$ 16,125	$ 17,429	$ 19,761	$ 20,103
Total	**$ 18,882**	**$ 16,420**	**$ 16,972**	**$ 18,274**	**$ 20,908**	**$ 20,801**
Total Compensation	$ 5,760,187	$ 5,852,286	$ 5,935,530	$ 6,084,269	$ 6,044,112	$ 7,061,370
Total Compensation Capitalized (CGAAP)	$ 2,886,918	$ 2,826,302	$ 2,757,625	$ 2,611,865	$ 2,581,945	$ 2,121,528
Total Compensation Charged to OM&A (CGAAP)	$ 2,873,269.18	$ 3,025,983.99	$ 3,177,905.12	$ 3,472,404.07	$ 3,462,166.65	$ 4,939,842.30
Total Compensation Capitalized (MIFRS)						
Total Compensation Charged to OM&A (MIFRS)						

b) PDI confirms Appendix 2-K is related to PDI only. A summary of PUSI employees from departments shared with PDI has been included in the following table.

Table 4-SEC-21b – PUSI Employee Costs

	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Actuals	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Number of Employees (FTEs including Part-Time)[1]						
Executive	5.0	5.0	5.0	5.0	5.0	5.0
Management	17.0	18.0	18.0	18.0	18.0	18.0
Non-Union	11.0	10.0	12.0	11.0	10.0	12.0
Union	73.0	73.0	69.0	70.0	72.0	75.0
Total	**106.0**	**106.0**	**104.0**	**104.0**	**105.0**	**110.0**
Number of Part-Time Employees (Headcount)						
Executive						
Management						
Non-Union						
Union	5.0	3.0	5.0	6.0	3.0	3.0
Total	**5.0**	**3.0**	**5.0**	**6.0**	**3.0**	**3.0**
Total Salary and Wages						
Executive	$ 579,166	$ 668,008	$ 724,572	$ 793,216	$ 765,555	$ 762,202
Management	$ 1,547,397	$ 1,592,868	$ 1,664,494	$ 1,658,475	$ 1,741,422	$ 1,727,167
Non-Union	$ 610,953	$ 659,560	$ 736,282	$ 574,508	$ 547,685	$ 716,771
Union	$ 4,609,090	$ 5,086,153	$ 4,721,341	$ 5,271,989	$ 5,052,851	$ 5,438,591
Total	**$ 7,346,606**	**$ 8,006,589**	**$ 7,846,689**	**$ 8,298,188**	**$ 8,107,513**	**$ 8,644,731**
Current Benefits						
Executive	$ 139,000	$ 93,572	$ 107,921	$ 136,611	$ 164,701	$ 171,252
Management	$ 371,375	$ 301,645	$ 312,753	$ 351,600	$ 390,504	$ 355,993
Non-Union	$ 223,737	$ 205,160	$ 251,953	$ 208,961	$ 249,926	$ 279,915
Union	$ 1,277,248	$ 1,151,648	$ 1,112,614	$ 1,219,997	$ 1,422,821	$ 1,507,699
Total	**$ 2,011,360**	**$ 1,752,024**	**$ 1,785,242**	**$ 1,917,169**	**$ 2,227,952**	**$ 2,314,860**
Accrued Pension and Post-Retirement Benefits						
Executive						
Management						
Non-Union	$ 100,654	$ 84,570	$ 105,483	$ 89,610	$ 126,188	$ 92,904
Union	$ 232,796	$ 202,968	$ 235,879	$ 230,424	$ 324,482	$ 227,049
Total	**$ 333,450**	**$ 287,538**	**$ 341,361**	**$ 320,034**	**$ 450,670**	**$ 319,953**
Total Benefits (Current + Accrued)						
Executive	$ 139,000	$ 93,572	$ 107,921	$ 136,611	$ 164,701	$ 171,252
Management	$ 371,375	$ 301,645	$ 312,753	$ 351,600	$ 390,504	$ 355,993
Non-Union	$ 324,392	$ 289,730	$ 357,436	$ 298,570	$ 376,114	$ 372,819
Union	$ 1,510,044	$ 1,354,616	$ 1,348,493	$ 1,450,422	$ 1,747,303	$ 1,734,748
Total	**$ 2,344,810**	**$ 2,039,562**	**$ 2,126,603**	**$ 2,237,203**	**$ 2,678,622**	**$ 2,634,813**
Total Compensation (Salary, Wages, & Benefits)						
Executive	$ 718,166	$ 761,580	$ 832,493	$ 929,827	$ 930,255	$ 933,454
Management	$ 1,918,772	$ 1,894,512	$ 1,977,247	$ 2,010,075	$ 2,131,926	$ 2,083,160
Non-Union	$ 935,345	$ 949,291	$ 1,093,718	$ 873,079	$ 923,799	$ 1,089,590
Union	$ 6,119,133	$ 6,440,769	$ 6,069,834	$ 6,722,410	$ 6,800,155	$ 7,173,339
Total	**$ 9,691,416**	**$ 10,046,151**	**$ 9,973,293**	**$ 10,535,391**	**$ 10,786,135**	**$ 11,279,544**
Compensation - Average Yearly Base Wages						
Executive	$ 110,424	$ 123,305	$ 127,766	$ 138,774	$ 138,127	$ 142,440
Management	$ 90,254	$ 87,268	$ 90,490	$ 90,206	$ 94,291	$ 93,615
Non-Union	$ 55,273	$ 65,093	$ 60,921	$ 51,459	$ 53,814	$ 59,205
Union	$ 57,312	$ 60,995	$ 61,308	$ 63,795	$ 62,505	$ 66,739
Total	**$ 57,087**	**$ 61,385**	**$ 61,266**	**$ 62,749**	**$ 61,820**	**$ 68,630**
Compensation - Average Yearly Overtime						
Executive						
Management						
Non-Union						
Union	$ 5,826	$ 8,414	$ 7,112	$ 11,034	$ 7,673	$ 5,776
Total						
Compensation - Average Yearly Incentive Pay						
Executive	$ 5,409	$ 10,297	$ 17,149	$ 19,869	$ 14,984	$ 10,000
Management	$ 769	$ 1,224	$ 1,982	$ 1,931	$ 2,455	$ 2,339
Non-Union	$ 268	$ 863	$ 436	$ 769	$ 955	$ 526
Union	$ -	$ 265	$ 5	$ 485	$ -	$ -
Total	**$ 2,013**	**$ 1,780**	**$ 2,067**	**$ 1,920**	**$ 2,849**	**$ 1,767**
Compensation - Average Yearly Benefits						
Executive	$ 27,800	$ 18,714	$ 21,584	$ 27,322	$ 32,940	$ 34,250
Management	$ 21,846	$ 16,758	$ 17,375	$ 19,533	$ 21,695	$ 19,777
Non-Union	$ 20,340	$ 20,516	$ 20,996	$ 18,996	$ 24,993	$ 23,326
Union	$ 17,497	$ 15,776	$ 16,125	$ 17,429	$ 19,761	$ 20,103
Total	**$ 18,882**	**$ 16,420**	**$ 16,972**	**$ 18,274**	**$ 20,908**	**$ 20,801**
Total Compensation	$ 9,691,416	$ 10,046,151	$ 9,973,293	$ 10,535,391	$ 10,786,135	$ 11,279,544

4-SEC-22

Reference: Exhibit 4, Tab 2, Schedule 5 p 4-53

With respect to Table 4-30 and 4-31:

a) Please confirm that the total PUSI budget for 2013 is $17,511,825 ($9,806,622/.56) and for 2009 Board approved was $14,885,515 ($8,291,232/.557).

b) Please provide a table for each of 2013 budget, 2012 actuals, 2011 actuals, and 2009 Board approved showing the total PUSI budget in each expense category (at least the categories listed in Table 4-30), how much of that budget is allocated to each entity within the PUG, and the basis of the allocation.

PDI Response

a) The PUSI budget for the activities listed in Table 4-30 and 4-31 is $17,507,796 for 2013 and $15,314,736 for 2009 Board Approved. PDI notes that there is an error on the last line of Table 4-30. PDI's 2009 Board Approved percentage should read 54.1%.

b) PDI has summarized the basis for allocation based on the information provided in Exhibit 4, Tab 2, Schedule 5 in the table below.

Table 4-SEC-22b1 – Basis for Allocation of Corporate Costs

ACTIVITY	Basis for Allocation
Electric Distribution Operations	Direct
Engineering Services	Direct
Field Technical Operations	Direct
Vehicles	Direct
Stores	Stores inventory issues
Customer Service	Number of customers, line items on bill
Administration	Direct where applicable; all other based on support allocations
Corporate Services	Direct where applicable; all other based on Customer Service
Finance	Direct where applicable; all other based on GL activity
Technology Services	Direct where applicable; all other based on number of users
Human Resources	Direct where applicable; number of employees
Purchasing	Purchase orders and inventory transactions
Facilities Management	Square footage useage
Software & Equipment Rent	Billing system - to Customer Service; all other base on Administration

PDI has provided a table for each of 2013 budget, 2012 actuals, 2011 actuals, and 2009 Board Approved as requested.

Table 4-SEC-22b2 – 2009 Board Approved PUSI Shared Services and Corporate Costs

	2009 Board Approved					
	PUSI	PDI	PUC	PUI	PUSI	Outside PUG
ACTIVITY	$	%	%	%	%	%
Electric Distribution Operations	2,305,598	85%	0%	1%	15%	0%
Engineering Services	1,899,924	53%	45%	1%	1%	0%
Field Technical Operations	605,051	100%	0%	0%	0%	0%
Vehicles	903,941	44%	40%	0%	16%	0%
Stores	284,399	71%	6%	23%	0%	0%
Customer Service	1,880,696	73%	23%	3%	1%	0%
Administration	1,426,913	37%	35%	17%	4%	8%
Corporate Services	384,582	79%	17%	3%	1%	0%
Finance	464,675	39%	30%	18%	10%	4%
Technology Services	2,904,228	22%	12%	7%	1%	59%
Human Resources	815,387	37%	40%	9%	5%	9%
Purchasing	187,898	38%	40%	12%	6%	4%
Facilities Management	803,008	64%	31%	2%	1%	3%
Software & Equipment Rent	448,436	49%	39%	12%	0%	0%

Table 4-SEC-22b3 – 2011 Actual PUSI Shared Services and Corporate Costs

	2011 Actual					
	PUSI	PDI	PUC	PUI	PUSI	Outside PUG
ACTIVITY	$	%	%	%	%	%
Electric Distribution Operations	2,512,005	87%	0%	1%	12%	0%
Engineering Services	1,524,696	52%	46%	0%	1%	0%
Field Technical Operations	534,662	99%	0%	0%	1%	0%
Vehicles	1,030,496	50%	34%	1%	16%	0%
Stores	191,361	73%	4%	16%	7%	0%
Customer Service	1,812,436	70%	25%	3%	1%	0%
Administration	1,354,198	40%	38%	17%	5%	0%
Corporate Services	329,758	82%	15%	3%	1%	0%
Finance	377,870	38%	28%	28%	6%	0%
Technology Services	3,358,691	18%	12%	6%	1%	63%
Human Resources	771,065	39%	42%	12%	7%	0%
Purchasing	278,227	40%	41%	12%	7%	0%
Facilities Management	1,051,009	49%	37%	5%	0%	8%
Software & Equipment Rent	369,726	42%	46%	12%	0%	0%

Table 4-SEC-22b4– 2012 Actual PUSI Shared Services and Corporate Costs

	2012 Actual					
	PUSI	PDI	PUC	PUI	PUSI	Outside PUG
ACTIVITY	$	%	%	%	%	%
Electric Distribution Operations	2,463,429	90%	1%	1%	9%	0%
Engineering Services	1,601,568	53%	45%	0%	1%	0%
Field Technical Operations	633,333	99%	0%	0%	1%	0%
Vehicles	1,079,128	49%	37%	5%	10%	0%
Stores	219,039	76%	4%	15%	5%	0%
Customer Service	1,884,046	67%	28%	4%	1%	0%
Administration	1,563,252	33%	38%	27%	2%	0%
Corporate Services	309,834	84%	13%	2%	0%	0%
Finance	374,180	40%	26%	28%	5%	0%
Technology Services	3,131,327	18%	13%	6%	1%	62%
Human Resources	771,274	40%	44%	13%	3%	0%
Purchasing	300,435	39%	36%	17%	8%	0%
Facilities Management	998,000	49%	38%	5%	0%	9%
Software & Equipment Rent	338,385	41%	38%	22%	0%	0%

Table 4-SEC-22b5 – 2013 Budget PUSI Shared Services and Corporate Costs

	2013 Test Year					
	PUSI	PDI	PUC	PUI	PUSI	Outside PUG
ACTIVITY	$	%	%	%	%	%
Electric Distribution Operations	2,524,938	88%	0%	0%	11%	0%
Engineering Services	2,117,401	59%	41%	0%	0%	0%
Field Technical Operations	898,940	100%	0%	0%	0%	0%
Vehicles	1,167,088	47%	26%	5%	21%	0%
Stores	158,184	76%	4%	15%	5%	0%
Customer Service	2,110,523	69%	28%	3%	1%	0%
Administration	1,389,174	40%	40%	15%	5%	0%
Corporate Services	394,510	88%	11%	1%	0%	0%
Finance	558,860	56%	19%	18%	6%	0%
Technology Services	3,447,247	26%	14%	6%	0%	55%
Human Resources	903,942	35%	41%	12%	12%	0%
Purchasing	309,489	40%	27%	27%	6%	0%
Facilities Management	1,038,000	51%	39%	5%	0%	5%
Software & Equipment Rent	489,500	42%	41%	16%	0%	0%

4-SEC-23

Reference: Exhibit 4, Appendix G

With respect to the opinion of the accountants:

a) Please provide details of the expertise of the firm providing the opinion in the policies and practices of the OEB.

b) Please provide a detailed list of all accounting, consulting and other engagements by Collins Barrow Kawarthas LLP or any related firm since 2012 with any of the Peterborough Utilities Group, the City of Peterborough, or any related entity.

PDI Response

a) Collins Barrow ("CB") is one of Canada's largest Chartered Accounting Firms. As a Chartered Accounting firm its staff and partners are professionally training and licensed to conduct review and audit engagements on financial statements as well as other financial information. The profession requires and regulates its members in terms of reporting disclosures, independence, and training to ensure reliance may be placed on their work.

Specific guidelines and standards are provided for its members on are provided for Review of Financial Information other than Financial Statements (Section 8500) as well as Review of Compliance with Agreements, Statutes and Regulations (Section 8600). The partners involved on the report for PDI are actively involved with 3 LDC's providing Audit, Tax and other services, such as this as required by its clients.

The following excerpt was obtained from the Collins Barrow website:

"Collins Barrow is Canada's largest association of Chartered Accounting firms and the eighth largest group of chartered accountants in Canada. Our clients come from a cross section of industries including: Private Equity, Manufacturing, Industrial, Wholesale, Retail and Distribution, Professional Services, Financial Services, Real Estate and Land Development, Hospitality and Entertainment, Technology and Communications, Energy and Mining, Biotech and Not for Profit. Our understanding and firsthand experience in the trends that are impacting these industries continues to prove that our professionals are well positioned to offer valued and effective solutions."

b) Since 2012, the only engagement Collins Barrow has completed for PDI and other members of the Peterborough Utilities Group are the 2012 year-end audits for each of our companies together with this report and tax preparation services for one of our affiliates. CB was recently successful in the City of Peterborough Tender for Audit Services, and as such will have recently completed the 2012 Audit for the City of Peterborough and all of its other Affiliates. PDI is not aware of work provided by CB to entities beyond the Peterborough Utilities Group umbrella. As noted in the response to part a) of this question as a Chartered Accounting firm, CB is bound by the independence requirements of the profession.

4-VECC–18

Reference: Exhibit 4, Tab 1, Schedule 1, Tab 2 Schedule 3 / Exhibit 1, Tab 2, Schedule 1

a) At Exhibit 1 PDI discuss the FUSE program. At Exhibit 4 there is a discussion of $20,000 in LEAP funding. Please explain how these programs work together (or separately) and if there is additional funding for the FUSE program

b) Please explain what if any relationship this program has (had) with the City of Peterborough program for assistance that is described at Exhibit 4, Tab 2, Schedule 3, page 4-27.

PDI Response

a) Both funds are administered by the Housing Resource Centre and assist low-income customers to prevent disconnection or restore services following disconnection.

   FUSE is funded by donations from PDI customers who have the option to make a donation on their monthly utility bill, and prior to 2011 by a corporate contribution from PDI.

   Since 2011 PDI has contributed to the LEAP fund instead of FUSE. Please refer to the response to 1-Energy Probe-3(b) for a breakdown of PDI contributions to LEAP and FUSE. The column labelled "Other" is the FUSE fund.

b) The programs referred to on page 4-27 are Discretionary Benefits and the Community Start Up Benefit. These funds assist the same client group as the FUSE and LEAP funds. A decrease in the amount of Discretionary Benefits and Community Start Up Benefit funds available places increased pressure on the LEAP and FUSE funds.

4-VECC–19

Reference: Exhibit 4, Tab 2, Schedule 3

a) Please provide a breakdown and comparison of account 5315 Customer billing in 2009 (pre-smart meters) and in 2013 (post smart meters.

b) Please provide the meter reading costs for 2009 through 2013.

PDI Response

a) Meter reading costs were included in Account 5315 Customer Billing as shown in the following table:

	2009 Actual	2013 Forecast
Account 5315 - Customer Billing		
Meter reading expense included in 5315	320,787	191,000
Other customer billing expenses	558,332	889,326
Total Account 5315	879,119	1,080,326

b) Meter reading costs are as follows

- 2009 $320,787
- 2010 $300,706
- 2011 $187,194
- 2012 $184,764
- 2013 test year $191,000

4-VECC–20

Reference: Exhibit 4, Tab 2, Schedule 3, pg. 4-21

a) PDI states it is forecasting $100,000 more in storm damage costs in 2013 as compared to 2009. What was the amount forecast for storm damage in the 2009 cost of service application?

b) Please provide the storm damage expenses in each of 2009 through 2012.

c) Does PDI carry insurance for storm damage? If so please provide the insurance benefits paid in each of the years 2009 through 2013.

PDI Response

a) The amount forecast in Account 5125 for storm damage in the 2009 cost of service application was $41,820.

b) Storm damage costs recorded in Account 5125 are as follows:

- 2009 $67,868
- 2010 $22,583
- 2011 $275,974
- 2012 actual $168,681
- 2013 test year $147,902

c) PDI does not carry insurance for storm damage.

4-VECC–21

Reference: Exhibit 4, Tab 2, Schedule 3/Schedule 6

a) Please provide the fees paid to the EDA for each of the years 2009 through 2013 (forecast).

b) Does PDI purchase insurance from the MEARIE Group? If so please describe the coverage provided, the premiums in 2012 and 2013 (forecast). Please also indicate whether insurance for 2013 was competitively tendered or sole sourced.

PDI Response

a) Annual EDA fees are as follows:

- 2009 actual $48,500
- 2010 actual $50,500
- 2011 actual $52,100
- 2012 actual $55,000
- 2013 test year $60,000

b) PDI purchases liability insurance from the MEARIE Group. The premiums for 2012 were $74,800 and included a premium discount of approximately 20%. The premiums forecast for 2013 are $95,237. Liability insurance was sole sourced.

4-VECC–22

Reference: Exhibit 4, Tab 2, Schedule 3, pg. 4-23

a) Please explain the methodology for forecasting bad debt expense (account 5335).

b) Please provide the actual 2012 bad debt expense.

c) Has PDI has changed from bi-monthly to monthly billing for any class of customers since its last cost of service application (2008-09)? If yes, please explain how this has impacted bad debt expenses. What is the current billing period (e.g. monthly or bimonthly) for each class?

PDI Response

a) PDI reviews the historical 5 year average of bad debt expense and compares this to receivables aging and a risk assessment of external factors that impact bad debts, such as social assistance availability, or other regulatory changes impacting payments or deposits.

b) Bad debt expense for 2012 was $162,459.

c) All classes are billed monthly. This has not changed since 2008/2009.

4-VECC–23

Reference: Exhibit 4, Tab 2, Schedule 4, Appendix 2-K

a) PDI has added (or contracted for) 6 new FTEs since 2009. Please provide a list of each of the new incremental positions that was added since 2009. Please provide a brief job description and indicate whether the position is related to a new incremental responsibilities that has arisen since 2009 (e.g. TOU Billing/CDM/GEA planning etc.) or whether the position was required to meet utility customer growth, or was for succession planning.

b) Please provide the total cost of these positions (salary and benefits) and the amount in 2013 allocated to PDI.

PDI Response

a) Please refer to the table below for a summary of the incremental positions since 2009.

Table 4-VECC-23 – PDI Incremental Positions

	Position	Job Duties	Rationale
1	Billing Integration Specialist	- Ongoing system changes due to OEB code amendments and time of use billing rate changes - Ongoing MDMR integration and reporting	Incremental responsibilities
2	Lineman	- Line Maintenance - Capital Construction - Emergency Response	Reduction in hours available due to increased storm response; maintenance; and restrictions from CVOR (increased rest periods)
3	Field Technician	- Load dispatching (Control Centre) - Substation and Meter Maintenance - Smart Meter Troubleshooting and Maintenance - Transformer Maintenance	Additional meter maintenance and troubleshooting for smart meter systems. Rotations to fill in for additional Load Dispatching (Control Centre) responsibilities.
4	Business Process Analyst	- Implement process improvements through system automation	Incremental responsibilities - increased complexity in business processes
5	Engineer	- Asset management planning - System planning and technical analysis	Incremental responsibilities
6	Financial Analyst-Regulatory	- Rate filings - Ongoing regulatory reporting and compliance	Incremental responsibilities

b) The salaries and benefits of the new positions is $492,000. PDI is allocated these new positions based on their respective department departmental allocations as provided in Exhibit 4, Tab 2, Schedule 5 Table 4-29. The total cost to PDI is $303,000.

4-VECC-24

Exhibit 4, Tab 2, Schedule 5

At Table 4-30 it shows that Vehicle related costs have increased by $152,190. Please explain why and provide a list of all vehicles used by PDI at year-end 2009 and at year-end 2012.

PDI Response

In Table 4-30, PDI's vehicle costs show a variance of $152,190 in 2013 versus 2009 Board Approved. Subsequent to the 2009 Cost of Service, a new truck was purchased to assist with GIS and locate activity. The remainder of the increase can be explained by an increase in maintenance costs over the 4 year period. A list of vehicles for 2009 and 2012 has been provided in the following tables.

Table 4-VECC-24a 2009 Vehicles

#	Description	Make	Model
5	Double Bucket	INTL	4900 4x2
6	Derrick Truck	INTL	4900
8	Single Bucket	INTL	DURASTAR
9	Single Bucket	INTL	4600
10	Derrick Truck	INTL	7400
11	Pick up	GMC	SILVERADO
16	Van	GMC	Cargo 1500
17	Double Bucket	INTL	7500
19	Pick up	CHEV	1500
21	Van	CHEV	UPLANDER
23	Single Bucket	INTL	4400
29	Small Pickup	CHEV	COLORADO
33	Pick up	CHEV	COLORADO
34	Dump Truck	GMC	3500
36	Transit Connect	CHEV	C.U.V
37	Compact Utility Vehicle	GMC	CONNECT
41	Crew Truck	GMC	SILVERADO
51	Double Bucket	INTL	7400
52	Pick up	CHEV	SILVERADO
53	Crew Truck	GMC	SILVERADO
54	Pick up	GMC	SIERRA
56	Crew Truck	GMC	3500
57	Flat Bed Trailer (Trench Box)	BCF	TRAILER
58	Pick up	CHEV	COLORADO
97	Tension Stringer/Puller	TIMBERLD	DPT40B
98	Tension Stringer/Puller	TIMBERLD	DPT40B
115	Pickup Truck	FORD	Ranger
325	Pole Trailer (Large)	TJWL	TRAILER
327	Reel Trailer (Large)	MART	THREE REEL
328	Reel Trailer (Small)	LBW	UTILITY

Table 4-VECC-24b 2012 Vehicles

#	Description	Make	Model
5	Double Bucket	INTL	4900 4x2
6	Derrick Truck	INTL	4900
8	Single Bucket	INTL	DURASTAR
9	Single Bucket	INTL	4600
10	Derrick Truck	INTL	7400
11	Pick up	CHEV	SILVERADO
16	Van	GMC	Cargo 1500
17	Double Bucket	INTL	7500
19	Pick up	GMC	1500
21	Van	CHEV	UPLANDER
23	Single Bucket	INTL	4400
29	Small Pickup	CHEV	COLORADO
33	Pick up	FORD	Ranger
34	Dump Truck	GMC	3500
36	Transit Connect	FORD	C.U.V
37	Compact Utility Vehicle	FORD	CONNECT
41	Crew Truck	CHEV	SILVERADO
51	Double Bucket	INTL	7400
52	Pick up	CHEV	SILVERADO
53	Crew Truck	GMC	SILVERADO
54	Pick up	CHEV	SILVERADO
56	Crew Truck	GMC	3500
57	Flat Bed Trailer (Trench Box)	BCF	TRAILER
58	Pick up	FORD	Ranger
97	Tension Stringer/Puller	TIMBERLD	DPT40B
98	Tension Stringer/Puller	TIMBERLD	DPT40B
115	Pickup Truck	FORD	Ranger
122	Pickup Truck	FORD	Ranger
325	Pole Trailer (Large)	TJWL	TRAILER
327	Reel Trailer (Large)	MART	THREE REEL
328	Reel Trailer (Small)	LBW	UTILITY

4-VECC–25

<u>Reference: Exhibit 4, Tab 3, Schedule 1</u>

Please provide the actual PILs remitted in each of 2009 through 2012.

PDI Response

Actual PILs remitted are as follows:

- 2009 $1,190,275
- 2010 $1,224,449
- 2011 $749,099
- 2012 $1,056,000

4-VECC–26

<u>Reference: Exhibit 4, Appendix G</u>

a) Was the letter from Collins Barrow the only report provided on the assessment of the corporate cost allocation? If not, please provide the full report. If yes, please explain how PDI came to the conclusion that the study was adequate.

b) Please provide the cost of the study.

PDI Response

a) The Collins Barrow report was the only third party assessment of the corporate cost allocation performed. The report included with the application was missing "Appendix 1 – Corporate Costs 2009 through 2011" which has been provided in this submission. PDI believes the study is adequate based on Collins Barrow's qualifications as detailed in PDI's reply to SEC – 24, and the fact that the report provides assurance regarding compliance with OEB allocation principles for three recent years, which reconcile to the PDI application. The principles applied during the three years reviewed are the same as those followed in 2012 and for the 2013 test year.

b) As auditors of PDI, PUSI, PUI and the PUC, for all of the years in question, Collins Barrow was knowledgeable of PUG systems and processes and able to efficiently and effectively assess methodology. Review of the costs could be achieved efficiently by leveraging on working papers prepared over the course of the regular audit. Alternate providers of such assurance would be required to redo all of the quantitative work in addition to assessing allocation principles. Accordingly the Collins Barrow report was deemed to be most cost efficient, professional means of providing the required assurance for our rate payers. The study cost was $2,034.

PETERBOROUGH DISTRIBUTION INC.

2013 COST OF SERVICE RATE APPLICATION

RESPONSE TO INTERROGATORIES

EXHIBIT 5 – COST OF CAPITAL AND RATE RETURN

EB-2012-0160

FILED: MAY 27, 2013

5-VECC–27

<u>Reference: Exhibit 5, Tab 1, Schedule 1</u>

Please provide the actual and deemed rate of return on equity for PDI for each of the years 2009 through 2012.

PDI Response

PDI has provided PDI's actual and deemed ROE for the years requested in the following table.

Table 5-VECC-27 – Actual vs Deemed Return on Equity 2009 through 2012

	2009	2010	2011	2012
Actual ROE	6.76%	8.86%	6.43%	5.36%
Deemed ROE	8.01%	8.01%	8.01%	8.01%

5-VECC–28

<u>Reference: Exhibit 5, Tab 1, Schedule 1, pg. 5-2</u>

PDI explains that it is negotiations to place $20,996,000 in long-term debt. Please update the status of these negotiations. In particular, please clarify whether the loan has been placed, with whom, the term and interest rate. If the negotiations have not been finalized please indicate when this will occur.

PDI Response

PDI has recently obtained financing from the Toronto Dominion Bank of $21,657,680 replacing the financing previously in place from PDI's parent company. The loan is currently provided on a variable short term basis, but can be converted to a fixed long term rate at the option of PDI. PDI is currently exploring this opportunity. The long-term rate has not yet been negotiated but PDI expects the rate negotiated will approximate the deemed long-term debt rate specified in the updated cost of capital parameters.

PETERBOROUGH DISTRIBUTION INC.

2013 COST OF SERVICE RATE APPLICATION

RESPONSE TO INTERROGATORIES

EXHIBIT 6 – REVENUE DEFICIENCY OR SURPLUS

EB-2012-0160

FILED: MAY 27, 2013

6-Energy Probe-23

Ref: Exhibit 6, Tab 1, Schedule 1

a) Please update Table 6-1 to reflect the short term debt rate and return on equity to reflect the Board's February 14, 2013 letter on the Cost of Capital Parameter Updates for 2013 Cost of Service Applications for Rates Effective May 1, 2013, along with any updates or changes that PDI proposes to make as a result of the interrogatory responses.

b) Please provide an updated RRWF in live Excel spreadsheet to reflect the response in part (a).

c) Please provide a table that shows a summary of the proposed cumulative changes noted in (a) above, along with a reference for each individual change to the corresponding interrogatory response.

PDI Response

a) PDI has provided an update to Table 6-1 reflecting the short-term debt rate of 2.07% and return on equity of 8.98%, along with the changes noted in response to 1-VECC-2.

Table 6-1 Revenue Deficiency

Description	2012 Bridge Actual	2013 Test Existing Rates	2013 Test - Required Revenue
Revenue			
Revenue Deficiency			516,958
Distribution Revenue	13,882,200	14,424,089	14,424,089
Other Operating Revenue (Net)	1,054,000	1,318,800	1,318,800
Total Revenue	**14,936,200**	**15,742,889**	**16,259,847**
Costs and Expenses			
Administrative & General, Billing & Collecting	4,460,697	5,858,459	5,858,459
Operation & Maintenance	2,894,971	3,380,332	3,380,332
Depreciation & Amortization	4,168,702	2,673,856	2,673,856
Property Taxes	126,150	105,000	105,000
Deemed Interest	1,643,062	1,630,846	1,630,846
Deferred PP&E Adjustment - Depreciation		0	0
Deferred PP&E Adjustment to Return on Rate Base			0
Total Costs and Expenses	**13,293,582**	**13,648,493**	**13,648,493**
Utility Income Before Income Taxes	**1,642,618**	**2,094,396**	**2,611,355**
Income Taxes:			
Corporate Income Taxes	407,400	137,586	254,125
Total Income Taxes	**407,400**	**137,586**	**254,125**
Utility Net Income	**1,235,218**	**1,956,810**	**2,357,230**
Income Tax Expense Calculation:			
Accounting Income	1,642,618	2,094,396	2,611,355
Tax Adjustments to Accounting Income	26,816	(1,484,070)	(1,484,070)
Taxable Income	**1,669,435**	**610,326**	**1,127,284**
Income Tax Expense	407,400	137,586	254,125
Tax Rate Refecting Tax Credits	24.40%	22.54%	22.54%
Actual Return on Rate Base:			
Rate Base	63,267,769	65,624,434	65,624,434
Interest Expense	1,643,062	1,630,846	1,630,846
Net Income	1,235,218	1,956,810	2,357,230
Total Actual Return on Rate Base	**2,878,280**	**3,587,656**	**3,988,075**
Actual Return on Rate Base	4.55%	5.47%	6.08%
Required Return on Rate Base:			
Rate Base	63,267,769	65,624,434	65,624,434
Return Rates:			
Return on Debt (Weighted)	4.33%	4.14%	4.14%
Return on Equity	8.01%	8.98%	8.98%
Deemed Interest Expense	1,643,062	1,630,846	1,630,846
Return On Equity	2,027,099	2,357,230	2,357,230
Total Return	**3,670,161**	**3,988,075**	**3,988,075**
Expected Return on Rate Base	5.80%	6.08%	6.08%
Revenue Deficiency After Tax	**791,881**	**400,420**	**0**
Revenue Deficiency Before Tax	**1,047,510**	**516,958**	**0**

b) PDI has provided an update to the RRWF to reflect the changes outlined in a) and c) in Excel format.

c) PDI has provided a table of the proposed changes to revenue requirement in response to 1-VECC-2.

PETERBOROUGH DISTRIBUTION INC.

2013 COST OF SERVICE RATE APPLICATION

RESPONSE TO INTERROGATORIES

EXHIBIT 7 – COST ALLOCATION

EB-2012-0160

FILED: MAY 27, 2013

7-Energy Probe-24

Ref: Exhibit 7, Tab 1, Schedule 1

a) Please confirm that figures shown in Table 7-3 for meter capital costs include average costs for smart meters.

b) For each of Tables 7-1, 7-2, 7-3 and 7-4, please provide a table that shows the proposed weights by rate class and the weights used in the last cost of service application.

c) Based on the differences shown in the response to part (b) above, please show, for each of the four weighting factors, the change in costs allocated to each rate class.

PDI Response

a) The figures shown in Table 7-3 for meter capital costs include average costs for smart meters.

b) The following Tables 7-1, 7-2, 7-3 and 7-4, have been revised to show the proposed weights by rate class and the weights used in the last cost of service application which was based on the original cost allocation study.

Table 7-1: Service Weighting Factors		
Rate Class	2013 Factor	Original Factor
Residential	1.00	1.0
General Service < 50 kW	6.61	2.0
General Service > 50 kW	41.30	10.0
Large User	0.0	30.0
Street Lighting	0.0	1.0
Sentinel Lighting	0.0	1.0
Unmetered Scattered Load	0.32	1.0

Table 7-2: Billing Weighting Factors		
Rate Class	2013 Factor	Original Factor
Residential	1.00	1.0
General Service < 50 kW	0.87	2.0
General Service > 50 kW	0.93	7.0
Large User	0.74	15.0
Street Lighting	0.62	1.0
Sentinel Lighting	0.82	0.1
Unmetered Scattered Load	0.82	1.0

Table 7-3: Meter Capital Installation Costs Per Meter		
Meter Type	2013	Original
Smart Meter – Residential	$87	
Smart Meter - General Service < 50 kW	$304	
Single Phase 200 Amp – Urban		$70
Single Phase 200 Amp – Rural		$170
Central Meter		$270
Network Meter (Costs to be updated)		$245
Three-phase - No demand		$230
Demand without IT (usually three-phase)		$520
Demand with IT	$2,170	$2,100
Demand with IT and Interval Capability - Secondary	$2,500	$2,300
Demand with IT and Interval Capability - Primary	$10,000	$10,000

Table 7-4: Meter Reading Weighting Factor		
Meter Type	2013 Factor	Original Factor
Residential	1.00	
General Service < 50 kW	1.00	
General Service > 50 kW	1.00	
Large User	1.00	
Residential - Urban - Outside		1.00
Residential - Urban - Outside with other services		1.00
Residential - Urban - Inside		2.00
Residential - Rural - Outside		3.00
GS – Walking		2.00
GS - Walking - with other		3.00
GS - Vehicle with other		3.00
Interval		49.00

c) The change in costs allocated to each rate class by using the original weighting factors for services is provided below.

Rate Class	Cost Allocated in the 2013 Study	Cost Allocated in the 2013 Study with Original Service Weighting Factors	Change
Residential	$10,471,540	$10,427,365	$44,175
General Service < 50 kW	$2,395,636	$2,118,991	$276,645
General Service > 50 kW	$2,614,948	$2,614,948	$0
Large User	$261,368	$261,368	$0
Street Lighting	$469,886	$775,535	($305,649)
Sentinel Lighting	$29,022	$34,573	($5,551)
Unmetered Scattered Load	$49,437	$59,058	($9,621)
Total	$16,291,837	$16,291,837	$0

The change in costs allocated to each rate class by using the original weighting factors for billing and collecting is provided below.

Rate Class	Cost Allocated in the 2013 Study	Cost Allocated in the 2013 Study with Original Billing and Collecting Weighting Factors	Change
Residential	$10,471,540	$10,002,023	$469,517
General Service < 50 kW	$2,395,636	$2,682,357	($286,721)
General Service > 50 kW	$2,614,948	$2,805,919	($190,971)
Large User	$261,368	$263,711	($2,343)
Street Lighting	$469,886	$469,975	($89)
Sentinel Lighting	$29,022	$18,392	$10,630
Unmetered Scattered Load	$49,437	$49,460	($22)
Total	$16,291,837	$16,291,837	$0

The change in costs allocated to each rate class by using the original meter installation cost is provided below. With the installation of smart meters the analysis below only reflects the original meter installation cost being used for meters that are not classified as smart meters.

Rate Class	Cost Allocated in the 2013 Study	Cost Allocated in the 2013 Study with Original Meter Installation Costs	Change
Residential	$10,471,540	$10,476,470	($4,930)
General Service < 50 kW	$2,395,636	$2,397,560	($1,924)
General Service > 50 kW	$2,614,948	$2,608,059	$6,889
Large User	$261,368	$261,404	($36)
Street Lighting	$469,886	$469,886	$0
Sentinel Lighting	$29,022	$29,022	$0
Unmetered Scattered Load	$49,437	$49,437	$0
Total	$16,291,837	$16,291,837	$0

7-SEC-24

Reference: Exhibit 7, Tab 1, Schedule 1, page 7-2

Please provide a detailed rationale for the 41.3 services weighting for GS>50.

PDI Response

The weightings were determined using a typical installation cost for each type of service (high voltage, low voltage, overhead, underground and weighted according to an estimate of the number of each type of service in our system. The total cost estimated was averaged for the rate class. GS>50 kW services in our territory are predominantly underground services and typically with larger three phase padmounted transformers.

7-SEC-25

Reference: Exhibit 7, Tab 1, Schedule 1, page 7-3

Please confirm that all GS>50 customers' meters are being replaced with smart meters. Please advise the meter costs for cost allocation purposes applicable to GS>50 customers with smart meters.

PDI Response

All GS>50 kW customers with the exception of interval metered (MIST) customers will have their metering installations upgraded to three element and smart meters. The meter cost for cost allocation purposes applicable to GS>50 customers with smart meters is $696,570.

7-VECC–29

Reference: Exhibit 7, Tab 1, Schedule 1, page 7-2 to 7-4

a) Please confirm that for classes other than Residential, GS<50, GS>50 and USL the customers are required to own and maintain the service assets.

b) If this is not the case, please explain why there are no Services weighting factors for these other classes.

c) Why are the Billing and Collecting weighting factors for Residential and GS<50 not equivalent, as both have the same types of rates and the SME is responsible for processing the meter reading data for both classes.

d) Who performs the billing data verification and validation process for PDI's GS>50 and Large User classes – is it PDI or the SME?

e) Given the GS>50 and Large User classes are billed on hourly prices why is their weighting factor less that for either Residential or GS<50?

f) Please explain why the meter reading weighting factors are the same for all customer classes.

g) Does PDI have more recent hourly load data than 2004 for either is GS>50 or Large User classes? If yes, why weren't the load profiles for these classes updated to reflect this newer data?

PDI Response

a) Yes, except Large User can request standard outdoor 1500 kVA transformer supplied by PDI. PDI is contemplating a future change to its Conditions of Service to eliminate the provision of any service assets to the Large User class. None have been supplied in recent years.

b) There are no Services weighting factors for the Large User class as none have been supplied in recent years. PDI is contemplating a future change to eliminate this provision as noted above.

c) The weighting factor is higher for the residential class as there is more effort involved in collecting due to the Customer Service Code Amendments for Residential Electricity Customers.

d) PDI performs the billing data verification and validation process for PDI's GS>50 and Large User classes.

e) The weighting factor is less for the GS>50 and Large User classes because there is less collection effort than for the Residential or GS<50 classes.

f) The meter reading weighting factors are the same for all customer classes because nearly all meters are read remotely.

g) PDI does not have more recent hourly load data.

7-VECC–30

<u>Reference: Cost Allocation Model, Sheet I8</u>

Why are the Secondary NCP values for the GS<50 class substantially less than the Primary and Line Transformer NCP values (i.e. more than 50% less) whereas for the Residential class the values are virtually equivalent?

PDI Response

The Secondary NCP values for the GS<50 class are substantially less than the Primary and Line Transformer NCP values since the number of GS<50 customers using the Secondary System is substantially less than those using the Primary System and PDI's Line Transformers. As shown in Sheet I6.2, 1,514 GS < 50 customers use the Secondary system while 3,547 customers use the Primary system and 3,511 GS<50 customers use PDI's Line Transformers. The NCP values have been adjusted to reflect the numbers of customers using various categories of capital assets.

7-VECC–31

Reference: Cost Allocation Model, Sheet I3

Please separate the meter reading expense, report it separately in Account 5310 (Sheet I3, line 393) and then provide an updated version of the Cost Allocation Model.

PDI Response

An updated cost allocation model is attached as PDI_APPL_2013 Cost AllocationModel_xlsm_20130225_Separate Meter Reading.xlsm.

PETERBOROUGH DISTRIBUTION INC.

2013 COST OF SERVICE RATE APPLICATION

RESPONSE TO INTERROGATORIES

EXHIBIT 8 – RATE DESIGN

EB-2012-0160

FILED: MAY 27, 2013

8-Preliminary-2

Ref: RTSR Model

Update RTSR models to incorporate 2013 UTR's (EB-2012-0031) and 2013 sub-transmission rates (EB-2012-0136).

PDI Response

The updated model is attached as "2013 RTSR MODEL_V3_20120628_PDI data updated April29.2013.xlsm."

8-Preliminary-3

Ref: Bill Impacts

Update bill impact models to reflect the changes to RTSRs referenced above and confirm that bill impacts continue to fall within accepted ranges.

PDI Response

The bill impact models have been updated and provided in Appendix 8-1. The bill impacts fall within accepted ranges as illustrated below.

Table 8-Preliminary-3 – Bill Impacts with Revised RTSRs

	Filed	Revised
Residential	0.88%	1.26%
GS < 50 kW	1.08%	1.46%
GS > 50 kW	-10.31%	-9.66%
Large Use	-11.07%	-10.46%
Unmetered Scattered Load	-45.73%	-45.52%
Sentinel Lighting	-23.79%	-23.33%
Street Lighting	-7.86%	-7.53%

8-Energy Probe-25

Ref: Exhibit 8, Tab 1, Schedule 4 & Exhibit 8, Tab 1, Schedule 6

Please explain why there are no rate schedules shown for MicroFit customers in either schedule 4 or schedule 6.

PDI Response

The MicroFIT service charge was inadvertently omitted from Schedule 4 and Schedule 6. Schedule 4 should have included PDI's current rate of $5.25 per month and Schedule 6 should have included a proposed rate of $5.40 per month in accordance with the Board's letter of September 30, 2012.

8-SEC-26

Reference: Exhibit 8, Tab 1, Schedule 1, page 8-4

Please confirm that, if the GS>50 fixed charge were set at the Min. System with PLCC, i.e. $86.31, the volumetric charge including the cost of the transformer allowance would be $3.1654/kW.

PDI Response

If the GS>50 fixed charge were set at the Min. System with PLCC, i.e. $86.31, the volumetric charge including the cost of the transformer allowance would be $3.1656/kW.

8-VECC–32

Reference: Exhibit 8, Tab 1, Schedule 1, page 8-2

a) Are the fixed-variable splits for the GS>50 and Large User classes based on variable revenues before or after deducting the transformer ownership allowance?

b) If before, please re-do Tables 8-3, 8-4 and 8-5 using variable revenues after the transformer allowance has been deducted.

PDI Response

a)The fixed-variable splits for the GS>50 and Large User classes are based on variable revenues after deducting the transformer ownership allowance.

b) Not required as per above answer.

8-VECC–33

Reference: Exhibit 8, Tab 1, Schedule 1, page 8-6

a) Please explain how the $684,342 in total LV costs for 2013 was established.

b) What were PDI's actual LV costs (as charged by Hydro One) in 2011 and 2012?

c) What was PDI's actual purchased energy for 2012?

PDI Response

a) The LV forecast was calculated using 2011 volumes and 2012 pricing.

b) Actual LV costs were $634,048 in 2011 and $715,326 in 2012.

c) Actual purchased energy for 2012 was $62,450,896.

PETERBOROUGH DISTRIBUTION INC.

2013 COST OF SERVICE RATE APPLICATION

RESPONSE TO INTERROGATORIES

EXHIBIT 9 – DEFERRAL AND VARIANCE ACCOUNTS

EB-2012-0160

FILED: MAY 27, 2013

9-Staff-29

<u>Ref: Exhibit 9, Tab 2, Schedule 3</u>
<u>Ref: Additional Information filed March 13, 2013</u>

a) Please provide a table similar to the one below that shows the LRAM amounts requested in this application by the year they are associated with and the year the lost revenues took place. Provide separate tables for each rate class.

b) Please discuss why PDI is not seeking to recover the persisting lost revenues in 2012 from 2005-2010 CDM programs at this time. Please reconcile your response with section 13.6 of the Board's CDM Guidelines (EB-2012-0003), which states that "LRAM for pre-2011 CDM activities should be completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application."

c) Please provide complete LRAM calculations for 2012 persisting lost revenues that are the result of 2005-2010 CDM programs.

d) Please provide LRAM specific rate riders, separate of any LRAMVA amounts claimed in relation to the effects of 2011 CDM programs in 2011. LRAMVA claim for effects of 2011 CDM programs in 2011:

e) Please provide LRAMVA specific rate riders, separate of any LRAM amounts claimed in relation to the persisting effects of 2005-2010 CDM programs.

PDI Response

a) The requested LRAM amount of $132,578 was for the year 2011 only, and included lost revenue for the year of $128,848 plus interest to April 30, 2013 of $3,730. The table requested by Board staff is provided for the year 2011:

Lost Revenues for 2011, incl interest to April 30, 2013

Residential Programs	Lost Revenue 2011
2005 programs	$ 2,620
2006 programs	$ 10,300
2007 programs	$ 28,379
2008 programs	$ 17,923
2009 programs	$ 7,340
2010 programs	$ 5,699
Total Residential	**$ 72,261**

GS<50 Programs	Lost Revenue 2011
2005 programs	$ 1,672
2006 programs	$ -
2007 programs	$ -
2008 programs	$ 1,557
2009 programs	$ 13,477
2010 programs	$ 15,512
Total GS<50	**$ 32,218**

GS>50 Programs	Lost Revenue 2011
2005 programs	$ -
2006 programs	$ -
2007 programs	$ -
2008 programs	$ 3,303
2009 programs	$ 14,201
2010 programs	$ 10,595
Total GS>50	**$ 28,099**

Total for all Classes	**$ 132,578**

b) PDI's 2012 rate application EB-2011-0194 filed under IRM requested the recovery of a Lost Revenue Adjustment Mechanism (LRAM) covering the effect of 2005 to 2010 programs in 2005 through 2010 and the persisting effects of 2005 to 2010 programs through April 2012. Board staff submitted that it was premature to consider lost revenues in 2011 and 2012 and the Board approved PDI's LRAM claim for the lost revenues over the 2005 to 2010 period, and did not approve the 2011 and 2012 persisting lost revenues. Based on this Decision, PDI believed that it would still be premature to file for recovery of 2012 persisting lost revenues.

   Furthermore, PDI believed it was following the guidance of Section 13.6 of the Board's CDM Guidelines (EB-2012-0003), Appendix A page 2, which indicates that LDC's filing a Cost of Service Application in 2009 and 2013 should file to recover LRAM 2010 persistence in 2011 with its 2013 COS application, and LRAM 2010 persistence in 2012 with its 2014 IRM application. PDI intends to apply for recovery of 2012 lost revenues arising from 2005 to 2010 CDM programs with its 2014 IRM rate application.

c) LRAM calculations for 2012 persisting lost revenues that are the result of 2005-2010 CDM programs are shown below:

LOST REVENUES FOR 2012, including interest to April 30, 2013

Residential

Year	Quarter	Quarterly lost revenue	Closing balance	OEB presribed quarterly rate	Total
2012	Q 1	$ 18,247	$ 18,247	0.37%	$ 68
2012	Q 2	$ 18,247	$ 36,494	0.37%	$ 135
2012	Q 3	$ 18,247	$ 54,741	0.37%	$ 203
2012	Q 4	$ 18,247	$ 72,988	0.37%	$ 270
2013	Q1		$ 72,988	0.37%	$ 270
2013	Apr		$ 72,988	0.12%	$ 88
			$ 72,988		$ 1,033
LRAM plus Carrying Charges - Residential					**$ 74,021**

GS<50

Year	Quarter	Quarterly lost revenue	Closing balance	OEB presribed quarterly rate	Total
2012	Q 1	$ 5,572	$ 5,572	0.37%	$ 21
2012	Q 2	$ 5,572	$ 11,144	0.37%	$ 41
2012	Q 3	$ 5,572	$ 16,716	0.37%	$ 62
2012	Q 4	$ 5,572	$ 22,288	0.37%	$ 82
2013	Q1		$ 22,288	0.37%	$ 82
2013	Apr		$ 22,288	0.12%	$ 27
			$ 22,288		$ 315
LRAM plus Carrying Charges - GS < 50					**$ 22,603**

GS>50

Year	Quarter	Quarterly lost revenue	Closing balance	OEB presribed quarterly rate	Total
2012	Q 1	$ 5,125	$ 5,125	0.37%	$ 19
2012	Q 2	$ 5,126	$ 10,251	0.37%	$ 38
2012	Q 3	$ 5,126	$ 15,377	0.37%	$ 57
2012	Q 4	$ 5,126	$ 20,503	0.37%	$ 76
2013	Q1		$ 20,503	0.37%	$ 76
2013	Apr		$ 20,503	0.12%	$ 25
			$ 20,503		$ 290
LRAM plus Carrying Charges - GS > 50					**$ 20,793**
LRAM plus Carrying Charges - all customer classes					**$117,417**

d) LRAM specific rate riders, separate of any LRAMVA amounts for 2011 CDM programs in 2011 are shown below:

LRAM Amounts and Rate Riders by Class

	LRAM	Carrying Charges	Total	2013 Forecasted Billed kWh / kW	Proposed Rate Rider
Residential	$ 70,228	$ 2,033	$ 72,261	294,240,107	$ 0.0002
GS<50	$ 31,312	$ 906	$ 32,218	112,158,205	$ 0.0003
GS>50	$ 27,308	$ 791	$ 28,099	862,205	$ 0.0326
Total	**$ 128,848**	**$ 3,730**	**$ 132,578**		

e) LRAMVA specific rate riders, separate of any LRAM amounts for 2005-2010 CDM programs in 2011 are shown below:

	LRAM	Carrying Charges	Total	2013 Forecasted Billed kWh / kW	LRAM VA Rate Rider
Residential	$ 9,446	$ 251	$ 9,697	294,240,107	$ -
GS<50	$ 4,489	$ 119	$ 4,608	112,158,205	$ -
GS>50	$ 529	$ 14	$ 543	862,205	$ 0.0006
Total	**$ 14,464**	**$ 384**	**$ 14,848**		

9-Staff-30

Ref: Deferral/Variance Account (DVA) Workform for 2013 Filers
Ref: S. 2.12 of Chapter 2 of the Filing Requirements for Electricity Transmission and Distribution Applications, June 28, 2012

Please provide an updated DVA Work Form reflecting the account balances (principal and interest) information for all the DVAs for all required years.

PDI Response

The DVA Work Form has been updated as requested.

9-Staff-31

<u>Ref: Exhibit 9, Tab 1, Schedule 3, page 9-7</u>

PDI states that it has not recorded any costs in Account 1508, Other Regulatory Assets, Sub-Account IFRS Transition Costs as of December 31, 2011. Please confirm that PDI has not recorded any IFRS transition costs in its 2013 capital expenditures or OM&A expenses. In addition, please state the amounts, the nature of the expenditures, and the reasons for inclusion of any IFRS transition costs in the 2013 capital expenditures and OM&A expenses.

PDI Response

PDI has not recorded any IFRS transition costs in its 2013 capital expenditures or OM&A expenses.

9-Staff-32

<u>Ref: Exhibit 9, Tab 2, Schedule 1</u>

.

a) How has PDI allocated the costs of the stranded meters between Residential and GS < 50 kW customers? Please explain your response and show all calculations. If available, spreadsheets showing the calculations in Microsoft Excel format should be provided.

b) Why has PDI proposed a 4 year recovery period for Residential customers?

c) Would PDI's CIS and billing system be able to accommodate a different recovery period for Residential and GS < 50 kW customers?

PDI Response

a) PDI has allocated the costs between Residential and GS<50 customers based on the net book value of the meters for each customer class that were removed from service:

TREATMENT OF STRANDED METER ASSETS		Residential	GS	Total
Stranded Meters transferred from Account 1860 to Account 1555:				
2009	Cost	1,562,477	117,364	1,679,841
	Accumulated Amortization	(692,352)	(45,397)	(737,749)
	Contributed Capital	-	-	-
	Net Asset	870,125	71,967	942,092
	Proceeds on Disposition	(5,089)	-	(5,089)
	Residual Net Book Value	865,036	71,967	937,003
2010	Cost	-	1,380,993	1,380,993
	Accumulated Amortization	-	(273,974)	(273,974)
	Contributed Capital	-	(42,633)	(42,633)
	Net Asset	-	1,064,386	1,064,386
	Proceeds on Disposition	-	(846)	(846)
	Residual Net Book Value	-	1,063,540	1,063,540
Stranded Meter Balance Account 1555 as reported at December 31, 2012:				
	Cost	1,562,477	1,498,357	3,060,834
	Accumulated Amortization	(692,352)	(319,371)	(1,011,723)
	Contributed Capital	-	(42,633)	(42,633)
	Net Asset	870,125	1,136,353	2,006,478
	Proceeds on Disposition	(5,089)	(846)	(5,935)
	Residual Net Book Value	**865,036**	**1,135,507**	**2,000,543**
Add Amortization not recorded after transfer to Account 1555:				
2009		(80,995)	(35,407)	(116,402)
2010		(80,995)	(76,331)	(157,326)
2011		(80,995)	(76,331)	(157,326)
2012		(80,995)	(76,331)	(157,326)
		(323,980)	(264,400)	(588,380)
Revised Stranded Meter Balance Account 1555 at December 31, 2012:				
	Cost	1,562,477	1,498,357	3,060,834
	Accumulated Amortization	(1,016,332)	(583,771)	(1,600,103)
	Contributed Capital	-	(42,633)	(42,633)
	Net Asset	546,145	871,953	1,418,098
	Proceeds on Disposition	(5,089)	(846)	(5,935)
	Residual Net Book Value	**541,056**	**871,107**	**1,412,163**

b) PDI has proposed a 4 year recovery in order to minimize the impact on customers, and based on OEB Guideline G-2011-0001 Smart Meter Funding and Cost Recovery – Final Disposition which suggests a recovery period of no longer than 4 years.

c) PDI's CIS and billing system would be able to accommodate a different recovery period for Residential and GS < 50 kW customers.

9-Energy Probe-26

Ref: Exhibit 9, Tab 2, Schedule 1

Please explain how PDI has calculated or estimated the net book value of the stranded meters for each of the residential and GS < 50 rate classes.

PDI Response

The estimated net book value of the stranded meters for each of the residential and GS<50 rate classes were calculated as:

The net book value of the meters at the time they were removed from service and transferred to Account 1555 Sub-account Stranded Meter Costs, less contributed capital (net of accumulated amortization), less net proceeds from sales

less

The depreciation expense that would have been applicable from the time the stranded meters were transferred to Account 1555 until December 31, 2012.

less

The amount of depreciation that would have been recorded from the date of removal until April 30, 2013.

APPENDIX 1-1

FINANCIAL STATEMENTS OF PETERBOROUGH DISTRIBUTION INC.
DECEMBER 31, 2012

FINANCIAL STATEMENTS OF

PETERBOROUGH DISTRIBUTION INC.

December 31, 2012

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Peterborough Distribution Inc.

Report on the Financial Statements
We have audited the accompanying financial statements of Peterborough Distribution Inc., which comprise the balance sheet as at December 31, 2012, and the statements of retained earnings, income and changes in cash position 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 controls as management determines are 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 controls relevant to the company'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 company's internal controls. 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 Peterborough Distribution Inc. as at December 31, 2012, and the results of its operations and changes in cash position for the year then ended in accordance with Canadian generally accepted accounting principles.

Collins Barrow Kawarthas LLP

Chartered Accountants
Licensed Public Accountants

Peterborough, Ontario
March 21, 2013

PETERBOROUGH DISTRIBUTION INC.
BALANCE SHEET

As at December 31, 2012

	2012 $	2011 $
ASSETS		
Current assets		
Cash	4,226,634	5,343,222
Accounts receivable	15,926,017	13,851,707
Due from related party (note 6)	-	11,795,000
Inventories	1,377,803	1,361,916
Prepaid expenses	91,380	121,213
	21,621,834	32,473,058
Other assets		
Property, plant and equipment (note 3)	54,679,268	49,373,941
Regulatory assets (note 4)	1,456,584	7,308,411
Future income taxes (note 8)	2,260,000	1,810,000
	58,395,852	58,492,352
	80,017,686	90,965,410

The accompanying notes are an integral part of these financial statements

PETERBOROUGH DISTRIBUTION INC.

BALANCE SHEET

As at December 31, 2012

	2012 $	2011 $
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Bank indebtedness (note 5)	-	11,795,000
Accounts payable and accrued liabilities	10,439,796	11,017,179
Income taxes payable	497,683	107,099
Customer deposits refundable within one year	773,000	703,000
Current portion of long-term debt (note 5)	900,835	856,815
	12,611,314	24,479,093
Long-term liabilities		
Customer deposits	926,038	931,812
Regulatory liabilities (note 4)	1,653,877	85,265
Long-term debt (note 5)	30,938,238	13,839,073
Due to related parties (note 6)	5,157,680	23,157,680
	38,675,833	38,013,830
Shareholder's equity		
Share capital (note 7)	21,657,680	21,657,680
Retained earnings	7,072,859	6,814,807
	28,730,539	28,472,487
	80,017,686	90,965,410

Approved on behalf of the Board

_______________ Director _______________ Director

The accompanying notes are an integral part of these financial statements

PETERBOROUGH DISTRIBUTION INC.

STATEMENT OF RETAINED EARNINGS

For the year ended December 31, 2012

	2012 $	2011 $
Retained earnings - beginning of year	6,814,807	6,625,384
Net income for the year	1,541,052	1,830,423
Dividends paid	(1,283,000)	(1,641,000)
Retained earnings - end of year	7,072,859	6,814,807

PETERBOROUGH DISTRIBUTION INC.
INCOME STATEMENT

For the year ended December 31, 2012

	2012 $	2011 $
Revenue		
Power recovery	70,397,921	68,935,891
Distribution	16,646,620	14,090,895
Other (note 10)	910,929	831,628
	87,955,470	83,858,414
Expenses		
Purchased power	70,397,921	68,935,891
Operations and administration	7,165,315	6,990,106
Amortization	5,693,972	3,424,461
	83,257,208	79,350,458
Income before the undernoted items and corporate taxes	4,698,262	4,507,956
Other expense (income)		
Interest expense (note 6)	2,582,850	2,558,345
Interest income	(489,788)	(711,220)
Other income	(113,785)	(44,978)
Loss on write-down of regulatory assets (note 4)	588,380	-
	2,567,657	1,802,147
Income before income taxes	2,130,605	2,705,809
Provision for (recovery of) income taxes (note 8)		
Current	1,039,553	755,386
Future	(450,000)	120,000
	589,553	875,386
Net income for the year	1,541,052	1,830,423

The accompanying notes are an integral part of these financial statements

PETERBOROUGH DISTRIBUTION INC.
STATEMENT OF CHANGES IN CASH POSITION

For the year ended December 31, 2012

	2012 $	2011 $
CASH PROVIDED FROM (USED FOR)		
Operating activities		
Net income for the year	1,541,052	1,830,423
Charges to operations not requiring a current cash payment -		
Amortization	5,693,972	3,424,461
Loss on write-down of regulatory assets	588,380	-
Future income tax (recovery)	(450,000)	120,000
	7,373,404	5,374,884
Change in non-cash working capital items	(2,247,163)	797,140
Increase (decrease) in customer deposits	64,226	(656,473)
	5,190,467	5,515,551
Investing activities		
Purchase of property, plant and equipment	(6,471,887)	(6,203,278)
Decrease (increase) in regulatory assets and liabilities (note 4)	632,747	(262,688)
Decrease in advances to related party	11,795,000	11,000,000
	5,955,860	4,534,034
Financing activities		
Proceeds from long-term debt	18,000,000	-
Repayment to related party	(18,000,000)	
Repayment of long-term debt	(856,815)	(814,959)
Repayment of bank indebtedness	(11,795,000)	(11,000,000)
Contributions in aid of construction	1,671,900	1,410,810
Dividends paid	(1,283,000)	(1,641,000)
	(12,262,915)	(12,045,149)
Net increase (decrease) in cash and equivalents	(1,116,588)	(1,995,564)
Cash - beginning of year	5,343,222	7,338,786
Cash - end of year	4,226,634	5,343,222

The accompanying notes are an integral part of these financial statements

1. NATURE OF OPERATIONS

Peterborough Distribution Inc. is an electricity distribution company, wholly owned by the City of Peterborough Holdings Inc. which, in turn, is wholly owned by the Corporation of the City of Peterborough. The company's distribution rates and conditions for providing services are regulated by the Ontario Energy Board.

2. SIGNIFICANT ACCOUNTING POLICIES

These financial statements are prepared in accordance with Canadian generally accepted accounting principles. The significant policies are detailed as follows:

(a) Revenue Recognition

In accordance with the Ontario Energy Board regulations, the company recognizes as revenue the regulated distribution service charges associated with the distribution of energy.

Revenue is recorded using the accrual basis of accounting, as energy is consumed by customers. Unbilled revenue is the estimated distribution revenue earned but not invoiced to customers between the date the meters were last read and the end of the year.

(b) Cash

Cash consists of balances with financial institutions.

(c) Accounting for Electricity Regulation

The company accounts for the impact of rate regulation by the Ontario Energy Board (OEB) as follows:

(i) Regulatory Decisions to Adjust Distribution Rates

In the event that a regulatory decision is rendered, providing regulatory approval and certainty to the recognition of an asset, or creation of a liability, and culminating in an adjustment to company distribution rates, such occurrences are immediately reflected in the company's accounts.

(ii) Regulatory Accounting Practice

In the absence of a regulatory decision impacting rates, and where the company is required by regulatory accounting practice or direction to accumulate balances for future rate recovery or create liabilities for future discharge, those amounts are recorded in accordance with that regulatory direction. 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 income for the period. Amounts currently confirmed by final regulatory decision, and amounts currently accounted for in the absence of final regulatory decision together with related provisions for future uncertainty, are more fully described in note 4.

2. SIGNIFICANT ACCOUNTING POLICIES, continued

(d) Use of Estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the balance sheet date and the reported amounts of revenues and expenses during the year. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities; allowance for doubtful accounts; amortization rates and carrying values of property, plant and equipment; income taxes; fair values of financial instruments; and contingencies. Actual results could differ from these estimates.

(e) Inventory

Inventories consist of distribution system maintenance and construction materials and are valued at the lower of moving average cost and replacement cost. Major spare parts and stand-by equipment are recorded in property, plant and equipment.

(f) Property, plant and equipment

Property, plant and equipment are recorded at cost and include labour, materials, engineering and purchased services.

The cost and related accumulated amortization for identifiable property, plant and equipment, such as substations, remain in the accounts until the assets are retired or disposed of at which time any gain or loss is reflected in operations. Property, plant and equipment which are recorded on a group basis, such as meters, are removed from the accounts only at the end of their estimated service lives.

In circumstances where external customers are required to make specific contributions to fund the construction and installation of specific fixed assets, the company nets the customer contributions against the acquisition cost.

Amortization is provided annually on a basis designed to amortize the assets over their estimated useful lives as follows:

Buildings	34 – 50 years straight-line
Substations	25 – 50 years straight-line
Overhead lines	20 – 25 years straight-line
Underground lines	20 – 25 years straight-line
Transformers	17 – 25 years straight-line
Meters	15 – 25 years straight-line
Other	4 – 5 years straight-line

(g) Customer deposits

Customers may be required to post security to obtain electricity or other services. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as customer deposits. In accordance with the Ontario Energy Board regulation, interest is paid on customer balances at the Bank of Canada prime rate, adjusted quarterly, less 2%.

2. SIGNIFICANT ACCOUNTING POLICIES, continued

(h) Corporate income taxes

Under the Electricity Act, 1998, the company is required to make payments in lieu of corporate income taxes to Ontario Electricity Financial Corporation (OEFC). The payments in lieu of taxes are calculated on a basis as if the company was a taxable company under the Income Tax Act (Canada).

Corporate income taxes are calculated using the liability method of tax accounting. Temporary differences arising from the difference between the tax basis of an asset and its carrying amount on the balance sheet are used to calculate future tax liabilities or assets. Future tax liabilities or assets are measured using tax rates anticipated to apply in the periods that the temporary differences are expected to be recovered or settled. The effect on future taxes of a change in tax rates is recognized in income in the year in which the change occurs.

(i) Financial instruments

(i) Comprehensive income

Comprehensive income consists of net income and other comprehensive income (OCI). OCI consists of the changes in the fair value of financial instruments, which have not been included in net income.

(ii) Recognition and measurement

Financial assets and liabilities are initially recognized and measured at fair value, except for certain related party transactions and are categorized as assets held-for-trading, held-to-maturity investments, loans and receivables, available-for-sale or other liabilities. After initial recognition, financial assets, including derivatives that are assets, are measured at fair values, except for held-to-maturity investments and certain loans and receivables which are measured at amortized cost using the effective interest method. All financial liabilities are measured at amortized cost using the effective interest rate method, except for financial liabilities that are classified as held-for-trading.

A gain or loss on a financial asset or financial liability classified as held-for-trading is recognized in net income for the period in which it arises. A gain or loss on an available-for-sale financial asset is recognized directly in other comprehensive income, a permanent component of shareholder's equity. For financial assets and financial liabilities carried at amortized cost, a gain or loss is recognized in net income when the financial asset or financial liability is derecognized or impaired and through the amortization process.

(iii) Hedge accounting

Hedge accounting standards establish how and when hedge accounting is used, and in particular, the criteria to be met for the application of hedge accounting. Under hedge accounting, all gains, losses, revenues and expenses from the derivative and the item it hedges are recorded in the statement of operations in the same period. The company presents the earnings and cash flow effects of hedging items with the hedged transaction. Ordinarily, the effective portion of the change in fair value of the cash flow hedging instrument is recorded in OCI and reclassified to earnings when the hedge ceases to be effective.

2. SIGNIFICANT ACCOUNTING POLICIES, continued

(j) International Financial Reporting Standards (IFRS)

On February 13, 2008 the AcSB confirmed that IFRS will be required to be adopted by publicly accountable enterprises and certain government enterprises for annual reporting purposes for fiscal years beginning on or after January 1, 2012. On September 10, 2011 the AcSB granted an optional one year deferral of IFRS adoption for entities subject to rate regulation. Subsequent to this through a series of additional one year extensions, the mandatory change over date for entities with rate regulated activities has been extended to January 1, 2015. At its December 2012 meeting, the IASB decided to develop an interim IFRS on rate regulated activities that "grandfathers" existing recognition and measurement policies. The company has elected to continue the deferral of transition to IFRS, pending resolution of these matters before the IASB.

The company is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable. The company does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required and any necessary system changes to gather and process the information. The impact of new IFRS standards and interpretations not yet effective has also not been assessed.

3. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2012 Net Book Value	2011 Net Book Value
	$	$	$	$
Land	134,968	0	134,968	134,968
Buildings	536,085	85,889	450,194	370,607
Substations	3,515,134	1,292,914	2,222,220	2,306,001
Overhead lines	35,845,235	14,852,938	20,992,297	19,806,759
Underground lines	23,468,589	10,008,546	13,460,043	13,407,440
Transformers	17,821,996	8,288,571	9,533,425	9,318,781
Meters	7,115,824	2,006,080	5,109,744	550,518
Other	2,936,270	2,202,945	733,325	62,238
Construction in process	2,043,052		2,043,052	3,416,629
	93,417,151	38,737,883	54,679,268	49,373,941

Prior to 2012 the company recorded a full year of amortization in the year property, plant and equipment was acquired. The regulator of the company recommends application of a half-year rule for calculation of amortization in the year of acquisition. During 2012 the company adopted this methodology prospectively to align itself with the recommendations of its regulator. As a result of estimating amortization in the year of acquisition in this manner, amortization expense for the year is $301,489 lower than would have been determined previously.

4. REGULATORY ASSETS AND LIABILITIES

The company has recorded the following regulatory assets:

	2012	2011
	$	$
Smart Meter Variance - new meters	-	5,215,103
Smart Meter Variance - replaced meters	1,412,163	2,000,543
Lost Revenue Adjustment Variance	29,428	-
Other	14,993	92,765
Regulatory Assets	1,456,584	7,308,411

During 2012, the Ontario Energy Board approved disposition of the Smart Meter variance account, excluding the portion related to the meters replaced ("stranded meters"). As prescribed by the regulator, the balance in the regulatory asset account as of December 31, 2011 of $5,215,103 was transferred to property, plant and equipment and the income statement with the effect of reducing net income before tax by $197,624. Details of the transaction are as follows:

Property plant and equipment	$ 5,017,480
Distribution revenue	(1,334,322)
Operations and administration expense	172,349
Amortization expense	1,181,832
Interest revenue reduction	177,764
	$ 5,215,103

The remaining balance in the Smart Meter variance account of $1,412,163 represents the estimated net recoverable value of stranded meter assets. Stranded meter assets of $2,000,543 at the beginning of the year were written down by $588,380 to the amount expected to be recovered in future rates. In the absence of rate regulation supporting the accumulation of these amounts, the company would write down the remaining $1,412,163 associated with the stranded meter assets, and reduce revenue by $44,421 on account of the other regulatory asset variance accounts.

The company has recorded the following regulatory liability accounts:

	2012	2011
	$	$
Retail Settlement Variance	574,581	39,868
Regulatory items approved for settlement	1,079,296	45,397
Regulatory liabilities	1,653,877	85,265

4. REGULATORY ASSETS AND LIABILITIES, continued

Retail settlement variance accounts are accumulated as prescribed by regulatory policy and will be subject to review and disposition through future rate review processes, the timing of which have yet to be determined. It is expected that the approved disposition of any asset or liability accumulated at that time will be through the adjustment of future rates.

In the absence of rate regulation supporting the accumulation of these amounts, revenue or the cost of purchased power would be adjusted for retail settlement variances as incurred. Net income would have been approximately $1,680,000 higher in 2012 and $1,200,000 lower in 2011 in the absence of rate regulatory accounting.

5. LONG-TERM DEBT

(a) Bank Borrowings

(i) Floating Rate Committed Term Facility

During the year the company revised the terms of its existing committed bank facility in the amount of $27,900,000 to extend the maturity date to January 31, 2014 and provide for the following two components:

1. Committed $22,900,000 term facility maturing 10 years from the initial draw, without repayment terms, with interest based on Bankers Acceptances. Once drawn the company may at its option fix the interest rate and repayment terms through the availability of 5 to 30 year interest rate swaps offered by the bank.

2. Committed three year $5,000,000 operating loan to facilitate ongoing capital expenditures. This component has not been utilized at December 31, 2012.

At December 31, 2012 the company had drawn $18,000,000 (2011 - $11,795,000) on the interest only facility due January 31, 2014.

(ii) Fixed Rate Committed Reducing Term Facility

The company has entered into receive-variable/pay-fixed interest rate swap agreements whereby the company cash flow hedged the variable interest rate loan commitment for two committed bank term loans totaling $13,839,073.

Bank debt is secured by a general security agreement covering all company assets, and a subordination of the general security agreement previously provided to the Corporation of the City of Peterborough (note 6).

5. LONG-TERM DEBT, continued

	2012 $	2011 $
Bank debt, bearing interest at 2.1% due January 31, 2014	18,000,000	–
Bank debt, bearing interest at 4.55% per annum payable in blended monthly payments of principal and interest of $50,658, due December 24, 2018	5,253,311	5,613,253
Bank debt, bearing interest at 5.36% per annum payable in blended monthly payments of principal and interest of $80,967, due December 22, 2019	8,585,762	9,082,635
	31,839,073	14,695,888
Less: principal payments due within one year	900,835	856,815
	30,938,238	13,839,073

The aggregate amount of principal payments required is as follows:

	$
2013	900,835
2014	18,947,128
2015	995,822
2016	1,047,034
2017	1,100,896
Thereafter	8,847,358
	31,839,073

(b) Letters of Credit

The company has posted $7,063,922 (2011 - $6,563,922) in stand-by letters of credit with the Independent Electricity System Operator, as required by regulation.

6. RELATED PARTIES

a) Due To Related Parties

	2012 $	2011 $
Demand loan from City of Peterborough Holdings Inc., bearing interest at 6.25% (2011 - 6.25%), per annum	3,657,680	21,657,680
Demand loan from the Corporation of the City of Peterborough bearing interest at bank Prime less 1.25%	1,500,000	1,500,000
	5,157,680	23,157,680

The demand loans are without specified maturity dates or repayment terms, and are secured by a general security agreement in favour of the Corporation of the City of Peterborough. The security has been subordinated to the security for the company's long-term debt (note 5).

The company does not expect to repay the loan from the Corporation of the City of Peterborough in fiscal 2013.

Included in interest expense is interest on the demand loans for the year ended December 31, 2012 in the amount of $1,379,927 (2011 - $1,379,855).

(b) Due From Related Party

As at December 31, 2011 the company had an outstanding loan due from Peterborough Utilities Inc, (PUI) in the amount of $11,795,000. The loan was repaid in full during 2012. Included in interest revenue is interest earned from PUI for the year ended December 31, 2012 of $147,575 (2011 - $308,369). The company and PUI are related by virtue of common ownership by the City of Peterborough Holdings Inc.

7. SHARE CAPITAL

Authorized
Unlimited number of common shares
Unlimited number of preferred shares

Issued

	2012 $	2011 $
1,000 common shares	21,657,680	21,657,680

8. INCOME TAXES

(a) The tax effects of the temporary differences that give rise to the future income tax assets are as follows:

	2012	2011
	$	$
Future Income Tax Asset		
Tax basis of equipment in excess of carrying amount	2,260,000	1,810,000

(b) The provision for income taxes recorded in the financial statements differs from the amount which would be obtained by applying the statutory income tax rate of 26.5% (2011 – 28.25%) to the income for the years as follows.

	2012	2011
	$	$
Income for the year before income taxes	2,130,605	2,705,809
Anticipated income tax expense	564,610	764,391
Impact of tax rate changes and other	24,943	110,995
Provision for income taxes	589,553	875,386

9. SUPPLEMENTARY CASH FLOW INFORMATION

	2012	2011
	$	$
Interest paid	2,579,748	2,563,305
Income taxes paid	650,000	642,000

10. OTHER SERVICES

	2012	2011
	$	$
Customer fees	475,243	385,947
Occupancy charges	174,480	179,250
Building and pole rentals	211,206	210,681
Miscellaneous	50,000	55,750
	910,929	831,628

11. RELATED PARTY TRANSACTIONS

The company provides electricity and services to the shareholder of its parent, the City of Peterborough and to affiliate companies. Electrical energy is sold to these parties at the same prices and terms as other electricity customers.

The company is also engaged in transactions in the normal course of operations with affiliated companies and the Peterborough Utilities Commission. The parties are related by virtue of common control.

Details of related party transactions are as follows:

	2012	2011
	$	$
Revenue		
Rental revenue	12,800	12,800
Interest revenue	147,575	308,369
	160,375	321,169
Expenses		
Professional services	3,154,814	3,239,531
Operating costs	2,323,439	2,287,642
Building rent	489,000	513,860
	5,967,253	6,041,033
Other - Capital expenditures	2,233,720	2,055,988

12. CAPITAL DISCLOSURES

The company's primary objective when managing capital is to address the expectations as outlined in the Unanimous Shareholder Declaration between the company's parent company, the City of Peterborough Holdings Inc., and its shareholder, the Corporation of the City of Peterborough. The expectation is that the company will maintain a prudent financial and capitalization structure consistent with industry norms and on the basis that it is intended to be a self-financed entity.

The industry norm for capital structure, as supported by the Ontario Energy Board as regulator, suggests that companies operating in the distribution industry would have capital comprised of 60% debt and 40% equity. The company is targeting to attain that structure, to the extent possible, in future years. The company's current capital structure is defined as follows:

	2012 $	2011 $
Debt		
Long-term debt (note 5)	31,839,073	14,695,888
Due to related parties (note 6)	5,157,680	23,157,680
	36,996,753	37,853,568

	2012 $	2011 $
Equity		
Share capital	21,657,680	21,657,680
Retained earnings	7,072,859	6,814,807
	28,730,539	28,472,487

The long-term debt (note 5) which has been principally used to finance short-term related party advances (note 6(b)) are not considered part of the company's permanent capital structure.

Changes to the company's capital structure are constrained by an existing lending agreement provision that limits the amount of dividend distributions and the repayment of related party debt subject to certain cash flow tests. Additionally the agreements provide for a restriction on the incurrence of new debt or the posting of security without prior lender consent. The company has complied with these requirements during the year.

13. FINANCIAL INSTRUMENTS

As a rate regulated entity, the company's operations and risks are also substantially influenced by regulation, limiting the necessity to actively engage in derivative financial products.

(a) Measurement

The following classes of financial assets and liabilities are recorded:

Financial assets and liabilities

Cash is classified as assets held-for-trading. Accounts receivable are classified as loans and receivables. Accounts payable and accrued liabilities, and long-term debt are classified as other financial liabilities. The carrying value of the accounts receivable, accounts payable and accruals and short term debt approximates their fair value due to their short-term nature.

Due to related parties

Demand loans due to related parties (note 6) in the aggregate amount of $5,157,680, (2011 - $23,157,680) which originated on the establishment of the company and from purchases of Asphodel Norwood Distribution Inc. and Lakefield Distribution Inc., were originally recorded at the exchange amount and have been classified as other financial liabilities. In applying the effective interest rate method, the fair value of that instrument does not differ from its carrying value.

(b) Credit risk

By regulation, in addition to the distribution service charges that the company earns, the customers' electricity bills include, transmission charges, non-competitive energy charges, debt retirement and electricity commodity charges. The company acts as an agent for billing and collecting these charges on behalf of other market participants and under regulation the company bears the risk of non-collection of these amounts.

To mitigate credit risk the company is permitted to request certain customers to provide deposits for a prescribed period. Furthermore, relief from substantial or catastrophic collection loss relief may be afforded by applying for recovery for those losses through distribution rate adjustments in future years, if approved by the regulator.

The company is not exposed to a significant concentration of credit risk within any customer segment or individual customer. The allowance for collection of doubtful accounts included in accounts receivable is in the amount of $378,000 (2011 - $328,000).

(c) Interest rate risk

As described in note 5 to the financial statements the company has entered into interest rate swap arrangements which are being used to manage the impact of fluctuating interest rates on approximately $13.8 million of the company's existing debt. The swaps require the periodic exchange of interest payments without the exchange of the notional principal amount on which the payments are based. The swap instruments are not recognized on the balance sheet.

13. FINANCIAL INSTRUMENTS – Continued

While certain of the company's debt obligations are subject to variable interest terms, they do not present a significant risk. The company has the option under it's new lending facility to fix the interest rate on this debt through the use of interest rate swaps.

(d) Foreign currency risk

The company conducts the majority of its business without significant exposure to foreign currency.

(e) Liquidity risk

Liquidity risk is the risk that the company will not be able to meet its financial obligations as they occur. At the present time the liquidity risk of the company is low as it has unutilized existing debt capacity, additional room within its capital structure to obtain additional financing as required, and sufficient cash flow to address existing debt obligations.

14. CONTINGENCIES

a) The company participates with other municipal utilities in Ontario in an agreement to exchange reciprocal contracts of indemnity through the Municipal Electric Association Reciprocal Insurance Exchange. Under this agreement, the company is contingently liable for additional assessments to the extent that premiums collected are not sufficient to cover actual loses, claims and costs experienced.

(b) The company assets are pledged as security and the company has provided an unlimited guarantee to support the indebtedness of the company's parent company, City of Peterborough Holdings Inc., to its shareholder, the Corporation of the City of Peterborough.

15. COMPARATIVE AMOUNTS

The financial statements have been reclassified, where applicable, to conform to the presentation used in the current year. The changes do not affect prior year earnings.

16. SUBSEQUENT EVENT

On January 8, 2013 the company utilized $21,657,680 of the committed 10 year loan facility described in note 5. The company borrowed an additional $3,657,680 and converted the outstanding borrowings of $18,000,000 to the 10 year component of the loan facility. Proceeds from this transaction were utilized to fully repay the loan outstanding to the City of Peterborough Holdings Inc. (note 6)

APPENDIX 1-2

PETERBOROUGH UTILITIES COMMISSION FINANCIAL STATEMENTS AT DECEMBER 31, 2012

PETERBOROUGH UTILITIES COMMISSION

FINANCIAL STATEMENTS

AT DECEMBER 31, 2012

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AUDITORS' REPORT

TO THE CHAIR AND MEMBERS OF THE PETERBOROUGH UTILITIES COMMISSION

Report on the Financial Statements

We have audited the accompanying financial statements of the Peterborough Utilities Commission, which comprise the statement of financial position as at December 31, 2012 and the statements of operations and accumulated surplus, cash flows and changes in net financial assets 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 Public Sector Accounting, and for such internal controls as management determines are 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 controls 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 of the effectiveness of the entity's internal controls. 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, these financial statements present fairly, in all material respects, the financial position of the Peterborough Utilities Commission as at December 31, 2012, and the results of its operations and cash flows for the year then ended in accordance with Canadian Public Sector Accounting Standards.

Collins Barrow Kawarthas LLP

Chartered Accountants
Licensed Public Accountants

Peterborough, Ontario
April 25, 2013

PETERBOROUGH UTILITIES COMMISSION

STATEMENT OF FINANCIAL POSITION
At December 31, 2012

	2012 $	2011 $
ASSETS		
FINANCIAL ASSETS		
Cash (Note 3)	17,707,647	13,379,512
Accounts receivable		
Customer accounts	755,263	722,164
Sewer surcharge	662,663	597,165
Sundry	248,681	951,105
Unbilled revenue on customer accounts	1,348,000	1,312,000
Unbilled sewer surcharge	1,231,000	1,203,000
	21,953,254	18,164,946
LIABILITIES		
Accounts payable and accrued charges	2,387,596	1,737,143
Sewer surcharge payable	2,407,680	2,298,204
Long term debt (Note 4)	12,144,285	6,650,714
Customer deposits	583,065	573,388
	17,522,626	11,259,449
NET FINANCIAL ASSETS	**4,430,628**	**6,905,497**
NON-FINANCIAL ASSETS		
Inventories	196,708	196,992
Tangible capital assets (Note 5)	104,693,682	96,883,218
Prepaid expenses	5,294	-
	104,895,684	97,080,210
ACCUMULATED SURPLUS (Note 6)	**109,326,312**	**103,985,707**

Approved By The Commission

________________, Chairman

________________, Member

The accompanying notes are an integral part of this financial statement.

Collins Barrow
Chartered Accountants

PETERBOROUGH UTILITIES COMMISSION

STATEMENT OF OPERATIONS AND ACCUMULATED SURPLUS
For The Year Ended December 31, 2012

	Budget $	Actual 2012 $	Actual 2011 $
REVENUES			
Sale of water	15,300,000	15,420,324	14,805,292
Capital installation charges	487,000	2,688,868	206,538
Development charges earned	330,000	717,972	878,444
Fire protection	650,000	650,000	650,000
Sewer surcharge billings	365,000	365,000	365,000
Riverview Park and Zoo (Schedule 2)	133,000	140,953	136,126
Interest	95,000	198,287	200,914
Other	80,000	135,540	98,737
Electricity	114,000	43,176	70,167
Donations	15,000	27,591	78,465
	17,569,000	20,387,711	17,489,683
EXPENSES			
Water treatment and storage	3,497,118	3,198,624	3,247,539
Water distribution	2,079,189	2,173,256	2,106,594
Riverview Park and Zoo (Schedule 2)	1,196,422	1,083,420	1,092,650
Administration	2,952,779	2,912,944	2,807,275
Amortization	5,400,000	5,343,804	4,685,444
Interest	391,000	335,058	256,789
	15,516,508	15,047,106	14,196,291
ANNUAL SURPLUS	2,052,492	5,340,605	3,293,392
OPENING ACCUMULATED SURPLUS	103,441,313	103,985,707	100,692,315
CLOSING ACCUMULATED SURPLUS	**105,493,805**	**109,326,312**	**103,985,707**

The accompanying notes are an integral part of this financial statement.

Collins Barrow
Chartered Accountants

PETERBOROUGH UTILITIES COMMISSION

STATEMENT OF CASH FLOWS
For The Year Ended December 31, 2012

	2012 $	2011 $
CASH PROVIDED BY (USED IN):		
OPERATIONS		
Annual surplus	5,340,605	3,293,392
Add: Non-cash charges to operations		
Amortization	5,343,804	4,685,444
	10,684,409	7,978,836
Change in non-cash working capital items (Note 8)	1,304,423	(1,472,684)
	11,988,832	6,506,152
INVESTING ACTIVITY		
Acquisition of tangible capital assets	(13,154,268)	(8,123,607)
FINANCING ACTIVITIES		
Repayment of long term debt	(1,006,429)	(990,357)
Proceeds from debenture debt	6,500,000	-
	5,493,571	(990,357)
NET CHANGE IN CASH DURING THE YEAR	4,328,135	(2,607,812)
CASH POSITION - BEGINNING OF YEAR	13,379,512	15,987,324
CASH POSITION - END OF YEAR	**17,707,647**	**13,379,512**

The accompanying notes are an integral part of this financial statement.

Collins Barrow
Chartered Accountants

PETERBOROUGH UTILITIES COMMISSION

STATEMENT OF CHANGES IN NET FINANCIAL ASSETS
For The Year Ended December 31, 2012

	Budget $	Actual 2012 $	Actual 2011 $
Annual Surplus	2,052,492	5,340,605	3,293,392
Acquisition Of Tangible Capital Assets	(13,779,150)	(13,154,268)	(8,123,607)
Amortization Of Tangible Capital Assets	5,400,000	5,343,804	4,685,444
Decrease (Increase) in Inventories	(5,000)	284	(9,660)
Decrease (Increase) in Prepaid Expenses	-	(5,294)	63,289
Change In Net Financial Assets	(6,331,658)	(2,474,869)	(91,142)
Net Financial Assets, beginning of year	4,550,258	6,905,497	6,996,639
Net Financial Assets, end of year	**(1,781,400)**	**4,430,628**	**6,905,497**

The accompanying notes are an integral part of this financial statement.

Collins Barrow
Chartered Accountants

PETERBOROUGH UTILITIES COMMISSION

NOTES TO THE FINANCIAL STATEMENTS
For The Year Ended December 31, 2012

1. NATURE OF ORGANIZATION

Operating under the authority of the Municipal Act, the Peterborough Utilities Commission (the "Commission") provides water services to the residents of the City of Peterborough along with operational governance and funding for the Riverview Park and Zoo.

2. *SIGNIFICANT ACCOUNTING POLICIES*

The financial statements of the Peterborough Utilities Commission have been prepared in accordance with Canadian generally accepted accounting principles for local governments and their local boards as recommended by the Public Sector Accounting Board of the Canadian Institute of Chartered Accountants.

Significant aspects of the accounting policies adopted by the Commission are as follows:

(a) Recognition of Revenue and Expenses

Revenue is recorded using the accrual basis of accounting, as water is used by customers. Unbilled revenue is calculated as follows:

Flat rate customers - at the flat rate between the last billing date and the year end date; and

Metered customers - the estimated consumption between the last meter reading date and the year end date.

The value of distribution systems installed by developers is recorded in revenue as capital installation charges in the year in which the Commission assumes ownership.

Expenses are recognized in the period the goods or services are acquired and a legal liability is incurred by transfers are due.

(b) Use of Estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenditures during the year. Significant estimates and assumptions used in the preparation of financial statements include, but are not limited to: estimates of revenue; allowance for doubtful accounts; amortization rates and carrying values of property, plant and equipment; and fair values of financial instruments. Actual results could differ from these estimates.

(c) Inventories

Inventories consist of maintenance supplies and construction materials and are valued at the lower of moving average cost and replacement cost.

(d) Tangible Capital Assets

Tangible capital assets are stated at cost. Amortization on the water treatment plant and reservoirs, distribution system and Riverview Park and Zoo (purchased from operating and donated funds) is recorded on a declining balance basis at a rate of 5% per annum. Water meters are amortized on a straight line basis over 20 years. The Commission capitalizes assets with a value of $5,000 or greater.

Tangible capital assets categorized as construction-in-progress are not amortized until they are put into service.

PETERBOROUGH UTILITIES COMMISSION

NOTES TO THE FINANCIAL STATEMENTS
For The Year Ended December 31, 2012

2. SIGNIFICANT ACCOUNTING POLICIES - (Continued)

(e) Reserve Funds

Certain amounts as approved by the Commission and those required under legislative or other authority are set aside in reserve funds for future operating or capital purposes. Transfers to and/or from reserve funds are an adjustment to the respective fund when approved or required by agreement.

The following reserve funds are included in the accumulated surplus:

(i) Water Treatment Plant Reserve Fund

In December 1990, the City of Peterborough passed a by-law authorizing the Peterborough Utilities Commission to establish a reserve fund for the purpose of upgrading the water treatment plant. Included in the 1991 rate increase was 5% for the future upgrade of the water treatment plant. This percentage, now inherent in the rate base, is appropriated to this fund each year. Utilization of these funds is authorized by the Commission.

(ii) Development Charges Act Reserve Fund

The Peterborough Utilities Commission is authorized under the City of Peterborough by-law 08-011 to establish a reserve fund for development charges. The purpose of the fund is to cover growth related net capital costs incurred by the Water Utility for water treatment, storage and distribution systems. Utilization of these funds is based upon a formula which was approved by the Commission at the time of the fund's inception.

(iii) Park And Zoo Major Projects Reserve Fund

In September 1993, the City of Peterborough passed a by-law authorizing the Peterborough Utilities Commission to establish a reserve fund for major projects at the Riverview Park and Zoo. The revenues received for this fund include donations from estates and the general public, the utility's share of profits from the refreshment booth operations and profits from the sale of birds and animals. Utilization of these funds is authorized by the Commission on a project by project basis based upon the recommendation of the Riverview Park and Zoo Advisory Committee.

(iv) Park and Zoo Animal Care Reserve Fund

In July 1999, the City of Peterborough passed a by-law authorizing the Peterborough Utilities Commission to establish a reserve fund for animal care at the Riverview Park and Zoo. The fund was established through a capital donation from a Peterborough resident. The income generated annually will be used for the care, treatment, habitat or display of the animals at the Riverview Park and Zoo for special or exceptional purposes beyond standard care.

(f) Financial Instruments

The Commission's financial instruments consist of cash, accounts receivable, accounts payable, customer deposits and long-term debt. Unless otherwise noted, it is management's opinion that the Commission is not exposed to significant currency, interest, liquidity or price risk.

The Commission is exposed to credit risk from customers. However, the Commission has a significant number of customers which minimizes the concentration of credit risk.

PETERBOROUGH UTILITIES COMMISSION

NOTES TO THE FINANCIAL STATEMENTS
For The Year Ended December 31, 2012

2. **SIGNIFICANT ACCOUNTING POLICIES** - (Continued)

(g) Non-Financial Assets

Tangible capital and other non-financial assets are accounted for as assets by the Commission because they can be used to provide services in future periods. These assets do not normally provide resources to discharge the liabilities of the Commission unless they are sold.

3. **CASH**

	2012 $	2011 $
Unrestricted cash	12,430,755	8,832,708
Restricted cash	5,276,892	4,546,804
	17,707,647	13,379,512

4. **LONG TERM DEBT**

Long term debt is issued on behalf of the Commission by The Corporation of the City of Peterborough and consists of the following:

Date of Maturity	Interest Rate %	2011 $	2010 $
July 2, 2013	3.125 - 4.75	364,285	710,714
March 5, 2020	3.893	5,280,000	5,940,000
July 5, 2027	3.180	6,500,000	-
		12,144,285	6,650,714

Principal repayments are required annually with semi-annual interest payments.

Future principal repayments for the long term debt are as follows:

2013	$ 1,368,541
2014	1,015,290
2015	1,026,678
2016	1,038,432
2017	1,050,561
2018 and subsequent	6,644,783
	$12,144,285

PETERBOROUGH UTILITIES COMMISSION

NOTES TO THE FINANCIAL STATEMENTS
For The Year Ended December 31, 2012

5. TANGIBLE CAPITAL ASSETS

	Water Treatment Plant and Reservoirs $	Water Distribution System $	Riverview Park and Zoo $	Other $	Construction In Progress $	Total $
Cost Or Deemed Cost						
Balance at January 1, 2011	36,172,680	121,587,901	6,343,031	17,403	2,088,518	166,209,533
Additions	283,015	4,135,303	183,682	-	3,521,607	8,123,607
Balance At December 31, 2011	36,455,695	125,723,204	6,526,713	17,403	5,610,125	174,333,140
Additions	256,210	15,966,540	1,463,793	-	-	17,686,543
Transfers to assets in service	-	-	-	-	(4,532,275)	(4,532,275)
Balance At December 31, 2012	36,711,905	141,689,744	7,990,506	17,403	1,077,850	187,487,408
Accumulated Amortization						
Balance at January 1, 2011	16,751,815	53,307,901	2,687,601	17,161	-	72,764,478
Amortization for the year	872,710	3,620,765	191,956	13	-	4,685,444
Balance At December 31, 2011	17,624,525	56,928,666	2,879,557	17,174	-	77,449,922
Additions	841,884	4,246,360	255,548	12	-	5,343,804
Balance At December 31, 2012	18,466,409	61,175,026	3,135,105	17,186	-	82,793,726
Net Book Value						
At December 31, 2011	18,831,170	68,794,538	3,647,156	229	5,610,125	96,883,218
At December 31, 2012	18,245,496	80,514,718	4,855,401	217	1,077,850	104,693,682

PETERBOROUGH UTILITIES COMMISSION

NOTES TO THE FINANCIAL STATEMENTS
For The Year Ended December 31, 2012

6. ACCUMULATED SURPLUS

	2012 $	2011 $
Operating surplus	11,500,023	9,206,399
Investment in tangible capital assets		
Tangible capital assets - net book value	104,693,682	96,883,218
Long term debt	(12,144,285)	(6,650,714)
Reserve funds (Schedule 1)	5,276,892	4,546,804
	109,326,312	103,985,707

7. RELATED PARTY TRANSACTIONS

In the ordinary course of business, the Commission enters into transactions with the Corporation of the City of Peterborough and other related corporations. These transactions, which include the sale of water and the purchase and sale of other goods and services, take place at fair market value. The affiliated corporations of the Commission are:

The City of Peterborough Holdings Inc.,
The Peterborough Call Centre Inc.,
Peterborough Utilities Services Inc.,
Peterborough Distribution Inc.,
Peterborough Utilities Inc.,
Campbellford/Seymour Electric Generation Inc.
Lily Lake Solar Inc.

Details of services provided to Peterborough Utilities Commission during the year by Peterborough Utilities Services Inc. are as follows:

	2012 $	2011 $
Expenditures		
Professional services	7,530,623	7,163,591
Building rent	375,000	394,011
Software and equipment rent	127,691	171,838
	8,033,314	7,729,440

PETERBOROUGH UTILITIES COMMISSION

NOTES TO THE FINANCIAL STATEMENTS
For The Year Ended December 31, 2012

8. STATEMENT OF FINANCIAL POSITION

Change in non-cash working capital items

	2012 $	2011 $
Accounts receivable	603,827	(931,468)
Unbilled revenue and sewer surcharge	(64,000)	(49,000)
Inventories	284	(9,660)
Accounts payable and sewer surcharge payable	759,929	(494,715)
Prepaid expenses	(5,294)	63,289
Customer deposits	9,677	(51,130)
	1,304,423	(1,472,684)

Other information

Interest paid	234,131	256,789

9. BUDGET FIGURES

The budget, approved by the Commission, for 2012 is reflected on the Statement of Operations and Accumulated Surplus and the Statement of Changes in Net Financial Assets. The budgets established for capital investment in tangible capital assets are on a project-oriented basis, the costs of which may be carried out over one or more years and, therefore may not be comparable with current year's actual amounts. Budget figures have been reclassified for the purposes of these financial statements to comply with Public Sector Accounting Board reporting requirements. Budget figures are not subject to audit.

PETERBOROUGH UTILITIES COMMISSION

SCHEDULE 1 - RESERVE FUNDS
For The Year Ended December 31, 2012

	Budget $	2012 Actual $	2011 Actual $
REVENUES			
Sale of water	638,010	641,013	615,804
Development charges	330,000	717,972	878,444
Interest	33,500	61,484	54,884
Donations	15,000	27,591	78,465
	1,016,510	1,448,060	1,627,597
TRANSFERS			
Transfer to tangible capital assets	(330,000)	(717,972)	(878,444)
Transfer to contributed capital	-	-	(375,000)
	(330,000)	(717,972)	(1,253,444)
CHANGE IN RESERVE FUNDS	686,510	730,088	374,153
OPENING RESERVE FUNDS	4,546,804	4,546,804	4,172,651
CLOSING RESERVE FUNDS	**5,233,314**	**5,276,892**	**4,546,804**

ANALYZED AS FOLLOWS:

	Budget $	2012 Actual $	2011 Actual $
INTERNALLY RESTRICTED			
Water treatment plant reserve fund	4,800,300	4,883,309	4,136,105
EXTERNALLY RESTRICTED			
Park and Zoo major projects reserve fund	327,575	341,372	309,760
Park and Zoo major animal care reserve fund	105,439	102,211	100,939
	433,014	443,583	410,699
	5,233,314	**5,276,892**	**4,546,804**

PETERBOROUGH UTILITIES COMMISSION

SCHEDULE 2 - STATEMENT OF OPERATIONS FOR RIVERVIEW PARK AND ZOO
For The Year Ended December 31, 2012

	Budget $	2012 Actual $	2011 Actual $
EXPENSES			
Maintenance park	498,916	429,226	429,244
Maintenance train	63,838	53,840	52,690
Maintenance zoo	531,654	545,737	564,096
Feed and medical	102,014	54,617	46,620
	1,196,422	1,083,420	1,092,650
REVENUES			
Train	125,000	130,941	127,864
Miscellaneous	8,000	10,012	8,262
	133,000	140,953	136,126
NET EXPENSES FOR THE YEAR	**1,063,422**	**942,467**	**956,524**

APPENDIX 1-3

CONSOLIDATED FINANCIAL STATEMENTS OF PETERBOROUGH UTILITIES SERVICES INC. DECEMBER 31, 2012

CONSOLIDATED
FINANCIAL STATEMENTS OF

PETERBOROUGH UTILITIES SERVICES INC.

December 31, 2012

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Collins Barrow

Chartered Accountants

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Peterborough Utilities Services Inc.

Report on the Financial Statements
We have audited the accompanying consolidated financial statements of Peterborough Utilities Services Inc., which comprise the consolidated balance sheet as at December 31, 2012, and the consolidated statements of income, comprehensive income, changes in equity 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 consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal controls as management determines are necessary to enable the preparation of consolidated 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 consolidated 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 consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal controls relevant to the company's preparation and fair presentation of the consolidated 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 company's internal controls. 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 consolidated 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 consolidated financial statements present fairly, in all material respects, the financial position of Peterborough Utilities Services Inc. and its subsidiary as at December 31, 2012 and its financial performance and cash flows for the year then ended in accordance with International Financial Reporting Standards.

Collins Barrow Kawarthas LLP

Chartered Accountants
Licensed Public Accountants

Peterborough, Ontario
March 21, 2013

PETERBOROUGH UTILITIES SERVICES INC.
CONSOLIDATED BALANCE SHEET

As at December 31, 2012

	2012 $	2011 $
ASSETS		
Current assets		
Cash	4,336,656	5,322,899
Accounts receivable	818,311	1,014,969
Due from related party (note 6)	1,400,000	-
Income taxes receivable	-	59,419
Inventories	8,526	7,708
Prepaid expenses	460,047	396,919
	7,023,540	6,801,914
Other assets		
Property, plant and equipment (note 4)	5,729,152	5,714,273
Deferred tax assets (note 8)	1,725,000	1,717,164
	7,454,152	7,431,437
	14,477,692	14,233,351

The accompanying notes are an integral part of these consolidated financial statements

PETERBOROUGH UTILITIES SERVICES INC.
CONSOLIDATED BALANCE SHEET

As at December 31, 2012

	2012 $	2011 $
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	2,122,945	1,949,383
Income taxes payable	33,452	-
Customer deposits refundable within a year	11,000	9,000
	2,167,397	1,958,383
Long-term liabilities		
Customer deposits	21,817	21,685
Deferred tax liabilities (note 8)	55,000	66,615
Employee future liabilities (note 5)	6,503,948	6,031,690
Due to parent company (note 6)	1,782,848	1,782,848
	8,363,613	7,902,838
Shareholder's equity		
Share capital (note 7)	4,182,848	4,182,848
Accumulated other comprehensive loss	(1,169,263)	(725,897)
Retained earnings	933,097	915,179
	3,946,682	4,372,130
	14,477,692	14,233,351

Approved on behalf of the Board

Director

Director

The accompanying notes are an integral part of these consolidated financial statements

PETERBOROUGH UTILITIES SERVICES INC.
CONSOLIDATED INCOME STATEMENT

For the year ended December 31, 2012

	2012 $	2011 $
Revenue		
Professional services	19,795,511	19,208,862
Rental income	1,341,447	1,420,735
	21,136,958	20,629,597
Expenses		
Employee wages and benefits	13,857,786	14,307,678
Supplies, services and materials	4,792,307	4,049,018
Amortization	955,809	939,751
	19,605,902	19,296,447
Income before the undernoted items and corporate taxes	1,531,056	1,333,150
Other expense (income)		
Finance income	(69,049)	(70,263)
Finance costs (note 6)	116,156	112,688
Other income	(7,876)	(10,651)
	39,231	31,774
Income before income taxes	1,491,825	1,301,376
Provision for income taxes (note 8**)**		
Current	412,521	344,978
Deferred	61,386	102,480
	473,907	447,458
Net income for the year	1,017,918	853,918

The accompanying notes are an integral part of these consolidated financial statements

PETERBOROUGH UTILITIES SERVICES INC.
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

For the year ended December 31, 2012

	2012 $	2011 $
Net income for the year	1,017,918	853,918
Other comprehensive income		
Employee benefit plan actuarial losses (note 5)	(524,202)	(487,494)
Income tax on other comprehensive income	80,836	137,717
Other comprehensive loss for the year	(443,366)	(349,777)
Total comprehensive income for the year	574,552	504,141

The accompanying notes are an integral part of these consolidated financial statements

PETERBOROUGH UTILITIES SERVICES INC.
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the year ended December 31, 2012

	Share Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Equity
Balance, January 1, 2011	4,182,848	1,811,261	(376,120)	5,617,989
Net income for the year	-	853,918	-	853,918
Actuarial loss on accrued employee benefit liabilities, net of tax	-	-	(349,777)	(349,777)
Dividends paid in 2011	-	(1,750,000)	-	(1,750,000)
Balance, December 31, 2011	4,182,848	915,179	(725,897)	4,372,130
Net income for the year	-	1,017,918	-	1,017,918
Actuarial loss on accrued employee benefit liabilities, net of tax	-	-	(443,366)	(443,366)
Dividends paid in 2012	-	(1,000,000)	-	(1,000,000)
Balance, December 31, 2012	4,182,848	933,097	(1,169,263)	3,946,682

The accompanying notes are an integral part of these consolidated financial statements

PETERBOROUGH UTILITIES SERVICES INC.
CONSOLIDATED STATEMENT OF CASH FLOWS

For the year ended December 31, 2012

	2012 $	2011 $
CASH PROVIDED FROM (USED FOR)		
Operating activities		
Net income for the year	1,017,918	853,918
Charges to operations not requiring a current cash payment -		
Amortization	955,809	939,751
Deferred income tax	61,386	102,480
Increase (decrease) in employee future liabilities	(51,944)	24,959
	1,983,169	1,921,108
Increase (decrease) in non-cash working capital items	399,144	(47,699)
Increase (decrease) in customer deposits	2,132	(27,740)
	2,384,445	1,845,669
Investing activities		
Purchase of property, plant and equipment	(970,688)	(948,530)
Advances (repayments) to related party	(1,400,000)	3,967,088
	(2,370,688)	3,018,558
Financing activities		
Dividends paid	(1,000,000)	(1,750,000)
Net increase (decrease) in cash	(986,243)	3,114,227
Cash - beginning of year	5,322,899	2,208,672
Cash - end of year	4,336,656	5,322,899

The accompanying notes are an integral part of these financial statements

1. NATURE OF OPERATIONS

Peterborough Utilities Services Inc. (the "Company") delivers outsourcing services to affiliated companies of the City of Peterborough Holdings Inc. and others. Peterborough Utilities Services Inc. is owned by the City of Peterborough Holdings Inc. which, in turn, is wholly owned by the Corporation of the City of Peterborough.

2. BASIS OF PREPARATION

(a) Statement of compliance

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS). The consolidated financial statements were authorized for issue by the Board of Directors on March 21, 2013.

(b) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis.

(c) Use of estimates and judgments

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Information about critical judgments in applying accounting policies that have the most significant effects on the amounts recognized in the consolidated financial statements and about assumptions and estimation uncertainties that have a significant risk of resulting in a material adjustment within the next financial year are included in the following notes:

- Note 4 – useful lives and the identification of significant components of property, plant and equipment;
- Note 5 – measurement of employee benefit obligations.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements unless otherwise indicated.

The accounting policies have been applied consistently by the Company and its subsidiaries. These consolidated statements have been presented in Canadian dollars, the functional currency of the Company.

3. SIGNIFICANT ACCOUNTING POLICIES, continued

(a) Basis of consolidation

The consolidated statements include the accounts of Peterborough Utilities Services Inc. and its wholly owned subsidiary The Peterborough Call Centre Inc. All significant intercompany balances and transactions have been eliminated. Subsidiaries are consolidated from the date that control commences until the date that it ceases.

(b) Financial instruments

- **Non-derivative financial assets**

The Company initially recognizes loans and receivables on the date that they are originated. All other financial assets are recognized initially on the settlement date of the instrument. The Company derecognizes a financial asset when the contractual rights to the cash flows from the asset expire, or it transfers the rights to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred. Any interest in transferred financial assets that is created or retained by the Company is recognized as a separate asset or liability.

Financial assets and liabilities are offset and the net amount presented in the balance sheet when, and only when, the Company has a legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

The Company has the following non-derivative financial assets which it has classified as follows:

• Cash	Loans and receivables
• Accounts receivable	Loans and receivables

Cash consists of balances with financial institutions.

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition loans and receivables are measured at amortized cost using the effective interest method, less any impairment losses.

- **Non-derivative financial liabilities**

The Company initially recognizes debt securities issued on the date that they are originated. All other financial liabilities are recognized initially on the settlement date of the instrument.

The Company derecognizes a financial liability when its contractual obligations are discharged or cancelled or expire. Financial assets and liabilities are offset and the net amount presented in the consolidated balance sheet when, and only when, the Company has a legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

3. SIGNIFICANT ACCOUNTING POLICIES, continued

The Company has the following non-derivative financial liabilities which it has classified as follows:

• Accounts payable and accrued liabilities	Financial liabilities at amortized cost
• Due to related party	Financial liabilities at amortized cost
• Due to parent company	Financial liabilities at amortized cost

Financial liabilities are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition these financial liabilities are measured at amortized cost using the effective interest method.

(c) Property, plant and equipment

- **Recognition and measurement**

Items of property, plant and equipment are measured at cost less accumulated depreciation and accumulated impairment losses.

Cost includes expenditure that is directly attributable to the acquisition of the asset. The cost of self constructed assets includes the cost of materials and direct labour, any other costs directly attributable to bringing the assets to a working condition for their intended use, the costs of dismantling and removing the items and restoring the site on which they are located, and borrowing costs on qualifying assets.

Purchased software that is integral to the functionality of the related equipment is capitalized as part of that equipment. When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

Gains and losses on disposal of an item of property, plant and equipment are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment, and are recognized net within other income in profit or loss.

- **Depreciation**

Depreciation is calculated over the depreciable amount, which is the cost of an asset, or other amount substituted for cost, less its residual value.

Depreciation is recognized in profit or loss on a straight-line basis over the estimated useful lives of each part of an item of property, plant and equipment. The major components of buildings are depreciated over the lesser of the remaining life of the major component or the remaining life of the building.

The estimated useful lives for the current and comparative periods are as follows:

Buildings	15- 50 years
Equipment	4 – 10 years
Vehicles	4 – 8 years
Computer hardware	4 – 5 years
Computer software	4 - 5 years

3. SIGNIFICANT ACCOUNTING POLICIES, continued

Depreciation methods, useful lives and residual values are reviewed at each financial year-end and adjusted if appropriate.

(d) Inventories

Inventories are measured at the lower of cost and net realizable value. The cost of inventories is based on weighted average cost, and includes expenditure incurred in acquiring the inventories and other costs incurred in bringing them to their existing location and condition. Net realizable value is the estimated selling price in the ordinary course of business, less the estimated costs of completion and selling expenses.

(e) Impairment

- **Financial assets (including receivables)**

A financial asset not carried at fair value through profit or loss is assessed at each reporting date to determine whether there is objective evidence that it is impaired. A financial asset is impaired if objective evidence indicates that a loss event has occurred after the initial recognition of the asset, and that the loss event had a negative effect on the estimated future cash flows of that asset that can be estimated reliably.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the asset's original effective interest rate. Losses are recognized in profit or loss and reflected in an allowance account against receivables. Interest on the impaired asset continues to be recognized through the unwinding of the discount. When a subsequent event causes the amount of impairment loss to decrease, the decrease in impairment loss is reversed through profit or loss.

- **Non-financial assets**

The carrying amounts of the Company's non-financial assets, other than inventories, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

An impairment loss is recognized if the carrying amount of an asset exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

(f) Employee benefits

- **O.M.E.R.S.**

The Company participates in an industry-wide multi-employer post-employment defined benefit pension plan, the Ontario Municipal Employees Retirement Systems (O.M.E.R.S). Both participating employers and employees are required to make plan contributions based on the employees' contributory earnings. The Company recognizes its employee benefit expense related to this plan as the contributions are made.

3. SIGNIFICANT ACCOUNTING POLICIES, continued

- **Employee benefit plans**

The Company provides certain health care, dental care, life insurance and other benefits for certain retired employees. These defined benefit plans are not funded. Accordingly, there are no plan assets.

The Company's net obligation in respect of these is calculated separately for each plan by estimating the amount of future benefit that employees have earned in return for their service in the current and prior periods; that benefit is discounted to determine its present value. Any unrecognized past service costs are deducted. The discount rate is the yield at the reporting date on AA credit-rated bonds that have maturity dates approximating the terms of the Company's obligations. The calculation is performed annually by an independent qualified actuary using the projected unit credit method.

When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized in profit or loss on a straight-line basis over the average period until the benefits become vested. To the extent that the benefits vest immediately, the expense is recognized immediately in profit or loss.

The Company recognizes all actuarial gains and losses arising from these plans in other comprehensive income during the period in which they occur and all expenses related to defined benefit plans in profit or loss. The actuarial gains and losses are not reclassified to profit or loss in subsequent periods.

- **Short-term employee benefits**

Short-term employee benefit obligations, including accumulating vested sick leave and vacation, are measured on an undiscounted basis using management's best estimates and are expensed as the related service is provided.

(g) Revenue

Revenue is recognized when services are provided.

(h) Finance income and finance costs

Finance income comprises interest income on funds invested and gains on the disposal of financial assets. Interest income is recognized as it accrues in profit or loss, using the effective interest method.

Finance costs comprise interest expense on borrowings, unwinding of the discount on provisions and impairment losses recognized on financial assets. Borrowing costs that are not directly attributable to the acquisition, construction or production of a qualifying asset are recognized in profit or loss using the effective interest method.

(i) Borrowing costs

Borrowing costs directly attributable to the acquisition or construction of an asset that necessarily takes a substantial period of time to get ready for its intended use are capitalized as part of the cost of the asset. All other borrowing costs are expensed in the period in which they are incurred. Borrowing costs consist of interest and other finance charges that the Company incurs in borrowing funds.

3. SIGNIFICANT ACCOUNTING POLICIES, continued

(j) Leases

Leases in terms of which the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. Assets held under finance lease are recognized as assets of the Company at the lower of the fair value at the inception of the lease or the present value of the minimum lease payments. The corresponding liability is recognized as a finance lease obligation. Finance lease payments are apportioned between finance charges and a reduction of the liability to achieve a constant rate of interest on the remaining liability. The Company does not presently have any finance leases.

Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

(k) Income tax

Under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). The payments in lieu of taxes are calculated on a basis as if the Company was a taxable company under the Income Tax Act (Canada).

Income tax expense comprises current and deferred tax. Current tax and deferred tax are recognized in profit or loss except to the extent that it relates to a business combination, or items recognized directly in equity or in other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes.

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

A deferred tax asset is recognized for unused tax losses, tax credits and deductible temporary differences, to the extent that it is probable that future taxable profits will be available against which they can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

3. SIGNIFICANT ACCOUNTING POLICIES, continued

(l) New standards and interpretations not yet effective or adopted:

(i) Effective for annual periods beginning on or after January 1, 2013

- IFRS 10 Consolidated Financial Statements (replaces IAS 27 and SIC 12) – Provides a single model for control analysis.
- IFRS 12 Disclosure of Interest in Other Entities (new) – Provides disclosure requirements for entities with interest in subsidiaries, joint ventures and other unconsolidated entities.
- IFRS 13 Fair Value Measurement (new) – replaces fair value guidance in other IFRS, providing a single source of guidance.

(ii) Effective for annual periods beginning on or after January 1, 2014

- IFRS 32 Financial Instruments: Presentation (Amendments) – Clarifies rules relating to offsetting financial assets and liabilities and contains new disclosures.

(iii) Effective for annual periods beginning on or after January 1, 2015

- IFRS 9 Financial Instruments: Recognition and Measurement (new) – modifies IAS 39 eliminating categories and redefines gain and loss remeasurement.

The Company has not early adopted these revised standards and is currently assessing the impact that these standards will have on the consolidated financial statements.

4. PROPERTY, PLANT AND EQUIPMENT

	Land	Building	Vehicles	Computer Hardware and Software	Equipment	Total
	$	$	$	$	$	$
Cost						
Balance at Jan 1, 2011	320,599	4,970,661	3,854,182	5,397,393	823,664	15,366,499
Additions		205,264	383,327	352,477	7,462	948,530
Disposals and retirements			(180,023)			(180,023)
Balance at Dec 31, 2011	320,599	5,175,925	4,057,486	5,749,870	831,126	16,135,006
						-
Additions		167,285	503,960	228,477	70,966	970,688
Disposals and retirements			(272,744)		(180,532)	(453,276)
Balance at Dec 31, 2012	320,599	5,343,210	4,288,702	5,978,347	721,560	16,652,418
Accumulated Depreciation						
Balance at Jan 1, 2011	-	1,476,511	2,614,270	4,927,108	643,114	9,661,003
Depreciation for the year		191,610	406,534	292,557	49,050	939,751
Disposals			(180,021)			(180,021)
Balance at Dec 31, 2011	-	1,668,121	2,840,783	5,219,665	692,164	10,420,733
Depreciation for the year		204,800	433,446	242,651	74,912	955,809
Disposals			(272,744)		(180,532)	(453,276)
Balance at Dec 31, 2012	-	1,872,921	3,001,485	5,462,316	586,544	10,923,266
Net Book Value						
At Dec 31, 2011	320,599	3,507,804	1,216,703	530,205	138,962	5,714,273
At Dec 31, 2012	320,599	3,470,289	1,287,217	516,031	135,016	5,729,152

5. EMPLOYEE FUTURE LIABILITIES

a) Employee Future Liabilities

Employee future liabilities are comprised of employee vested sick leave and the accrued employee benefit liability related to the Company's post-employment medical and life insurance plan. Under that plan, the Company provides certain health care, dental care, life insurance and other benefits for certain retired employees. The present value of the employee benefit liability is actuarially determined and fully reflected as an obligation. Actuarial gains and losses arising from these plans are recognized in other comprehensive income (OCI) during the period in which they occur.

5. EMPLOYEE FUTURE LIABILITIES, Continued

Significant actuarial assumptions adopted in measuring the Company's accrued benefit obligation are a discount rate of 3.85% (2011 – 4.75%) and a salary scale of 2.5% (2011 – 2.4%). For measurement purposes, 8.0% annual increase in the per capita cost of covered health benefits was assumed for 2012 (2011 – 8.0%). The rate is assumed to decrease gradually to 5% for 2019 and remain at that level thereafter. A 5% annual rate of increase in the per capita cost of covered dental costs was assumed for each year.

Information about these liabilities is as follows:

	2012 $	2011 $
Accrued employee benefit liability - beginning of year	4,287,578	3,731,063
Current service cost	148,221	135,084
Interest cost	198,027	200,467
Benefits paid	(238,978)	(266,530)
Actuarial losses charged to other comprehensive income	524,202	487,494
Accrued employee benefit liability, end of year	4,919,050	4,287,578
Employee vested sick leave obligation	1,584,898	1,744,112
Employee future liabilitiies	6,503,948	6,031,690

The expense recognized in net income is summarized as:

Current service cost	148,221	135,084
Interest cost	198,027	200,467
Benefits paid	(238,978)	(266,530)
Expense recognized in net income	107,270	69,021

Actuarial losses recognized in other comprehensive income, excluding the effect of tax are summarized as follows:

Cumulative actuarial losses in OCI, beginning of year	1,020,061	532,567
Recognized during the year	524,202	487,494
Cumulative actuarial losses in OCI	1,544,263	1,020,061

5. EMPLOYEE FUTURE LIABILITIES, Continued

b) Pension Plan

The Company's share of contributions to the O.M.E.R.S. defined benefit pension plan during the year amounted to $1,005,867 (2011 = $831,253).

6. RELATED PARTY BALANCES

a) Due to Parent Company

	2012 $	2011 $
Demand loan from the City of Peterborough Holdings Inc. bearing interest at 6.25% (2011 – 6.25%)	1,782.848	1,782,848

Included in finance cost for the year is interest on the demand loan of $111,428 (2011 - $111,428). The loans are without maturity date or specified repayment terms. The Company does not expect repayment in fiscal 2012.

b) Due from Related Party

On December 31, 2012 the company advanced to Peterborough Utilities Inc., (PUI) $1,400,000, (2011 – nil). The advances bear interest at an annual rate of 2.2%. No interest was charged in 2012. PUI is related by virtue of common ownership by the City of Peterborough Holdings Inc.

7. SHARE CAPITAL

Authorized
Unlimited number of common shares
Unlimited number of preferred shares

Issued

	2012 $	2011 $
1,000 common shares	4,182,848	4,182,848

8. INCOME TAXES

(a) The effects of the temporary differences that give rise to the future income tax assets and liabilities are as follows:

	2012 $	2011 $
Deferred income tax asset		
Vested sick leave	420,000	493,000
Employee benefit liabilities	1,305,000	1,224,164
	1,725,000	1,717,164
Deferred income tax liability		
Carrying amount of property, plant and equipment in excess of tax basis	55,000	66,615

b) The provision for income taxes recorded in the financial statements differs from the amount which would be obtained by applying the statutory income tax rate of 26.5% (2011 – 28%) to the income for the years as follows:

	2012 $	2011 $
Income for the year before income taxes	1,491,825	1,301,376
Anticipated income tax expense	395,334	367.639
Impact of allocation of Ontario small business deduction PUSI	-	(36,240)
Impact of rate changes and other	78,573	116,059
Provision for income taxes	473,907	447,458

9. RELATED PARTY TRANSACTIONS

During the year, the Company engaged in transactions in the normal course of operations with affiliate companies and the Peterborough Utilities Commission. The parties are related by virtue of common control. The cost of key management personnel included in the payroll of the Company are ultimately borne by the Company's affiliate customers and accordingly are disclosed in their respective statements as required under IFRS. Details of related party transactions are as follows:

9. RELATED PARTY TRANSACTIONS, continued

	2012 $	2011 $
Revenue		
Professional and operating services	13,078,135	12,443,139
Building rent	912,000	960,943
Software and equipment rent	338,385	369,726
Capital	2,988,348	2,818,412
	17,316,868	16,592,220
Expenses - Professonal services	122,788	282,468

10. CAPITAL DISCLOSURES

The Company's primary objective when managing capital is to address the expectation as outlined in the Unanimous Shareholder Declaration between the Company's parent company, the City of Peterborough Holdings Inc., and its shareholder, the Corporation of the City of Peterborough. The expectation is that the Company will maintain a prudent financial and capitalization structure consistent with industry norms and on the basis that it is intended to be a self-financed entity.

The Company considers that the industry norm for capital structure is comprised of 60% debt and 40% equity. The Company is targeting to attain that structure, to the extent possible, in future years.

The Company's current capital structure is defined as follows:

10. CAPITAL DISCLOSURES, continued

	2012	2011
	$	$
Debt		
Due to parent company	1,782,848	1,782,848
Equity		
Share capital	4,182,848	4,182,848
Accumulated other comprehensive loss	(1,169,263)	(725,897)
Retained earnings	933,097	915,179
	3,946,682	4,372,130

11. FINANCIAL INSTRUMENTS

(a) Credit risk

Credit risk arises from the potential that a counter party will fail to perform its obligations. The Company is not exposed to credit risk from customers as a significant portion of the Company's revenue is derived from related parties.

(b) Interest rate risk

The Company is not exposed to any significant interest rate risk.

(c) Foreign currency risk

The Company is not exposed to any significant currency risk.

(d) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet is financial obligations as they occur. At the present time the liquidity risk of the Company is low as it has significant cash resources and room within its capital structure to obtain external financing as required.

12. CONTINGENCIES

The Company has the following contingent liabilities:

(a) The Company participates with other municipal utilities in Ontario in an agreement to exchange reciprocal contracts of indemnity through the Municipal Electric Association Reciprocal Insurance Exchange. Under this agreement the company is contingently liable for additional assessments to the extent that premiums collected are not sufficient to cover actual losses, claims and costs experienced.

(b) The Company assets are pledged as security and the Company has provided an unlimited guarantee related to the indebtedness of the Company's parent company, City of Peterborough Holdings Inc., to its shareholder, the Corporation of the City of Peterborough.

APPENDIX 1-4

SHAREHOLDER DIRECTION AND UNANIMOUS SHAREHOLDER DECLARATION

SHAREHOLDER DIRECTION AND UNANIMOUS SHAREHOLDER DECLARATION

Amended to July 30, 2012

WHEREAS City of Peterborough Holdings Inc. (the "Corporation") is a corporation existing under the Business Corporations Act (Ontario);

AND WHEREAS the Corporation of the City of Peterborough (the "Shareholder") is the beneficial owner of all of the issued shares of the Corporation;

AND WHEREAS the Corporation and the Subsidiaries (together the "Corporations") are the successors to the electricity utility portion of the Peterborough Utilities Commission;

AND WHEREAS the Corporations business (the "Business") is integral to the well-being and infrastructure of the City of Peterborough;

AND WHEREAS the Business is subject to the provisions of the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* being Schedules A and B, respectively, to the *Energy Competition Act, 1998, S.O.,* c.15, as such statutes may be amended or reenacted from time to time;

AND WHEREAS the Shareholder wishes to establish certain principles of governance relating to the Corporations and to set forth those matters which may be undertaken by the Corporations only with the approval of the Shareholder;

NOW THEREFORE THIS DIRECTION AND DECLARATION WITNESSES:

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ARTICLE 1 - INTERPRETATION

1.1 Definitions

In this Direction and Declaration, in addition to the terms defined in the recitals, the following terms will have the meanings set out below:

"Associate" means a person that is associated with the Corporation or any Subsidiary as such relationship is defined in the OBCA;

"Board" means the board of directors of the Corporation;

"body corporate" means a firm, partnership, unincorporated association, joint venture, body corporate, corporation, bank, trust, pension fund, union, governmental agency, board, tribunal, ministry or commission or other legal entity of any kind whatsoever, but excludes an individual or natural person;

"Business Plan" means a five year business plan and budget for the Corporation and the Subsidiaries prepared and approved in accordance with Section 6.1;

"Chair" means the director of the Corporation appointed as Chair of the Board, by the Board, from time to time.

"Distribution Company" means Peterborough Distribution Inc.

"Financial Statements" means, for any particular period, audited or unaudited (as stipulated in this Direction and Declaration), consolidated or unconsolidated (as stipulated in this Direction and Declaration), comparative financial statements of the Corporation consisting of not less than a balance sheet, a statement of income and retained earnings, a statement of changes in financial position, a report or opinion of the Auditor (in the case of audited Financial Statements) and such other statements, reports, notes and information prepared in accordance with generally accepted accounting principles (consistently applied) and as are required in accordance with any applicable law;

"Lien" means any mortgage, hypothecy, assignment, encumbrance, lien or security interest, regardless of form, that secures the payment of any indebtedness or liability or the observance or performance of any obligation;

"OBCA" means the *Business Corporations Act* (Ontario), as such statute may be amended or reenacted from time to time;

"person" means an individual, a natural person or a body corporate;

"Regulator" means the Ontario Energy Board, the Independent Electricity Market Operator and each other governmental or regulatory authority having jurisdiction over the Corporations;

"Retail Company" means Peterborough Utilities Inc.;

"Services Company" means Peterborough Utilities Services Inc.

"Subsidiary" means, with respect to the Corporation, Peterborough Utilities Inc., Peterborough Utilities Services Inc. and Peterborough Distribution Inc.;

"Third party" means a person who deals at arm's length (as interpreted by subsection 251(l) of the *Income Tax Act* (Canada)) with the Corporation or the Subsidiaries.

1.2 Calculation of Time

In this Direction and Declaration, a period of days will be deemed to begin on the first day after the event which began the period and to end at 5:00 p.m. (Peterborough time) on the last day of the period. If, however, the last day of the period does not fall on a business day, the period will terminate at 5:00 p.m. (Peterborough time) on the next business day.

1.3 Paramountcy

In the event of any inconsistency between the terms of this Direction and Declaration and the terms of the articles or the by-laws of the Corporation or any of its Subsidiaries, the terms of this Direction and Declaration shall prevail to the extent of the conflict.

ARTICLE 2 - EXPECTATIONS AND PRINCIPLES

2.1 Purposes

The purposes of this Direction and Declaration are as follows:

(a) subject to the Board's authority to manage or supervise the management of the business and affairs of the Corporations, to provide the Board with the Shareholder's expectations relating to the principles of governance and other fundamental principles and policies regarding the Business;

(b) to inform the residents of the City of Peterborough of the Shareholder's fundamental principles regarding the Business; and

(c) to set out the accountability, responsibility and relationship between the Board and the Shareholder.

Except as provided in Article 5 hereof, this Direction and Declaration is not intended to constitute a unanimous shareholder declaration under the OBCA or to formally restrict the exercise of the powers of the Board.

2.2 Shareholder Expectations

The Shareholder expects that the Board will establish policies to:

(a) develop and maintain a prudent financial and capitalization structure for the Corporation and its Subsidiaries consistent with industry norms and sound financial principles and established on the basis that the Corporation and its Subsidiaries are intended to be self-financing entities;

(b) establish just and reasonable rates for the regulated Distribution Company of the Corporation, or any of its Subsidiaries, which are:

  (i) consistent with similar utilities in comparable growth areas and as may be permitted by the Ontario Energy Board;

  (ii) intended to preserve and enhance the value of the Corporation and its Subsidiaries; and

  (iii) consistent with the encouragement of economic development and activity within the City of Peterborough;

(c) provide service with reliability consistent with Ontario electric utility standards;

(d) subject to Section 7.2 hereof, provide the Shareholder with a reasonable return on equity:

  (i) comparable to the return received by other growth municipalities as permitted by the Ontario Energy Board pursuant to the OEB Act;

  (ii) through the payment of dividends, interest or otherwise; and

(iii) consistent with a prudent financial structure and capitalization and maintaining just and reasonable rates;

(e) manage all risks related to the business conducted by the Corporation and its Subsidiaries, through the adoption of appropriate risk management strategies and internal controls consistent with industry norms; and

(f) develop a long range strategic plan for the Corporation and its Subsidiaries which is consistent with the maintenance of a viable, competitive business and preserves the value of the Business.

2.3 Principles

The following principles will govern the operations of the Corporations:

(a) The Business is integral to the well being and the infrastructure of the City of Peterborough. The Corporation recognizes that it is in the best interests of the Corporations and the community of stakeholders whom the Business affects that the Corporations conduct its affairs:

(i) on a commercially prudent basis;

(ii) in a manner consistent with the energy policies as may be established by the Shareholder from time to time;

(iii) on a for-profit basis and in accordance with the financial performance objectives of the Shareholder as set out herein.

(b) The Distribution Company will provide a reliable, effective and efficient electricity distribution system.

(c) Distribution rates applicable to customers of the Distribution Company will be approved by the Board to be fair to all classes of customers and to achieve the returns permitted by the Ontario Energy Board.

(d) The Business is at all times subject to such licences, codes, policies, rules, orders, interim orders, approvals, consents and other actions of any Regulator.

(e) The Distribution Company will provide its services with an emphasis on customer satisfaction, addressing the customer service indicators and service reliability indicators accepted from time to time by the Ontario Energy Board.

(f) The Corporations will operate in a safe and environmentally responsible manner.

(g) The Distribution Company will promote energy conservation and environmental responsibility.

(h) The Board is responsible for determining and implementing the appropriate balance among the foregoing principles and for causing the Corporations to conduct its affairs in accordance with the same.

ARTICLE 3 - BUSINESS OF THE CORPORATIONS

3.1 Business of the Corporations

Subject to the ongoing ability of the Corporations to meet the financial objectives of the Shareholder set out in this Direction and Declaration and the ability of the Board to demonstrate the same, the Corporations may engage in any of the following business activities:

(a) the Distribution Company may engage only in the following business activities:

  (i) distributing electricity;

  (ii) business activities, the principal purpose of which is to use more effectively the assets of the distribution system of the Distribution Company;

(b) the Retail Company may engage only in the following business activities:

  (i) retailing electricity, subject to the approval of the Board of the Corporation;

  (ii) owning, operating or having an ownership interest in one or more electricity generation facilities;

  (iii) renting or selling, water heaters, plenum heaters and lights;

  (iv) providing telecommunication and metering-related services;

  (v) providing services relating to improving energy efficiency;

(vi) other customer services, subject to the approval of the Board of the Corporation;

(vii) other business activities which are subject to the approval of the Shareholder;"

(c) the Services Company may engage only in the following business activities:

(i) provide accounting, engineering, collection, human resources, information services, customer services, billing and maintenance and operation to the Distribution Company, the Peterborough Utilities Commission, the Retail Company and to other utilities, generators, municipalities and third parties;

(ii) business activities that develop or engage the ability of the Services Company to carry on any of the activities contemplated by subsection 3.1(c)(i); and

iii) other business activities which are subject to the approval of the Shareholder.

ARTICLE 4 - OPERATION AND CONTROL

4.1 Board of Directors and Responsibilities

Subject to any matters requiring approval of the Shareholder pursuant to this Direction and Declaration, the Board will supervise the management of the business and affairs of the Corporation, including the following specific matters:

(a) approving any dividend payment or distribution of capital in excess of the payments provided for in Section 7.2;

(b) approving the dividend payments by the Subsidiaries;

(c) appointing the officers of the Corporation and the Subsidiaries;

(d) approving the remuneration of senior management of the Corporation and the Subsidiaries (for this purpose, "senior management" means the President and Vice-Presidents of each such company);

(e) finally determining any dispute or disagreement which may occur between any two or more of the Subsidiaries.

4.2 Board of Directors

The Corporation shall be managed by the Board, which shall consist of no less than seven (7) and no more than nine (9) directors., including the Mayor or designate from Council and one (1) other member of Council, and the directors are to be elected by the Shareholder. At least one-third of the directors of the Distribution Company are to be independent from the Corporation and the other Subsidiaries (for this purpose, independent means an individual who is not a councillor or employee of the Shareholder or an officer, director or employee of the Corporation or any of the other Subsidiaries). In selecting directors, the Shareholder shall consider candidates nominated by the nominating committee of the Board (the "Nominating Committee"), but shall not be obliged to select such candidates

It is expected that the Nominating Committee will develop a process to identify and evaluate potential Board candidates in order to recommend a slate of candidates acceptable to the Shareholder.

4.3 Board of Directors of Subsidiaries

Subject to any matters requiring approval of the Shareholder pursuant to this Direction and Declaration and subject to matters to be approved by the Board of the Corporation pursuant to Section 4.1, the business and affairs of the Subsidiaries will be managed or supervised by their respective boards of directors. The Corporation will elect the directors of the Subsidiaries from among the directors of the Corporation. The independent directors required for the Distribution Company may be appointed by the Shareholder, as required, in addition to the directors from the Corporation.

4.4 Qualifications of Directors

A majority of the Board and the board of directors of each Subsidiary will be residents of Canada. In electing directors to the Board the Shareholder will give due regard to the qualifications of candidates, including experience or knowledge with respect to:

(a) service on public utility commissions or boards of major corporations or other commercial enterprises;

(b) corporate finance and financial services;

(c) corporate governance;

(d) corporate planning and strategies;

(e) information services;

(f) engineering;

(g) general counsel to large corporations, including but not limited to practice in large commercial transactions and regulatory practice in Ontario;

(h) public policy issues and laws relating to the companies in the electricity industry; and

(i) environmental matters, employment relations and occupational health and safety issues.

Preference may be given to qualified candidates for the Board who are residents within the distribution area of the Distribution Company.

4.5 Standards of Governance

The Shareholder expects the Board to observe substantially the same standards of corporate governance as may be established from time to time by the Toronto Stock Exchange or any other applicable regulatory or governmental authority in Canada for publicly traded corporations, with any appropriate modification to reflect the fact that the Corporation is not itself a public corporation.

4.6 Vacancies

If a member of the Board ceases to be a director for any reason, the Shareholder will fill the vacancy created thereby as soon as reasonably possible. If a member of the board of directors of any Subsidiary ceases to be a director for any reason, the Corporation will cause the vacancy to be filled by another director of the Corporation as soon as reasonably possible.

4.7 Term

The term of office for a director who is not a member of the City of Peterborough Council will be three years or until his or her successor is elected. No non-member of Council shall serve greater than a total of nine continuous years as a director. The term of office for a director who is a member of the City of Peterborough Council will be equal to the term of Council or until his or her successor is elected.

4.8 President and Chief Executive Officer

The President and Chief Executive Officer of the Corporation and any Subsidiary may not be a director of the Corporation or a Subsidiary.

4.9 Committees

The Board may establish committees of the Board at the Board's discretion.

4.10 Conflict of Interest Policy

The directors and officers of the Corporation and the Subsidiaries will strictly abide by the requirements of the OBCA and the Corporation in respect of conflicts of interest, including any requirements in respect of disclosure and abstention from voting. A detailed conflict of interest policy will be established by the Corporation within six (6) months of the date hereof and will form a part of the Bylaws of the Corporation.

4.11 Confidentiality

The Shareholder and the directors and officers of the Corporation and the Subsidiaries (each a "Receiving Party") will ensure that no confidential information of the Shareholder or the Corporations is disclosed or otherwise made available to any person. except to the extent that:

(a) disclosure to a Receiving Party's employees or agents is necessary for the performance of any Receiving Party's duties and obligations under this Direction and Declaration;

(b) disclosure is required in the course of judicial proceedings or pursuant to law; or

(c) the confidential information becomes part of the public domain (other than through unauthorized disclosure by the Receiving Party).

A detailed confidentiality policy consistent with the practices of corporate governance will be established by the Corporation within six (6) months of the date hereof and will form a part of the Bylaws of the Corporation.

4.12 Remuneration

(a) The remuneration of the members of the Board for their respective services as directors will be as determined by the Shareholder from time to time. Each director the Corporation , excluding the "one (1) other member of Council" referenced in article 4.2, and the two directors appointed directly to Peterborough Distribution Inc. will be paid $6,000 per annum for his or her services.

(b) The Chair of the Corporation will also be paid an additional $4,000 per annum and the chairs of each of the subsidiaries and committees will be paid an additional $2,000 per annum.

Each director of the Corporation and a Subsidiary will be paid $400 for each meeting of the Board attended, and that director remuneration be reviewed every two years."

4.13 Report and Annual Meeting

(a) Within six (6) months after the end of each fiscal year, the Board shall report to a public meeting of City Council, and provide such information concerning the Corporation and its Subsidiaries as the Board considers appropriate.

(b) Prior to the end of each fiscal year, the Shareholder shall consider candidates for the Board, as proposed by a Nominating Committee of the Board, and shall elect members of the Board for terms to be effective January 1st of the succeeding year, as required. Such election may be by resolution in writing signed by the Shareholder Representative in accordance with Section 5.5.

(c) Within six (6) months after the end of each fiscal year, the Shareholder, by resolution in writing signed by the Shareholder Representative in accordance with Section 5.5, shall appoint the auditors for the Corporation and complete such other business as would normally be completed at an annual meeting of shareholders under the OBCA.

ARTICLE 5 - SHAREHOLDER MATTERS

5.1 Decisions of the Shareholder

The following will apply to any approvals or decisions that the Shareholder must provide:

(a) all approvals and decisions will be made in writing signed by the Shareholder Representative; and

(b) no approval will be given unless the Corporation has given reasonable advance notice in writing of the need for approval and has provided such information as is reasonably necessary for the Shareholder to make an informed decision regarding the subject matter requiring approval.

5.2 Matters Requiring Shareholder Approval under the OBCA

In accordance with the provisions of the OBCA, neither the Corporation nor any Subsidiary will, without the approval of the Shareholder:

(a) amend its articles or make, amend or repeal any by-law;

(b) amalgamate (except for an amalgamation with one or more Subsidiaries), apply to continue as a body corporate under the laws of another jurisdiction, merge, consolidate or reorganize, or approve or effect any plan of arrangement, in each case whether statutory or otherwise;

(c) take or institute proceedings for any winding up, arrangement, reorganization or dissolution;

(d) create new classes of shares or reorganize, consolidate, subdivide or otherwise change its outstanding securities;

(e) sell or otherwise dispose of, by conveyance, transfer, lease, sale and leaseback, or other transaction, all or substantially all of its assets or undertaking;

(f) change the Auditor;

(g) make any change to the number of directors comprising the Board;

(h) enter into any transaction or take any action that requires shareholder approval pursuant to the OBCA.

5.3 Other Matters Requiring Shareholder Approval

Without first having obtained the approval of the Shareholder, the Corporation will not, either directly, or through a Subsidiary or any other entity in which the Corporation has a direct or indirect controlling interest:

(a) enter into any transaction to sell or purchase assets with an aggregate value in excess of $20 million;

(b) 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 any of its Subsidiaries;

(c) establish any requirement for capital contributions to the Corporation by the Shareholder;

(d) the Distribution Company to take on or assume any financial obligation which would increase the debt/equity ratio of the Corporation and its Subsidiaries above the debt/equity ratio allowed for the Distribution Company for rate purposes by the Ontario Energy Board, at the date of this Amended Shareholder Direction and Unanimous Shareholder Declration being a ratio of 60:40;

(e) the Retail Company to take on or assume any financial obligation which would increase the debt/equity ratio of the Retail Company above a ratio of 80:20;

(f) the Services Company to take on or assume any financial obligation which would increase the debt/equity ratio of the Services Company above a ratio of 80:20;

(g) redeem or purchase any of its outstanding shares;

(h) make any decision that would materially adversely affect the tax or regulatory status of the Corporation or any of its Subsidiaries;

(i) materially alter the nature of or geographic extent of the business of the Corporation or any of its Subsidiaries in a manner which would have a financial impact equal to or greater than $20 million;

(j) enter into any joint venture, partnership, strategic alliance or other venture, including ventures in respect of the generation or co-generation of electricity, which would require an investment of, or which would have a financial impact, equal to or greater than $20 million;

(k) enter into any business activity not permitted under Section 3.1 hereof;

(l) provide any financial assistance, whether by loan, guarantee or otherwise, to any director of officer of the Corporation or of any Subsidiary or Associate, save and except any computer purchase assistance plan which is generally available to all employees;

(m) establish a new Subsidiary, other than establishing wholly-owned subsidiary companies for purposes of carrying on the permitted activities of Secton 3.1;

(n) invest funds in publicly-traded securities other than government debt, Canadian chartered bank or Canadian corporate securities rated less than A/R-1 (low) (or its equivalent) by CBRS Inc. or Dominion Bond Rating Service Limited; and

(o) change the remuneration for members of the Board as provided for in Section 4.10 hereof.

For the purposes of calculating a debt/equity ratio pursuant to this Section, Shareholder debt will be considered to be equity.

For the purpose of paragraph (j) of this Section 5.3, the term "financial assistance" does not include remuneration paid in the normal course of business to directors, officers or employees, including honoraria, wages, salaries or bonuses, or any reimbursement for expenses arising from such persons' duties.

This Section 5.3 shall constitute a Unanimous Shareholder Declaration pursuant to the OBCA.

5.4 Decisions of the Shareholder

Approvals or decisions of the Shareholder required pursuant to this Direction and Declaration or the OBCA shall require a resolution or by-law of the City Council of the Shareholder which may be passed at a meeting of Council and shall be given in writing signed by the Shareholder Representative.

5.5 Shareholder Representative

The Shareholder hereby designates the Mayor or the individual designated by the Mayor from time to time as the legal representative of the Shareholder (the "Shareholder Representative") for purposes of providing, pursuant to Section 5.4, any consent or approval required by this Direction and Declaration or by the OBCA.

ARTICLE 6 - REPORTING

6.1 Business Plan

(a) Not later than one hundred and twenty days (120) days after the end of each fiscal year, the Board will approve and submit to the Finance Department of the Shareholder (the "Finance Department") a business plan for the Corporations for the next five (5) fiscal years (the "Business Plan"). The Business Plan will be prepared on a consistent basis with the Business Plan then in effect. The Corporation will carry on its business and operations in accordance with the Business Plan which will include, in respect of the period covered by such plan:

(i) the strategic direction and any new business initiatives which the Corporations will undertake;

(ii) an operating and capital expenditure budget for the next fiscal year and an operating and capital expenditure projection for each fiscal year thereafter, including the resources necessary to implement the draft business plan;

(iii) the projected annual revenues and profits for each fiscal year for the Corporation and each of the Subsidiaries;

(iv) pro forma consolidated and unconsolidated financial statements, including projected dividend payments to the Shareholder;

(v) any material variances in the projected ability of any business activity to meet or continue to meet the financial objectives of the Shareholder; and

(vi) any material variances from the Business Plan then in effect.

6.2 Quarterly Reports

(a) Quarterly financial statements presented to the Board will be provided to the City Treasurer.

6.3 Access to Records

The duly appointed representatives of the Shareholder (as approved by report to the Council of the City of Peterborough from time to time) shall have unrestricted access to the books and records of the Corporation and the Subsidiaries during normal business hours. Such representatives shall treat all information of the Corporations with the same level of care and confidentiality as any confidential information of the Shareholder.

6.4 Audit

The Corporation's consolidated and unconsolidated Financial Statements will be audited annually.

6.5 Accounting

The Corporation will, in consultation with the Auditor, adopt and use the accounting policies and procedures which may be approved by the Board from time to time and all such policies and procedures will be in accordance with generally accepted accounting principles and applicable regulatory requirements.

6.6 Annual Financial Statements

The Board will cause the Auditor to deliver, as soon as practicable and in any event within one hundred and twenty days (120) days after the end of each fiscal year, the audited consolidated Financial Statements of the Corporation for consideration by the Shareholder.

6.7 Reporting on Major Developments

In addition to the annual meeting described in Section 4.11(a), the Board shall report to the Shareholder on such major business developments, or material adverse results, as the Board, in its discretion, considers appropriate and such reports may be considered by the Shareholder at a meeting of Council.

ARTICLE 7 - FINANCIAL PERFORMANCE

7.1 Financial Performance

The Board will be responsible for ensuring that the Corporations meet the financial performance standards set out in this Article 7.

7.2 <u>Dividend Policy</u>

Commencing January 1, 2013, the target dividend from the Corporation to the Shareholder for a particular calendar year shall be an amount that is the dividend paid by the Corporation to the Shareholder with respect to the preceding calendar year increased by 3% per annum.
The annual cash dividend will be payable quarterly. The amount of the cash dividend paid by the Corporation to the Shareholder may be subject to adjustment by the Shareholder from time to time based on the financial requirements of the Shareholder and the Corporation.

ARTICLE 8 - REVISIONS TO THIS DIRECTION AND DECLARATION

The Shareholder acknowledges that this Direction and Declaration may be revised from time to time as circumstances may require in the sole discretion of the Shareholder and that the Shareholder shall promptly provide the Board with copies of such revisions.

DATED at Peterborough this 30th day of July, 2012.

SIGNED, SEALED AND DELIVERED in the presence of:	)	**THE CORPORATION OF THE CITY OF PETERBOROUGH**
	)	Daryl Bennett, Mayor
	)	John Kennedy, Clerk

APPENDIX 1-5

ESTIMATED RESIDENTIAL BILL IMPACTS 2011
AS USED IN 2011 ANNUAL REPORT

Estimated Bill Impacts - 800 kWh

August 9, 2011

The following estimated bills are provided for information purposes only. They are not intended to represent actual bills but rather to provide an estimate for comparison between utility service areas. The values in the Electricity column reflect the Regulated Price Plan (RPP) rates that were in effect at that time. Because of rounding, amounts in the sub-total and total columns may be off by one cent.

The numbers in the chart have been calculated using the following data and assumptions:
- shows estimated total bill impacts for those utilities with 2011 distribution rates
- a residential consumer using 800 kilowatt hours per month
- loss factor adjustment has been applied
- a consumer who is on the RPP, purchasing their electricity through their utility

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Algoma Power Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$62.06	$56.45	$60.15	$5.61	9.9%	$1.91	3.2%
Delivery	$54.72	$49.53	$49.53	$5.19	10.5%	$5.19	10.5%
Regulatory	$6.22	$6.31	$6.31	($0.09)	-1.4%	($0.09)	-1.4%
Debt Retirement Charge	$1.60	$1.60	$1.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$124.60	$113.89	$117.59	$10.72	9.4%	$7.01	6.0%
Tax*	$16.20	$14.81	$5.88	$1.39	9.4%	$10.32	175.5%
Ontario Clean Energy Benefit	*($14.08)*	*($12.87)*		*($1.21)*		*($14.08)*	
Total Estimated Residential Bill	**$126.72**	**$115.82**	**$123.47**	**$10.90**	**9.4%**	**$3.25**	**2.6%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Atikokan Hydro Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$61.36	$55.06	$58.52	$6.30	11.4%	$2.84	4.9%
Delivery	$50.95	$46.46	$46.46	$4.49	9.7%	$4.49	9.7%
Regulatory	$6.16	$6.16	$6.16	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$124.08	$113.28	$116.74	$10.79	9.5%	$7.33	6.3%
Tax*	$16.13	$14.73	$5.84	$1.40	9.5%	$10.29	176.3%
Ontario Clean Energy Benefit	*($14.02)*	*($12.80)*		*($1.22)*		*($14.02)*	
Total Estimated Residential Bill	**$126.18**	**$115.21**	**$122.58**	**$10.98**	**9.5%**	**$3.60**	**2.9%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Bluewater Power Distribution Corporation				$ Change	% Change	$ Change	% Change
Electricity	$58.85	$53.02	$56.14	$5.83	11.0%	$2.71	4.8%
Delivery	$40.22	$36.64	$36.64	$3.58	9.8%	$3.58	9.8%
Regulatory	$5.94	$5.94	$5.94	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$110.61	$101.20	$104.32	$9.41	9.3%	$6.29	6.0%
Tax*	$14.38	$13.16	$5.22	$1.22	9.3%	$9.16	175.7%
Ontario Clean Energy Benefit	*($12.50)*	*($11.44)*		*($1.06)*		*($12.50)*	
Total Estimated Residential Bill	**$112.49**	**$102.92**	**$109.53**	**$9.57**	**9.3%**	**$2.96**	**2.7%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Brant County Power Inc.				$ Change	% Change	$ Change	% Change
Electricity	$59.65	$53.73	$56.97	$5.91	11.0%	$2.68	4.7%
Delivery	$34.74	$37.51	$37.51	($2.77)	-7.4%	($2.77)	-7.4%
Regulatory	$6.01	$6.02	$6.02	($0.01)	-0.1%	($0.01)	-0.1%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$106.00	$102.86	$106.10	$3.13	3.0%	($0.10)	-0.1%
Tax*	$13.78	$13.37	$5.31	$0.41	3.0%	$8.47	159.7%
Ontario Clean Energy Benefit	*($11.98)*	*($11.62)*		*($0.35)*		*($11.98)*	
Total Estimated Residential Bill	**$107.80**	**$104.61**	**$111.41**	**$3.18**	**3.0%**	**($3.61)**	**-3.2%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Brantford Power Inc.				$ Change	% Change	$ Change	% Change
Electricity	$59.25	$53.35	$56.52	$5.90	11.1%	$2.73	4.8%
Delivery	$28.56	$31.84	$31.84	($3.28)	-10.3%	($3.28)	-10.3%
Regulatory	$5.98	$5.98	$5.98	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$99.39	$96.77	$99.94	$2.62	2.7%	($0.55)	-0.5%
Tax*	$12.92	$12.58	$5.00	$0.34	2.7%	$7.92	158.6%
Ontario Clean Energy Benefit	*($11.23)*	*($10.93)*		*($0.30)*		*($11.23)*	
Total Estimated Residential Bill	**$101.08**	**$98.41**	**$104.93**	**$2.67**	**2.7%**	**($3.85)**	**-3.7%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Burlington Hydro Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.16	$53.27	$56.43	$5.89	11.0%	$2.73	4.8%
Delivery	$37.45	$35.76	$35.76	$1.69	4.7%	$1.69	4.7%
Regulatory	$5.97	$5.97	$5.97	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$108.18	$100.61	$103.76	$7.57	7.5%	$4.42	4.3%
Tax*	$14.06	$13.08	$5.19	$0.98	7.5%	$8.88	171.1%
Ontario Clean Energy Benefit	*($12.22)*	*($11.37)*		*($0.86)*		*($12.22)*	
Total Estimated Residential Bill	**$110.02**	**$102.32**	**$108.95**	**$7.70**	**7.5%**	**$1.07**	**1.0%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Cambridge and North Dumfries Hydro Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$58.41	$52.66	$55.72	$5.74	10.9%	$2.69	4.8%
Delivery	$27.06	$27.03	$27.03	$0.03	0.1%	$0.03	0.1%
Regulatory	$5.91	$5.91	$5.91	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$96.97	$91.20	$94.25	$5.77	6.3%	$2.72	2.9%
Tax*	$12.61	$11.86	$4.71	$0.75	6.3%	$7.89	167.5%
Ontario Clean Energy Benefit	*($10.96)*	*($10.31)*		*($0.65)*		*($10.96)*	
Total Estimated Residential Bill	**$98.62**	**$92.75**	**$98.96**	**$5.87**	**6.3%**	**($0.34)**	**-0.3%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Canadian Niagara Power Inc. - Eastern Ontario Power				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$61.14	$54.88	$58.31	$6.26	11.4%	$2.83	4.9%
Delivery	$37.37	$33.48	$33.48	$3.89	11.6%	$3.89	11.6%
Regulatory	$6.14	$6.14	$6.14	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$4.08	$4.08	$4.08	$0.00	0.0%	$0.00	0.0%
Sub-Total	$108.74	$98.58	$102.02	$10.16	10.3%	$6.72	6.6%
Tax*	$14.14	$12.82	$5.10	$1.32	10.3%	$9.04	177.1%
Ontario Clean Energy Benefit	*($12.29)*	*($11.14)*		*($1.15)*		*($12.29)*	
Total Estimated Residential Bill	**$110.59**	**$100.26**	**$107.12**	**$10.33**	**10.3%**	**$3.47**	**3.2%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Canadian Niagara Power Inc. - Fort Erie				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.07	$53.20	$56.35	$5.87	11.0%	$2.73	4.8%
Delivery	$43.12	$41.33	$41.33	$1.79	4.3%	$1.79	4.3%
Regulatory	$5.96	$5.96	$5.96	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$0.00	$0.00	$0.00	$0.00	#DIV/0!	$0.00	#DIV/0!
Sub-Total	$108.15	$100.50	$103.64	$7.66	7.6%	$4.51	4.4%
Tax*	$14.06	$13.06	$5.18	$1.00	7.6%	$8.88	171.3%
Ontario Clean Energy Benefit	*($12.22)*	*($11.36)*		*($0.87)*		*($12.22)*	
Total Estimated Residential Bill	**$109.99**	**$102.21**	**$108.82**	**$7.79**	**7.6%**	**$1.17**	**1.1%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Canadian Niagara Power Inc. - Port Colborne Hydro Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$60.71	$53.16	$56.29	$7.56	14.2%	$4.42	7.9%
Delivery	$45.53	$48.56	$48.56	($3.03)	-6.2%	($3.03)	-6.2%
Regulatory	$6.11	$5.96	$5.96	$0.15	2.5%	$0.15	2.5%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$117.95	$113.27	$116.41	$4.68	4.1%	$1.54	1.3%
Tax*	$15.33	$14.73	$5.82	$0.61	4.1%	$9.51	163.4%
Ontario Clean Energy Benefit	*($13.33)*	*($12.80)*		*($0.53)*		*($13.33)*	
Total Estimated Residential Bill	**$119.96**	**$115.20**	**$122.23**	**$4.76**	**4.1%**	**($2.27)**	**-1.9%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Centre Wellington Hydro Ltd.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.44	$53.50	$56.69	$5.94	11.1%	$2.74	4.8%
Delivery	$31.82	$32.57	$32.57	($0.75)	-2.3%	($0.75)	-2.3%
Regulatory	$5.99	$5.99	$5.99	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$102.85	$97.66	$100.86	$5.19	5.3%	$1.99	2.0%
Tax*	$13.37	$12.70	$5.04	$0.67	5.3%	$8.33	165.1%
Ontario Clean Energy Benefit	*($11.62)*	*($11.04)*		*($0.59)*		*($11.62)*	
Total Estimated Residential Bill	**$104.60**	**$99.32**	**$105.90**	**$5.27**	**5.3%**	**($1.30)**	**-1.2%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Chapleau Public Utilities Corporation				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$60.73	$54.55	$57.92	$6.18	11.3%	$2.81	4.8%
Delivery	$34.16	$30.63	$30.63	$3.53	11.5%	$3.53	11.5%
Regulatory	$6.11	$6.11	$6.11	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$106.60	$96.88	$100.26	$9.72	10.0%	$6.34	6.3%
Tax*	$13.86	$12.59	$5.01	$1.26	10.0%	$8.84	176.4%
Ontario Clean Energy Benefit	*($12.05)*	*($10.95)*		*($1.10)*		*($12.05)*	
Total Estimated Residential Bill	**$108.41**	**$98.53**	**$105.27**	**$9.88**	**10.0%**	**$3.14**	**3.0%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Chatham-Kent Hydro Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.30	$53.39	$56.57	$5.91	11.1%	$2.74	4.8%
Delivery	$35.04	$33.29	$33.29	$1.75	5.3%	$1.75	5.3%
Regulatory	$5.98	$5.98	$5.98	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$105.93	$98.26	$101.44	$7.67	7.8%	$4.49	4.4%
Tax*	$13.77	$12.77	$5.07	$1.00	7.8%	$8.70	171.5%
Ontario Clean Energy Benefit	*($11.97)*	*($11.10)*		*($0.87)*		*($11.97)*	
Total Estimated Residential Bill	**$107.73**	**$99.93**	**$106.51**	**$7.80**	**7.8%**	**$1.22**	**1.1%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
COLLUS Power Corporation				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$61.34	$55.04	$58.50	$6.30	11.4%	$2.84	4.9%
Delivery	$31.60	$30.97	$30.97	$0.63	2.0%	$0.63	2.0%
Regulatory	$6.16	$6.16	$6.16	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$104.70	$97.77	$101.23	$6.93	7.1%	$3.47	3.4%
Tax*	$13.61	$12.71	$5.06	$0.90	7.1%	$8.55	168.9%
Ontario Clean Energy Benefit	*($11.83)*	*($11.05)*		*($0.78)*		*($11.83)*	
Total Estimated Residential Bill	**$106.48**	**$99.43**	**$106.29**	**$7.05**	**7.1%**	**$0.19**	**0.2%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Cooperative Hydro Embrun Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$60.26	$54.16	$57.47	$6.09	11.3%	$2.79	4.8%
Delivery	$35.33	$34.55	$34.55	$0.78	2.3%	$0.78	2.3%
Regulatory	$6.07	$6.07	$6.07	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$107.26	$100.38	$103.69	$6.88	6.8%	$3.57	3.4%
Tax*	$13.94	$13.05	$5.18	$0.89	6.8%	$8.76	168.9%
Ontario Clean Energy Benefit	*($12.12)*	*($11.34)*		*($0.78)*		*($12.12)*	
Total Estimated Residential Bill	**$109.08**	**$102.09**	**$108.87**	**$6.99**	**6.8%**	**$0.21**	**0.2%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
E.L.K. Energy Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$61.60	$55.25	$58.75	$6.35	11.5%	$2.85	4.9%
Delivery	$36.00	$30.22	$30.22	$5.77	19.1%	$5.77	19.1%
Regulatory	$6.18	$6.18	$6.18	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$109.38	$97.26	$100.75	$12.12	12.5%	$8.63	8.6%
Tax*	$14.22	$12.64	$5.04	$1.58	12.5%	$9.18	182.3%
Ontario Clean Energy Benefit	*($12.36)*	*($10.99)*		*($1.37)*		*($12.36)*	
Total Estimated Residential Bill	**$111.24**	**$98.91**	**$105.79**	**$12.33**	**12.5%**	**$5.45**	**5.1%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Enersource Hydro Mississauga Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$58.88	$53.04	$56.16	$5.83	11.0%	$2.72	4.8%
Delivery	$31.68	$32.35	$32.35	($0.67)	-2.1%	($0.67)	-2.1%
Regulatory	$5.95	$5.95	$5.95	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$102.10	$96.93	$100.05	$5.17	5.3%	$2.05	2.0%
Tax*	$13.27	$12.60	$5.00	$0.67	5.3%	$8.27	165.3%
Ontario Clean Energy Benefit	*($11.54)*	*($10.95)*		*($0.58)*		*($11.54)*	
Total Estimated Residential Bill	**$103.84**	**$98.58**	**$105.05**	**$5.25**	**5.3%**	**($1.22)**	**-1.2%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
ENWIN Utilities Ltd.				$ Change	% Change	$ Change	% Change
Electricity	$58.98	$53.13	$56.26	$5.85	11.0%	$2.72	4.8%
Delivery	$36.73	$35.09	$35.09	$1.64	4.7%	$1.64	4.7%
Regulatory	$5.96	$5.96	$5.96	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$107.27	$99.78	$102.91	$7.49	7.5%	$4.36	4.2%
Tax*	$13.95	$12.97	$5.15	$0.97	7.5%	$8.80	171.0%
Ontario Clean Energy Benefit	*($12.12)*	*($11.27)*		*($0.85)*		*($12.12)*	
Total Estimated Residential Bill	**$109.10**	**$101.47**	**$108.06**	**$7.62**	**7.5%**	**$1.04**	**1.0%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Erie Thames Powerlines Corporation				$ Change	% Change	$ Change	% Change
Electricity	$59.30	$53.39	$56.56	$5.91	11.1%	$2.74	4.8%
Delivery	$40.56	$36.10	$36.10	$4.46	12.3%	$4.46	12.3%
Regulatory	$5.98	$5.98	$5.98	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$111.44	$101.07	$104.24	$10.37	10.3%	$7.19	6.9%
Tax*	$14.49	$13.14	$5.21	$1.35	10.3%	$9.27	177.9%
Ontario Clean Energy Benefit	*($12.59)*	*($11.42)*		*($1.17)*		*($12.59)*	
Total Estimated Residential Bill	**$113.33**	**$102.79**	**$109.46**	**$10.54**	**10.3%**	**$3.87**	**3.5%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Espanola Regional Hydro Distribution Corporation				$ Change	% Change	$ Change	% Change
Electricity	$60.03	$53.98	$57.26	$6.05	11.2%	$2.77	4.8%
Delivery	$30.93	$32.25	$32.25	($1.32)	-4.1%	($1.32)	-4.1%
Regulatory	$6.05	$6.05	$6.05	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$102.61	$97.88	$101.16	$4.73	4.8%	$1.45	1.4%
Tax*	$13.34	$12.72	$5.06	$0.61	4.8%	$8.28	163.7%
Ontario Clean Energy Benefit	*($11.59)*	*($11.06)*		*($0.53)*		*($11.59)*	
Total Estimated Residential Bill	**$104.35**	**$99.54**	**$106.21**	**$4.81**	**4.8%**	**($1.86)**	**-1.8%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Essex Powerlines Corporation				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$60.40	$54.28	$57.61	$6.12	11.3%	$2.79	4.8%
Delivery	$36.29	$35.75	$35.75	$0.53	1.5%	$0.53	1.5%
Regulatory	$6.08	$6.08	$6.08	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$108.37	$101.72	$105.05	$6.66	6.5%	$3.33	3.2%
Tax*	$14.09	$13.22	$5.25	$0.87	6.5%	$8.84	168.2%
Ontario Clean Energy Benefit	*($12.25)*	*($11.49)*		*($0.75)*		*($12.25)*	
Total Estimated Residential Bill	**$110.21**	**$103.45**	**$110.30**	**$6.77**	**6.5%**	**($0.08)**	**-0.1%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Festival Hydro Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$58.54	$52.77	$55.84	$5.77	10.9%	$2.70	4.8%
Delivery	$35.93	$36.72	$36.72	($0.79)	-2.2%	($0.79)	-2.2%
Regulatory	$5.92	$5.92	$5.92	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$105.99	$101.01	$104.08	$4.97	4.9%	$1.90	1.8%
Tax*	$13.78	$13.13	$5.20	$0.65	4.9%	$8.57	164.8%
Ontario Clean Energy Benefit	*($11.98)*	*($11.41)*		*($0.56)*		*($11.98)*	
Total Estimated Residential Bill	**$107.79**	**$102.73**	**$109.29**	**$5.06**	**4.9%**	**($1.50)**	**-1.4%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Festival Hydro Inc. - Hensall				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$58.54	$52.77	$55.84	$5.77	10.9%	$2.70	4.8%
Delivery	$32.60	$29.66	$29.66	$2.93	9.9%	$2.93	9.9%
Regulatory	$5.92	$5.92	$5.92	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$102.65	$93.95	$97.02	$8.70	9.3%	$5.63	5.8%
Tax*	$13.35	$12.21	$4.85	$1.13	9.3%	$8.49	175.1%
Ontario Clean Energy Benefit	*($11.60)*	*($10.62)*		*($0.98)*		*($11.60)*	
Total Estimated Residential Bill	**$104.40**	**$95.55**	**$101.87**	**$8.85**	**9.3%**	**$2.53**	**2.5%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Fort Frances Power Corporation				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.17	$53.28	$56.44	$5.89	11.0%	$2.73	4.8%
Delivery	$27.97	$25.30	$25.30	$2.67	10.5%	$2.67	10.5%
Regulatory	$5.97	$5.97	$5.97	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$3.76	$3.76	$3.76	$0.00	0.0%	$0.00	0.0%
Sub-Total	$96.87	$88.31	$91.47	$8.56	9.7%	$5.40	5.9%
Tax*	$12.59	$11.48	$4.57	$1.11	9.7%	$8.02	175.3%
Ontario Clean Energy Benefit	*($10.95)*	*($9.98)*		*($0.97)*		*($10.95)*	
Total Estimated Residential Bill	**$98.52**	**$89.82**	**$96.05**	**$8.70**	**9.7%**	**$2.47**	**2.6%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Greater Sudbury Hydro Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.93	$53.90	$57.16	$6.03	11.2%	$2.77	4.8%
Delivery	$35.37	$34.20	$34.20	$1.17	3.4%	$1.17	3.4%
Regulatory	$6.04	$6.04	$6.04	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$106.94	$99.73	$103.00	$7.21	7.2%	$3.94	3.8%
Tax*	$13.90	$12.97	$5.15	$0.94	7.2%	$8.75	170.0%
Ontario Clean Energy Benefit	*($12.08)*	*($11.27)*		*($0.81)*		*($12.08)*	
Total Estimated Residential Bill	**$108.76**	**$101.43**	**$108.15**	**$7.33**	**7.2%**	**$0.61**	**0.6%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Grimsby Power Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.77	$53.77	$57.01	$6.00	11.2%	$2.76	4.8%
Delivery	$33.20	$26.14	$26.14	$7.06	27.0%	$7.06	27.0%
Regulatory	$6.02	$6.02	$6.02	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$104.60	$91.54	$94.78	$13.06	14.3%	$9.82	10.4%
Tax*	$13.60	$11.90	$4.74	$1.70	14.3%	$8.86	186.9%
Ontario Clean Energy Benefit	*($11.82)*	*($10.34)*		*($1.48)*		*($11.82)*	
Total Estimated Residential Bill	**$106.38**	**$93.09**	**$99.52**	**$13.28**	**14.3%**	**$6.86**	**6.9%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Guelph Hydro Electric Systems Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.15	$53.27	$56.42	$5.88	11.0%	$2.73	4.8%
Delivery	$36.53	$35.37	$35.37	$1.16	3.3%	$1.16	3.3%
Regulatory	$5.97	$5.97	$5.97	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$107.25	$100.21	$103.37	$7.04	7.0%	$3.88	3.8%
Tax*	$13.94	$13.03	$5.17	$0.92	7.0%	$8.77	169.8%
Ontario Clean Energy Benefit	*($12.12)*	*($11.32)*		*($0.80)*		*($12.12)*	
Total Estimated Residential Bill	**$109.08**	**$101.91**	**$108.54**	**$7.16**	**7.0%**	**$0.54**	**0.5%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Haldimand County Hydro Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$60.90	$54.68	$58.08	$6.22	11.4%	$2.82	4.9%
Delivery	$49.71	$50.15	$50.15	($0.44)	-0.9%	($0.44)	-0.9%
Regulatory	$5.80	$5.80	$5.80	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$122.01	$116.24	$119.64	$5.77	5.0%	$2.37	2.0%
Tax*	$15.86	$15.11	$5.98	$0.75	5.0%	$9.88	165.2%
Ontario Clean Energy Benefit	*($13.79)*	*($13.13)*		*($0.65)*		*($13.79)*	
Total Estimated Residential Bill	**$124.09**	**$118.21**	**$125.62**	**$5.87**	**5.0%**	**($1.53)**	**-1.2%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Halton Hills Hydro Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.75	$53.75	$56.99	$6.00	11.2%	$2.76	4.8%
Delivery	$33.79	$33.02	$33.02	$0.77	2.3%	$0.77	2.3%
Regulatory	$6.02	$6.02	$6.02	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$105.17	$98.40	$101.64	$6.77	6.9%	$3.53	3.5%
Tax*	$13.67	$12.79	$5.08	$0.88	6.9%	$8.59	169.0%
Ontario Clean Energy Benefit	*($11.88)*	*($11.12)*		*($0.77)*		*($11.88)*	
Total Estimated Residential Bill	**$106.96**	**$100.07**	**$106.72**	**$6.89**	**6.9%**	**$0.24**	**0.2%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Hearst Power Distribution Company Limited				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.51	$53.56	$56.76	$5.95	11.1%	$2.75	4.8%
Delivery	$30.09	$24.45	$24.45	$5.65	23.1%	$5.65	23.1%
Regulatory	$6.00	$6.00	$6.00	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$101.20	$89.60	$92.81	$11.60	12.9%	$8.39	9.0%
Tax*	$13.16	$11.65	$4.64	$1.51	12.9%	$8.52	183.5%
Ontario Clean Energy Benefit	*($11.44)*	*($10.13)*		*($1.31)*		*($11.44)*	
Total Estimated Residential Bill	**$102.92**	**$91.13**	**$97.45**	**$11.80**	**12.9%**	**$5.47**	**5.6%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of August 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**Aug 1/11 vs Apr 30/11**		**Aug 1/11 vs May 1/10**	
Horizon Utilities Corporation				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.17	$53.36	$56.53	$5.82	10.9%	$2.65	4.7%
Delivery	$38.94	$31.56	$31.56	$7.38	23.4%	$7.38	23.4%
Regulatory	$5.66	$5.98	$5.98	($0.32)	-5.3%	($0.32)	-5.3%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$109.38	$96.50	$99.67	$12.88	13.4%	$9.71	9.7%
Tax*	$14.22	$12.54	$4.98	$1.67	13.4%	$9.24	185.3%
Ontario Clean Energy Benefit	*($12.36)*	*($10.90)*		*($1.46)*		*($12.36)*	
Total Estimated Residential Bill	**$111.24**	**$98.14**	**$104.65**	**$13.10**	**13.4%**	**$6.59**	**6.3%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Hydro 2000 Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$60.77	$54.58	$57.96	$6.19	11.3%	$2.81	4.9%
Delivery	$26.96	$31.78	$31.78	($4.82)	-15.2%	($4.82)	-15.2%
Regulatory	$6.11	$6.11	$6.11	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$99.44	$98.07	$101.45	$1.37	1.4%	($2.01)	-2.0%
Tax*	$12.93	$12.75	$5.07	$0.18	1.4%	$7.85	154.9%
Ontario Clean Energy Benefit	*($11.24)*	*($11.08)*		*($0.16)*		*($11.24)*	
Total Estimated Residential Bill	**$101.13**	**$99.73**	**$106.52**	**$1.40**	**1.4%**	**($5.39)**	**-5.1%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Hydro Hawkesbury Inc.				$ Change	% Change	$ Change	% Change
Electricity	$59.42	$53.48	$56.68	$5.94	11.1%	$2.74	4.8%
Delivery	$19.28	$18.51	$18.51	$0.77	4.2%	$0.77	4.2%
Regulatory	$5.99	$5.99	$5.99	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$90.29	$83.59	$86.78	$6.71	8.0%	$3.51	4.1%
Tax*	$11.74	$10.87	$4.34	$0.87	8.0%	$7.40	170.5%
Ontario Clean Energy Benefit	*($10.20)*	*($9.45)*		*($0.76)*		*($10.20)*	
Total Estimated Residential Bill	**$91.83**	**$85.01**	**$91.12**	**$6.82**	**8.0%**	**$0.71**	**0.8%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Hydro One Brampton Networks Inc.				$ Change	% Change	$ Change	% Change
Electricity	$58.81	$53.02	$56.14	$5.78	10.9%	$2.67	4.8%
Delivery	$32.46	$31.61	$31.61	$0.85	2.7%	$0.85	2.7%
Regulatory	$5.94	$5.94	$5.94	($0.00)	-0.1%	($0.00)	-0.1%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$102.81	$96.18	$99.29	$6.63	6.9%	$3.51	3.5%
Tax*	$13.36	$12.50	$4.96	$0.86	6.9%	$8.40	169.2%
Ontario Clean Energy Benefit	*($11.62)*	*($10.87)*		*($0.75)*		*($11.62)*	
Total Estimated Residential Bill	**$104.55**	**$97.82**	**$104.26**	**$6.74**	**6.9%**	**$0.29**	**0.3%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Hydro Ottawa Limited				$ Change	% Change	$ Change	% Change
Electricity	$58.77	$52.96	$56.06	$5.81	11.0%	$2.71	4.8%
Delivery	$35.48	$35.84	$35.84	($0.37)	-1.0%	($0.37)	-1.0%
Regulatory	$5.94	$5.94	$5.94	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.52	$5.52	$5.52	$0.00	0.0%	$0.00	0.0%
Sub-Total	$105.71	$100.26	$103.36	$5.45	5.4%	$2.34	2.3%
Tax*	$13.74	$13.03	$5.17	$0.71	5.4%	$8.57	165.9%
Ontario Clean Energy Benefit	*($11.95)*	*($11.33)*		*($0.62)*		*($11.95)*	
Total Estimated Residential Bill	**$107.51**	**$101.97**	**$108.53**	**$5.54**	**5.4%**	**($1.03)**	**-0.9%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Innisfil Hydro Distribution Systems Limited				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$61.31	$55.02	$58.48	$6.30	11.4%	$2.84	4.9%
Delivery	$46.27	$48.69	$48.69	($2.43)	-5.0%	($2.43)	-5.0%
Regulatory	$6.16	$6.16	$6.16	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$119.34	$115.47	$118.93	$3.87	3.4%	$0.41	0.3%
Tax*	$15.51	$15.01	$5.95	$0.50	3.4%	$9.57	160.9%
Ontario Clean Energy Benefit	*($13.49)*	*($13.05)*		*($0.44)*		*($13.49)*	
Total Estimated Residential Bill	**$121.37**	**$117.43**	**$124.87**	**$3.93**	**3.4%**	**($3.51)**	**-2.8%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of July 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**July 1/11 vs Apr 30/11**		**July 1/11 vs May 1/10**	
Kenora Hydro Electric Corporation Ltd.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.32	$53.40	$56.58	$5.92	11.1%	$2.74	4.8%
Delivery	$36.94	$28.71	$28.71	$8.23	28.7%	$8.23	28.7%
Regulatory	$5.67	$5.98	$5.98	($0.31)	-5.2%	($0.31)	-5.2%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$107.53	$93.69	$96.87	$13.84	14.8%	$10.66	11.0%
Tax*	$13.98	$12.18	$4.84	$1.80	14.8%	$9.14	188.6%
Ontario Clean Energy Benefit	*($12.15)*	*($10.59)*		*($1.56)*		*($12.15)*	
Total Estimated Residential Bill	**$109.36**	**$95.29**	**$101.72**	**$14.07**	**14.8%**	**$7.64**	**7.5%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Kingston Hydro Corporation				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$58.77	$53.12	$56.25	$5.65	10.6%	$2.52	4.5%
Delivery	$35.39	$27.14	$27.14	$8.26	30.4%	$8.26	30.4%
Regulatory	$5.63	$5.95	$5.95	($0.33)	-5.5%	($0.33)	-5.5%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$105.40	$91.81	$94.94	$13.59	14.8%	$10.46	11.0%
Tax*	$13.70	$11.94	$4.75	$1.77	14.8%	$8.95	188.6%
Ontario Clean Energy Benefit	*($11.91)*	*($10.37)*		*($1.54)*		*($11.91)*	
Total Estimated Residential Bill	**$107.19**	**$93.37**	**$99.69**	**$13.82**	**14.8%**	**$7.50**	**7.5%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Kitchener-Wilmot Hydro Inc.				$ Change	% Change	$ Change	% Change
Electricity	$58.62	$52.84	$55.92	$5.78	10.9%	$2.70	4.8%
Delivery	$29.03	$27.99	$27.99	$1.04	3.7%	$1.04	3.7%
Regulatory	$5.92	$5.92	$5.92	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$99.18	$92.35	$95.44	$6.82	7.4%	$3.74	3.9%
Tax*	$12.89	$12.01	$4.77	$0.89	7.4%	$8.12	170.2%
Ontario Clean Energy Benefit	*($11.21)*	*($10.44)*		*($0.77)*		*($11.21)*	
Total Estimated Residential Bill	**$100.86**	**$93.92**	**$100.21**	**$6.94**	**7.4%**	**$0.65**	**0.7%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Lakefront Utilities Inc.				$ Change	% Change	$ Change	% Change
Electricity	$60.02	$53.97	$57.25	$6.05	11.2%	$2.77	4.8%
Delivery	$33.91	$31.66	$31.66	$2.25	7.1%	$2.25	7.1%
Regulatory	$6.05	$6.05	$6.05	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$105.57	$97.27	$100.55	$8.30	8.5%	$5.03	5.0%
Tax*	$13.72	$12.65	$5.03	$1.08	8.5%	$8.70	173.0%
Ontario Clean Energy Benefit	*($11.93)*	*($10.99)*		*($0.94)*		*($11.93)*	
Total Estimated Residential Bill	**$107.37**	**$98.93**	**$105.58**	**$8.44**	**8.5%**	**$1.79**	**1.7%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Lakeland Power Distribution Ltd.				$ Change	% Change	$ Change	% Change
Electricity	$60.30	$54.20	$57.51	$6.10	11.3%	$2.79	4.8%
Delivery	$32.65	$38.04	$38.04	($5.40)	-14.2%	($5.40)	-14.2%
Regulatory	$6.07	$6.07	$6.07	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$104.61	$103.91	$107.22	$0.70	0.7%	($2.61)	-2.4%
Tax*	$13.60	$13.51	$5.36	$0.09	0.7%	$8.24	153.7%
Ontario Clean Energy Benefit	*($11.82)*	*($11.74)*		*($0.08)*		*($11.82)*	
Total Estimated Residential Bill	**$106.39**	**$105.68**	**$112.59**	**$0.72**	**0.7%**	**($6.19)**	**-5.5%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
London Hydro Inc.				$ Change	% Change	$ Change	% Change
Electricity	$59.18	$53.29	$56.45	$5.89	11.1%	$2.73	4.8%
Delivery	$34.70	$33.09	$33.09	$1.61	4.9%	$1.61	4.9%
Regulatory	$5.97	$5.97	$5.97	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$105.45	$97.95	$101.11	$7.50	7.7%	$4.34	4.3%
Tax*	$13.71	$12.73	$5.06	$0.98	7.7%	$8.65	171.2%
Ontario Clean Energy Benefit	*($11.92)*	*($11.07)*		*($0.85)*		*($11.92)*	
Total Estimated Residential Bill	**$107.25**	**$99.62**	**$106.17**	**$7.63**	**7.7%**	**$1.08**	**1.0%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Middlesex Power Distribution Corporation				$ Change	% Change	$ Change	% Change
Electricity	$60.44	$54.31	$57.65	$6.13	11.3%	$2.79	4.8%
Delivery	$39.10	$33.90	$33.90	$5.20	15.3%	$5.20	15.3%
Regulatory	$6.08	$6.08	$6.08	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$111.22	$99.90	$103.23	$11.33	11.3%	$7.99	7.7%
Tax*	$14.46	$12.99	$5.16	$1.47	11.3%	$9.30	180.1%
Ontario Clean Energy Benefit	*($12.57)*	*($11.29)*		*($1.28)*		*($12.57)*	
Total Estimated Residential Bill	**$113.12**	**$101.60**	**$108.39**	**$11.52**	**11.3%**	**$4.72**	**4.4%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Middlesex Power Distribution Corporation - Dutton				$ Change	% Change	$ Change	% Change
Electricity	$60.78	$54.31	$57.65	$6.47	11.9%	$3.14	5.4%
Delivery	$43.66	$36.78	$36.78	$6.88	18.7%	$6.88	18.7%
Regulatory	$6.11	$6.08	$6.08	$0.03	0.5%	$0.03	0.5%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$116.16	$102.78	$106.11	$13.38	13.0%	$10.05	9.5%
Tax*	$15.10	$13.36	$5.31	$1.74	13.0%	$9.79	184.6%
Ontario Clean Energy Benefit	*($13.13)*	*($11.61)*		*($1.51)*		*($13.13)*	
Total Estimated Residential Bill	**$118.13**	**$104.52**	**$111.42**	**$13.61**	**13.0%**	**$6.72**	**6.0%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Middlesex Power Distribution Corporation - Newbury				$ Change	% Change	$ Change	% Change
Electricity	$60.27	$54.31	$57.65	$5.95	11.0%	$2.62	4.5%
Delivery	$45.83	$40.73	$40.73	$5.09	12.5%	$5.09	12.5%
Regulatory	$6.07	$6.08	$6.08	($0.02)	-0.3%	($0.02)	-0.3%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$117.76	$106.73	$110.06	$11.03	10.3%	$7.70	7.0%
Tax*	$15.31	$13.87	$5.50	$1.43	10.3%	$9.81	178.2%
Ontario Clean Energy Benefit	*($13.31)*	*($12.06)*		*($1.25)*		*($13.31)*	
Total Estimated Residential Bill	**$119.76**	**$108.54**	**$115.57**	**$11.22**	**10.3%**	**$4.19**	**3.6%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Midland Power Utility Corporation				$ Change	% Change	$ Change	% Change
Electricity	$60.71	$54.53	$57.91	$6.18	11.3%	$2.81	4.8%
Delivery	$39.98	$38.03	$38.03	$1.95	5.1%	$1.95	5.1%
Regulatory	$6.11	$6.11	$6.11	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$112.40	$104.27	$107.64	$8.13	7.8%	$4.76	4.4%
Tax*	$14.61	$13.55	$5.38	$1.06	7.8%	$9.23	171.5%
Ontario Clean Energy Benefit	*($12.70)*	*($11.78)*		*($0.92)*		*($12.70)*	
Total Estimated Residential Bill	**$114.31**	**$106.04**	**$113.02**	**$8.27**	**7.8%**	**$1.28**	**1.1%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Milton Hydro Distribution inc.				$ Change	% Change	$ Change	% Change
Electricity	$58.89	$53.00	$56.11	$5.89	11.1%	$2.78	5.0%
Delivery	$32.43	$31.99	$31.99	$0.44	1.4%	$0.44	1.4%
Regulatory	$5.95	$5.94	$5.94	$0.01	0.1%	$0.01	0.1%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$102.87	$96.53	$99.64	$6.34	6.6%	$3.23	3.2%
Tax*	$13.37	$12.55	$4.98	$0.82	6.6%	$8.39	168.4%
Ontario Clean Energy Benefit	*($11.62)*	*($10.91)*		*($0.72)*		*($11.62)*	
Total Estimated Residential Bill	**$104.62**	**$98.17**	**$104.62**	**$6.45**	**6.6%**	**($0.00)**	**0.0%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Newmarket - Tay Power Distribution Ltd. - Newmarket				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.02	$53.16	$56.30	$5.86	11.0%	$2.72	4.8%
Delivery	$37.98	$35.40	$35.40	$2.58	7.3%	$2.58	7.3%
Regulatory	$5.96	$5.96	$5.96	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$108.56	$100.12	$103.26	$8.44	8.4%	$5.30	5.1%
Tax*	$14.11	$13.02	$5.16	$1.10	8.4%	$8.95	173.4%
Ontario Clean Energy Benefit	*($12.27)*	*($11.31)*		*($0.95)*		*($12.27)*	
Total Estimated Residential Bill	**$110.41**	**$101.82**	**$108.42**	**$8.58**	**8.4%**	**$1.99**	**1.8%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Newmarket - Tay Power Distribution Ltd. - Tay				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.02	$53.16	$56.30	$5.86	11.0%	$2.72	4.8%
Delivery	$33.10	$39.41	$39.41	($6.30)	-16.0%	($6.30)	-16.0%
Regulatory	$5.96	$5.96	$5.96	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$103.68	$104.13	$107.26	($0.44)	-0.4%	($3.58)	-3.3%
Tax*	$13.48	$13.54	$5.36	($0.06)	-0.4%	$8.12	151.3%
Ontario Clean Energy Benefit	*($11.72)*	*($11.77)*		*$0.05*		*($11.72)*	
Total Estimated Residential Bill	**$105.44**	**$105.90**	**$112.63**	**($0.45)**	**-0.4%**	**($7.18)**	**-6.4%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of June 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**June 1/11 vs Apr 30/11**		**June 1/11 vs May 1/10**	
Niagara Peninsula Energy Inc. - Niagara Falls				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$60.14	$54.28	$57.61	$5.86	10.8%	$2.53	4.4%
Delivery	$36.46	$33.96	$33.96	$2.50	7.4%	$2.50	7.4%
Regulatory	$6.06	$6.08	$6.08	($0.02)	-0.4%	($0.02)	-0.4%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$108.26	$99.92	$103.25	$8.34	8.3%	$5.01	4.8%
Tax*	$14.07	$12.99	$5.16	$1.08	8.3%	$8.91	172.6%
Ontario Clean Energy Benefit	*($12.23)*	*($11.29)*		*($0.94)*		*($12.23)*	
Total Estimated Residential Bill	**$110.10**	**$101.62**	**$108.41**	**$8.48**	**8.3%**	**$1.68**	**1.6%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of June 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**June 1/11 vs Apr 30/11**		**June 1/11 vs May 1/10**	
Niagara Peninsula Energy Inc. - Peninsula West				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$60.14	$54.28	$57.61	$5.86	10.8%	$2.53	4.4%
Delivery	$33.57	$30.91	$30.91	$2.66	8.6%	$2.66	8.6%
Regulatory	$6.06	$6.08	$6.08	($0.02)	-0.4%	($0.02)	-0.4%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$105.37	$96.87	$100.20	$8.50	8.8%	$5.17	5.2%
Tax*	$13.70	$12.59	$5.01	$1.10	8.8%	$8.69	173.4%
Ontario Clean Energy Benefit	*($11.91)*	*($10.95)*		*($0.96)*		*($11.91)*	
Total Estimated Residential Bill	**$107.16**	**$98.51**	**$105.21**	**$8.64**	**8.8%**	**$1.95**	**1.9%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Niagara-on-the-Lake Hydro Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.53	$53.57	$56.78	$5.96	11.1%	$2.75	4.8%
Delivery	$32.45	$33.99	$33.99	($1.53)	-4.5%	($1.53)	-4.5%
Regulatory	$6.00	$6.00	$6.00	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$103.58	$99.16	$102.37	$4.42	4.5%	$1.22	1.2%
Tax*	$13.47	$12.89	$5.12	$0.57	4.5%	$8.35	163.1%
Ontario Clean Energy Benefit	*($11.70)*	*($11.21)*		*($0.50)*		*($11.70)*	
Total Estimated Residential Bill	**$105.34**	**$100.85**	**$107.49**	**$4.50**	**4.5%**	**($2.14)**	**-2.0%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Norfolk Power Distribution Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$60.14	$54.07	$57.36	$6.07	11.2%	$2.78	4.8%
Delivery	$44.41	$45.89	$45.89	($1.48)	-3.2%	($1.48)	-3.2%
Regulatory	$6.06	$6.06	$6.06	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$116.20	$111.61	$114.91	$4.59	4.1%	$1.30	1.1%
Tax*	$15.11	$14.51	$5.75	$0.60	4.1%	$9.36	162.9%
Ontario Clean Energy Benefit	*($13.13)*	*($12.61)*		*($0.52)*		*($13.13)*	
Total Estimated Residential Bill	**$118.18**	**$113.51**	**$120.65**	**$4.67**	**4.1%**	**($2.47)**	**-2.0%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
North Bay Hydro Distribution Limited				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.63	$53.66	$56.88	$5.98	11.1%	$2.75	4.8%
Delivery	$36.03	$35.01	$35.01	$1.02	2.9%	$1.02	2.9%
Regulatory	$6.01	$6.01	$6.01	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$107.28	$100.28	$103.50	$7.00	7.0%	$3.78	3.6%
Tax*	$13.95	$13.04	$5.18	$0.91	7.0%	$8.77	169.5%
Ontario Clean Energy Benefit	*($12.12)*	*($11.33)*		*($0.79)*		*($12.12)*	
Total Estimated Residential Bill	**$109.10**	**$101.98**	**$108.68**	**$7.12**	**7.0%**	**$0.43**	**0.4%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Northern Ontario Wires Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.43	$53.49	$56.69	$5.94	11.1%	$2.74	4.8%
Delivery	$35.22	$37.32	$37.32	($2.10)	-5.6%	($2.10)	-5.6%
Regulatory	$5.99	$5.99	$5.99	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$106.25	$102.41	$105.60	$3.84	3.7%	$0.64	0.6%
Tax*	$13.81	$13.31	$5.28	$0.50	3.7%	$8.53	161.6%
Ontario Clean Energy Benefit	*($12.01)*	*($11.57)*		*($0.43)*		*($12.01)*	
Total Estimated Residential Bill	**$108.05**	**$104.15**	**$110.88**	**$3.90**	**3.7%**	**($2.83)**	**-2.6%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Oakville Hydro Electricity Distribution Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$58.98	$53.13	$56.26	$5.85	11.0%	$2.72	4.8%
Delivery	$33.12	$34.12	$34.12	($1.00)	-2.9%	($1.00)	-2.9%
Regulatory	$5.96	$5.96	$5.96	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$103.66	$98.81	$101.94	$4.85	4.9%	$1.72	1.7%
Tax*	$13.48	$12.85	$5.10	$0.63	4.9%	$8.38	164.4%
Ontario Clean Energy Benefit	*($11.71)*	*($11.17)*		*($0.55)*		*($11.71)*	
Total Estimated Residential Bill	**$105.42**	**$100.49**	**$107.04**	**$4.94**	**4.9%**	**($1.61)**	**-1.5%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Orangeville Hydro Limited				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.56	$53.60	$56.81	$5.96	11.1%	$2.75	4.8%
Delivery	$36.82	$35.09	$35.09	$1.73	4.9%	$1.73	4.9%
Regulatory	$6.01	$6.01	$6.01	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$107.98	$100.29	$103.50	$7.69	7.7%	$4.48	4.3%
Tax*	$14.04	$13.04	$5.18	$1.00	7.7%	$8.86	171.3%
Ontario Clean Energy Benefit	*($12.20)*	*($11.33)*		*($0.87)*		*($12.20)*	
Total Estimated Residential Bill	**$109.82**	**$101.99**	**$108.68**	**$7.82**	**7.7%**	**$1.14**	**1.1%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Orillia Power Distribution Corporation				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$60.15	$54.07	$57.37	$6.07	11.2%	$2.78	4.8%
Delivery	$35.08	$32.40	$32.40	$2.68	8.3%	$2.68	8.3%
Regulatory	$6.06	$6.06	$6.06	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$3.92	$3.92	$3.92	$0.00	0.0%	$0.00	0.0%
Sub-Total	$105.20	$96.45	$99.74	$8.75	9.1%	$5.46	5.5%
Tax*	$13.68	$12.54	$4.99	$1.14	9.1%	$8.69	174.2%
Ontario Clean Energy Benefit	*($11.89)*	*($10.90)*		*($0.99)*		*($11.89)*	
Total Estimated Residential Bill	**$106.99**	**$98.09**	**$104.73**	**$8.90**	**9.1%**	**$2.26**	**2.2%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Oshawa PUC Networks Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.68	$53.69	$56.92	$5.98	11.1%	$2.76	4.8%
Delivery	$27.22	$28.41	$28.41	($1.20)	-4.2%	($1.20)	-4.2%
Regulatory	$6.02	$6.02	$6.02	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$98.51	$93.72	$96.95	$4.79	5.1%	$1.56	1.6%
Tax*	$12.81	$12.18	$4.85	$0.62	5.1%	$7.96	164.2%
Ontario Clean Energy Benefit	*($11.13)*	*($10.59)*		*($0.54)*		*($11.13)*	
Total Estimated Residential Bill	**$100.18**	**$95.31**	**$101.80**	**$4.87**	**5.1%**	**($1.61)**	**-1.6%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of June 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**June 1/11 vs Apr 30/11**		**June 1/11 vs May 1/10**	
Parry Sound Power Corporation				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$61.71	$54.20	$57.52	$7.51	13.9%	$4.20	7.3%
Delivery	$44.51	$31.94	$31.94	$12.57	39.4%	$12.57	39.4%
Regulatory	$5.87	$6.07	$6.07	($0.20)	-3.3%	($0.20)	-3.3%
Debt Retirement Charge	$5.20	$5.20	$5.20	$0.00	0.0%	$0.00	0.0%
Sub-Total	$117.30	$97.41	$100.73	$19.88	20.4%	$16.57	16.4%
Tax*	$15.25	$12.66	$5.04	$2.58	20.4%	$10.21	202.8%
Ontario Clean Energy Benefit	*($13.25)*	*($11.01)*		*($2.25)*		*($13.25)*	
Total Estimated Residential Bill	**$119.29**	**$99.07**	**$105.77**	**$20.22**	**20.4%**	**$13.53**	**12.8%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Peterborough Distribution Incorporated				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.68	$53.69	$56.92	$5.98	11.1%	$2.76	4.8%
Delivery	$31.64	$30.78	$30.78	$0.86	2.8%	$0.86	2.8%
Regulatory	$6.02	$6.02	$6.02	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.36	$5.36	$5.36	$0.00	0.0%	$0.00	0.0%
Sub-Total	$102.70	$95.85	$99.08	$6.85	7.1%	$3.62	3.7%
Tax*	$13.35	$12.46	$4.95	$0.89	7.1%	$8.40	169.5%
Ontario Clean Energy Benefit	*($11.60)*	*($10.83)*		*($0.77)*		*($11.60)*	
Total Estimated Residential Bill	**$104.44**	**$97.48**	**$104.03**	**$6.96**	**7.1%**	**$0.41**	**0.4%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
PowerStream Inc. - Barrie				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$60.17	$54.09	$57.39	$6.08	11.2%	$2.78	4.8%
Delivery	$36.95	$34.08	$34.08	$2.88	8.4%	$2.88	8.4%
Regulatory	$6.06	$6.06	$6.06	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$108.78	$99.83	$103.13	$8.95	9.0%	$5.66	5.5%
Tax*	$14.14	$12.98	$5.16	$1.16	9.0%	$8.99	174.3%
Ontario Clean Energy Benefit	*($12.29)*	*($11.28)*		*($1.01)*		*($12.29)*	
Total Estimated Residential Bill	**$110.63**	**$101.53**	**$108.28**	**$9.11**	**9.0%**	**$2.35**	**2.2%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
PowerStream Inc. - South				$ Change	% Change	$ Change	% Change
Electricity	$58.49	$52.73	$55.79	$5.76	10.9%	$2.70	4.8%
Delivery	$31.47	$30.78	$30.78	$0.68	2.2%	$0.68	2.2%
Regulatory	$5.91	$5.91	$5.91	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$101.47	$95.03	$98.09	$6.44	6.8%	$3.38	3.4%
Tax*	$13.19	$12.35	$4.90	$0.84	6.8%	$8.29	169.0%
Ontario Clean Energy Benefit	*($11.47)*	*($10.74)*		*($0.73)*		*($11.47)*	
Total Estimated Residential Bill	**$103.19**	**$96.64**	**$102.99**	**$6.55**	**6.8%**	**$0.20**	**0.2%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
PUC Distribution Inc.				$ Change	% Change	$ Change	% Change
Electricity	$59.47	$53.52	$56.72	$5.94	11.1%	$2.75	4.8%
Delivery	$25.83	$24.90	$24.90	$0.93	3.8%	$0.93	3.8%
Regulatory	$6.00	$6.00	$6.00	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$1.60	$1.60	$1.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$92.90	$86.02	$89.22	$6.88	8.0%	$3.68	4.1%
Tax*	$12.08	$11.18	$4.46	$0.89	8.0%	$7.62	170.7%
Ontario Clean Energy Benefit	*($10.50)*	*($9.72)*		*($0.78)*		*($10.50)*	
Total Estimated Residential Bill	**$94.48**	**$87.48**	**$93.68**	**$7.00**	**8.0%**	**$0.80**	**0.9%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Renfrew Hydro Inc.				$ Change	% Change	$ Change	% Change
Electricity	$61.72	$55.35	$58.86	$6.37	11.5%	$2.86	4.9%
Delivery	$31.76	$32.71	$32.71	($0.95)	-2.9%	($0.95)	-2.9%
Regulatory	$6.19	$6.19	$6.19	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$4.88	$4.88	$4.88	$0.00	0.0%	$0.00	0.0%
Sub-Total	$104.55	$99.13	$102.65	$5.42	5.5%	$1.91	1.9%
Tax*	$13.59	$12.89	$5.13	$0.70	5.5%	$8.46	164.8%
Ontario Clean Energy Benefit	*($11.81)*	*($11.20)*		*($0.61)*		*($11.81)*	
Total Estimated Residential Bill	**$106.33**	**$100.82**	**$107.78**	**$5.51**	**5.5%**	**($1.45)**	**-1.3%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Rideau St. Lawrence Distribution Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$61.43	$55.11	$58.58	$6.32	11.5%	$2.84	4.9%
Delivery	$30.05	$32.20	$32.20	($2.15)	-6.7%	($2.15)	-6.7%
Regulatory	$6.17	$6.17	$6.17	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$103.25	$99.08	$102.55	$4.17	4.2%	$0.70	0.7%
Tax*	$13.42	$12.88	$5.13	$0.54	4.2%	$8.29	161.8%
Ontario Clean Energy Benefit	*($11.67)*	*($11.20)*		*($0.47)*		*($11.67)*	
Total Estimated Residential Bill	**$105.00**	**$100.76**	**$107.68**	**$4.24**	**4.2%**	**($2.67)**	**-2.5%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Sioux Lookout Hydro Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$60.66	$54.49	$57.85	$6.17	11.3%	$2.81	4.8%
Delivery	$37.81	$42.04	$42.04	($4.24)	-10.1%	($4.24)	-10.1%
Regulatory	$6.10	$6.10	$6.10	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$110.17	$108.23	$111.60	$1.94	1.8%	($1.43)	-1.3%
Tax*	$14.32	$14.07	$5.58	$0.25	1.8%	$8.74	156.7%
Ontario Clean Energy Benefit	*($12.45)*	*($12.23)*		*($0.22)*		*($12.45)*	
Total Estimated Residential Bill	**$112.04**	**$110.07**	**$117.18**	**$1.97**	**1.8%**	**($5.14)**	**-4.4%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of July 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**July 1/11 vs Apr 30/11**		**July 1/11 vs May 1/10**	
St. Thomas Energy Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$58.81	$52.94	$56.03	$5.88	11.1%	$2.78	5.0%
Delivery	$36.21	$32.63	$32.63	$3.58	11.0%	$3.58	11.0%
Regulatory	$5.63	$5.93	$5.93	($0.30)	-5.1%	($0.30)	-5.1%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$106.26	$97.10	$100.20	$9.15	9.4%	$6.06	6.0%
Tax*	$13.81	$12.62	$5.01	$1.19	9.4%	$8.80	175.7%
Ontario Clean Energy Benefit	*($12.01)*	*($10.97)*		*($1.03)*		*($12.01)*	
Total Estimated Residential Bill	**$108.06**	**$98.75**	**$105.21**	**$9.31**	**9.4%**	**$2.85**	**2.7%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Thunder Bay Hydro Electricity Distribution Inc.				$ Change	% Change	$ Change	% Change
Electricity	$59.43	$53.49	$56.69	$5.94	11.1%	$2.74	4.8%
Delivery	$31.91	$29.11	$29.11	$2.80	9.6%	$2.80	9.6%
Regulatory	$5.68	$5.99	$5.99	($0.31)	-5.2%	($0.31)	-5.2%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$102.62	$94.20	$97.39	$8.42	8.9%	$5.23	5.4%
Tax*	$13.34	$12.25	$4.87	$1.09	8.9%	$8.47	174.0%
Ontario Clean Energy Benefit	*($11.60)*	*($10.64)*		*($0.95)*		*($11.60)*	
Total Estimated Residential Bill	**$104.37**	**$95.80**	**$102.26**	**$8.57**	**8.9%**	**$2.10**	**2.1%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Tillsonburg Hydro Inc.				$ Change	% Change	$ Change	% Change
Electricity	$59.25	$53.35	$56.52	$5.90	11.1%	$2.73	4.8%
Delivery	$33.98	$34.06	$34.06	($0.08)	-0.2%	($0.08)	-0.2%
Regulatory	$5.98	$5.98	$5.98	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$104.82	$98.99	$102.16	$5.83	5.9%	$2.66	2.6%
Tax*	$13.63	$12.87	$5.11	$0.76	5.9%	$8.52	166.8%
Ontario Clean Energy Benefit	*($11.84)*	*($11.19)*		*($0.66)*		*($11.84)*	
Total Estimated Residential Bill	**$106.60**	**$100.67**	**$107.27**	**$5.93**	**5.9%**	**($0.67)**	**-0.6%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of August 1, 2011	Apr 30, 2011	May 1, 2010	Aug 1/11 vs Apr 30/11		Aug 1/11 vs May 1/10	
Toronto Hydro-Electric System Limited				$ Change	% Change	$ Change	% Change
Electricity	$58.98	$53.13	$56.26	$5.85	11.0%	$2.72	4.8%
Delivery	$39.59	$40.50	$40.50	($0.91)	-2.2%	($0.91)	-2.2%
Regulatory	$5.65	$5.95	$5.95	($0.31)	-5.2%	($0.31)	-5.2%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$109.81	$105.18	$108.31	$4.64	4.4%	$1.50	1.4%
Tax*	$14.28	$13.67	$5.42	$0.60	4.4%	$8.86	163.6%
Ontario Clean Energy Benefit	*($12.41)*	*($11.89)*		*($0.52)*		*($12.41)*	
Total Estimated Residential Bill	**$111.68**	**$106.97**	**$113.72**	**$4.71**	**4.4%**	**($2.04)**	**-1.8%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Veridian Connections Inc.				$ Change	% Change	$ Change	% Change
Electricity	$59.39	$53.46	$56.65	$5.93	11.1%	$2.74	4.8%
Delivery	$28.97	$28.71	$28.71	$0.26	0.9%	$0.26	0.9%
Regulatory	$5.99	$5.99	$5.99	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$99.96	$93.77	$96.96	$6.19	6.6%	$3.00	3.1%
Tax*	$12.99	$12.19	$4.85	$0.80	6.6%	$8.15	168.0%
Ontario Clean Energy Benefit	*($11.29)*	*($10.60)*		*($0.70)*		*($11.29)*	
Total Estimated Residential Bill	**$101.65**	**$95.36**	**$101.80**	**$6.29**	**6.6%**	**($0.15)**	**-0.1%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Veridian Connections Inc. - Gravenhurst				$ Change	% Change	$ Change	% Change
Electricity	$63.00	$56.39	$60.08	$6.62	11.7%	$2.92	4.9%
Delivery	$38.84	$40.71	$40.71	($1.88)	-4.6%	($1.88)	-4.6%
Regulatory	$6.30	$6.30	$6.30	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$113.74	$109.01	$112.70	$4.74	4.3%	$1.05	0.9%
Tax*	$14.79	$14.17	$5.63	$0.62	4.3%	$9.15	162.4%
Ontario Clean Energy Benefit	*($12.85)*	*($12.32)*		*($0.54)*		*($12.85)*	
Total Estimated Residential Bill	**$115.68**	**$110.86**	**$118.33**	**$4.82**	**4.3%**	**($2.65)**	**-2.2%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Wasaga Distribution Inc.				$ Change	% Change	$ Change	% Change
Electricity	$61.27	$54.98	$58.43	$6.29	11.4%	$2.84	4.9%
Delivery	$30.96	$29.60	$29.60	$1.37	4.6%	$1.37	4.6%
Regulatory	$6.15	$6.15	$6.15	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$103.99	$96.33	$99.78	$7.65	7.9%	$4.20	4.2%
Tax*	$13.52	$12.52	$4.99	$0.99	7.9%	$8.53	170.9%
Ontario Clean Energy Benefit	*($11.75)*	*($10.89)*		*($0.86)*		*($11.75)*	
Total Estimated Residential Bill	**$105.75**	**$97.97**	**$104.77**	**$7.78**	**7.9%**	**$0.98**	**0.9%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Waterloo North Hydro Inc.				$ Change	% Change	$ Change	% Change
Electricity	$59.15	$53.79	$57.03	$5.37	10.0%	$2.12	3.7%
Delivery	$35.77	$30.54	$30.54	$5.23	17.1%	$5.23	17.1%
Regulatory	$5.97	$6.03	$6.03	($0.06)	-0.9%	($0.06)	-0.9%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$106.50	$95.95	$99.19	$10.55	11.0%	$7.30	7.4%
Tax*	$13.84	$12.47	$4.96	$1.37	11.0%	$8.88	179.1%
Ontario Clean Energy Benefit	*($12.03)*	*($10.84)*		*($1.19)*		*($12.03)*	
Total Estimated Residential Bill	**$108.31**	**$97.58**	**$104.15**	**$10.73**	**11.0%**	**$4.15**	**4.0%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Welland Hydro-Electric System Corp.				$ Change	% Change	$ Change	% Change
Electricity	$59.96	$53.92	$57.19	$6.04	11.2%	$2.77	4.8%
Delivery	$36.73	$36.86	$36.86	($0.12)	-0.3%	($0.12)	-0.3%
Regulatory	$6.04	$6.04	$6.04	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$108.34	$102.42	$105.69	$5.92	5.8%	$2.65	2.5%
Tax*	$14.08	$13.31	$5.28	$0.77	5.8%	$8.80	166.5%
Ontario Clean Energy Benefit	*($12.24)*	*($11.57)*		*($0.67)*		*($12.24)*	
Total Estimated Residential Bill	**$110.18**	**$104.16**	**$110.97**	**$6.02**	**5.8%**	**($0.79)**	**-0.7%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Wellington North Power Inc.				$ Change	% Change	$ Change	% Change
Electricity	$61.02	$54.78	$58.19	$6.24	11.4%	$2.82	4.9%
Delivery	$32.31	$31.89	$31.89	$0.43	1.3%	$0.43	1.3%
Regulatory	$6.13	$6.13	$6.13	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$105.06	$98.40	$101.81	$6.66	6.8%	$3.25	3.2%
Tax*	$13.66	$12.79	$5.09	$0.87	6.8%	$8.57	168.3%
Ontario Clean Energy Benefit	*($11.87)*	*($11.12)*		*($0.75)*		*($11.87)*	
Total Estimated Residential Bill	**$106.85**	**$100.07**	**$106.90**	**$6.78**	**6.8%**	**($0.06)**	**-0.1%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
West Coast Huron Energy Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.55	$53.59	$56.80	$5.96	11.1%	$2.75	4.8%
Delivery	$36.03	$33.31	$33.31	$2.72	8.2%	$2.72	8.2%
Regulatory	$6.00	$6.00	$6.00	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$107.19	$98.51	$101.72	$8.68	8.8%	$5.47	5.4%
Tax*	$13.93	$12.81	$5.09	$1.13	8.8%	$8.85	174.0%
Ontario Clean Energy Benefit	*($12.11)*	*($11.13)*		*($0.98)*		*($12.11)*	
Total Estimated Residential Bill	**$109.01**	**$100.18**	**$106.81**	**$8.83**	**8.8%**	**$2.21**	**2.1%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Westario Power Inc.				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$61.58	$55.23	$58.73	$6.35	11.5%	$2.85	4.9%
Delivery	$31.11	$34.03	$34.03	($2.91)	-8.6%	($2.91)	-8.6%
Regulatory	$6.18	$6.18	$6.18	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$104.47	$101.04	$104.53	$3.43	3.4%	($0.06)	-0.1%
Tax*	$13.58	$13.14	$5.23	$0.45	3.4%	$8.35	159.8%
Ontario Clean Energy Benefit	*($11.81)*	*($11.42)*		*($0.39)*		*($11.81)*	
Total Estimated Residential Bill	**$106.25**	**$102.76**	**$109.76**	**$3.49**	**3.4%**	**($3.51)**	**-3.2%**

	A	B	C	A - B		A - C	
RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5				
RPP Monthly Threshold (kWh)	600	1000	600				
	As of May 1, 2011	**Apr 30, 2011**	**May 1, 2010**	**May 1/11 vs Apr 30/11**		**May 1/11 vs May 1/10**	
Whitby Hydro Electric Corporation				**$ Change**	**% Change**	**$ Change**	**% Change**
Electricity	$59.47	$53.52	$56.72	$5.94	11.1%	$2.75	4.8%
Delivery	$39.81	$37.45	$37.45	$2.36	6.3%	$2.36	6.3%
Regulatory	$6.00	$6.00	$6.00	$0.00	0.0%	$0.00	0.0%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$110.88	$102.57	$105.77	$8.30	8.1%	$5.10	4.8%
Tax*	$14.41	$13.33	$5.29	$1.08	8.1%	$9.13	172.5%
Ontario Clean Energy Benefit	*($12.53)*	*($11.59)*		*($0.94)*		*($12.53)*	
Total Estimated Residential Bill	**$112.76**	**$104.32**	**$111.06**	**$8.44**	**8.1%**	**$1.70**	**1.5%**

RPP Prices (¢ per kWh)	6.8 / 7.9	6.4 / 7.4	6.5 / 7.5
RPP Monthly Threshold (kWh)	600	1000	600

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

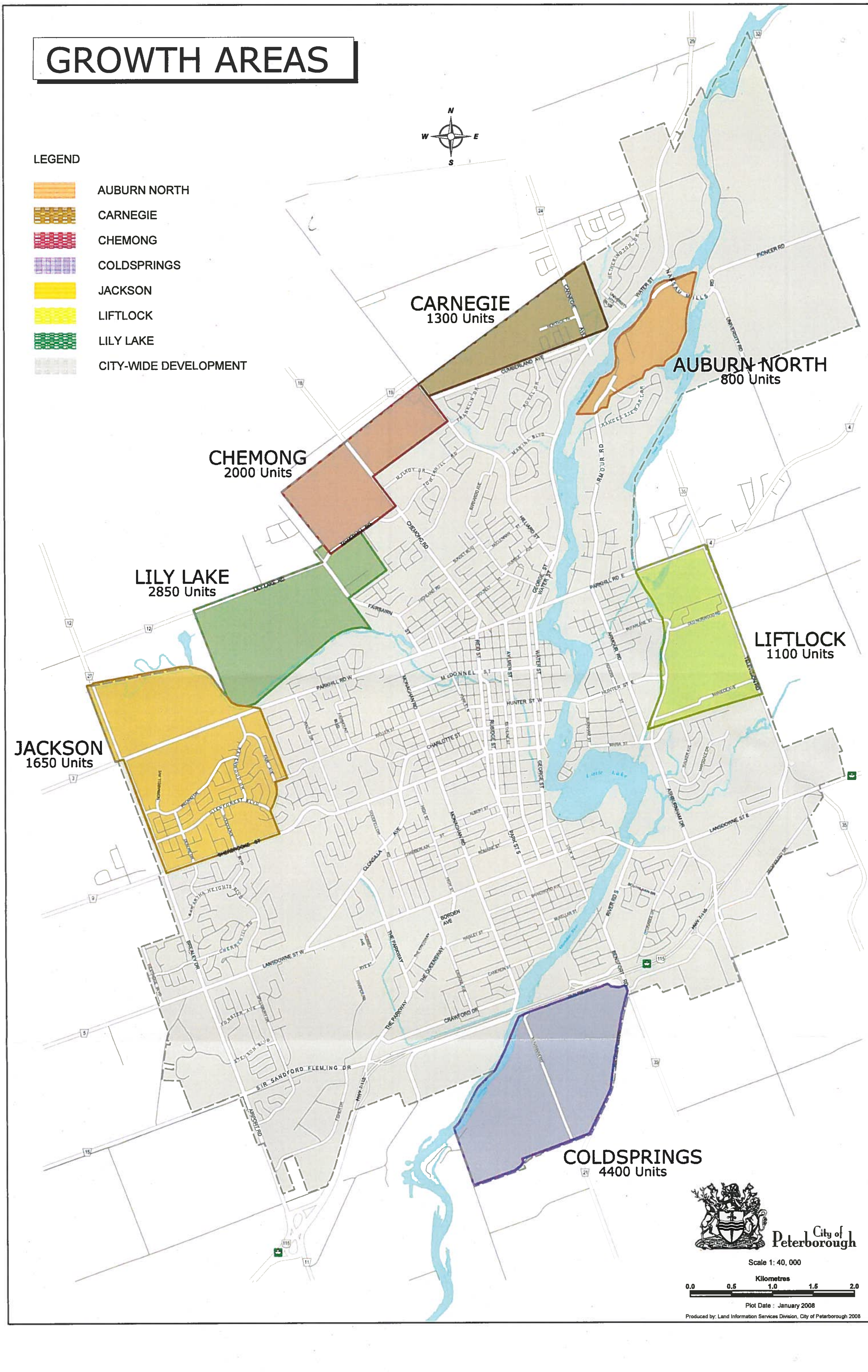
Estimated Bill Impacts - 800 kWh

	A	B	C	A - B		A - C	
	As of May 1, 2011	Apr 30, 2011	May 1, 2010	May 1/11 vs Apr 30/11		May 1/11 vs May 1/10	
Woodstock Hydro Services Inc.				$ Change	% Change	$ Change	% Change
Electricity	$59.32	$53.45	$56.64	$5.87	11.0%	$2.68	4.7%
Delivery	$40.57	$35.85	$35.85	$4.73	13.2%	$4.73	13.2%
Regulatory	$5.98	$5.99	$5.99	($0.00)	-0.1%	($0.00)	-0.1%
Debt Retirement Charge	$5.60	$5.60	$5.60	$0.00	0.0%	$0.00	0.0%
Sub-Total	$111.48	$100.89	$104.08	$10.59	10.5%	$7.41	7.1%
Tax*	$14.49	$13.12	$5.20	$1.38	10.5%	$9.29	178.5%
Ontario Clean Energy Benefit	*($12.60)*	*($11.40)*		*($1.20)*		*($12.60)*	
Total Estimated Residential Bill	**$113.38**	**$102.60**	**$109.28**	**$10.77**	**10.5%**	**$4.10**	**3.8%**

* As of July 1, 2010, Ontario harmonized its retail sales tax with the GST to implement the HST at the rate of 13%. On May 1, 2010, the GST was 5%.

APPENDIX 2-1

PETERBOROUGH GROWTH MAP



GROWTH AREAS
LEGEND
AUBURN NORTH
CARNEGIE
CHEMONG
COLDSPRINGS
JACKSON
LIFTLOCK
LILY LAKE
CITY-WIDE DEVELOPMENT
N
W
E
S
CARNEGIE
1300 Units
AUBURN NORTH
800 Units
CHEMONG
2000 Units
LILY LAKE
2850 Units
LIFTLOCK
1100 Units
JACKSON
1650 Units
COLDSPRINGS
4400 Units
City of Peterborough
Scale 1: 40, 000
Kilometres
0.0
0.5
1.0
1.5
2.0
Plot Date : January 2008
Produced by: Land Information Services Division, City of Peterborough 2008

APPENDIX 4-1

APPENDIX 1 TO CORPORATE COST ALLOCATION REPORT

Appendix 1 - Corporate Costs 2009 through 2011

ACTIVITY	2009 Actual	PUSI 2009 Actual	PDI %	2010 Actual	PUSI 2010 Actual	PDI %	2011 Actual	PUSI 2011 Actual	PDI %
Electric Distribution Operations	$2,043,804	$2,294,096	89%	$2,141,338	$2,358,177	91%	$2,177,301	$2,512,005	87%
Engineering Services	$887,422	$1,583,820	56%	$715,392	$1,425,425	50%	$797,583	$1,524,696	52%
Field Technical Operations	$551,098	$561,592	98%	$588,294	$589,126	100%	$527,963	$534,662	99%
Vehicles	$502,616	$857,180	59%	$497,567	$916,572	54%	$512,120	$1,030,496	50%
Stores	$184,301	$233,481	79%	$141,989	$184,909	77%	$138,850	$191,361	73%
Operating Activities	**$4,169,241**	**$5,530,169**	**75%**	**$4,084,580**	**$5,474,209**	**75%**	**$4,153,817**	**$5,793,220**	**72%**
Customer Service	$1,387,816	$1,895,924	73%	$1,213,090	$1,695,681	72%	$1,274,143	$1,812,436	70%
Administration	$519,762	$1,253,342	41%	$580,116	$1,434,127	40%	$538,872	$1,354,198	40%
Corporate Services	$301,682	$357,514	84%	$280,039	$351,277	80%	$269,083	$329,758	82%
Finance	$198,243	$403,359	49%	$127,861	$363,346	35%	$142,979	$377,870	38%
Technology Services	$639,718	$2,913,003	22%	$600,363	$3,140,829	19%	$600,329	$3,358,691	18%
Human Resources	$249,640	$671,745	37%	$283,163	$738,898	38%	$303,800	$771,065	39%
Purchasing	$74,613	$177,103	42%	$61,122	$230,197	27%	$110,324	$278,227	40%
Facilities Management	$514,062	$1,053,887	49%	$503,276	$1,028,905	49%	$513,860	$1,051,009	49%
Software & Equipment Rent	$167,915	$390,373	43%	$180,017	$407,400	44%	$153,791	$369,726	42%
Support Activities	**$4,053,452**	**$9,116,249**	**44%**	**$3,829,047**	**$9,390,659**	**41%**	**$3,907,181**	**$9,702,980**	**40%**
TOTAL	**$8,222,693**	**$14,646,418**	**56%**	**$7,913,627**	**$14,864,868**	**53%**	**$8,060,998**	**$15,496,199**	**52%**

APPENDIX 8-1

REVISED 2013 BILL IMPACTS

File Number:	EB-2012-0160
Exhibit:	8
Tab:	Appendix M
Schedule:	

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 800 **kWh** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 11.9100	1	$ 11.91	$ 13.2000	1	$ 13.20	$ 1.29	10.83%
Smart Meter Rate Adder	Monthly	$ 1.7600	1	$ 1.76		1	$ -	-$ 1.76	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0116	800	$ 9.28	$ 0.0129	800	$ 10.32	$ 1.04	11.21%
Smart Meter Disposition Rider	Monthly	$ 0.3700	1	$ 0.37	$ 0.3700	1	$ 0.37	$ -	0.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0016	800	$ 1.28	$ 0.0002	800	$ 0.16	-$ 1.12	-87.50%
Sub-Total A				$ 24.60			$ 24.05	**-$ 0.55**	**-2.24%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0015	800	-$ 1.20	-$ 0.0013	800	-$ 1.04	$ 0.16	-13.33%
Tax Change Rate Rider	per kWh	-$ 0.0005	800	-$ 0.40		800	$ -	$ 0.40	-100.00%
Global Adj Disposition Rider	per kWh	-$ 0.0015	800	-$ 1.20		800	$ -	$ 1.20	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.3500	1	$ 0.35	$ 0.35	
Low Voltage Service Charge	per kWh	$ 0.0005	800	$ 0.40	$ 0.0009	800	$ 0.72	$ 0.32	80.00%
Smart Meter Entity Charge	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 22.20**			**$ 24.08**	**$ 1.88**	**8.47%**
RTSR - Network	per kWh	$ 0.0066	839	$ 5.54	$ 0.0068	844	$ 5.74	$ 0.20	3.63%
RTSR - Line and Transformation Connection	per kWh	$ 0.0047	839	$ 3.94	$ 0.0046	844	$ 3.88	-$ 0.06	-1.56%
Sub-Total C - Delivery (including Sub-Total B)				**$ 31.68**			**$ 33.70**	**$ 2.02**	**6.37%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	839	$ 4.36	$ 0.0052	844	$ 4.39	$ 0.03	0.58%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	839	$ 0.92	$ 0.0011	844	$ 0.93	$ 0.01	0.58%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0067	839	$ 5.62	$ 0.0067	844	$ 5.65	$ 0.03	0.58%
Energy - RPP - Tier 1		$ 0.0750	839	$ 62.92	$ 0.0740	844	$ 62.44	-$ 0.48	-0.76%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	537	$ 34.90	$ 0.0630	540	$ 34.02	-$ 0.88	-2.51%
TOU - Mid Peak		$ 0.1000	151	$ 15.10	$ 0.0990	152	$ 15.04	-$ 0.06	-0.42%
TOU - On Peak		$ 0.1170	151	$ 17.67	$ 0.1180	152	$ 17.92	$ 0.25	1.44%
Total Bill on RPP (before Taxes)				**$ 105.76**			**$ 107.36**	**$ 1.61**	**1.52%**
HST		13%		$ 13.75	13%		$ 13.96	$ 0.21	1.52%
Total Bill (including HST)				$ 119.51			$ 121.32	$ 1.81	1.52%
Ontario Clean Energy Benefit [1]				-$ 11.95			-$ 12.13	-$ 0.18	1.51%
Total Bill on RPP (including OCEB)				**$ 107.56**			**$ 109.19**	**$ 1.63**	**1.52%**
Total Bill on TOU (before Taxes)				**$ 110.51**			**$ 111.90**	**$ 1.40**	**1.26%**
HST		13%		$ 14.37	13%		$ 14.55	$ 0.18	1.26%
Total Bill (including HST)				$ 124.87			$ 126.45	$ 1.58	1.26%
Ontario Clean Energy Benefit [1]				-$ 12.49			-$ 12.65	-$ 0.16	1.28%
Total Bill on TOU (including OCEB)				**$ 112.38**			**$ 113.80**	**$ 1.42**	**1.26%**
Loss Factor (%)		4.8700%			5.4800%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

File Number:	EB-2012-0160
Exhibit:	8
Tab:	Appendix M
Schedule:	

Appendix 2-W
Bill Impacts

Customer Class: **General Service Less Than 50KW**

Consumption **2000** **kWh** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 29.9000	1	$ 29.90	$ 31.1500	1	$ 31.15	$ 1.25	4.18%
Smart Meter Rate Adder	Monthly	$ 6.1500	1	$ 6.15		1	$ -	-$ 6.15	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0090	2000	$ 18.00	$ 0.0094	2000	$ 18.80	$ 0.80	4.44%
Smart Meter Disposition Rider	Monthly	$ 5.5200	1	$ 5.52	$ 5.5200	1	$ 5.52	$ -	0.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0006	2000	$ 1.20	$ 0.0003	2000	$ 0.60	-$ 0.60	-50.00%
Sub-Total A				$ 60.77			$ 56.07	**-$ 4.70**	**-7.73%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0015	2000	-$ 3.00	-$ 0.0013	2000	-$ 2.60	$ 0.40	-13.33%
Tax Change Rate Rider	per kWh	-$ 0.0004	2000	-$ 0.80		2000	$ -	$ 0.80	-100.00%
Global Adj Disposition Rider	per kWh	-$ 0.0015	2000	-$ 3.00		2000	$ -	$ 3.00	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 5.1200	1	$ 5.12	$ 5.12	
Low Voltage Service Charge	per kWh	$ 0.0005	2000	$ 1.00	$ 0.0008	2000	$ 1.60	$ 0.60	60.00%
Smart Meter Entity Charge	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 54.97**			**$ 60.19**	**$ 5.22**	**9.50%**
RTSR - Network	per kWh	$ 0.0060	2097	$ 12.58	$ 0.0062	2110	$ 13.08	$ 0.50	3.93%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	2097	$ 9.02	$ 0.0042	2110	$ 8.86	-$ 0.16	-1.76%
Sub-Total C - Delivery (including Sub-Total B)				**$ 76.57**			**$ 82.13**	**$ 5.56**	**7.26%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2097	$ 10.91	$ 0.0052	2110	$ 10.97	$ 0.06	0.58%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2097	$ 2.31	$ 0.0011	2110	$ 2.32	$ 0.01	0.58%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0067	2097	$ 14.05	$ 0.0067	2110	$ 14.13	$ 0.08	0.58%
Energy - RPP - Tier 1		$ 0.0750	1000	$ 75.00	$ 0.0740	1000	$ 74.00	-$ 1.00	-1.33%
Energy - RPP - Tier 2		$ 0.0880	1097	$ 96.57	$ 0.0870	1110	$ 96.54	-$ 0.04	-0.04%
TOU - Off Peak		$ 0.0650	1342	$ 87.25	$ 0.0630	1350	$ 85.06	-$ 2.19	-2.51%
TOU - Mid Peak		$ 0.1000	378	$ 37.75	$ 0.0990	380	$ 37.59	-$ 0.16	-0.42%
TOU - On Peak		$ 0.1170	378	$ 44.17	$ 0.1180	380	$ 44.81	$ 0.64	1.44%
Total Bill on RPP (before Taxes)				**$ 275.66**			**$ 280.34**	**$ 4.68**	**1.70%**
HST		13%		$ 35.84	13%		$ 36.44	$ 0.61	1.70%
Total Bill (including HST)				$ 311.50			$ 316.78	$ 5.29	1.70%
***Ontario Clean Energy Benefit* [1]**				-$ 31.15			-$ 31.68	-$ 0.53	1.70%
Total Bill on RPP (including OCEB)				**$ 280.35**			**$ 285.10**	**$ 4.76**	**1.70%**
Total Bill on TOU (before Taxes)				**$ 273.27**			**$ 277.26**	**$ 4.00**	**1.46%**
HST		13%		$ 35.52	13%		$ 36.04	$ 0.52	1.46%
Total Bill (including HST)				$ 308.79			$ 313.31	$ 4.52	1.46%
***Ontario Clean Energy Benefit* [1]**				-$ 30.88			-$ 31.33	-$ 0.45	1.46%
Total Bill on TOU (including OCEB)				**$ 277.91**			**$ 281.98**	**$ 4.07**	**1.46%**
Loss Factor (%)		4.8700%			5.4800%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

File Number:	EB-2012-0160
Exhibit:	8
Tab:	Appendix M
Schedule:	

Appendix 2-W
Bill Impacts

Customer Class: **General Service Greater Than 50KW**

Consumption 75000 kWh ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
250 kW

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 247.4900	1	$ 247.49	$ 237.5300	1	$ 237.53	-$ 9.96	-4.02%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 2.4354	250	$ 608.85	$ 2.3444	250	$ 586.10	-$ 22.75	-3.74%
Smart Meter Disposition Rider	Monthly		1	$ -	$ -	1	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ 0.0611	250	$ 15.28	$ 0.0326	250	$ 8.15	-$ 7.13	-46.64%
Sub-Total A				$ 871.62			$ 831.78	**-$ 39.84**	**-4.57%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.6140	250	-$ 153.50	-$ 0.5284	250	-$ 132.10	$ 21.40	-13.94%
Tax Change Rate Rider	per kW	-$ 0.0734	250	-$ 18.35		250	$ -	$ 18.35	-100.00%
Global Adj Disposition Rider	per kW	-$ 0.6241	250	-$ 156.03		250	$ -	$ 156.03	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1930	250	$ 48.25	$ 0.3187	250	$ 79.67	$ 31.42	65.12%
Smart Meter Entity Charge	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 591.99**			**$ 779.35**	**$ 187.36**	**31.65%**
RTSR - Network	per kW	$ 2.4345	262	$ 638.27	$ 2.5134	264	$ 662.78	$ 24.52	3.84%
RTSR - Line and Transformation Connection	per kW	$ 1.6613	262	$ 435.55	$ 1.6362	264	$ 431.47	-$ 4.09	-0.94%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,665.81**			**$ 1,873.60**	**$ 207.79**	**12.47%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	75000	$ 390.00	$ 0.0052	0	$ -	-$ 390.00	-100.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	75000	$ 82.50	$ 0.0011	0	$ -	-$ 82.50	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0067	75000	$ 502.50	$ 0.0067	0	$ -	-$ 502.50	-100.00%
Energy - RPP - Tier 1		$ 0.0750	1000	$ 75.00	$ 0.0740	1000	$ 74.00	-$ 1.00	-1.33%
Energy - RPP - Tier 2		$ 0.0880	77653	$ 6,833.42	$ 0.0870	77653	$ 6,755.77	-$ 77.65	-1.14%
TOU - Off Peak		$ 0.0650	50338	$ 3,271.94	$ 0.0630	50338	$ 3,171.27	-$ 100.68	-3.08%
TOU - Mid Peak		$ 0.1000	14157	$ 1,415.75	$ 0.0990	14157	$ 1,401.59	-$ 14.16	-1.00%
TOU - On Peak		$ 0.1170	14157	$ 1,656.42	$ 0.1180	14157	$ 1,670.58	$ 14.16	0.85%
Total Bill on RPP (before Taxes)				**$ 9,549.48**			**$ 8,703.62**	**-$ 845.86**	**-8.86%**
HST		13%		$ 1,241.43	13%		$ 1,131.47	-$ 109.96	-8.86%
Total Bill (including HST)				$ 10,790.91			$ 9,835.09	-$ 955.82	-8.86%
Ontario Clean Energy Benefit [1]				-$ 1,079.09			-$ 983.51	$ 95.58	-8.86%
Total Bill on RPP (including OCEB)				**$ 9,711.82**			**$ 8,851.58**	**-$ 860.24**	**-8.86%**
Total Bill on TOU (before Taxes)				**$ 8,985.17**			**$ 8,117.28**	**-$ 867.88**	**-9.66%**
HST		13%		$ 1,168.07	13%		$ 1,055.25	-$ 112.82	-9.66%
Total Bill (including HST)				$ 10,153.24			$ 9,172.53	-$ 980.71	-9.66%
Ontario Clean Energy Benefit [1]				-$ 1,015.32			-$ 917.25	$ 98.07	-9.66%
Total Bill on TOU (including OCEB)				**$ 9,137.92**			**$ 8,255.28**	**-$ 882.64**	**-9.66%**

Loss Factor (%) 4.8700% 5.4800%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

File Number:	EB-2012-0160
Exhibit:	8
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Appendix 2-W
Bill Impacts

Customer Class: **Large User**

Consumption 2000000 kWh ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
5000 kW

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 6,311.79	1	$ 6,311.79	$ 6,576.42	1	$ 6,576.42	$ 264.63	4.19%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 0.7373	5000	$ 3,686.50	$ 0.7682	5000	$ 3,841.00	$ 154.50	4.19%
Smart Meter Disposition Rider	Monthly		1	$ -	$ -	1	$ -	$ -	
LRAM & SSM Rate Rider	per kW		5000	$ -		5000	$ -	$ -	
Sub-Total A				$ 9,998.29			$ 10,417.42	**$ 419.13**	**4.19%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.7037	5000	-$ 3,518.50	-$ 0.6163	5000	-$ 3,081.50	$ 437.00	-12.42%
Tax Change Rate Rider	per kW	-$ 0.0358	5000	-$ 179.00		5000	$ -	$ 179.00	-100.00%
Global Adj Disposition Rider	per kW	-$ 0.7152	5000	-$ 3,576.00		5000	$ -	$ 3,576.00	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.2364	5000	$ 1,182.00	$ 0.3904	5000	$ 1,952.00	$ 770.00	65.14%
Smart Meter Entity Charge	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 3,906.79**			**$ 9,287.92**	**$ 5,381.13**	**137.74%**
RTSR - Network	per kW	$ 2.8683	5086	$ 14,586.74	$ 2.9613	5086	$ 15,061.17	$ 474.43	3.25%
RTSR - Line and Transformation Connection	per kW	$ 2.0352	5086	$ 10,350.01	$ 2.0045	5086	$ 10,194.89	-$ 155.12	-1.50%
Sub-Total C - Delivery (including Sub-Total B)				**$ 28,843.54**			**$ 34,543.98**	**$ 5,700.44**	**19.76%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2000000	$ 10,400.00	$ 0.0052	0	$ -	-$ 10,400.00	-100.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2000000	$ 2,200.00	$ 0.0011	0	$ -	-$ 2,200.00	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0067	2000000	$ 13,400.00	$ 0.0067	0	$ -	-$ 13,400.00	-100.00%
Energy - RPP - Tier 1		$ 0.0750	1000	$ 75.00	$ 0.0740	1000	$ 74.00	-$ 1.00	-1.33%
Energy - RPP - Tier 2		$ 0.0880	2033200	$ 178,921.60	$ 0.0870	2033200	$ 176,888.40	-$ 2,033.20	-1.14%
TOU - Off Peak		$ 0.0650	1301888	$ 84,622.72	$ 0.0630	1301888	$ 82,018.94	-$ 2,603.78	-3.08%
TOU - Mid Peak		$ 0.1000	366156	$ 36,615.60	$ 0.0990	366156	$ 36,249.44	-$ 366.16	-1.00%
TOU - On Peak		$ 0.1170	366156	$ 42,840.25	$ 0.1180	366156	$ 43,206.41	$ 366.16	0.85%
Total Bill on RPP (before Taxes)				**$ 233,840.39**			**$ 211,506.63**	**-$ 22,333.76**	**-9.55%**
HST		13%		$ 30,399.25	13%		$ 27,495.86	-$ 2,903.39	-9.55%
Total Bill (including HST)				$ 264,239.64			$ 239,002.49	-$ 25,237.15	-9.55%
***Ontario Clean Energy Benefit* [1]**				-$ 26,423.96			-$ 23,900.25	$ 2,523.71	-9.55%
Total Bill on RPP (including OCEB)				**$ 237,815.68**			**$ 215,102.24**	**-$ 22,713.44**	**-9.55%**
Total Bill on TOU (before Taxes)				**$ 218,922.36**			**$ 196,019.02**	**-$ 22,903.34**	**-10.46%**
HST		13%		$ 28,459.91	13%		$ 25,482.47	-$ 2,977.43	-10.46%
Total Bill (including HST)				$ 247,382.27			$ 221,501.50	-$ 25,880.77	-10.46%
***Ontario Clean Energy Benefit* [1]**				-$ 24,738.23			-$ 22,150.15	$ 2,588.08	-10.46%
Total Bill on TOU (including OCEB)				**$ 222,644.04**			**$ 199,351.35**	**-$ 23,292.69**	**-10.46%**

Loss Factor (%) Current: 1.7100% Proposed: 1.7200%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

Consumption 600000 kWh ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)
1500 kW

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 3.1600	1	$ 3.16	$ 3.2700	1	$ 3.27	$ 0.11	3.48%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 13.1880	1500	$ 19,782.00	$ 13.6620	1500	$ 20,493.00	$ 711.00	3.59%
Smart Meter Disposition Rider	Monthly		1	$ -	$ -	1	$ -	$ -	
LRAM & SSM Rate Rider	per kW		1500	$ -		1500	$ -	$ -	
Sub-Total A				$ 19,785.16			$ 20,496.27	**$ 711.11**	**3.59%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5182	1500	-$ 777.30	-$ 0.6019	1500	-$ 902.85	-$ 125.55	16.15%
Tax Change Rate Rider	per kW	-$ 0.5916	1500	-$ 887.40		1500	$ -	$ 887.40	-100.00%
Global Adj Disposition Rider	per kW	-$ 0.5267	1500	-$ 790.05		1500	$ -	$ 790.05	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1497	1500	$ 224.55	$ 0.2471	1500	$ 370.65	$ 146.10	65.06%
Smart Meter Entity Charge	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 17,554.96**			**$ 19,964.07**	**$ 2,409.11**	**13.72%**
RTSR - Network	per kW	$ 1.8350	1573	$ 2,886.55	$ 1.8945	1582	$ 2,997.48	$ 110.93	3.84%
RTSR - Line and Transformation Connection	per kW	$ 1.2884	1573	$ 2,026.72	$ 1.2690	1582	$ 2,007.81	-$ 18.91	-0.93%
Sub-Total C - Delivery (including Sub-Total B)				**$ 22,468.22**			**$ 24,969.36**	**$ 2,501.14**	**11.13%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	600000	$ 3,120.00	$ 0.0052	0	$ -	-$ 3,120.00	-100.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	600000	$ 660.00	$ 0.0011	0	$ -	-$ 660.00	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0067	600000	$ 4,020.00	$ 0.0067	0	$ -	-$ 4,020.00	-100.00%
Energy - RPP - Tier 1		$ 0.0750	1000	$ 75.00	$ 0.0740	1000	$ 74.00	-$ 1.00	-1.33%
Energy - RPP - Tier 2		$ 0.0880	628220	$ 55,283.36	$ 0.0870	628220	$ 54,655.14	-$ 628.22	-1.14%
TOU - Off Peak		$ 0.0650	402701	$ 26,175.55	$ 0.0630	402701	$ 25,370.15	-$ 805.40	-3.08%
TOU - Mid Peak		$ 0.1000	113260	$ 11,325.96	$ 0.0990	113260	$ 11,212.70	-$ 113.26	-1.00%
TOU - On Peak		$ 0.1170	113260	$ 13,251.37	$ 0.1180	113260	$ 13,364.63	$ 113.26	0.85%
Total Bill on RPP (before Taxes)				**$ 85,626.83**			**$ 79,698.75**	**-$ 5,928.08**	**-6.92%**
HST		13%		$ 11,131.49	13%		$ 10,360.84	-$ 770.65	-6.92%
Total Bill (including HST)				$ 96,758.32			$ 90,059.59	-$ 6,698.74	-6.92%
Ontario Clean Energy Benefit [1]				-$ 9,675.83			-$ 9,005.96	$ 669.87	-6.92%
Total Bill on RPP (including OCEB)				**$ 87,082.49**			**$ 81,053.63**	**-$ 6,028.87**	**-6.92%**
Total Bill on TOU (before Taxes)				**$ 81,021.36**			**$ 74,917.09**	**-$ 6,104.27**	**-7.53%**
HST		13%		$ 10,532.78	13%		$ 9,739.22	-$ 793.55	-7.53%
Total Bill (including HST)				$ 91,554.14			$ 84,656.32	-$ 6,897.82	-7.53%
Ontario Clean Energy Benefit [1]				-$ 9,155.41			-$ 8,465.63	$ 689.78	-7.53%
Total Bill on TOU (including OCEB)				**$ 82,398.73**			**$ 76,190.69**	**-$ 6,208.04**	**-7.53%**

Loss Factor (%) 4.8700% 5.4800%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Sentinel Lighting**

Consumption 150 **kWh** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

1 **kW**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 3.73	1	$ 3.73	$ 2.33	1	$ 2.33	-$ 1.40	-37.53%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 17.8300	1	$ 17.83	$ 11.1552	1	$ 11.16	-$ 6.67	-37.44%
Smart Meter Disposition Rider	Monthly		1	$ -	$ -	1	$ -	$ -	
LRAM & SSM Rate Rider	per kW		1	$ -		1	$ -	$ -	
Sub-Total A				$ 21.56			$ 13.49	**-$ 8.07**	**-37.45%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 0.5502	1	-$ 0.55	-$ 0.4974	1	-$ 0.50	$ 0.05	-9.60%
Tax Change Rate Rider	per kW	-$ 0.5203	1	-$ 0.52		1	$ -	$ 0.52	-100.00%
Global Adj Disposition Rider	per kW	-$ 0.5592	1	-$ 0.56		1	$ -	$ 0.56	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.1532	1	$ 0.15	$ 0.2530	1	$ 0.25	$ 0.10	65.14%
Smart Meter Entity Charge	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 20.08**			**$ 13.24**	**-$ 6.84**	**-34.07%**
RTSR - Network	per kW	$ 1.8487	1	$ 1.94	$ 1.9086	1	$ 2.01	$ 0.07	3.84%
RTSR - Line and Transformation Connection	per kW	$ 1.3191	1	$ 1.38	$ 1.2992	1	$ 1.37	-$ 0.01	-0.94%
Sub-Total C - Delivery (including Sub-Total B)				**$ 23.41**			**$ 16.62**	**-$ 6.78**	**-28.97%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	150	$ 0.78	$ 0.0052	0	$ -	-$ 0.78	-100.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	150	$ 0.17	$ 0.0011	0	$ -	-$ 0.17	-100.00%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0067	150	$ 1.01	$ 0.0067	0	$ -	-$ 1.01	-100.00%
Energy - RPP - Tier 1		$ 0.0750	157	$ 11.80	$ 0.0740	157	$ 11.64	-$ 0.16	-1.33%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	101	$ 6.54	$ 0.0630	101	$ 6.34	-$ 0.20	-3.08%
TOU - Mid Peak		$ 0.1000	28	$ 2.83	$ 0.0990	28	$ 2.80	-$ 0.03	-1.00%
TOU - On Peak		$ 0.1170	28	$ 3.31	$ 0.1180	28	$ 3.34	$ 0.03	0.85%
Total Bill on RPP (before Taxes)				**$ 37.40**			**$ 28.51**	**-$ 8.89**	**-23.76%**
HST		13%		$ 4.86	13%		$ 3.71	-$ 1.16	-23.76%
Total Bill (including HST)				$ 42.27			$ 32.22	-$ 10.04	-23.76%
Ontario Clean Energy Benefit [1]				-$ 4.23			-$ 3.22	$ 1.01	-23.88%
Total Bill on RPP (including OCEB)				**$ 38.04**			**$ 29.00**	**-$ 9.03**	**-23.75%**
Total Bill on TOU (before Taxes)				**$ 38.29**			**$ 29.36**	**-$ 8.93**	**-23.33%**
HST		13%		$ 4.98	13%		$ 3.82	-$ 1.16	-23.33%
Total Bill (including HST)				$ 43.27			$ 33.18	-$ 10.09	-23.33%
Ontario Clean Energy Benefit [1]				-$ 4.33			-$ 3.32	$ 1.01	-23.33%
Total Bill on TOU (including OCEB)				**$ 38.94**			**$ 29.86**	**-$ 9.08**	**-23.33%**
Loss Factor (%)		4.8700%			5.4800%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scattered Load**

Consumption 35000 **kWh** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 11.1000	1	$ 11.10	$ 2.1500	1	$ 2.15	-$ 8.95	-80.63%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.1464	35000	$ 5,124.00	$ 0.0283	35000	$ 990.50	-$ 4,133.50	-80.67%
Smart Meter Disposition Rider	Monthly		1	$ -	$ -	1	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		35000	$ -		35000	$ -	$ -	
Sub-Total A				$ 5,135.10			$ 992.65	**-$ 4,142.45**	**-80.67%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0015	35000	-$ 52.50	-$ 0.0014	35000	-$ 49.00	$ 3.50	-6.67%
Tax Change Rate Rider	per kWh	-$ 0.0033	35000	-$ 115.50		35000	$ -	$ 115.50	-100.00%
Global Adj Disposition Rider	per kWh	-$ 0.0015	35000	-$ 52.50		35000	$ -	$ 52.50	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -		1	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0005	35000	$ 17.50	$ 0.0008	35000	$ 28.00	$ 10.50	60.00%
Smart Meter Entity Charge	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 4,932.10**			**$ 971.65**	**-$ 3,960.45**	**-80.30%**
RTSR - Network	per kWh	$ 0.0060	36705	$ 220.23	$ 0.0062	36918	$ 228.89	$ 8.66	3.93%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	36705	$ 157.83	$ 0.0042	36918	$ 155.06	-$ 2.77	-1.76%
Sub-Total C - Delivery (including Sub-Total B)				**$ 5,310.16**			**$1,355.60**	**-$ 3,954.56**	**-74.47%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	36705	$ 190.86	$ 0.0052	36918	$ 191.97	$ 1.11	0.58%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	36705	$ 40.37	$ 0.0011	36918	$ 40.61	$ 0.23	0.58%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0067	36705	$ 245.92	$ 0.0067	36918	$ 247.35	$ 1.43	0.58%
Energy - RPP - Tier 1		$ 0.0750	1000	$ 75.00	$ 0.0740	1000	$ 74.00	-$ 1.00	-1.33%
Energy - RPP - Tier 2		$ 0.0880	35705	$ 3,142.00	$ 0.0870	35918	$3,124.87	-$ 17.13	-0.55%
TOU - Off Peak		$ 0.0650	23491	$ 1,526.91	$ 0.0630	23628	$1,488.53	-$ 38.37	-2.51%
TOU - Mid Peak		$ 0.1000	6607	$ 660.68	$ 0.0990	6645	$ 657.88	-$ 2.80	-0.42%
TOU - On Peak		$ 0.1170	6607	$ 773.00	$ 0.1180	6645	$ 784.14	$ 11.14	1.44%
Total Bill on RPP (before Taxes)				**$ 9,004.56**			**$5,034.65**	**-$ 3,969.91**	**-44.09%**
HST		13%		$ 1,170.59	13%		$ 654.50	-$ 516.09	-44.09%
Total Bill (including HST)				$10,175.15			$5,689.15	-$ 4,486.00	-44.09%
Ontario Clean Energy Benefit [1]				-$ 1,017.52			-$ 568.92	$ 448.60	-44.09%
Total Bill on RPP (including OCEB)				**$ 9,157.63**			**$5,120.23**	**-$ 4,037.40**	**-44.09%**
Total Bill on TOU (before Taxes)				**$ 8,748.15**			**$4,766.33**	**-$ 3,981.82**	**-45.52%**
HST		13%		$ 1,137.26	13%		$ 619.62	-$ 517.64	-45.52%
Total Bill (including HST)				$ 9,885.41			$5,385.96	-$ 4,499.45	-45.52%
Ontario Clean Energy Benefit [1]				-$ 988.54			-$ 538.60	$ 449.94	-45.52%
Total Bill on TOU (including OCEB)				**$ 8,896.87**			**$4,847.36**	**-$ 4,049.51**	**-45.52%**

Loss Factor (%) Current: 4.8700% Proposed: 5.4800%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.