May 4, 2012

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
26th Floor, Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli

Re: PowerStream Inc. (Licence ED-2004-0420)
2013 Electricity Distribution Rates Application EB-2012-0161

Please find enclosed two (2) paper copies and a CD containing the above captioned application in PDF format, along with electronic copies of the completed Board models. Please note also that this Application has been filed through the Board's Regulatory Electronic Submission System (RESS).

PowerStream Inc. ("PowerStream") is a distributor as defined in, and is licenced as such under, the Ontario Energy Board Act, 1998. PowerStream holds Electricity Distribution Licence ED-2004-0420.

On December 15, 2008 the Board approved the amalgamation of PowerStream Inc. and Barrie Hydro Distribution Inc. (EB-2008-0335). The companies merged on January 1, 2009, and started to operate under the same Licence ED-2004-0420 on March 16, 2010.

PowerStream Inc. continues to have two separate rate zones, pre-amalgamation PowerStream Inc. ("PowerStream South") and pre-amalgamation Barrie Hydro Distribution Inc. ("PowerStream Barrie").

The cost of service rate application filed under this cover is for PowerStream Inc., EB-2012-0161 includes the following highlights:

- The establishment of a Base Revenue Requirement for the 2013 test year and rates to recover this amount;
- Harmonization of distribution rates between the two rate zones noted above; and
- The clearance of deferral and variance accounts and the updating of a number of rates and charges

PowerStream has calculated customer bill impacts, from the rates proposed in this application, including rate riders, as follows:

For PowerStream South:

- a Residential customer using 800 kWhs per month will see a $2.41 (7.5%) increase in the Delivery line and an increase of $2.80 (2.6%) on the total monthly bill; and

- a General Service less than 50 kW customer using 2,000 kWhs per month will see a $0.79 (1.1%) increase in the Delivery line and a increase of $1.69 (0.6%) on the total monthly bill.

For PowerStream Barrie:

- a Residential customer using 800 kWhs per month will see a $3.38 (8.8%) decrease in the Delivery line and a decrease of $5.13 (4.4%) on the total monthly bill; and

- a General Service less than 50 kW customer using 2,000 kWhs per month will see a $1.94 (2.5%) decrease in the Delivery line and a decrease of $6.20 (2.2%) on the total monthly bill.

If you have any questions, please do not hesitate to contact the undersigned.

Yours truly,

Original signed by

Colin Macdonald
Vice President, Rates and Regulatory Affairs

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ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by PowerStream Inc. for an Order or Orders approving or fixing just and reasonable distribution rates effective January 1, 2013.

APPLICATION

1. PowerStream Inc. ("PowerStream" or the "Company") is a distributor as defined in the *Ontario Energy Board Act, 1998* (the "Act"). PowerStream holds Electricity Distribution Licence ED-2004-0420**.**

2. PowerStream hereby applies to the Ontario Energy Board (the "Board" or the "OEB"), pursuant to section 78 of the Act, for an Order or Orders approving or fixing just and reasonable rates for electricity distribution service for the period January 1, 2013 to December 31, 2013.

3. This Application has been guided by the Chapter 2 of the Board's *Filing Requirements for Transmission and Distribution Applications*, updated June 22, 2011 (the "Filing Requirements") and the Board's *2006 Electricity Distribution Rate Handbook* (the "2006 Handbook"). It is based on a 2013 forward test year ("Test Year"), as contemplated by the Filing Requirements.

4. PowerStream currently has two rate zones, one for the former PowerStream service territory in York Region ("South") and one for the former Barrie Hydro service territory in Barrie and Simcoe County ("Barrie"). In this Application, PowerStream seeks to harmonize rates into a single rate. There will continue to be separate deferral and variance disposition rate riders for each rate zone, until the individual rate zone balances are cleared.

5. In this Application, PowerStream is seeking approval of a 2013 Base Revenue Requirement of $169,488,000 which includes a forecast 2013 Revenue Deficiency of $7,443,000. If the 2013 Base Revenue Requirement and the other changes proposed are approved, the total electricity bill of a residential customer using 800 kWh/month and of a General Service < 50 kW customer using 2,000 kWh/month in the PowerStream rate zone will be increased by $2.80 (2.6 percent) and $1.69 (0.6 percent), respectively. Similarly, the total electricity bill of a residential customer using 800 kWh/month and of a General Service < 50 kW customer using 2,000 kWh/month in the Barrie rate zone will be reduced by $5.13 (4.4 percent) and $6.20 (2.2 percent), respectively.

6. PowerStream is seeking approval of a full year of depreciation in the 2013 Test Year as opposed to the more conventional half year depreciation. This is intended to help fund capital expenditures during the Incentive Regulation Mechanism ("IRM") period.

7. PowerStream proposes disposition of deferral and variance account balances as at December 31, 2011, the most recent audited balances, along with accrued interest up to December 31, 2012 based on the proposed January 1, 2013 effective date for the rate riders. In the case of International Financial Reporting Standards ("IFRS") Transitional Costs and savings arising from the Harmonized Sales Tax ("HST"), PowerStream is proposing to include the projected balances as at December 31, 2012.

8. In this Application, PowerStream is seeking disposition of the remaining stranded meter costs resulting from the smart meter program. In 2011 PowerStream requested and received approval for its "final" smart meter cost recovery application (EB-2011-0128). In that application PowerStream proposed to defer disposition of the stranded meter cost until its next Cost of Service rate filing for 2013.

9. PowerStream is requesting certain variance and deferral accounts to track amounts that arise due to the adoption of IFRS, notably the de-recognition of assets and post retirement employee benefits.

10. PowerStream pays low voltage ("LV") charges to Hydro One Networks Inc. ("Hydro One") for use of certain Hydro One distribution assets. The difference between Hydro One's LV charges to PowerStream (recorded in Account 4750) and the LV amounts billed to PowerStream's customers (recorded in Account 4075) is recorded in Account 1550 – LV Variance Account, in accordance with Appendix B of a Board directive dated June 13, 2006. In this Application, PowerStream is seeking: (i) to clear Account 1550 to December 31, 2011; and (ii) to recover in 2013 rates, a forecast LV amount of $2,731,456 through an updated LV charge.

11. PowerStream is proposing a funding rate adder of $0.20 per customer per month for the planned Green Energy Act ("GEA") spending over the years 2012 to 2016.

12. PowerStream requests a charge to customers to recover the cost of the Meter Data Management and Repository ("MDM/R") system as proposed by the Independent Electricity System Operator ("IESO") and as determined by the Board. (PowerStream notes that the IESO has filed with the OEB applications to recover costs associated with the MDM/R system. PowerStream has not included these costs in this Application and anticipates that the Board will provide for recovery of MDM/R costs when they are approved.)

13. This Application seeks the Board's approval of new Retail Transmission Service ("RTS") rates to reflect currently approved Hydro One's sub-transmission ("ST") rates (EB-2009-0096) effective January 1, 2011 and most recent Uniform Transmission Rates approved by the Board (EB-2011-0268), issued on December 20, 2011 and effective January 1, 2012.

14. PowerStream accordingly applies to the Board, pursuant to section 78 of the Act for the following Order or Orders:

a. an Order approving PowerStream's proposed final rates for the 2013 rate year, or fixing such other rates as the Board may find to be just and reasonable effective January 1 2013;

b. an Order approving harmonized rates for the predecessor Barrie Hydro and PowerStream rate zones;

c. an Order approving clearance of the balances recorded in certain other deferral and variance accounts by means of a rate rider for the period January 1, 2013 to December 31, 2014;

d. an Order approving an updated Low Voltage (“LV”) charge**,** effective January 1, 2013;

e. an Order approving updated Retail Transmission Service (“RTS”) rates, effective January 1, 2013;

f. an Order allowing continuation of the present Transformer Ownership Allowance credit;

g. an Order approving a funding rate adder for the planned Green Energy Act (“GEA”) spending over the years 2012 to 2016;

h. an Order approving certain variance and deferral accounts to track amounts that arise due to the adoption of IFRS, notably the de-recognition of asset and post retirement employee benefits; and

i. an Order making current rates interim, effective January 1, 2013, if and only if the preceding Orders cannot be issued in time to implement final rates, effective January 1, 2013.

15. This Application is supported by the written evidence that is enumerated in Exhibit A1, Tab 1, Schedule 1 and filed with this Application. PowerStream may amend or supplement this written evidence prior to or during the course of the Board’s hearing of this Application.

16. PowerStream requests that the Board give reasons, in writing, for its final decision and order(s) in this proceeding. This request is made pursuant to subsection 17(1) of the *Statutory Powers Procedure Act.*

17. The following are the names and addresses of PowerStream's authorized representatives and its counsel for the purpose of serving documents on PowerStream in this proceeding

(a) authorized representatives:

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DATED AT TORONTO, ONTARIO THIS 4TH DAY OF MAY, 2012

PowerStream Inc.
by its counsel
Borden Ladner Gervais LLP
per:

____
James C. Sidlofsky

SPECIFIC APPROVALS REQUESTED

PowerStream requests an Order or Orders approving:

1. PowerStream's Base Revenue Requirement for the Test Year adjusted, as required, to update the rate of return on equity ("ROE") and short-term debt rate as described in Exhibit F;
2. harmonized rates for the predecessor Barrie Hydro and PowerStream rate zones;
3. corresponding final rates, effective January 1, 2013, that will enable PowerStream to recover its Board-approved Base Revenue Requirement;
4. harmonized Specific Service Charges;
5. the disposition of the remaining stranded meter costs resulting from the smart meter program by means of a rate rider to metered customers effective January , 2013 to December 31, 2013;
6. the clearance of the balances recorded in certain deferral and variance accounts by means of class-specific rate riders effective January 1, 2013 to December 31, 2014;
7. an updated Low Voltage ("LV") charge, effective January 1, 2013;
8. new Retail Transmission Service ("RTS") rates, effective January 1, 2013;
9. maintaining the present Transformer Ownership Allowance credit to certain large customers;
10. a funding rate adder for the planned Green Energy Act ("GEA") spending over the years 2012 to 2016;

11. certain variance and deferral accounts to track amounts that arise due to the adoption of International Financial Reporting Standards ("IFRS"), notably the de-recognition of assets and post retirement employee benefits;

12. a charge to customers to recover the cost of the Meter Data Management and Repository ("MDM/R") system as proposed by the Independent Electricity System Operator ("IESO") and as determined by the Board. (PowerStream notes that the IESO has filed with the OEB applications to recover costs associated with the MDM/R system. PowerStream has not included these costs in this Application and anticipates that the Board will provide for recovery of MDM/R costs when they are approved.); and

13. an order declaring PowerStream's current (i.e., 2012) rates as interim rates, effective January 1, 2013, if and only if the preceding approvals cannot be issued in time to implement final rates, effective January 1, 2013.

SUMMARY OF APPLICATION

INTRODUCTION

PowerStream's Application has been guided by the OEB Filing Requirements dated June 22, 2011 and the 2006 Electricity Distribution Rate ("EDR") Handbook. It is based on a 2013 forward test year. Accordingly, the rates for which approval is sought are based on a revenue requirement that is underpinned by forecasts of 2013 revenue and expenses.

In addition, PowerStream requests approval to move the implementation date of the new rates from May 1, 2013 to January 1, 2013 for the reasons discussed at Exhibit A3, Tab1, Schedule 8.

PowerStream was created on June 1, 2004 by the amalgamation of Hydro Vaughan Distribution Inc. ("Hydro Vaughan"), Markham Hydro Distribution Inc. ("Markham Hydro"), and Richmond Hill Hydro Inc. ("Richmond Hill Hydro"). PowerStream completed the acquisition of Aurora Hydro Connections Limited ("Aurora Hydro") on November 1, 2005 thus adding a fourth municipality to the service territory. On January 1, 2009 PowerStream merged with Barrie Hydro Distribution Inc. ("Barrie Hydro"). PowerStream is the second largest municipally owned electricity distribution utility in Ontario.

PowerStream currently has two rate zones, one for the former PowerStream Inc. service territory in York Region ("South") and one for the former Barrie Hydro service territory in Barrie and Simcoe County ("Barrie"). In this Application, PowerStream seeks to harmonize rates into a single rate zone effective January 1, 2013.

In 2012, subject to OEB approval, PowerStream will purchase a half interest in Collingwood Utility Services Corp., the holding company for Collus Power Inc.

PowerStream strongly supports government and regulatory initiatives and is an active participant in the Board's consultative processes.

PREVIOUS RATE APPLICATIONS:

2009 Cost of Service Application

PowerStream filed a 2009 Cost of Service Application with the Board on October 10, 2008 for rates effective on May 1, 2009. Through the OEB process PowerStream reached a settlement agreement with the various intervenors which was subsequently approved by the Panel hearing the application. The resulting 2009 Base Revenue requirement amounted to $114.6 million, resulting in an average increase of 2.2% in distribution rates.

Smart Meter Filings (2010 and 2011)

In 2010 PowerStream filed an application (EB-2010-0209) for recovery of costs associated with the installation of 137,356 smart meters in its South rate zone. The Board approved an annual incremental revenue requirement of $3,661,000.

In 2011, PowerStream had substantially completed its Smart Meter Implementation Program and filed an application (EB-2011-0128) for final recovery of costs associated with the installation of 69,393 smart meters in the Barrie rate zone and the remaining 21,725 smart meters in the South rate zone. The Board approved an annual incremental revenue requirement of $1,722,000 for Barrie and $1,367,000 for the South.

To calculate the 2013 revenue deficiency, the total 2010 and 2011 approved smart meter incremental revenue requirement (“SMIRR”) has been added to the calculation of 2013 revenue at current rates.

In this Application, PowerStream is seeking recovery of stranded asset costs and additional smart meter costs described below.

In Chapter 2 of the Board’s Filing Requirements dated June 22, 2011, section 2.5.1.5 – *Treatment of Stranded Assets Related to Smart Meter Deployment*, distributors are directed to apply for recovery of these stranded asset costs.

In its November 31, 2011 Decision and Order on PowerStream’s 2011 smart meter application (EB-2011-0128, at pages 10-11), the Board directed PowerStream to track the repair and maintenance costs related to customer equipment to permit installation of a smart meter after April 30, 2011 in account 1556 and include this in its next rebasing application. This has been done.

PowerStream notes that the Independent Electricity System Operator ("IESO") has filed with the OEB applications to recover costs associated with the Provincial Meter Data Management and Repository ("MDM/R") system. PowerStream has not included these costs in this Application and requests that the Board will provide for recovery of MDM/R costs when they are approved.

2010, 2011 and 2012 3rd Generation Incentive Regulation applications

PowerStream filed applications for, and was granted, distribution rate adjustments under the Board's 3rd Generation Incentive Regulation Mechanism for 2010, 2011 and 2012. The increases associated with each rate year were 0.18%, 0.18%, and 0.88% respectively. Based on the results of the Board's cost benchmarking studies, PowerStream is in the second efficiency cohort and has stretch factor of 0.4%.

SCOPE OF 2013 RATE APPLICATION

This Application seeks approval of a change in electricity distribution rates effective January 1, 2013. The average proposed rate increase across all customer classes is 4.6%, effective January 1, 2013. The proposed realignment of PowerStrean's rate year (which currently runs from May 1st through April 30th) with its fiscal year (January 1st through December 31st) is discussed at Exhibit A3, Tab 1, Schedule 8.

The proposed rates are underpinned by 2013 forecasts of operations, maintenance and administration (”OM&A”) expenses, return on rate base, amortization expense and payments in lieu of taxes ("PILs"). The sum of these amounts is PowerStream's "2013 Service Revenue Requirement". PowerStream's "2013 Base Revenue Requirement" is defined as: (i) PowerStream's 2013 Service Revenue Requirement less (ii) certain non-rate revenue amounts, referred to herein as "Revenue Offsets."

PowerStream merged with Barrie Hydro in 2009 and achieved significant efficiency savings as a result. These are discussed in more detail in the Exhibit D1, Tab 1, Schedule 3. In addition, the budgeted staff levels in 2013 are forecast to be slightly lower than the 2009 merged company levels. Details on staffing, compensation and benefits at PowerStream are discussed in Exhibit D1, Schedule 5, Tab 4.

The value of PowerStream's 2013 rate base has been calculated as the sum of: (i) the net book value ("NBV") of the average of the PowerStream assets opening and closing balances for 2013; and (ii) an allowance for working capital (underpinned by a forecast of the 2013 Cost of Power). The return on rate base, rate of return on equity ("ROE") and short-term debt rates have all been determined in accordance with the *Board's Report on the Cost of Capital for Ontario's Regulated Utilities of December 11, 2009*. PowerStream has included a full year of amortization expense on 2013 in-service capital additions as explained in Exhibit D1, Tab 4, Schedule 1, Depreciation and Amortization.

In the calculations of Cost of Capital, PowerStream used the parameters prescribed in Board's letter of March 2, 2012 for applications for rates effective May 1, 2012. These parameters will be updated as necessary during the course of this proceeding to reflect the Board's parameters for cost of service applications for rates effective January 1, 2013, expected in the fall of this year.

PILs have been determined in accordance with the methodology prescribed in the 2006 EDR Handbook. The "Large Corporation Tax" has now been eliminated and is therefore no longer included in the PILs calculation.

In order to forecast 2013 revenue at existing rates, PowerStream prepared load (i.e., energy consumption and demand) and customer forecasts for 2013. The methodology used for those forecasts was developed by PowerStream and is described, in detail, in Exhibit C1, Tab 1, Schedules 2 and 3. Current rates (i.e., those in effect as of May 1, 2012) were applied to the forecast output in order to determine a "Forecast Revenue at Current Rates".

To calculate the 2013 revenue deficiency, the total 2010 and 2011 Board approved smart meter incremental revenue requirement ("SMIRR") has been added to the calculation of 2013 revenue at current rates. The difference between this amount and PowerStream's 2013 Base Revenue Requirement is equal to PowerStream's 2013 Revenue Deficiency.

In addition to the recovery of the 2013 Base Revenue Requirement, PowerStream is seeking to recover from ratepayers, or provide a credit to ratepayers, as the case may be, amounts associated with:

(i) the clearance of certain regulatory asset accounts;

(ii) the clearance of certain other deferral and variance accounts;

PowerStream proposes to dispose of these balances by way of volumetric rate riders.

INCREASE IN REVENUE REQUIREMENT FOR 2013

An analysis of the drivers of the increase in PowerStream's 2013 Revenue Requirement, relative to 2009, is provided in Exhibit F, Tab 1, Schedule 3. Detailed comparisons from 2009 to 2013 are not possible as PowerStream has adopted Modified International Financial Standards (“MIFRS”) in 2012. PowerStream has provided the financial data for 2011 in both Canadian Generally Accepted Accounting Principles (“CGAAP”) and in MIFRS. Comparisons can be made between 2009 and 2011 in CGAAP and between 2011 and 2013 in MIFRS. The impacts of moving to MIFRS on the financial results are detailed in Exhibit A3, Schedule 1, Tab 5.

Table 1, below, summarizes changes in PowerStream’s Service Revenue Requirement and Base Revenue Requirement from the last Board Approved rebasing years (2008 for Barrie and 2009 for PowerStream) through the 2013 Test Year.

Table 1: PowerStream Revenue Requirement ($ Millions)

	OEB Approved		Actual				Bridge	Test
	2008 Barrie	2009 PowerStream	2009	2010	2011	2011	2012	2013
	CGAAP					MIFRS		
OM&A Expenses	10.0	43.2	59.7	56.8	62.1	73.9	81.6	85.7
Depreciation	10.2	36.2	41.9	46.0	45.8	33.9	32.1	35.8
Target Net Income	5.5	16.9	20.5	27.1	28.9	29.1	29.0	30.6
Interest	5.5	17.7	22.0	23.7	26.1	26.3	23.0	24.0
Taxes	2.9	7.1	9.9	10.8	6.3	0.1	1.8	2.5
Service Revenue Requirement	**34.1**	**121.1**	**154.0**	**164.4**	**169.2**	**163.3**	**167.5**	**178.6**
Revenue offsets	2.6	6.6	10.1	8.9	9.2	9.9	8.8	9.1
Base Revenue Requirement	**31.5**	**114.5**	**143.9**	**155.5**	**160.0**	**153.4**	**158.7**	**169.5**

The principal reasons for the increases are summarized below:

PowerStream's rate base increased by $199 million or 31 percent between 2009 and 2013, an average annual increase of 7.7 percent. These increased expenditures have been required to serve increased demand and customer growth and to ensure that the reliability of PowerStream's distribution system is maintained or improved. Specifically the increase reflects: (i) investments in new distribution plant; (ii) upgrades of existing plant; (iii) general plant purchases; and (iv) increases in PowerStream's allowance for working capital.

Significant drivers of the increase in rate base are: an increase in Operations Capital to fund a new Customer Information System ("CIS"); increases in Sustainable Capital to support increased infrastructure replacement and rehabilitation; and an increase in Developmental Capital for subdivisions and electrical distribution infrastructure projects to supply customer load growth. These matters are summarized in Exhibit B1, Tab 1, Schedule 1.

PowerStream's OM&A expenses are forecast to increase by $32.5 million. The most significant factor for this increase is the impact of moving to MIFRS. PowerStream increased its OM&A expenditures to serve increased demand and customer growth and to ensure that system reliability is maintained or improved.

Significant drivers of these changes are: (i) implementation of increased asset inspections and testing; (ii) additional work on worst performing feeders, (iii) introduction of a new Outage Management System/SCADA; (iv) continuation of the hiring of new apprentices to ensure that qualified staff are available; and (v) increased head office activities to deal with a more complex regulatory and industry structure. These matters are summarized in Exhibit D1, Tab 1, Schedules 1.

PowerStream's amortization expenses are forecast to decrease by $6.1 million or 14.5 percent between 2009 and 2013, reflective of the asset additions over these years offset by the impact of moving to MIFRS. This is discussed in Exhibit D1, Tab 4, Schedule 1.

PowerStream has used the cost of capital parameters in the Board’s letter of March 2, 2012 (for May 1, 2012 cost of service rate applications). As discussed in Exhibit E, Tab 1, Schedule 1, PowerStream expects that the Board will issue its cost of capital parameters for applications for rates effective January 1, 2013 in the Fall of this year. These parameters will be used to determine PowerStream's 2013 Revenue Requirement.

The reduction in Working Capital Allowance (“WCA”) from the default 15 percent to 13 percent partially offsets the increase in PowerStream’s rate base. The 13 percent allowance is based on the guidance in the Board’s letter of April 12, 2011.

There is also a reduction in PILs relative to 2009 Board approved as outlined in Exhibit D2.

OTHER CHANGES AFFECTING RATES

In addition to changes in the Base Revenue Requirement, there are a number of other factors that will affect the quantum of PowerStream's 2013 distribution rates:

- Distribution rates will increase as a result of clearance of the balances recorded in certain deferral and variance accounts. If approved, an amount of $3,558,608 will be cleared over the two year period Jan 1, 2013 to Dec. 31, 2014. The charge to customers is proposed to be in the form of a volumetric rate rider.
- Distribution rates will increase as a result of the forecast Low Voltage amount of $2,371,456 and the corresponding updated Low Voltage charge.

- There will be a transformer ownership allowance credit for certain General Service > 50kW and Large Use customers totalling $2,345,656.
- PowerStream used the Board's methodology to adjust its Retail Service Transmission ("RTS") rates to incorporate the new Uniform Transmission Rates for Ontario transmitters. PowerStream's current RTS rates are based on the Board's Final Rate Order in EB-2011-0005, issued on April 20, 2012, and the rates are effective May 1, 2012. In this Application, RTS rates have been further updated to reflect the Board's approval, on an interim basis, of Hydro One Network Inc.'s sub-transmission rates effective January 1, 2011 (EB-2009-0096) and the Board's Decision and Rate Order for Ontario Uniform Transmission Rates that became effective January 1, 2012 (EB-2011-0268)

LIST OF PROPOSED RATES AND CHARGES

Tables 2 and 3, below, set out the proposed distribution rates and rate riders for which approvals are sought in this Application. At Exhibit H, Tab 6, Schedule 6 to this Application, PowerStream has provided calculations to confirm that the proposed rates will provide the 2013 Base Revenue Requirement.

Table 2: Summary of Current and Proposed Rates

Customer Class	*Billing Determinant*	Current 2012 Rates				Proposed 2013 Rates	
		PowerStream South		PowerStream Barrie		PowerStream Harmonized	
		Fixed	Variable	Fixed	Variable	Fixed	Variable
Residential	*kWh*	11.99	0.0135	15.34	0.0137	13.57	0.0151
GS<50 kW	*kWh*	28.64	0.0116	16.11	0.0164	27.91	0.0148
GS>50 kW	*kW*	84.45	3.5036	395.68	1.8393	148.18	3.5449
Large Use	*kW*	2,173.63	1.0484	9,690.24	0.5918	6,017.47	1.7969
Unmetered Scattered Load	*kWh*	14.32	0.0087	7.95	0.0161	8.06	0.0156
Sentinel Lights	*kW*	2.00	9.3917	-	-	3.51	8.7473
Street Lighting	*kW*	0.84	4.8616	3.02	11.2961	1.34	5.8850

Notes:

1. Existing rates are those in effect May 1, 2012.

2. Detailed proposed tariff sheets are included in Exhibit H, Tab 6, Schedule 2.

3. The variable rates represent the distribution portion only, before rate riders and Low Voltage charges

Table 3: Deferral and Variance Account Disposition Rate Riders

Customer Class	Existing Rate Riders		Proposed Rate Riders			
	South	North	PowerStream South		PowerStream Barrie	
			All Customers	GA rate rider - non-RPP Customers	All Customers	GA rate rider - non-RPP Customers
Residential	$ -	$ (0.0006)	$ -	$ 0.0017	$ 0.0008	$ 0.0030
General Service <50 Kw	$ -	$ (0.0004)	$ (0.0012)	$ 0.0017	$ (0.0009)	$ 0.0030
General Service >50 Kw	$ -	$ (0.0705)	$ (0.5397)	$ 0.0017	$ (0.5536)	$ 0.0030
Large User	$ -	$ -	$ (0.1895)	$ 0.0017	$ (0.0829)	$ 0.0001
Unmetered Scattered Load	$ -	$ (0.0009)	$ (0.0022)	$ 0.0017	$ (0.0014)	$ 0.0030
Sentinel Lights	$ -	$ -	$ (0.7433)	$ 0.0017	$ (0.2135)	$ 0.0030
Street Lighting	$ -	$ (0.1545)	$ (0.6372)	$ 0.0017	$ (0.4548)	$ 0.0001

Notes:

1. These rate riders are not included in the variable charges in Table 1 and are shown as separate lines in rate schedules.

2. Existing rates are those in effect May 1, 2012.

3. Detailed proposed tariff sheets are included in Exhibit H, Tab 6, Schedule 2.

BILL AND RATE IMPACTS

Tables 4, 5 and 6, below, set out the monthly bill impacts of PowerStream's application, for a "typical" customer in each rate class. No rate mitigation is proposed as discussed in Exhibit H, Tab 6, Schedule 5.

Table 4: Impacts on Total Bill for Typical Customer

Customer Class	*Billing Determinant*	*Consumption per customer*	*Load per customer*	Total Monthly Bill Impact			
				PowerStream South		PowerStream Barrie	
		kwh	*kW*	$	%	$	%
Residential	*kWh*	*800*	-	$ 2.80	2.6%	$ (5.13)	(4.4%)
GS<50 kW	*kWh*	*2,000*	-	$ 1.69	0.6%	$ (6.20)	(2.2%)
GS>50 kW	*kW*	*80,000*	*250*	$ 173.03	1.6%	$ (80.10)	(0.7%)
Large Use	*kW*	*2,800,000*	*7,350*	$ 14,692.57	4.2%	$ (8,215.58)	(2.2%)
Unmetered Scattered Load	*kWh*	*150*	-	$ (5.79)	(16.6%)	$ (0.58)	(2.0%)
Sentinel Lights	*kW*	*180*	*1*	$ 0.62	1.8%		
Street Lighting	*kW*	*280*	*1*	$ 1.43	3.7%	$ (9.38)	(19.0%)

Notes:

1. Consumption levels are based on the "typical customer" amounts.
2. Includes consumption adjusted by proposed loss factors. See Exhibit H, Tab 7, Schedule 2 for a discussion on loss adjustment factors.
3. Includes all regulatory charges, HST at 13% and OCEB for eligible classes.

Table 5: Impact on the Distribution Portion of Bill for Typical Customer

Customer Class	Billing Determinant	Consumption per customer	Load per customer	Monthly Distribution Charge Impact			
				PowerStream South		PowerStream Barrie	
		kwh	kW	$	%	$	%
Residential	kWh	800		$ 2.12	8.8%	$ (1.51)	(5.4%)
GS<50 kW	kWh	2,000		$ 0.09	0.2%	$ 2.27	4.1%
GS>50 kW	kW	80,000	250	$ 105.83	11.0%	$ 253.90	28.4%
Large Use	kW	2,800,000	7,350	$ 13,488.85	132.8%	$ 3,618.60	22.2%
Unmetered Scattered Load	kWh	150		$ (5.22)	(33.6%)	$ 0.04	0.4%
Sentinel Lights	kW	180	1	$ 0.53	4.7%		
Street Lighting	kW	280	1	$ 1.07	19.1%	$ (7.21)	(51.8%)

Notes:

1. Includes fixed and variable distribution charges, low voltage charges and regulatory assets rate riders.
2. Consumption levels are from the "typical customer" amounts.

Table 6: Impact on the Delivery Portion of Bill for Typical Customer

Customer Class	Billing Determinant	Consumption per customer	Load per customer	Monthly Delivery Charge Impact			
				PowerStream South		PowerStream Barrie	
		kwh	kW	$	%	$	%
Residential	kWh	800	-	$ 2.41	7.5%	$ (3.38)	(8.8%)
GS<50 kW	kWh	2,000	-	$ 0.79	1.1%	$ (1.94)	(2.5%)
GS>50 kW	kW	80,000	250	$ 120.63	6.5%	$ 84.53	4.2%
Large Use	kW	2,800,000	7,350	$ 13,002.28	31.2%	$ (7,270.43)	(12.5%)
Unmetered Scattered Load	kWh	150	-	$ (5.18)	(30.5%)	$ (0.24)	(2.0%)
Sentinel Lights	kW	180	1	$ 0.49	3.4%		
Street Lighting	kW	280	1	$ 1.16	13.9%	$ (7.80)	(44.9%)

Notes:

1. The "delivery" portion includes all distribution charges, as defined in Table 5 above and transmission charges
2. Consumption levels are from the "typical customer" amounts.

REVENUE DEFICIENCY

The components of PowerStream's 2013 revenue deficiency are set out below in Table 1. The revenue deficiency is $7.5 million

Table 1 – 2013 Revenue Deficiency

	%	2013 Test Year, '$000
Rate Base		838,473
Cost of Capital	6.51%	
Return on Rate Base		54,555
Distribution Expenses		85,701
Amortization		35,844
Payment in Lieu of taxes		2,450
Service Revenue Requirement		178,550
Less Revenue offsets		(9,062)
Base Revenue Requirement		**169,488**
Revenue at Current Rates		**162,045**
Revenue Deficiency		**(7,443)**

CAUSES OF REVENUE DEFICIENCY

The underpinning causes of the 2013 revenue deficiency are enumerated in Table 1 below. The "Evidentiary Reference" column provides the links to the detailed explanations of the deficiency.

Table 1: Causes of Revenue Deficiency

Driver	Impact on Revenue Deficiency ($ millions)	Evidentiary Reference
Increase in Return on Capital	9.1	Exhibit B
Increase in Distribution Expenses	32.5	Exhibit D1, Tab 1-4
Decrease in Amortization Expenses	(10.5)	Exhibit B1, Tab 2, Schedules 8-9
Decrease in PILs	(7.6)	Exhibit D2
Decrease in Revenue Offsets	0.1	Exhibit C2
Load Growth and IRM increases	(8.8)	Exhibit C1
SMIRR (Smart Meter Incremental Revenue Requirement)	(7.2)	Exhibit C1
Total 2013 Revenue Deficiency	**7.5**	Exhibit G

Note that the implementation of Modified International Financial Reporting Standards ("MIFRS") significantly impacts the increase in Distribution Expenses and the decreases in Amortization and PILs

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

Choose Your Utility:

Peterborough Distribution Incorporated
PowerStream Inc.

File Number: EB-2012-0161

Rate Year: 2013

Application Contact Information

Name: Tom Barrett

Title: Manager, Rates & Applications

Phone Number: (905) 532-4640

Email Address: tom.barrett@powersrteam.ca

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

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Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Data Input (1)

		Initial Application		(6)		Per Board Decision	
1	**Rate Base**						
	Gross Fixed Assets (average)	$802,388,655	(8)	$ 802,388,655		$802,388,655	
	Accumulated Depreciation (average)	($86,568,565)	(5)	($86,568,565)		($86,568,565)	
	Allowance for Working Capital:						
	Controllable Expenses	$85,701,101		$ 85,701,101		$85,701,101	
	Cost of Power	$857,779,706		$ 857,779,706		$857,779,706	
	Working Capital Rate (%)	13.00%		13.00%		13.00%	
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$162,044,558					
	Distribution Revenue at Proposed Rates	$169,487,804					
	Other Revenue:						
	Specific Service Charges	$3,385,000					
	Late Payment Charges	$2,500,000					
	Other Distribution Revenue	$2,032,000					
	Other Income and Deductions	$1,145,000					
	Total Revenue Offsets	$9,062,000	(7)				
	Operating Expenses:						
	OM+A Expenses	$83,906,062		$ 83,906,062		$83,906,062	
	Depreciation/Amortization	$35,844,204	(9)	$ 35,844,204		$35,844,204	
	Property taxes	$1,795,039		$ 1,795,039		$1,795,039	
	Other expenses						
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($20,821,865)	(3)				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$1,832,511					
	Income taxes (grossed up)	$2,449,645					
	Federal tax (%)	15.00%					
	Provincial tax (%)	10.19%					
	Income Tax Credits	($627,700)					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(2)		(2)		(2)
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)						
		100.0%					
	Cost of Capital						
	Long-term debt Cost Rate (%)	4.96%					
	Short-term debt Cost Rate (%)	2.08%					
	Common Equity Cost Rate (%)	9.12%					
	Prefered Shares Cost Rate (%)						

Notes:

General Data inputs are required on Sheets 3, 10A and 10B. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) 4.0% unless an Applicant has proposed or been approved for another amount.

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) Gross Fixed assets amount is adjusted by the amounts in PP&E deferral account and GEA capital deferral accounts

(9) Depreciation amount is adjusted by the depreciation of amounts in PP&E deferral and GEA capital deferral accounts

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$802,388,655	$ -	$802,388,655	$ -	$802,388,655
2	Accumulated Depreciation (average)	(3)	($86,568,565)	$ -	($86,568,565)	$ -	($86,568,565)
3	Net Fixed Assets (average)	(3)	$715,820,090	$ -	$715,820,090	$ -	$715,820,090
4	Allowance for Working Capital	(1)	$122,652,505	$ -	$122,652,505	$ -	$122,652,505
5	**Total Rate Base**		$838,472,595	$ -	$838,472,595	$ -	$838,472,595

Allowance for Working Capital - Derivation

(1)

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$85,701,101	$ -	$85,701,101	$ -	$85,701,101
7	Cost of Power		$857,779,706	$ -	$857,779,706	$ -	$857,779,706
8	Working Capital Base		$943,480,807	$ -	$943,480,807	$ -	$943,480,807
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$122,652,505	$ -	$122,652,505	$ -	$122,652,505

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study.

(3) Average of opening and closing balances for the year.

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

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PowerStream Inc.
Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$169,487,804	($169,487,804)	$ -	$ -	$ -
2	Other Revenue	(1)	$9,062,000	($9,062,000)	$ -	$ -	$ -
3	Total Operating Revenues		$178,549,804	($178,549,804)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$83,906,062	$ -	$83,906,062	$ -	$83,906,062
5	Depreciation/Amortization		$35,844,204	$ -	$35,844,204	$ -	$35,844,204
6	Property taxes		$1,795,039	$ -	$1,795,039	$ -	$1,795,039
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$121,545,305	$ -	$121,545,305	$ -	$121,545,305
10	Deemed Interest Expense		$23,967,373	($23,967,373)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$145,512,678	($23,967,373)	$121,545,305	$ -	$121,545,305
12	**Utility income before income taxes**		$33,037,126	($154,582,431)	($121,545,305)	$ -	($121,545,305)
13	Income taxes (grossed-up)		$2,449,645	$ -	$2,449,645	$ -	$2,449,645
14	**Utility net income**		$30,587,481	($154,582,431)	($123,994,950)	$ -	($123,994,950)

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application				Per Board Decision
(1)	Specific Service Charges	$3,385,000		$ -		$ -
	Late Payment Charges	$2,500,000		$ -		$ -
	Other Distribution Revenue	$2,032,000		$ -		$ -
	Other Income and Deductions	$1,145,000		$ -		$ -
	Total Revenue Offsets	$9,062,000	$ -	$ -	$ -	$ -

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$30,587,480	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($20,821,865)	$ -	($20,821,865)
3	Taxable income	$9,765,615	$ -	($20,821,865)
	Calculation of Utility income Taxes			
4	Income taxes	$1,832,511	$1,832,511	$1,832,511
6	Total taxes	$1,832,511	$1,832,511	$1,832,511
7	Gross-up of Income Taxes	$617,134	$617,134	$617,134
8	Grossed-up Income Taxes	$2,449,645	$2,449,645	$2,449,645
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$2,449,645	$2,449,645	$2,449,645
10	Other tax Credits	($627,700)	($627,700)	($627,700)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	10.19%	10.19%	10.19%
13	Total tax rate (%)	25.19%	25.19%	25.19%

Notes

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.
Capitalization/Cost of Capital

Initial Application

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$469,544,653	4.96%	$23,269,764
2	Short-term Debt	4.00%	$33,538,904	2.08%	$697,609
3	**Total Debt**	60.00%	$503,083,557	4.76%	$23,967,373
	Equity				
4	Common Equity	40.00%	$335,389,038	9.12%	$30,587,480
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$335,389,038	9.12%	$30,587,480
7	**Total**	100.00%	$838,472,595	6.51%	$54,554,853

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$838,472,595	0.00%	$ -

Per Board Decision

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
8	Long-term Debt	0.00%	$ -	4.96%	$ -
9	Short-term Debt	0.00%	$ -	2.08%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	9.12%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$838,472,595	0.00%	$ -

Notes

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

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.
Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$7,443,273		($48,350,517)		$121,545,305
2	Distribution Revenue	$162,044,558	$162,044,531	$162,044,558	$217,838,321	$ -	($121,545,305)
3	Other Operating Revenue Offsets - net	$9,062,000	$9,062,000	$ -	$ -	$ -	$ -
4	**Total Revenue**	$171,106,558	$178,549,804	$162,044,558	$169,487,804	$ -	$ -
5	Operating Expenses	$121,545,305	$121,545,305	$121,545,305	$121,545,305	$121,545,305	$121,545,305
6	Deemed Interest Expense	$23,967,373	$23,967,373	$ -	$ -	$ -	$ -
	Total Cost and Expenses	$145,512,678	$145,512,678	$121,545,305	$121,545,305	$121,545,305	$121,545,305
7	**Utility Income Before Income Taxes**	$25,593,880	$33,037,126	$40,499,253	$47,942,499	($121,545,305)	($121,545,305)
8	Tax Adjustments to Accounting Income per 2009 PILs	($20,821,865)	($20,821,865)	($20,821,865)	($20,821,865)	$ -	$ -
9	**Taxable Income**	$4,772,015	$12,215,261	$19,677,388	$27,120,634	($121,545,305)	($121,545,305)
10	Income Tax Rate	25.19%	25.19%	25.19%	25.19%	25.19%	25.19%
11	**Income Tax on Taxable Income**	$1,202,204	$3,077,366	$4,957,285	$6,832,447	($30,620,666)	($30,620,666)
12	**Income Tax Credits**	($627,700)	($627,700)	($627,700)	($627,700)	$ -	$ -
13	**Utility Net Income**	$25,019,376	$30,587,481	$36,169,668	($123,994,950)	($90,924,639)	($123,994,950)
14	**Utility Rate Base**	$838,472,595	$838,472,595	$838,472,595	$838,472,595	$838,472,595	$838,472,595
	Deemed Equity Portion of Rate Base	$335,389,038	$335,389,038	$ -	$ -	$ -	$ -
15	Income/(Equity Portion of Rate Base)	7.46%	9.12%	0.00%	0.00%	0.00%	0.00%
16	Target Return - Equity on Rate Base	9.12%	9.12%	0.00%	0.00%	0.00%	0.00%
17	Deficiency/Sufficiency in Return on Equity	-1.66%	0.00%	0.00%	0.00%	0.00%	0.00%
18	Indicated Rate of Return	5.84%	6.51%	4.31%	0.00%	-10.84%	0.00%
19	Requested Rate of Return on Rate Base	6.51%	6.51%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Rate of Return	-0.66%	0.00%	4.31%	0.00%	-10.84%	0.00%
21	Target Return on Equity	$30,587,480	$30,587,480	$ -	$ -	$ -	$ -
22	Revenue Deficiency/(Sufficiency)	$5,568,104	$1	($36,169,668)	$ -	$90,924,639	$ -
23	**Gross Revenue Deficiency/(Sufficiency)**	$7,443,273 **(1)**		($48,350,517) **(1)**		$121,545,305 **(1)**	

Notes:

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

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$83,906,062		$83,906,062		$83,906,062	
2	Amortization/Depreciation	$35,844,204		$35,844,204		$35,844,204	
3	Property Taxes	$1,795,039		$1,795,039		$1,795,039	
5	Income Taxes (Grossed up)	$2,449,645		$2,449,645		$2,449,645	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$23,967,373		$ -		$ -	
	Return on Deemed Equity	$30,587,480		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$178,549,803		$123,994,950		$123,994,950	
9	Revenue Offsets	$9,062,000		$ -		$ -	
10	**Base Revenue Requirement**	$169,487,803		$123,994,950		$123,994,950	
11	Distribution revenue	$169,487,804		$ -		$ -	
12	Other revenue	$9,062,000		$ -		$ -	
13	**Total revenue**	$178,549,804		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$1	(1)	($123,994,950)	(1)	($123,994,950)	(1)

Notes

(1) Line 11 - Line 8

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Bill Impacts - Residential (1)

○ Application of New Loss Factor to all applicable items ○ Application of new Loss Factor to Delivery Items Only

Consumption 800 kWh

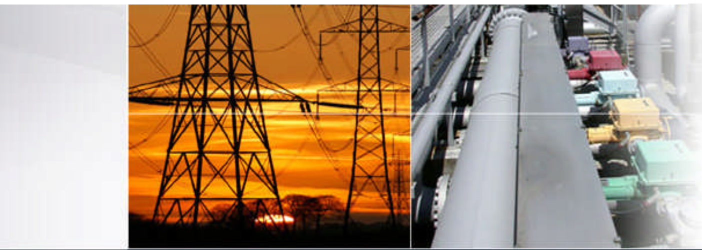
		Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge	monthly	$ 11.9900	1	$ 11.99	$ 13.5700	1	$ 13.57	$ 1.58	13.18%
2	Smart Meter Rate Adder	monthly	$ 1.2800	1	$ 1.28		1	$ -	-$ 1.28	-100.00%
3	Service Charge Rate Adder(s)	monthly		1	$ -	$ 0.2000	1	$ 0.20	$ 0.20	
4	Service Charge Rate Rider(s)	monthly	$ 0.1400	1	$ 0.14		1	$ -	-$ 0.14	-100.00%
5	Distribution Volumetric Rate	per kWh	$ 0.0135	800	$ 10.80	$ 0.0151	800	$ 12.08	$ 1.28	11.85%
6	Low Voltage Rate Adder	per kWh	$ 0.0001	800	$ 0.08	$ 0.0003	800	$ 0.24	$ 0.16	200.00%
7	Volumetric Rate Adder(s)	per kWh	-$ 0.0004	800	-$ 0.32		800	$ -	$ 0.32	-100.00%
8	Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
9	Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider			800	$ -		800	$ -	$ -	
11	Deferral/Variance Account Disposition Rate Rider			800	$ -		800	$ -	$ -	
12					$ -			$ -	$ -	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 23.97**			**$ 26.09**	**$ 2.12**	**8.84%**
17	RTSR - Network	per kWh	$ 0.0073	823.92	$ 6.01	$ 0.0071	827.6	$ 5.88	-$ 0.14	-2.31%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0027	823.92	$ 2.22	$ 0.0032	827.6	$ 2.65	$ 0.42	19.05%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 32.21**			**$ 34.61**	**$ 2.41**	**7.47%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	823.92	$ 4.28	$ 0.0052	827.6	$ 4.30	$ 0.02	0.45%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	823.92	$ 0.91	$ 0.0011	827.6	$ 0.91	$ 0.00	0.45%
22	Special Purpose Charge	per kWh	$ -	823.92	$ -	$ -	827.6	$ -	$ -	
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
25	Energy	per kWh	$ 0.0762	823.92	$ 62.75	$ 0.0762	827.6	$ 63.03	$ 0.28	0.45%
26		per kWh			$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 106.00**			**$ 108.71**	**$ 2.71**	**2.56%**
29	HST		13%		$ 13.78	13%		$ 14.13	$ 0.35	2.56%
30	**Total Bill (including Sub-total B)**				**$ 119.78**			**$ 122.84**	**$ 3.06**	**2.55%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 11.98**	-10%		**-$ 12.28**	**-$ 0.30**	**2.50%**
32	**Total Bill (including OCEB)**				**$ 107.80**			**$ 110.56**	**$ 2.76**	**2.56%**
33	**Loss Factor (%)**	**Note 1**	2.99%			3.45%				

Notes:

(1): Enter existing and proposed total loss factor (Secondary Metered Customer < 5,000 kW) as a percentage.

(2) The weighted average commodity charge is used in this template, so the results will be comparable with the calculation when two tier prices are used.There is a small rounding difference to Appendix 2-V.

(3) These Bill Impacts are for PowerStream South rate zone



Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Bill Impacts - Residential (2)

◯ Application of New Loss Factor to all applicable items ◯ Application of new Loss Factor to Delivery Items Only

Consumption 800 kWh

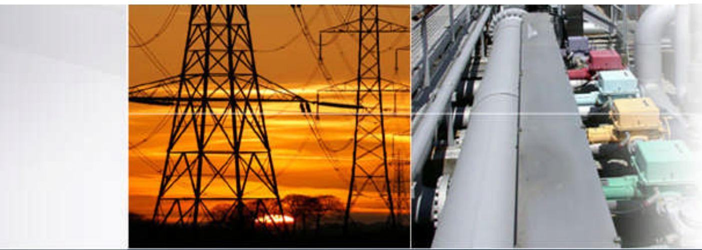
			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
1	Monthly Service Charge	monthly	$ 15.3400	1	$ 15.34	$ 13.5700	1	$ 13.57	-$ 1.77	-11.54%
2	Smart Meter Rate Adder	monthly		1	$ -		1	$ -	$ -	
3	Service Charge Rate Adder(s)	monthly		1	$ -	$ 0.2000	1	$ 0.20	$ 0.20	
4	Service Charge Rate Rider(s)	monthly	$ 1.7800	1	$ 1.78		1	$ -	-$ 1.78	-100.00%
5	Distribution Volumetric Rate	per kWh	$ 0.0137	800	$ 10.96	$ 0.0151	800	$ 12.08	$ 1.12	10.22%
6	Low Voltage Rate Adder	per kWh	$ 0.0008	800	$ 0.64	$ 0.0003	800	$ 0.24	-$ 0.40	-62.50%
7	Volumetric Rate Adder(s)	per kWh		800	$ -		800	$ -	$ -	
8	Volumetric Rate Rider(s)	per kWh	-$ 0.0006	800	-$ 0.48		800	$ -	$ 0.48	-100.00%
9	Smart Meter Disposition Rider	per kWh		800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider	per kWh	$ 0.0004	800	$ 0.32	$ 0.0004	800	$ 0.32	$ -	0.00%
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0006	800	-$ 0.48	-$ 0.0006	800	-$ 0.48	$ -	0.00%
12	Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	$ 0.0008	800	$ 0.64	$ 0.64	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 28.08**			**$ 26.57**	**-$ 1.51**	**-5.38%**
17	RTSR - Network	per kWh	$ 0.0069	845.2	$ 5.83	$ 0.0071	827.6	$ 5.88	$ 0.04	0.76%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0054	845.2	$ 4.56	$ 0.0032	827.6	$ 2.65	-$ 1.92	-41.97%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 38.48**			**$ 35.09**	**-$ 3.38**	**-8.79%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	845.2	$ 4.40	$ 0.0052	827.6	$ 4.30	-$ 0.09	-2.08%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	845.2	$ 0.93	$ 0.0011	827.6	$ 0.91	-$ 0.02	-2.08%
22	Special Purpose Charge	per kWh		845.2	$ -	$ -	827.6	$ -	$ -	
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
25	Energy	per kWh	$ 0.0757	845.2	$ 63.98	$ 0.0757	827.6	$ 62.65	-$ 1.33	-2.08%
26					$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 113.63**			**$ 108.81**	**-$ 4.82**	**-4.25%**
29	HST		13%		$ 14.77	13%		$ 14.14	-$ 0.63	-4.25%
30	**Total Bill (including Sub-total B)**				**$ 128.40**			**$ 122.95**	**-$ 5.45**	**-4.24%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 12.84**	-10%		**-$ 12.30**	**$ 0.54**	**-4.21%**
32	**Total Bill (including OCEB)**				**$ 115.56**			**$ 110.65**	**-$ 4.91**	**-4.25%**
33	**Loss Factor (%)**	**Note 1**	5.65%			3.45%				

Notes:

(1): Enter existing and proposed total loss factor (Secondary Metered Customer < 5,000 kW) as a percentage.

(2) The weighted average commodity charge is used in this template, so the results will be comparable with the calculation when two tier prices are used. There is a small rounding difference to Appendix 2-V.

(3) These Bill Impacts are for PowerStream Barrie rate zone



Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Bill Impacts - General Service < 50 kW (1)

◉ Application of New Loss Factor to all applicable items ○ Application of new Loss Factor to Delivery Items Only

Consumption 2000 kWh

			Current Board-Approved			Proposed			Impact	
		Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
1	Monthly Service Charge	monthly	$ 28.6400	1	$ 28.64	$ 27.9100	1	$ 27.91	-$ 0.73	-2.55%
2	Smart Meter Rate Adder	monthly	$ 1.0100	1	$ 1.01		1	$ -	-$ 1.01	-100.00%
3	Service Charge Rate Adder(s)	monthly		1	$ -	$ 0.2000	1	$ 0.20	$ 0.20	
4	Service Charge Rate Rider(s)	monthly	$ 3.3700	1	$ 3.37		1	$ -	-$ 3.37	-100.00%
5	Distribution Volumetric Rate	per kWh	$ 0.0116	2000	$ 23.20	$ 0.0148	2000	$ 29.60	$ 6.40	27.59%
6	Low Voltage Rate Adder	per kWh	$ 0.0001	2000	$ 0.20	$ 0.0003	2000	$ 0.60	$ 0.40	200.00%
7	Volumetric Rate Adder(s)	per kWh		2000	$ -		2000	$ -	$ -	
8	Volumetric Rate Rider(s)	per kWh	-$ 0.0003	2000	-$ 0.60		2000	$ -	$ 0.60	-100.00%
9	Smart Meter Disposition Rider	per kWh		2000	$ -		2000	$ -	$ -	
10	LRAM & SSM Rider	per kWh		2000	$ -		2000	$ -	$ -	
11	Deferral/Variance Account Disposition Rate Rider	per kWh		2000	$ -	-$ 0.0012	2000	-$ 2.40	-$ 2.40	
12					$ -			$ -	$ -	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 55.82**			**$ 55.91**	**$ 0.09**	**0.16%**
17	RTSR - Network	per kWh	$ 0.0066	2059.8	$ 13.59	$ 0.0065	2069	$ 13.45	-$ 0.15	-1.08%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0024	2059.8	$ 4.94	$ 0.0028	2069	$ 5.79	$ 0.85	17.19%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 74.36**			**$ 75.15**	**$ 0.79**	**1.07%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2059.8	$ 10.71	$ 0.0052	2069	$ 10.76	$ 0.05	0.45%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2059.8	$ 2.27	$ 0.0011	2069	$ 2.28	$ 0.01	0.45%
22	Special Purpose Charge	per kWh		2059.8	$ -		2069	$ -	$ -	
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
25	Energy	per kWh	$ 0.0833	2059.8	$ 171.50	$ 0.0833	2069	$ 172.26	$ 0.77	0.45%
26					$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 273.08**			**$ 274.70**	**$ 1.62**	**0.59%**
29	HST		13%		$ 35.50	13%		$ 35.71	$ 0.21	0.59%
30	**Total Bill (including Sub-total B)**				**$ 308.58**			**$ 310.41**	**$ 1.83**	**0.59%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 30.86**	-10%		**-$ 31.04**	**-$ 0.18**	**0.58%**
32	**Total Bill (including OCEB)**				**$ 277.72**			**$ 279.37**	**$ 1.65**	**0.59%**
33	**Loss Factor**	(1)	2.99%			3.45%				

Notes:

(1): See Note (1) from Sheet 10A. Bill Impacts - Residential

(2) The weighted average commodity charge is used in this template, so the results will be comparable with the calculation when two tier prices are used. There is a rounding difference to Appendix 2-V.

(3) These Bill Impacts are for PowerStream South rate zone

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

PowerStream Inc.

Bill Impacts - General Service < 50 kW (2)

◉ Application of New Loss Factor to all applicable items ○ Application of new Loss Factor to Delivery Items Only

Consumption 2000 kWh

#		Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge	monthly	$ 16.1100	1	$ 16.11	$ 27.9100	1	$ 27.91	$ 11.80	73.25%
2	Smart Meter Rate Adder	monthly		1	$ -		1	$ -	$ -	
3	Service Charge Rate Adder(s)	monthly	$ 4.7300	1	$ 4.73	$ 0.2000	1	$ 0.20	-$ 4.53	-95.77%
4	Service Charge Rate Rider(s)	monthly		1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate	per kWh	$ 0.0164	2000	$ 32.80	$ 0.0148	2000	$ 29.60	-$ 3.20	-9.76%
6	Low Voltage Rate Adder	per kWh	$ 0.0007	2000	$ 1.40	$ 0.0003	2000	$ 0.60	-$ 0.80	-57.14%
7	Volumetric Rate Adder(s)	per kWh		2000	$ -		2000	$ -	$ -	
8	Volumetric Rate Rider(s)	per kWh	-$ 0.0004	2000	-$ 0.80		2000	$ -	$ 0.80	-100.00%
9	Smart Meter Disposition Rider	per kWh		2000	$ -		2000	$ -	$ -	
10	LRAM & SSM Rider	per kWh	$ 0.0007	2000	$ 1.40	$ 0.0007	2000	$ 1.40	$ -	0.00%
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0004	2000	-$ 0.80	-$ 0.0004	2000	-$ 0.80	$ -	0.00%
12	Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0009	2000	-$ 1.80	-$ 1.80	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 54.84**			**$ 57.11**	**$ 2.27**	**4.14%**
17	RTSR - Network	per kWh	$ 0.0063	2113	$ 13.31	$ 0.0065	2069	$ 13.45	$ 0.14	1.03%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0048	2113	$ 10.14	$ 0.0028	2069	$ 5.79	-$ 4.35	-42.88%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 78.29**			**$ 76.35**	**-$ 1.94**	**-2.48%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2113	$ 10.99	$ 0.0052	2069	$ 10.76	-$ 0.23	-2.08%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2113	$ 2.32	$ 0.0011	2069	$ 2.28	-$ 0.05	-2.08%
22	Special Purpose Charge	per kWh		2113	$ -		2069	$ -	$ -	
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
25	Energy	per kWh	$ 0.0834	2113	$ 176.19	$ 0.0834	2069	$ 172.52	-$ 3.67	-2.08%
26					$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 282.05**			**$ 276.16**	**-$ 5.89**	**-2.09%**
29	HST		13%		$ 36.67	13%		$ 35.90	-$ 0.77	-2.09%
30	**Total Bill (including Sub-total B)**				**$ 318.71**			**$ 312.06**	**-$ 6.65**	**-2.09%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 31.87**	-10%		**-$ 31.21**	**$ 0.66**	**-2.07%**
32	**Total Bill (including OCEB)**				**$ 286.84**			**$ 280.85**	**-$ 5.99**	**-2.09%**
33	**Loss Factor**	**(1)**	5.65%			3.45%				

Notes:

(1): See Note (1) from Sheet 10A. Bill Impacts - Residential

(2) The weighted average commodity charge is used in this template, so the results will be comparable with the calculation when two tier prices are used. There is a rounding difference to Appendix 2-V.

(3) These Bill Impacts are for PowerStream Barrie rate zone

BUSINESS PLANNING AND BUDGETING PROCESS

Introduction

PowerStream commences its annual business planning and budgeting process in the first quarter of each year. The outcome of this process is a detailed budget for the two upcoming years (the "Two Year Budget") and a more general plan for the three subsequent years, collectively called "the Five Year Budget Outlook". Upon final approval by the Board of Directors in December, the Five Year Budget Outlook serves as a guideline and a basis for PowerStream's operating and capital activities. More specifically the first year of the Five Year Budget Outlook serves as the reporting budget for the upcoming year. The second year of the budget underpins the "test year" in a cost of service rate application, when one is scheduled. The Five Year Budget Outlook is reviewed and updated each year.

Business Planning Philosophy

PowerStream makes a concerted effort to ensure that a corporate strategy is in place and that activities in the organization are aligned with this strategy. The "balanced scorecard" approach has been adopted for communication of the corporate strategy and for the measurement of results. The "balance" comes from the recognition that although the organization needs to make a financial return, there are other perspectives that are equally as important. For PowerStream, the four perspectives are:

- "Foundation" – people, health and safety, and the proper use of technology;
- "Processes" – process improvement, advocacy and good corporate governance;
- "Customers" – reliable service and excellent customer service; and
- "Financial" – achieve the OEB-allowed rate of return and pursue appropriate growth opportunities.

PowerStream uses a Strategy Map (Figure 1) as a means to communicate corporate strategy using a single page. The Strategy Map is read from bottom to top:

- The company's values underpin the four perspectives noted above;

- A sound Foundation, good Processes and good Customer Service should lead to acceptable Financial Results; and
- The four perspectives, considered as a whole, should enable PowerStream's Mission and Vision to be fulfilled.

Figure 1

PowerStream Strategy Map

STRATEGIC THEME
Deliver Better Results

VISION: We will be a socially responsible company, committed to the environment and sustainable growth, leading the way into the future with boldness, innovation and industry best in class performance.

STRATEGIC THEME
Deliver Profitable Growth

MISSION: To deliver reliable power and related services safely and efficiently to support our customers' quality of life, and to provide value to our shareholders and the communities we serve.

FINANCIAL

F1 - Provide an Optimized Rate of Return - [EMT]

- Deliver the budgeted net income and rate of return

F2 - Develop New Revenue Streams - [BB MB)

- Pursue Business Growth Opportunities
- Implement the Solar PV business plan

CUSTOMERS

C1 - Provide Professional Customer Service - [EMT]

- Improve service levels and customer focus
- Improve reliability

C2 - Foster Conservation and Sustainability - [MB DN]

- Implement and continue to develop the four year CDM plan

PROCESSES

I1 - Optimize Core Business Processes - [DN, EOC]

- Prioritize and execute cross functional process improvements

I2 – Continue Proactive and Positive Advocacy - [BB JG]

- Align advocacy with business strategy and continue advocacy activities

I3 – Practice Good Governance – [BB DN JG]

- Provide governance education & training
- Implement shareholder communication plans

FOUNDATION

E1 - Be a Best-In-Class Employer - [DN MH]

- Improve Employee Satisfaction
- Implement the relevant actions from the Journey to Excellence
- Develop a Skilled and Engaged workforce
- Continue to Develop and implement a Succession Plan
- Develop a Workforce Plan

E2 - Ensure a Safe and Healthy Workplace - [DN MH]

- Improve Health and Safety

E3 - Build Integrated Technology Platforms - [BB DN MH]

- Implement planned IS initiatives
- Implement planned Smart Grid initiatives
- Implement planned CIS initiatives

Values: RESPECT, TEAMWORK, PERFORMANCE, ACCOUNTABILITY, INITIATIVE

Planning Cycle

The annual business planning and budgeting process starts early in the year with the Board of Directors revisiting the corporate strategy (which could lead to changes to the Strategy Map). Operating and capital budgets are then prepared that align with and support the corporate strategy. At the end of the year, the Five Year Budget Outlook is presented to the Board of Directors for approval. The timeline is further outlined in Table 1, below:

Table 1: Annual Business Planning and Budget Process Cycle

Timeline	Activity
February/March	Executive Management Team ("EMT") and Board of Directors hold a Strategic Planning Session and establish and re-affirm or adjust the corporate strategy. There may be some resulting edits to the Strategy Map.
April/May	The corporate strategy is communicated to the organization through the use of the Strategy Map.
June	There is an official "kick-off" of the budget process.
July to September	Detailed budgets for 2012 and 2013 are prepared. Forecasts are prepared for the following three years so that a Five Year Budget Outlook can be drafted.
September	The Audit & Finance Committee and the Board of Directors are updated on the status of budget preparation.
October/November	The EMT reviews and finalizes the Five Year Budget Outlook. Business unit leaders are asked to justify their requests. It is not unusual to have budget cuts to meet the envelope that was previously approved.
December	The Five Year Budget Outlook is presented to the Audit and Finance Committee and then the Board of Directors for approval.

BUDGET PREPARATION

OM&A Budget

The Corporate Finance department coordinates the development of the OM&A budget.

Templates are provided that have the headcount and associated payroll costs "pre-loaded". The approved 2011 staff budget is used as a basis for the determination of staffing requirements for the 2012 and 2013' years, i.e. the assumption is that there will be no increase in headcount. If there are requirements for additional staff, the request must be justified, supported and aligned with the corporate strategy and supporting objectives, including the risks to the organization if the position is not filled.

Payroll costs are adjusted for each of 2012 and 2013 based on the following assumptions:

- A 3% annual increase for both union and non-union staff;
- Progression for qualified staff; and
- Payroll benefits added based on recent trends.

Note that non-payroll costs are assumed to increase by 2% annually in 2012 and in 2013.

The 2012 and 2013 budgets are in Modified International Financial Reporting Standards (“MIFRS”).

The end result of the budget process is a detailed budget for 2012 and for 2013. Following the preparation of this detailed budget, assumptions are used to derive the forecasts for 2014 to 2016 so that the Five Year Budget Outlook can be assembled.

PowerStream’s *Operating and Maintenance* budget is prepared with the following additional considerations:

- Asset Condition Assessment studies, required reliability standards, historical failure rates, environment health and safety regulations, and operating requirements are analysed;
- Programs and plans are designed to meet the cyclic maintenance requirements based on systems operating performance;
- The Operating and Maintenance budget is done at a work order level, allowing better planning, reporting, productivity and performance monitoring;
- 2011 actual work program spending is considered;
- The work programs costs are developed based on unit inputs such as work hours, vehicle hours and materials estimates; and

- Burdens are applied to the work programs to obtain the full cost of the jobs, based on pre-determined set of rates. (See Exhibit A3, Tab 1, Schedule 4 for details on the Burden Process.)

Capital Budget

The capital budget is developed in parallel with the OM&A budget and the process is led by the Engineering Services Department. A five year plan is completed at the beginning of the year. Business units that have major capital requirements assemble five year departmental plans which are later summarized into a Corporate Five Year Plan (Exhibit B2, Tab 2, Schedule 1). The capital budgeting process builds upon the Corporate Five Year Corporate and as with the OM&A budget, a detailed two year budget for 2012 and 2013 is prepared.

PowerStream has a robust capital planning process that utilizes software and a multi-disciplinary review that helps to determine the value and risks associated with a portfolio of projects. Exhibits B1-1-1 through B-1-3 as well as Exhibits B1-2-1 through B1-2-4 describe the capital planning process in detail as well as provide key support documents.

OTHER BUDGET AREAS

A number of other areas have a budget for 2012 and 2013 as well as a forecast for 2014 to 2016 in order to underpin the Five Year Budget Outlook:

Distribution Revenue – The Rates and Regulatory department is responsible for the development of the distribution revenue and cost of power budgets. For the 2012 and 2013 budgets, a forecast of energy sales was developed that used inputs such as expected growth in the economy, anticipated customer growth, weather normalization and Conservation and Demand Management ("CDM") impacts. For the years 2014 to 2016, a high level growth assumption is assumed. The forecast sales by class, combined with rates by class, determine distribution revenue. Complete details are in Exhibit C1, Throughput Revenue.

Other Revenue – The budget for Other Revenue (which mainly includes late payment, other charges and gains or losses loss on disposal of assets) is determined based on past levels and any known future events. Other Revenue is discussed in Exhibit C2.

Depreciation- The Depreciation budget was determined using new, mostly lower depreciation rates. This was a result of updated estimates of useful lives for property, plant and equipment following a study conducted by Kinectrics Inc. Depreciation is addressed in Exhibit D1, Tab 4, Schedule 1.

Interest and Financing Costs – Interest Expense and Financing costs are calculated based on the expected level of debt required to meet the planned capital investment level. Interest income is based on anticipated cash balances. Other aspects include costs related to letters of credit, lines of credit, and interest on regulatory assets and liabilities. Details are in Exhibit E, Tab 1, Schedule 4.

CHANGES IN POLICIES

PowerStream has changed several policies since the last cost of service filing with the Ontario Energy Board (“OEB”) in 2009 (EB-2008-0244). The majority of the significant changes are with respect to policies that have changed as a result of the adoption of International Financial Reporting Standards (“IFRS”).

Major changes to the policies for Burdens and Capitalization are detailed in Exhibit A3, Tab 1, Schedule 3 and Exhibit A3, Tab 1, Schedule 4 respectively.

In 2009, following the merger of Barrie Hydro and PowerStream a significant number of policies, procedures and guidelines were harmonized.

ACCOUNTING ORDERS

PowerStream has no outstanding accounting orders from the OEB.

COMPLIANCE WITH THE UNIFORM SYSTEM OF ACCOUNTS

PowerStream has no known issues with compliance to the OEB Uniform System of Accounts.

BURDEN PROCESS

Definition and Application

Burdens are payroll benefits and overhead costs that are indirectly associated with PowerStream's work activities. The OEB Accounting Practices Handbook ("APH") dated July 2007, Article 340 states that *"The general method of charging indirect costs should be on a fully allocated cost basis"*. Article 340 uses the term "clearing accounts" to address the application of burdens.

PowerStream follows the guidelines that are described in the APH. Burdens are applied to capital, operating and recoverable projects and work activities. The terms burdens, overheads and clearing accounts are used interchangeably.

Burden Allocation Process Highlights

The burden allocation process ensures PowerStream captures indirect costs and properly allocates these costs to Operations, Maintenance and Administration ("OM&A") expenses and capital accounts based on predetermined rates.

There are five types of burdens used to allocate the overhead costs:

- Payroll Burden

Payroll burden costs include benefit costs such as the employer's portion of the Canada Pension Plan, Employment Insurance, OMERS Pension, Employer Health Tax, Workers Safety Insurance Board premiums and dental and medical plans. Payroll burden rates are applied to the direct wages based on employee category.

- Stores Burden

Stores burden recovers the cost of operating the warehouse, such as the salaries of warehouse and purchasing staff assigned to this function. Stores burden is applied to the materials issued from the warehouse or directly shipped to work sites.

- Vehicle Burden

Vehicle burden rates (in dollars per hour of vehicle use) are developed for the purpose of recovering the costs for vehicles, such as amortization, repair, maintenance, fuel, and insurance. Individual rates are developed for major vehicle classifications based on expected utilization.

- Direct Labour Capitalization Burden

Direct Labour Capitalization ("DLC") burden, used to be called "Management Labour Burden", and applies to capital activities. The DLC burden rate is established to allocate a portion of staff compensation (including salary and payroll burden) to capital projects based on the results of a staff survey and interviews. The purpose of the survey and interviews was to determine the amount of the time that staff spent on capital related work, not otherwise directly charged to specific capital work orders.

- Engineering Burden

The engineering burden recovers the management costs and operating costs for the engineering, operations and construction areas. Engineering burden is charged to each work order at a rate of 60% based on the payroll and contract labour costs incurred on the work order. This burden is being eliminated under International Financial Reporting Standards ("IFRS") as outlined below.

Burden Allocation Procedure

Burden rates are used to allocate the indirect costs such as payroll benefits, fleet and stores overhead costs to OM&A expenses and capital spending. Due to the implementation of modified IFRS ("MIFRS"), the burden process has been modified and the rates updated. PowerStream has also reviewed its allocation procedures in order to be compliant with MIFRS. As a result, the burden procedures have been adjusted effective January 1, 2012.

A summary of the major changes to the burden rates is shown below:

- Payroll burden rate for "Outside A" reduced from 80% to 70%
- Payroll burden rate for "Outside B" changed from 40% to 35%

- Store burden rate changed from 15% to 10%
- Vehicle burden rate reduced by about 30%, overall for all vehicles
- Direct labour capitalization rate changed from 6% to 10%
- Engineering burdens are eliminated

For a more detailed discussion of the impact of IFRS on burdens please see Exhibit A3, Schedule 1, Tab 5.

- **Payroll Burden**

Payroll burden rates are applied to the direct wages based on the different characteristics that define various PowerStream work groups.

Outside A: includes union staff from Lines, Inspection & Locates, Metering, Station Maintenance, and Protection & Control areas.

This work group's wages are charged against a work order. The work order may be capital in nature or an operations, maintenance or administrative expense. The 2012 payroll burden rate for this class of employees is 70%. The burden rate is applied to the wages and the resulting dollar amount is charged to the same work order to reflect the full compensation cost.

PowerStream decreased its payroll burden rates from 80% to 70% for 2012 due to the impact of MIFRS. As required under MIFRS, some of the payroll burden costs are not directly attributable to capital activity and therefore these costs must be expensed directly to OM&A.

Outside B: includes union staff in Mechanics, Control Room, and Building Maintenance & Stores. The "Outside A" and "Outside B" categories are used to distinguish between staff directly involved in capital or operations and maintenance activities ("A") , as opposed to those who perform more of a supporting role ("B").

Burden rates for "Outside A" staff are higher than "Outside B" in order to reflect sick time, vacation, training and safety meetings charged to the payroll burden pool and allocated only to "Outside A" employees and for hours spent on capital, operating and maintenance work. The cost of small tools and safety items is also included in this burden pool.

For all other employee categories, the costs related to sick time, vacation, training and safety meetings are charged directly to their specific expense account (e.g. Billing and Collecting) and are not included in the payroll burden pool.

Inside & Management: This group includes union and management staff in administrative areas such as Billing and Collection, Finance, Accounting, Legal, Information Services and Engineering. As an illustration, "Inside" billing staff wages are charged to the Billing and Collecting expense category. A payroll burden rate of 35% is applied to these wages and then charged to the Billing and Collection expense category to reflect the full compensation cost.

The burden rates applied to the wages of PowerStream's different payroll categories are shown in Table 1, below.

Table 1: Payroll Burden Rates

Payroll Categories	**2011 Rates GAAP**	**2012 – 2013 Rates IFRS**
"Outside A"		
Lines, Inspection & Locates, Metering Station Maintenance, Protection & Control	**80%**	**70%**
"Outside B"		
Mechanics, Control Room, Building Maintenance & Stores	**40%**	**35%**
Inside and Management	**40%**	**35%**
Temporary, Student & Board	**10%**	**10%**

- **Stores Burden**

In 2012 PowerStream decreased its stores burden rate due to the impact of MIFRS. The 2012 and 2013 stores burden rate is 10% for materials issued from the warehouse. The stores burden rate on direct shipments is 5% to reflect the lower use of stores and purchasing resources.

Table 3 below shows the Stores Burden Rates.

Table 3: Stores Burden Rates

Stores Burden	**2011 Rates GAAP**	**2012 - 2013 Rates IFRS**
Warehouse Issue	**15%**	**10%**
Direct Shipment	**5%**	**5%**

- **Vehicle Burden**

The vehicle charges are based on vehicle timesheets that are prepared by the “Outside A” employees which identify the vehicle, number of hours, the work order and the capital or O&M cost category to be charged. The vehicle rate is based on the classification of the vehicle being used.

PowerStream decreased its vehicle rates due to the impact of MIFRS. It was determined that some of the cost components cannot be allocated to capital and therefore must be expensed directly to OM&A.

Vehicle Burden Rates are shown in Table 4 below.

Table 4: Vehicle Burden Rates ($ per hour)

Vehicle Classification	2011 Rates GAAP	2012- 2013 Rates IFRS
H01 Car	**13.09**	**12.66**
H02 Trailers	**21.62**	**20.92**
H03 ½ Ton Pick Up	**15.93**	**15.41**
H04 1 Ton Pickup	**18.21**	**17.62**
H05 ½ Ton Van	**15.14**	**14.64**
H06 ¾ Ton Pickup	**15.14**	**14.64**
H07 1 Ton Van	**23.67**	**22.90**
H08 Dump Truck	**44.38**	**42.94**
H09 Fork Truck	**31.86**	**30.83**
H10 1.5 Ton Pick Up	**36.42**	**35.23**
H11 Tension Machine	**30.16**	**29.18**
H12 Single Bucket Truck	**46.94**	**45.41**
H13 Flat Bed Truck	**42.77**	**41.37**
H14 Digger	**61.93**	**59.91**
H15 Double Bucket Truck	**52.76**	**51.04**

- **Engineering Burden**

The Engineering burden pool costs includes the management payroll costs and operating expenses for the engineering, operation and construction areas. A 60% engineering burden rate was applied to work orders in order to recover these costs. However, under MIFRS, these costs are being removed from the Engineering burden pool and allocated to the capital projects through the Direct Labor Capitalization burden where a portion of the management payroll costs are related to capital activity, with the remaining balance are being expensed. As a result, the Engineering Burden has been eliminated.

- **Direct Labour Capitalization Burden**

The DLC pool includes a portion of an employee's salary when it is determined by management that these employees spend a portion of their time on capital projects and a portion of their time on other projects. The portion that is related to capital is removed from OM&A and added to a pool of costs. In order to allocate the pool costs to the capital projects, a burden rate of 10% is applied to the overall capital work order costs. The DLC burden rate was increased from 6% to 10% in 2012 due to the elimination of the Engineering Burden under MIFRS and stated above. This rate is reevaluated annually, and the allocation percentage is updated accordingly.

Over/Under Absorption of Burdens

All payroll benefit and overhead burden rates are applied through PowerStream's JD Edwards accounting system. The rates are applied against the incremental monthly costs such that the applied burdens are charged to the same OM&A or capital cost categories. The same offsetting amount is applied against the burden cost pool.

Any over or under applied balance in the burden pools, after application of the burdens, is allocated monthly to the applicable capital and OM&A accounts on a proportional basis.

The burden results are reviewed and analyzed on a monthly basis. During the annual budget time, burden rates are reviewed and assessed based on the OM&A and capital budget. This is to ensure that the burden rates are appropriate in order to fully allocate the overheads to work activities.

CAPITALIZATION AND DEPRECIATION POLICY

Overview

PowerStream follows capitalization policies and principles that are based on International Financial Reporting Standards (“IFRS”), in particular International Accounting Standard (“IAS”) 16 Property, Plant and Equipment, and guidelines set out by the OEB in the *OEB Board Report on Transition to IFRS*.

PowerStream capitalizes interest on funds for construction using the weighted average interest rate on borrowings outstanding during the period for 2011 and onwards. Previously, the OEB’s prescribed interest rate was used.

Capital assets are depreciated using the straight line method of depreciation. PowerStream has undertaken its own depreciation study with Kinectrics to determine the economic life of assets as required under IFRS. The useful lives determined are in line with the OEB depreciation study. In general the useful lives have been extended as a result of the study.

Please refer to Exhibit A3, Tab 1, Schedule 5 for more details on PowerStream’s transition to IFRS.

CAPITALIZATION POLICY

There are two main types of capital projects: distribution system assets (categorized as sustainment, development and operations) and information system assets.

Distribution System Assets

- **Definition of Cost**

IFRS defines a capital asset as items that:

1. are held for use in production or supply of goods or services, for rental to others, or for administrative purposes; and
2. are expected to be used for more the one period (i.e. life expectancy of 1 year or more).

Under IFRS, in order to qualify for capitalization a minimum purchase value of $1,000 is no longer required. Alternatively, the capital purchase needs to be assessed on whether it relates to a repair or a replacement. A repair relates to maintenance of an item, whereas replacement relates to an entire asset or part being removed and a new asset or part being installed. Further guidance and examples are provided below.

Cost of the item budgeted should include:

- Purchase price (i.e. materials, labour, vehicle, etc)
- Import duties
- Non-refundable purchase taxes after deducting trade discounts and rebates
- Cost of site preparation
- Initial delivery and handling costs
- Installation and assembly costs
- Costs of testing materials to ensure they are working correctly when purchased not when installed (i.e. testing costs that occur after the asset is installed cannot be capitalized)
- Professional fees (i.e. lawyers fees)

The cost of an item shall not include:

- Advertising or promotional costs
- Training costs
- Administrative and other general overhead
- Costs to redeploy or relocate an item (i.e. physically relocate the same item from one location to another location)
- Maintenance costs

Example 1: If there is a budget to construct an asset and the following costs are included on the invoice:

- Materials, labour, vehicle = $100,000
- Training costs = $10,000
- External feasibility study = $5,000
- Ongoing maintenance = $15,000

Total cost of the project = $130,000.

Under IFRS only $100,000 (i.e. materials, labour and vehicle) could be included in the capital budget, the remaining costs would be included in the OM&A budget.

- **Maintenance vs. Replacement**

Under IFRS maintenance costs are required to be expensed, however asset replacement costs are required to be capitalized and included in the capital budget.

Example 2: A crew is dispatched as a result of an emergency call. If they repair the asset then this would be considered as an OM&A cost; if they have to remove the asset and replace it with a new one, then this would be considered as a capital cost.

Example 3: A “betterment” projects which involve testing a pole and then replacing the pole. This project would need to be separated into what relates to maintenance and what relates to replacement. Testing of the pole relates to maintenance and the new pole relates to replacement. The testing would be considered OM&A and the replacement would be considered capital.

Information System Assets

For information system projects which include software, hardware, website development, etc., investments are classified as intangible assets under IFRS and as a result only certain types of costs can be capitalized or included in the capital budget:

Cost	Capitalize under IFRS	Capitalize under CGAAP	Comments for IFRS
Purchase price	Yes	Yes	This can include materials, labour, vehicle, import duties, non-refundable purchase taxes after deducting trade discounts and rebates, cost of site preparation, initial delivery and handling costs, installation and assembly costs, costs of testing materials to ensure they are

Cost	Capitalize under IFRS	Capitalize under CGAAP	Comments for IFRS
			working correctly when purchased not when installed, professional fees (i.e. lawyers fees)).
Capital upgrades	Yes – but please note the exceptions under the comments section.	Yes	Need to prove that capital upgrades are: • Identifiable – expenditure on upgrade activities is capable of being separated in connection with the related software asset. • Non-monetary in substance – upgrade expenditure is not money held, nor an asset to be received in fixed or determinable amounts of money. • Control – such expenditure does not merely maintain existing future economic benefits but rather gives rise to additional future economic benefits through significant increases in functionality which creates operating efficiencies and thus cost savings.
Consultant and professional fees	Yes	Yes	Consultant and professional fees incurred for design, programming and installation of new/upgrade system.
Data costs	Yes	Yes	Need to prove that data costs meet the following criteria: • Identifiable – Expenditure on data costs is capable of being separated in connection with the related software asset.

Cost	**Capitalize under IFRS**	**Capitalize under CGAAP**	**Comments for IFRS**
			• Non-monetary in substance – Data costs are not money held, nor an asset to be received in fixed or determinable amounts of money. • Control – Such expenditure does not merely maintain existing future economic benefits but rather gives rise to additional future economic benefits by providing current information and viewing capability of the service area. This creates operating efficiencies and thus cost savings.
Report writing	No	Yes	Report writing would be required to be budgeted under the OM&A budget. This could include consultant and professional fees incurred for report writing.
Support costs	No	Yes	Support costs from the vendor are not allowed to be capitalized. These costs must be included in the OM&A budget.
Maintenance fees	No	Yes	Maintenance costs would need to be separated out from the vendors invoice and included in the OM&A budget as an expense.
Research costs associated with the capital upgrades	No	Yes	Any research or due diligence performed prior to the upgrade must be included in the OM&A budget and expensed.
Training	No	Yes	Training provided by the vendor must be separated out from the cost of the asset and included in the

Cost	**Capitalize under IFRS**	**Capitalize under CGAAP**	**Comments for IFRS**
			OM&A budget as an expense.

Example 4: An invoice is received from a vendor, and included on that invoice is the following:

- Cost of software - $50,000
- Installation costs - $5,000
- Support costs after implementation - $2,000
- Training of staff on software - $1,000
- Ongoing maintenance - $30,000

Total cost on the invoice is $88,000.

Under IFRS the $55,000 (i.e. cost of software and installation costs) would be in the capital budget as capital costs and $33,000 would be in the OM&A budget to be expensed.

Example 5: The upgrade of JDE software has to be separately identifiable from the original JDE software which is being upgraded as the upgrade would be classified as capital and have a different useful life.

DEPRECIATION POLICY

Capital assets are depreciated using the straight line method of depreciation. PowerStream has undertaken its own depreciation study with Kinectrics to determine the economic life of assets as required by IFRS. The useful lives determined are in line with the OEB depreciation study. In general the useful lives have been extended as a result of the study.

The following are the methods of depreciation and useful lives of PowerStream's assets:

Capital Asset	CGAAP Useful life	IFRS Useful life
Building and Fixtures- TS and MS	50	40
Building Structure	50	40
Transformer Stations	40	40
Power Transformer	40	40
Tap Changer	40	25
Switch Gear and Relays	40	30
Protection and Control System	40	20
230 KV Bus & Equipment Support Steel Structure	40	40
Grounding System	40	40
Distribution Stations	30	30
Power Transformer	30	40
Switch Gear	30	30
Protection and Control System	30	20
Poles, Towers & Fixtures	25	40
Overhead ("O/H") Conductors & Devices	25	40
Underground ("U/G") Conduit	25	40
U/G Conductors & Devices	25	45
O/H Transformers	25	40
U/G Transformers	25	30
O/H Services	25	40
U/G Services	25	25
Meters	25	25
Interval Meters	25	15
Smart Meters	15	15
Street Lighting	25	25

Capital Asset	**CGAAP Useful life**	**IFRS Useful life**
Building & Fixtures	50	50
Cityview- Structural	50	50
Cityview- Other	50	50
Barrie Hydro Building- Structural	50	50
Barrie Hydro Building- Other	50	50
Leasehold Improvements	10	10
Leasehold Improvements- JOC/Cochrane	2	2
Office Furniture & Equipment	10	10
Computer Hardware	5	5
Desktops/Laptops (includes immaterial monitors)	5	4
Servers (including servers and SAN)	5	5
MFP's (including all printers)	5	5
Switches/Routers	5	6
Computer software	3	4
Transportation		
Heavy Vehicles	8	12
Light Vehicles	5	7
Trailers	5	22
Stores Equipment	10	10
Tools, Shop & Garage	10	10
Communication Equipment	10	6
Wireless Communication Devices	3	3
System Supervisory Equipment	15	15
RTU	15	15
Display Wall	15	10
Sentinel Light	25	25

INTERNATIONAL FINANCIAL REPORTING STANDARDS

Introduction

PowerStream has filed this rate application using Modified International Financial Reporting Standards (“MIFRS”) for the years 2011 to 2013. MIFRS is encompassed within PowerStream’s transition to International Financial Reporting Standards (“IFRS”).

In simple terms, MIFRS is a “subset” of IFRS that fulfils the OEB’s rate filing and reporting requirements. The difference between IFRS and MIFRS is that IFRS does not recognize rate regulated accounting (i.e., regulatory assets and liabilities) but MIFRS does. Adopting IFRS was a significant undertaking for PowerStream.

IFRS is the accounting standard that PowerStream was required to adopt based on the ruling of the Accounting Standards Board of Canada (“AcSB”) which in 2008 prescribed that publicly accountable entities are required to transition to IFRS by 2012. As a result, PowerStream initiated a project to adopt IFRS. IFRS, as prescribed by the International Accounting Standards Board (“IASB”) are intended to provide transparency and comparability in a global context. Over one hundred countries worldwide have adopted IFRS or have committed to the conversion to IFRS.

Table 1 below highlights the changes to PowerStream’s balance sheet and income statement that result from MIFRS starting in 2011. These changes are described in more detail in this exhibit.

Table 1: MIFRS – Impacts on Balance Sheet and Income Statement

Area	MIFRS	Jan 1, 2011 Opening Balance Sheet Impact	Dec 31, 2011 Balance Sheet Impact	Dec 31, 2011 Income Statement Impact
Property, Plant and equipment (PP&E)	Useful lives were extended as a result of the depreciation study with Kinectrics. Losses resulting from derecognizing assets no longer in service. Costs that are not directly attributable to the asset are expensed.	None None None	Increase in PP&E by $13.3M Decrease in PP&E by $1.2M Decrease in PP&E by $11.6M	Decrease in Depreciation expense by $13.3M Increase in Depreciation expense by $1.2M Increase in OM&A by $11.6M
Customer Contributions - Damage claims	Amounts received from third parties for damaged assets are recognized into revenue immediately.	None	Decrease in customer contributions (PP&E) by $0.7M	Increase in other revenue by $0.7M
Interest Capitalization	Interest will be capitallized using the weighted average interest rate from borrowings outstanding during the period. Projects that are greater than 4 months will include interest capitalization.	None	Decrease in PP&E by $0.3M	Increase in Interest Expense by $0.3M
Employee Future Benefits	There are adjustments made on the employee future benefit liability resulting from the change in accounting standards.	Increase in employee future benefit liability by $1.6M	Decrease in employee future benefit liability by $0.3M	Decrease in OM&A by $0.3M
Customer Deposits and Subdivision Liabilities	These amounts are required to be reclassified as current liabilities as they are payable upon demand.	Increase in current customer deposits by $12M Increase in current subdivision deposits by $1.2M	None	None

For this filing PowerStream has followed the direction of the Ontario Energy Board ("OEB" or "Board") as outlined in:

- The Report of the Board, *Transition to International Financial Reporting Standards* (*EB-2008-0408)* issued in July 2009*;*
- The letter from the Board on February 24, 2010 clarifying the overhead capitalization policy;
- The OEB Depreciation Study performed by Kinectrics released in July 2010;

- The November 8, 2010 letter from the Board that updated the report for the optional one year delay in the adoption of IFRS from 2011 to 2012 as announced by the AcSB;
- The Addendum to the Report of the Board in June 2011, *Implementing International Reporting Standards in an Incentive Rate Mechanism Environment;* and
- The Accounting Procedures Handbook effective January 1, 2012.

This exhibit discusses the impact of transitioning from Canadian Generally Accepted Accounting Principles ("CGAAP") to MIFRS for OEB reporting for 2011 and 2012.

Although 2012 is the year of transition to IFRS, 2011 must also be restated under IFRS for comparative purposes. Throughout this rate application, 2011 actual financial information is stated in both CGAAP and MIFRS. The reader must therefore use caution when making certain year-over-year comparisons. Table 2 below shows which years are stated in CGAAP and which years are in MIFRS.

Table 2: Accounting Standard Underpinning Each Year in Application

2008 Approved	2008 Actual	2009 Approved	2009 Actual	2010 Actual	2011 Actual	2011 Actual	2012 Budget	2013 Forecast
Historical							***Bridge***	***Test***
Canadian GAAP						*MIFRS*		

In order to implement IFRS effectively and efficiently and to ensure compliance with MIFRS as specified by the OEB, PowerStream created an IFRS project team which included representatives from the following departments:

- Finance;
- Accounting;
- Rates and Regulatory;
- Engineering;

- Information Systems; and
- Internal Audit.

PowerStream also engaged KPMG as its external advisor for the IFRS project to ensure compliance with the applicable IFRS standards issued by the IASB and MIFRS guidance issued by the OEB, as well as any updates to the standards issued.

PowerStream's IFRS project consisted of four phases: initial assessment, detailed assessment, design and implementation. PowerStream completed its initial assessment in 2008 and detailed assessment during the first quarter of 2009, which involved a high level review of the major differences between CGAAP and IFRS. During the detailed assessment, it was determined that the area of accounting differences with the highest potential impact to PowerStream would be the accounting for Property, Plant and Equipment ("PP&E"). PowerStream developed a detailed project plan for the impacted areas to determine the IFRS options, business process changes and system changes.

During 2010 PowerStream completed the design phase of the project. The design phase involved establishing an IFRS project team, which worked with KPMG on writing a number of technical papers for each IFRS topic. Within these papers an analysis was made of the issues, and the team developed recommendations for changes in accounting and business processes. Based on the outcomes of these technical papers, PowerStream determined the projected impacts of adopting IFRS on its financial statements after considering the exemptions available under *First Time Adoption of IFRS* ("IFRS 1"). IFRS 1 is a standard applied by first time IFRS adopters during the preparation of their IFRS financial statements. The objective of this standard is to ensure that an entity's first IFRS financial statements contain high quality information that:

(a) Is transparent for users and comparable over all periods presented;

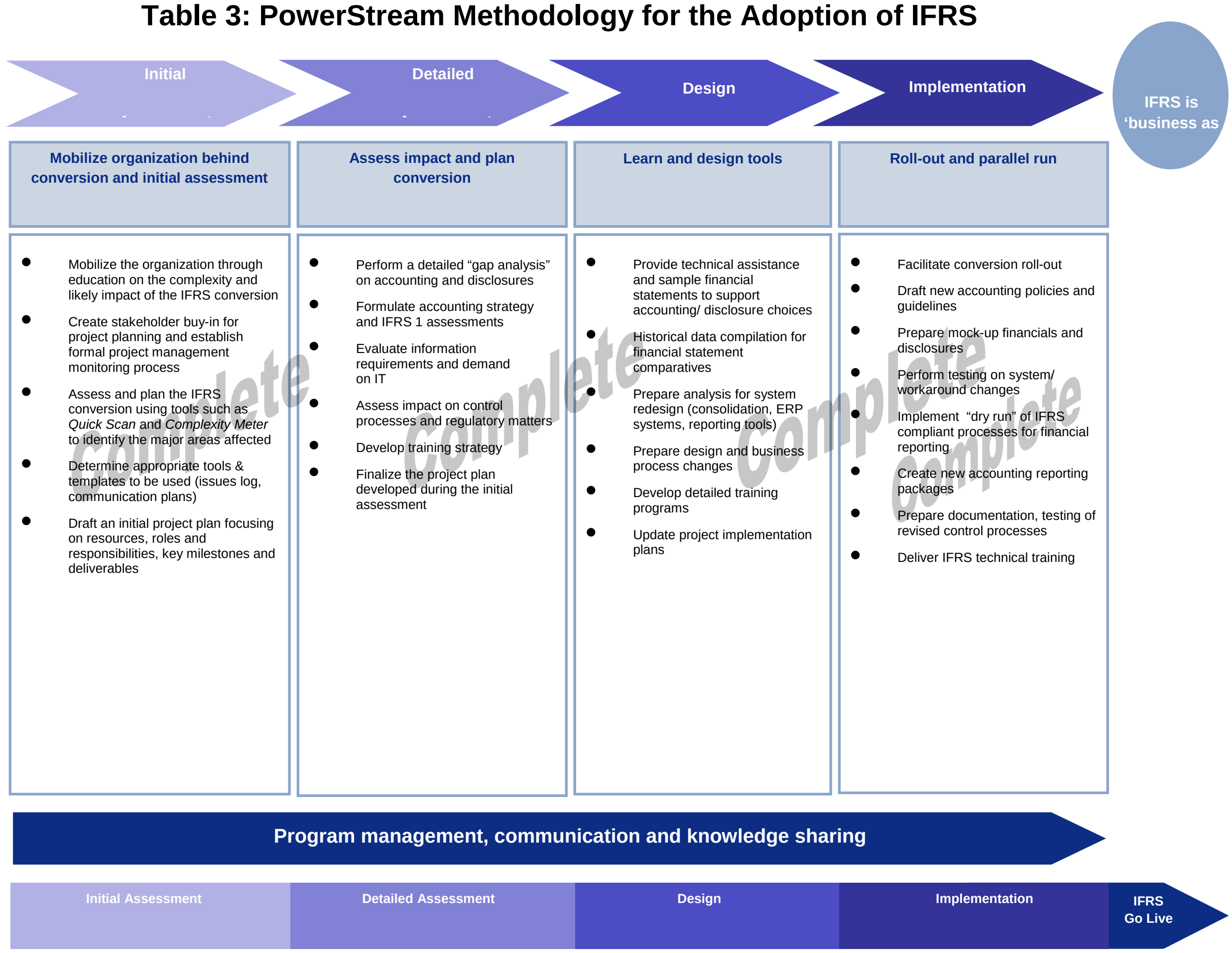
(b) Provides a suitable starting point for accounting in accordance with IFRS; and

(c) Can be generated at a cost that does not exceed the benefits.

In 2011 PowerStream completed the implementation phase. During this phase PowerStream developed new accounting policies, processes and procedures, and it prepared IFRS financial statements. PowerStream also developed revised internal control processes and updated key controls as well as trained staff on the new changes. Further system changes were implemented in order to enable PowerStream to report under IFRS and MIFRS.

Table 3 below summarizes PowerStream's methodology for the adoption of IFRS.

Table 3: PowerStream Methodology for the Adoption of IFRS



International Context

On February 13, 2008, the AcSB confirmed that Canadian publicly accountable enterprises will be required to adopt IFRS for fiscal years commencing on or after January 1, 2011. As well, in October 2009 the Canadian Public Sector Accounting Board ("PSAB") issued an amendment to the scope of the public sector accounting standards that supported government and business enterprises adopting IFRS. As a result of these decisions, PowerStream commenced its IFRS project in May 2008. In September 2010, the AcSB approved an optional one year deferral for qualifying entities with rate regulated activities. PowerStream elected to take the one year deferral; accordingly the adoption of IFRS occurred on January 1, 2012.

On July 23, 2009, the IASB issued an Exposure Draft ("ED") proposing accounting requirements for rate-regulated activities. The ED proposed to allow entities with rate regulated activities to recognize regulatory assets and liabilities. On February 17, 2010, the IASB met to discuss the ED and the comment letters received. The result of this meeting was that the IASB asked their staff to continue to perform further research on the project and to focus on the key issue of whether regulatory assets and regulatory liabilities exist in accordance with the current framework. On September 3, 2010, the IASB staff issued an agenda paper on rate regulated accounting which concluded that regulatory assets and liabilities did not meet the definition of assets and liabilities under the current IFRS framework. On September 16, 2010 the IASB met to discuss the agenda paper on rate regulated accounting. The IASB members were divided on this issue and decided to obtain feedback on what the next steps in this project should be. This was done through public consultation where comments were due by November 2011. As of the date of filing, rate regulated accounting is not allowed under IFRS and this appears unlikely to change.

OEB Guidance on MIFRS

In May 2008, the OEB initiated a consultative process to determine the nature of any changes to regulatory reporting requirements in response to IFRS. The OEB held public meetings and a formal stakeholder conference in May 2009. PowerStream participated at each opportunity offered to assist the OEB. On July 28, 2009, the OEB released a Report from the Board on how regulatory reporting requirements will change in response to IFRS. This report provided specific guidance on how to account for certain transactions. This guidance sometimes differed from what was required by IFRS and as a result the OEB called this guidance Modified IFRS ("MIFRS").

On February 24, 2010 the OEB issued additional guidance on the accounting for overhead costs associated with capital work. In this letter the OEB specifically noted that the Board is requiring full compliance with IFRS requirements on capitalization of overheads which may result in a reduction in capitalized overhead for some electricity distributors that had previously capitalized administration and overhead costs.

On November 8, 2010 the OEB issued an amendment to their July 2009 Board Report on the transition to IFRS. This amendment reflected the change in the transition date to IFRS from January 1, 2011 to January 1, 2012 as approved by the AcSB.

On November 17, 2010, the OEB initiated a working group to develop recommendations on how IFRS should be implemented in an Incentive Rate Mechanism environment. PowerStream was selected to be included in this working group. On June 13, 2011 the OEB issued a Report from the Board entitled *Implementing IFRS in an Incentive Rate Mechanism Environment* which provided further guidance on implementing MIFRS. This report addressed the issuance of additional deferral accounts to track the differences in PP&E as a result of the transition to IFRS.

The key difference between IFRS and MIFRS is that MIFRS allows regulatory accounting to be applied. This includes the recognition of rate regulated assets and liabilities on the balance sheet with minimal impact to the income statement. IFRS does not allow regulatory accounting and thus rate regulated assets and liabilities under IFRS will flow through the income statement as expenses and revenues.

PowerStream IFRS Project Team and Governance Structure

<u>Project Team</u>

PowerStream established a project team to ensure the successful transition from CGAAP to IFRS. This project team was assisted by KPMG and regularly reported to an IFRS Steering Committee, the Audit and Finance Committee and PowerStream's Board of Directors.

The IFRS project team was accountable for leading the business changes. This accountability included:

- identifying major impacts and affected areas;
- identifying major impacts to external stakeholders;

- facilitating engagement and communication to all stakeholders;
- determining timelines and priorities;
- developing implementation plans and resource requirements;
- identifying system, process, policy and procedure changes;
- delivering business requirements to facilitate system changes;
- approving system changes as acceptable to supporting business requirements;
- providing training;
- liaising with the areas which have the highest impact to establish new systems and procedures to handle the new reporting requirements;
- managing the transition from testing phase to formal reporting; and
- conducting a post implementation review.

The project had the following phases:

- Phase 1: Awareness and Initial Assessment; completed in August 2008;
- Phase 2: Detailed Assessment Phase; completed in March 2009;
- Phase 3: Design; completed in March 2010; and
- Phase 4: Implementation; completed in March 2012.

<u>Governance Structure</u>

The IFRS project has a governance structure in place to ensure that the project was completed on budget and on time. The governance structure consists of four groups:

- The project sponsors;
- The Steering Committee;
- Project Manager;
- Core team; and
- External support.

The project sponsors provided the overall vision and leadership for the project. The project sponsors also raised the visibility of the project within the PowerStream organization and were called upon to resolve issues that could not be addressed or resolved by the Steering Committee. The project sponsors presented updates on the IFRS project at the Audit and Finance Committee meetings and the Board of Director meetings, throughout the project.

The Steering Committee provided executive sponsorship and stakeholder buy-in for PowerStream. The committee met on a monthly basis throughout the project.

The Project Manager has the support of the Steering Committee and was responsible for the day-to-day management of the project.

PowerStream also assembled a core team comprised of knowledgeable users in the financial reporting, taxation, budgeting, regulatory, engineering, operations and financial systems areas. These team members were the decision-making drivers pertaining to the business processes.

PowerStream enlisted external resources to provide support in a number of areas of the IFRS project and included the following parties:

- KPMG was used as an external IFRS consultant. They identified the differences between IFRS and CGAAP, and drafted IFRS white papers to support our positions under IFRS on a number of accounting topics.
- Rondinone Management Services was used as the external system consultant. They assisted in the set up of the ledgers in order to track and reconcile CGAAP, IFRS and MIFRS.
- Deloitte is PowerStream’s external auditor. They reviewed and signed off on all position papers and completed the audit of the opening IFRS balances, system work, IFRS policies, procedures and process flows as well as the reconciliations between ledgers.
- Deloitte’s tax experts were also used for tax advisory services. They advised us on the impacts on our taxes as a result of IFRS.
- Kinectrics Inc. prepared the depreciation study that was undertaken to determine the useful lives of our assets and components under IFRS.

- Dion Durrell provided us with a summarized actuarial report to determine the employee future benefit liability under IFRS.

Summary of Differences between CGAAP and MIFRS

In the discussion below, PowerStream has focused on the differences between CGAAP and MIFRS, rather than CGAAP and IFRS. MIFRS is the relevant comparison as it is used for regulatory purposes and rate filings; table 4 below summarizes the differences between CGAAP and MIFRS.

1 **Table 4: Summary of Differences between CGAAP and MIFRS**

Area	CGAAP	MIFRS
PP&E – Useful lives	OEB approved useful lives are used.	PowerStream has undertaken its own depreciation study with Kinectrics to determine the economic life of its assets as required by IFRS. The useful lives determined are in line with the ranges in the OEB depreciation study. In general the useful lives have been extended as a result of the study.
PP&E – Derecognition	The pooled method is used when an asset is removed from service, as a result no gain or loss is recognized upon removal of the asset. The asset remains in the general ledger until the end of its useful life.	Derecognition involves removing the cost and the associated depreciation from the general ledger. If an asset is removed from service earlier than its retirement date then a gain or loss is recognized as depreciation expense and disclosed separately.
Burdens (Directly attributable costs)	Capitalization policy in place which included capitalization of administration and overhead costs.	Costs must be directly attributable to the capital project and cannot include indirect administrative or overhead costs.
Customer Contributions - Classification	Customer contributions are amortized over the useful life of the asset (i.e. using OEB useful lives) and classified as a contra asset on the balance sheet and amortized to depreciation expense.	Customer contributions are amortized over the new MIFRS useful lives and classified as deferred income on the balance sheet, treated as an offset to rate base and amortized to depreciation expense over the life of the asset to which it relates.
Customer Contributions – Damage claims	When a pole or other item of PP&E is damaged by a 3rd party the recoverable work performed is included in customer contributions.	If a pole or other item of PP&E is damaged by a 3rd party the asset would need to be derecognized with a gain or loss on disposal being recognized and the recoverable amount would be recognized as other revenue immediately.
Intangible Assets	Intangible assets are classified separately from PP&E.	Intangible assets are added to PP&E and included in rate base under MIFRS.
Interest Capitalization	Interest is capitalized using the AFUDC	Interest will be capitalized using

Area	CGAAP	MIFRS
	rate provided by the OEB when projects are greater than one month in duration.	the weighted average interest rate from borrowings outstanding during the period. For debt incurred at non-arm's length PowerStream compared the deemed interest rate that is published as part of the cost of capital parameters updates to the actual interest rate and concluded that there were no differences. Projects that are greater than four months will include interest capitalization.
Employee Future Benefits	Employee future benefit liability is calculated by the actuary.	Employee future benefit liability is calculated by the actuary, however there are one time IFRS adjustments that were made and have flown through Retained Earnings, these included a change in attribution period, write off of the transitional obligation, recognition of all unamortized actuary gains and losses, and recognition of all unamortized past service costs.
Customer Deposits and Subdivision Liabilities	Classified as current and long term based on historic trends.	These amounts are required to be classified as current as they are payable upon demand.
Income Taxes	Taxes are prepared under CGAAP which is the same as OEB for 2011	Taxes are prepared based on the external IFRS financial statements, which includes the above changes in determination of taxable income.

The changes on the conversion from CGAAP to MIFRS are discussed in more detail below.

Property, Plant and Equipment ("PP&E")

- PowerStream undertook a depreciation study with Kinectrics which provided a range of useful lives. PowerStream's engineers used their knowledge of PowerStream's assets and maintenance program then concluded on the appropriate useful life for PowerStream. The results are consistent with the ranges in the Board's useful life study.

- Gains or losses on retirement (“derecognition”) are recognized in other income in IFRS and as depreciation expense under MIFRS. PowerStream implemented a process to track assets that have been removed from the field in order to determine the gain or loss to be recognized.
- The IFRS 1 deemed cost exemption for entities with operations subject to rate regulation was taken which allowed PowerStream to not have to restate PP&E balances from periods prior to the transition to IFRS (i.e. January 1, 2011). PP&E cost was deemed to be opening net book value.

Burdens (Directly attributable costs)

- Costs that were capitalized under CGAAP were analyzed to determine if they met the IFRS criteria of directly attributable to the asset. Any costs that were not directly attributable were expensed in both IFRS and MIFRS.
- Costs no longer capitalized include training costs, building costs, engineering and administrative costs that can not be directly attributed to the asset.

Customer Contributions

- Customer contributions will be treated as deferred revenue rather than as an offset to PP&E.
- Deferred revenue is the appropriate classification as the revenue received for supplying the customer with an ongoing access to the supply of goods occurs over the life of the asset.
- Deferred revenue is amortized into the other revenue over the life of the asset.
- Money received from third parties that relate to assets that are damaged due to accidents is recognized directly into revenue when invoiced. Previously this would have been recognized as customer contributions.
- The IFRS 1 election on customer contributions was taken which allowed PowerStream to recognize customer contributions from January 1, 2011 onwards as deferred revenue, contributions up to December 31, 2010 will remain as an offset to PP&E.

Intangible Assets

- Land rights and computer software were reclassified from PP&E to intangible assets as they are classified as intangible assets under IFRS and in recent changes to CGAAP. For MIFRS these have been included in the PP&E amounts used to calculate rate base.

Interest Capitalization

- Interest will now be capitalized on capital projects using the weighted average of the actual interest rates incurred rather then the rates prescribed by the Board.
- For non-arm's length debt the Board noted that the interest rate can be no greater then the Board's published rates, otherwise an entity should use the Board's published rates in the weighted average interest rate calculation. PowerStream has determined that the rate on PowerStream's promissory notes were below the Board's published long term debt rate when issued, thus these notes will be included in the weighted average interest calculation at the actual rate.
- Capital projects that are four months or greater will include interest, otherwise they will not. Previously PowerStream capitalized interest after one month under CGAAP.
- The IFRS 1 deemed cost election for rate regulated entities noted above was also applied to interest capitalization. The election allowed interest capitalization to not be restated upon adoption of IFRS.

Employee Future Benefits

- PowerStream had a number of one-time adjustments on transition to IFRS that affected the employee future benefit liability, these adjustments flowed through retained earnings as they related to prior periods and included the following:
    - Write off of transitional obligation that is not allowed under IFRS;
    - Write off of unamortized past service costs;
    - Write off of unamortized actuary gains and losses that PowerStream elected to do under IFRS; and

  - o A one time adjustment for the change in attribution period.

Customer deposits and subdivision liabilities

- Customer deposits and subdivision liabilities are currently classified between current and long term based on historic trends. IFRS requires that they only be classified as current as these amounts are payable upon demand.

Income taxes

- For MIFRS purposes, PowerStream will be using the IFRS external financial statements as the starting point to calculate the PILs payable. The tax impacts under MIFRS are summarized below:
  - Current tax liability will be lower under MIFRS as compared to CGAAP due expensing non-directly attributable costs formerly capitalized.
  - A lower amount will be added back for depreciation expense due to extension of the useful lives of assets under MIFRS and the recognition of losses due to derecognition. This will cause temporary "timing" differences between the net book value of PP&E and the corresponding Undepreciated Capital Cost (UCC) balance to increase. Under IFRS the future tax impact of the differences are recognized in current income tax expense.
  - Under MIFRS, the future tax impact is not recognized in the current tax expense. Instead it is set up as a regulatory asset or liability to reflect that the future tax impact will be taken into account in the setting of future rates.

Summary of the Impacts of MIFRS

Table 5 below summarizes the financial impacts on the balance sheet as a result of implementing MIFRS. These amounts are as at December 31, 2011 and only include accounts that will change as a result of MIFRS, all other normal business changes between CGAAP and MIFRS are not discussed here.

Table 5: MIFRS Impacts on Balance Sheet at End of 2011 ($000)

Description	CGAAP	MIFRS	Increase/ (decrease)
PP&E (including intangibles)	$ 688,638	$ 689,577	$ 939
Future Income tax assets	$ 49,533	$ 52,027	$ 2,494
Current Customer deposits	$ 1,005	$ 13,035	$ 12,030
Current Subdivision deposits	$ 2,984	$ 3,185	$ 201
Long term Customer deposits	$ 12,030	$ -	$ (12,030)
Long term Subdivision deposits	$ 201	$ -	$ (201)
Net Regulatory Liabilities	$ 44,655	$ 47,510	$ 2,855
Employee Future Benefit liability	$ 15,265	$ 16,811	$ 1,546
Retained Earnings	$ 56,563	$ 55,220	$ (1,343)

The analysis of the balance sheet changes are discussed below by balance sheet account line item.

Property, plant and equipment including intangibles:

The increase in the property, plant and equipment account from CGAAP to MIFRS is the result of the following:

- Derecognizing the assets that are no longer in service (decrease of $1.2M);
- Lower interest capitalization (decrease of $0.2M);
- Revenue collected from damage claims (increase of $0.7M); and
- Costs that are no longer allowed to be capitalized are not included in PP&E as they are not directly attributable (decrease of $11.6M); this is offset by the lower depreciation expense as a result of extending the useful lives of our assets (increase of $13.3M).

Future income taxes and regulatory liabilities:

Future income tax assets have changed as a result of the decrease in the PP&E balance and the increase in the employee future benefit liability balance.

The regulatory liability account for future income taxes offsets the future income tax asset account, in respect of distribution related timing differences, and as such the future tax impact is not reflected in income tax expense under MIFRS. The future tax impacts will be recognized when they arise consistent with how income tax expense is incorporated into distribution rates, on a taxes payable basis.

Current and long term customer deposits and current and long term subdivision liabilities:

Long term customer deposits and subdivision liabilities have been reclassified to a current liability. The reason for this reclassification is that these deposits are payable on demand and thus cannot be classified as long term under MIFRS.

Employee future benefits:

The employee future benefit liability account has increased as compared to CGAAP as a result of the following:

- Changes that occurred as a result of the transition to MIFRS (i.e. unamortized actuarial gain and loss write off, write off of transitional obligation, write off of unamortized past service costs and change in the attribution period) caused an increase of approximately $1.6M.

Retained earnings decreased under MIFRS for the following reasons:

- Employee future benefit liability changes as discussed above which decreased retained earnings by $1.6M.
- The offset of the above change is an increase in net income under MIFRS in 2011.

Table 6 below summarizes the financial impacts on the 2011 income statement as a result of implementing MIFRS.

Table 6: MIFRS Impacts on the 2011 Income Statement ($000)

Description	CGAAP	MIFRS	Increase/ (decrease)
Other Revenue	$ 9,901	$ 15,073	$ 5,172
Operating expense	$ 62,904	$ 78,303	$ 15,399
Depreciation expense	$ 46,045	$ 35,250	$ (10,795)
Interest expense	$ 23,743	$ 23,976	$ 234
Income taxes	$ 5,948	$ 5,948	$ -
Net Income	$ 32,175	$ 32,509	$ 335

The analysis of the income statement changes are discussed below by income statement account line item.

Other revenue:

Other revenue has increased mainly for the following reasons:

- When a pole is damaged by an individual, PowerStream invoices the individual's insurance company to cover the cost of replacing the pole. The amount invoiced was previously included in capital contributions but under MIFRS it is included in other revenue as soon as it is invoiced (increase of $0.7M).
- Joint Service Revenue has been reclassified from Operating Expenses to Other Revenue under MIFRS (increase of $3.9M). Under CGAAP, the revenues were netted against the expenses in the Operating Expenses portion of the income statement.

Operating Expenses:

- Operating expenses have increased as a result of costs that are now being expensed which were previously capitalized as they are not directly attributable to the asset being installed (increase of $11.6M).
- The reclassification of Joint Service Revenue noted above has also resulted in an increase in operating expense of $3.9M under MIFRS.

Depreciation expense:

Depreciation expense has decreased under MIFRS as a result of extending the useful lives of our assets from the previous OEB prescribed useful life to the useful life that was determined in the Kinetrics study (decrease of $13.3M offset by a $1.3M decrease in depreciation on vehicles, stores and tools reclassified to the burden pool). This was offset by an increase in depreciation expense as a result of the losses from derecognizing assets that are no longer in service (increase by $1.2M).

Interest expense:

Interest expense increased under MIFRS as a result of less interest being capitalized to projects (increase of $0.2M).

Income taxes:

There is no change in income tax expense as the 2011 income taxes were filed based on the 2011 CGAAP financial statements.

The changes in depreciation expense under MIFRS have no effect on taxable income and taxes payable as depreciation expense is added back and replaced with capital cost allowance (“CCA”) in arriving at taxable income. For 2012 onwards, the burden amounts expensed under IFRS and MIFRS that were capitalized under CGAAP will reduce both financial statement and taxable income under MIFRS. This will be offset partially by the lower capital additions to the capital cost pool resulting in lower capital cost allowance. The net impact is lower taxable income and taxes payable under MIFRS.

Impact on External Financial Statements

For external reporting purposes, financial statements will be presented under IFRS. As noted previously, the key difference between IFRS and MIFRS is that IFRS does not recognize rate regulated accounting (i.e. does not permit the recognition of regulatory assets and liabilities on the balance sheet, instead these will flow through the income statement).

IFRS Deferral Accounts

The OEB has approved two variance and deferral accounts related to IFRS for use by all electricity distributors:

- Account 1508 Other Regulatory Assets, IFRS Transition Costs
- Account 1575 IFRS-CGAAP Transitional PP&E Amounts

In *Addendum to Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment (EB-2008-0408),* ("Addendum") *the* Board recognizes that there are a number of additional deferral accounts that may be needed depending on the circumstances of each distributor.

In addition to the above OEB approved variance and deferral accounts, PowerStream requests the following additional variance and deferral accounts:

- a variance account to track the difference between the estimated PP&E derecognition expense included in the approved 2013 rates and the actual costs in each year until the next setting of cost of service rates; and
- a deferral account for the changes in the post retirement employee benefits liability and costs under MIFRS compared to CGAAP up to this cost of service rebasing; and
- A variance account for changes in the post retirement employee benefits expense included in the approved 2013 rates and the actual costs in each year until the next setting of cost of service rates.

Each of these accounts is discussed below under their respective headings.

Account 1508 Other Regulatory Assets, IFRS Transition Costs:

As noted in the OEB Board Report on the transition to IFRS, when a utility incurs incremental costs related to the transition to IFRS during a period for which rates have already been set and for which the Board did not consider such costs, the utility may record in a Board approved deferral account such incremental costs for consideration by the Board at the next cost of service proceeding.

In the OEB Accounting Procedures Handbook Frequently Asked Questions dated October 2009, further guidance was provided. This distinguished between the case where the utility did not have any amount in rates related to IFRS transition and the case where the most recent cost of service rates did include an amount related to IFRS transition costs in its administrative costs.

The former Barrie Hydro did not include any amounts related to IFRS in its 2008 Cost of Service rate filing. PowerStream did include an amount of $745,000 in its OM&A in its 2009 Cost of Service rate filing. This was based on estimated incremental one-time non-capital IFRS transition costs of $2,980,000 divided by four years representing the test year (2009) and three years on Incentive Regulation Mechanism (2010 to 2012).

PowerStream has captured the costs related to incremental IFRS transition costs and the IFRS revenue in rates in account 1508 Sub-account IFRS Transition Costs Variance.

PowerStream's actual IFRS transition costs to December 31, 2011 and projected total costs to December 31, 2012 are shown in Table 7 along with the amounts collected from customers in rates.

Table 7: Actual and Forecasted IFRS Transition Costs, Accrued Interest and Amounts Collected in Rates

	Actual to Dec. 31, 2011	**Forecast to Dec. 31, 2012**
Costs	$ 1,917,398	$ 2,511,745
Interest	$ 7,218	$ 6,640
Collected in Rates	$ (1,986,660)	$ (2,731,660)
Net balance	**$ (62,044)**	**$ (213,275)**

The majority of the projected incremental IFRS transition costs of $2.5 million relate to third party consultants that were used to help implement IFRS as noted below. The main categories of costs are as follows:

- KPMG consulting costs - KPMG was used as IFRS consultant for the implementation of the IFRS project. They identified the differences between CGAAP and IFRS and documented our positions in twenty-two white papers which were used to substantiate our conclusions to our auditors as well as identify the steps to implement each position. These costs would not have been incurred if PowerStream had not been required to transition to IFRS.
- Rondinone Management consulting costs - Rondinone Management Services were used as Information System consultants. They helped set up the ledgers in the financial system in order to track and reconcile CGAAP, IFRS and MIFRS. These costs would not have been incurred if we had not been required to transition to IFRS.
- Deloitte external audit costs - As part of the IFRS financial statements we are required to disclose balances at January 1, 2011, December 31, 2011 and December 31, 2012 on our December 31, 2012 financial statements. To enable the auditors to audit the December 31, 2012 financial statements they are required to audit our opening balances at January 1, 2011 and comparative information on December 31, 2011. The anticipated December 31, 2012 audit fee will not be included in the deferral account as this is not incremental to the transition to IFRS, however the opening balance audit and December 31, 2011 comparative audit are costs that are incremental to PowerStream's annual financial statement audit and are a specific requirement for the transition to IFRS.

The remaining costs included in this account relate to other external resources that were used to assist in preparing the documentation of our new policies, procedures and process flows as a result of implementing IFRS. There were also costs included in this account for additional labour costs of contract staff to work on the IFRS project and training. These costs would not have been incurred if we had not been required to transition to IFRS.

The account has been credited on a monthly basis to reflect the annual amount of $745,000 ($62,083 per month) in rates for IFRS transition. As of December 31, 2011, PowerStream has collected 32 months, from May 1, 2009 to December 31, 2011 for a total $1,986,660. By December 31, 2012, PowerStream will have collected 44 months of revenue with this included in rates for a total of $2,731,660.

Interest (carrying charges) has been calculated monthly based on the opening principal balance in this sub-account at the OEB prescribed interest rates, on a simple interest basis. As of December 31, 2011, accrued interest was a debit balance of $7,218. Accrued carrying charges are forecast to be $6,640 at December 31, 2012. The debit balance for carrying charges reflects the fact that the principal balance was in a debit balance for much of the period.

Table 8 provides a summary of the above types of costs making up the costs recorded to December 31, 2011 and the projected total cost to the end of 2012.

Table 8: Summary of Non-Capital IFRS Transition Costs

	Actual to Dec. 31, 2011	**Forecast to Dec. 31, 2012**
IFRS consultant	$ 1,319,300	$ 1,444,300
IT consultant	$ 255,510	$ 424,175
Auditors	$ 197,606	$ 460,106
Staffing, training & other	$ 144,982	$ 183,164
Total	$ 1,917,398	$ 2,511,745

The proposed disposition of the projected over collection is discussed in Exhibit I, Deferral and Variance Accounts.

Account 1575 IFRS-CGAAP Transitional PP&E Amounts:

On page 11 of the Addendum to the Report of the Board, the Board approved a generic Property, Plant and Equipment ("PP&E") deferral account: *"to capture PP&E differences arising only as a result of accounting policy changes caused by the transition from CGAAP to MIFRS. It is for use by utilities to record PP&E differences arising during the period since their last rebasing under CGAAP up to their first rebasing under IFRS, including utilities using IRM rate-setting methodology."*

Due to the deadlines for submission of cost of service rate applications, the Board realized that it would be necessary to forecast the PP&E amounts for the bridge year. The Board addressed this on page 13 to 14 of the Addendum: "*Clearing an account on the basis of* *forecast numbers is a departure from the Board's standard practice. The Board recognized that this is a unique account, which is "cleared" through an adjustment to rate base, which itself includes components that are forecast for the bridge and test years, for example capital additions and working capital allowance. The Board believes that in general, the account should be cleared at the first rebasing under MIFRS, while recognizing that some portion of the amount for which clearance is sought is based on a forecast."*

PowerStream is applying for cost of service ("COS") rates effective January 1, 2013 on the basis of MIFRS. PowerStream has adopted IFRS as of January 1, 2012, and as required, has restated 2011 under IFRS for purposes of accounting and financial reporting under IFRS.

PowerStream has tracked and recorded the actual PP&E differences arising on the restatement of 2011 under IFRS in account 1575 as directed in the Accounting Procedures Handbook. For purposes of the 2013 COS filing, PowerStream has forecast the PP&E differences for 2012.

The PP&E differences between are summarized in Table 9 below.

Table 9: PP&E Differences between CGAAP and MIFRS ($000)

Net book value of PP&E	**MIFRS**	**CGAAP**	**Difference**
December 31, 2011 Actual	$ 687,999	$ 687,079	$ 920
Change in 2012			$ 1,655
December 31, 2012 Forecasted	$ 719,053	$ 716,478	$ 2,575

The sources of these differences are summarized in Table 10 below.

Table 10: Summary of PP&E Differences ($000)

Summary of Differences	MIFRS	CGAAP	Difference
2011 Actual			
Derecognition	$ (1,198)	$ -	$ (1,198)
Depreciation	$ (35,720)	$ (48,971)	$ 13,251
Burdens capitalized	$ 18,089	$ 29,717	$ (11,628)
Damage Claims (contributed capital)	$ -	$ (728)	$ 728
Interest Capitalized	$ 303	$ 536	$ (233)
Subtotal			**$ 920**
2012 Forecasted			
Derecognition	$ (1,400)	$ -	$ (1,400)
Depreciation	$ (32,158)	$ (46,963)	$ 14,805
Burdens capitalized	$ 18,000	$ 30,200	$ (12,200)
Damage Claims (contributed capital)	$ -	$ (700)	$ 700
Interest Capitalized	$ 300	$ 550	$ (250)
Subtotal			**$ 1,655**
Total			**$ 2,575**

The total PP&E difference at December 31, 2012 between CGAAP and MIFRS of $2,575,586 has been deducted from rate base before the calculation of the deemed interest and allowed return on equity components of revenue requirement.

PowerStream proposes to amortize this difference over 4 years resulting in a reduction of $643,896 to depreciation expense.

The proposed revenue requirement requested in this Application reflects both of the above adjustments.

Derecognition Expense Variance Account:

PowerStream has only one year of history regarding derecognition of PP&E, namely 2011 where this was tracked under IFRS and MIFRS. Under CGAAP, there was no derecognition of pooled assets and as such no record of this information.

PP&E derecognition arises mainly from storm and accident damage requiring assets to be retired prematurely. Storm damage can vary greatly from year to year.

In 2011, under MIFRS PowerStream had a loss of $1.2 million on derecognition of PP&E. The 2011 year was considered to be below average in the frequency and intensity of storms and as a result storm damages were lower than a more typical year.

For 2012, PowerStream forecasts a loss of $1.4 million from PP&E derecognition. For 2013 PowerStream has included $1.4 million for PP&E derecognition as an adjustment to depreciation expense under MIFRS.

PowerStream have not tracked this expense in the past so it has very little data on which to base an estimate. The nature of this expense is such that it may vary greatly from one year to the next. Given the magnitude of the 2011 amount, such variations could be significant. For these reasons, PowerStream requests a variance account to track the difference between actual PP&E derecognition costs and the amount that is approved in setting the 2013 rates, until its next rebasing.

Post Retirement Employee Benefit ("PREB") Expense Deferral Account:

Under IFRS, the PREB liability was increased by $1.7 million with a corresponding charge against retained earnings. This was the result of recognizing "Unrecognized Losses", "Unrecognized Past Service Cost" and "Unrecognized Transitional Obligation" amounts.

Under CGAAP, these amounts were being amortized over the remaining average service life of the employees, with a portion of these being recognized each year as part of the employee benefits expense. This expense would have formed part of the revenue requirement and be recovered in future rates.

This variance between what is in rates and the expense recognized under IFRS/MIFRS is material and should be tracked in a manner similar to the PP&E Transitional Amounts account.

IFRS has resulted in a sudden one-time recognition of these costs as at January 1, 2011. As a result of this change, PREB employee benefits expense under IFRS/MIFRS is lower in 2011 by approximately $130,000 than it would have been under CGAAP.

This expense will be lower in 2012 and in 2013 by a similar amount as a result of this change. The amount budgeted for 2013 and included in the Application is lower as a result.

PowerStream proposes that the following amounts shown in Table 11 be recorded in this deferral account.

Table 11: IFRS – CGAAP PREB Differences for Recovery

	CGAAP	MIFRS	Difference
Write-off accrued costs not booked	$ -	$ 1,678	$ 1,678
2011 Reduction in PREB expense	$ -	$ (130)	$ (130)
2012 Reduction in PREB expense	$ -	$ (130)	$ (130)
Total	**$ -**	**$ 1,418**	**$ 1,418**

PowerStream proposes that these differences be recovered over a 4 year period by increasing the OM&A in the 2013 revenue requirement by $354,500.

Post Retirement Employee Benefit (“PREB”) Expense Variance Account:

Changes in actuarial valuations of the PREB liability under CGAAP are amortized over a long period of time resulting in relatively small impacts and a more predictable annual expense. Under IFRS, changes in actuarial valuation are recognized much more quickly, often fully in the year, and can have a significant impact on the annual expense. As a result the annual expense can be much more volatile under IFRS.

The nature of this expense is such that it may vary greatly from one year to the next. Due to this volatility, PowerStream requests a variance account to track the difference between actual PREB expense and the amount that is approved in setting the 2013 rates, until its next rebasing.

PROCESS IMPROVEMENT INITIATIVES

Since 2004, as a result of merger and acquisition activities and the subsequent integration of various distributors, PowerStream has learned to recognize and value the importance of improving business processes.

Bringing distributors together effectively in order to gain efficiencies requires the review and harmonization of many processes, such as budgeting, financial reporting, billing, control room operations and work practices in the field. PowerStream has adopted the process improvement as a way to improve customer service, power system reliability and ensure the overall effectiveness of the business. This approach allows PowerStream to meet new requirements and demands while minimizing the need for additional resources.

PowerStream has three major process improvement initiatives underway:

- PowerStream's "Journey to Excellence";
- Project Management Office; and
- Internal Audit and Enterprise Risk Management

Journey to Excellence

PowerStream has adopted the Excellence Canada (formerly National Quality Institute) Progressive Excellence Program ("PEP") – a principle-driven, criteria based implementation program for organizational excellence, that focuses on quality and a healthy workplace. PowerStream has branded its journey through the PEP program and achievement of organizational excellence as the "Journey to Excellence ."

The PEP framework has been adopted by many leading companies and has four progressively higher levels of achievement: *Foundation*, *Transformation*, *Role Model* and *World Class*. PowerStream's progress will be assessed by experts from Excellence Canada in formal audits. PowerStream must show sustained improvements in organizational performance in the areas of:

- Leadership
- Planning and Programs

- Client Focus
- People Management
- Process Management
- Supplier/Partner Focus

PowerStream achieved the first level, *Foundation*, at the end of 2010. This level required demonstration that there was broad support of the vision, mission, values and quality and wellness policies in all areas. PowerStream was required to show that well-being and quality were ingrained in decision making and that there was a commitment to environmental excellence. In order to prepare for the Excellence Canada assessment, PowerStream needed to ensure there were written policies and procedures for key areas of the business.

It is planned to reach level two, *Transformation*, by the end of 2012. At this level, PowerStream must demonstrate the application of our methods for reaching our goals established in Level 1. This includes identifying customer needs, building an approach to quality assurance, introduction of measures for customer and employee satisfaction, establishing environmental sustainability measures, and establishing indicators to review progress. A significant focus on process improvement will be an important part of achieving Level 2 status. The *Transformation* level requires that PowerStream demonstrate that staff at all levels of the organization understand and have their work aligned with the corporate vision, mission and strategic goals.

PowerStream plans to continue this Journey to Excellence and reach level three, Role Model, by the end of 2015.

Project Management Office

The primary objectives of the Project Management Office (“PMO”) at PowerStream are:

- review process improvement initiatives and ensure that they are aligned with and support the corporate strategy;
- prioritize initiatives based on the value to PowerStream;
- assess initiatives in consideration of conflicting demand for resources;

- implement consistent Project Management processes, tools and templates; and
- apply Project Management best practices.

Table 1 below, shows the major initiatives underway at PowerStream with PMO oversight.

Table 1: PowerStream – Major Initiatives With PMO Oversight

JD Edwards Disaster Recovery Solution
Cascade ("CMMS") Ph 2&3- Computerized Maintenance Management System (CMMS) for MS and TS stations
JD Edwards functionality (Leave Administration, Manager Self-Service and Time Entry Self Service) to remainder of Management staff (78 people)
Outage Management System Upgrade
Web Based Geographic Information Systems ("GIS") Integrated Tool for Asset Attribute Tracking
JDE International Financial Reporting Standards ("IFRS") Requirements Phase 3
Self Service Enhancements to PowerStream Corporate Website
Electronic Accounts Payable ("A/P") Approval Process & Automation
Electronic Bill Presentment
Customer Information System ("CIS") Replacement
Outage Management System – Mobile functionality
Outage Communication via Website
Outage Communication via Email Notifications
JD Edwards modification re: Bill of Materials
JD Edwards Automated Purchase Requisition Rollout
Lines Field Inspection Mobility Solution
Call Recording capability in Control Room
Construction Standards – Merger Integration
Inventory Planning Process Transformation – Phase 1
Work Order Closing Process Review
SPreventative Maintenance. Distribution- Process Review
GIS Update Process Review

Internal Audit and Enterprise Risk Management

The Internal Audit area creates and executes a three year audit plan that is updated annually. As examples, audits have been completed for accounts payable, purchasing, business continuity, unbilled revenue, information services governance and capital project management. The Internal Audit plan is created or updated after the company performs its Enterprise Risk Assessment to ensure internal audit is focusing on the key risks of the organization.

A final audit report for an area is reviewed with management and key recommendations are identified to improve controls and efficiency. Management's responses to each recommendation are captured in the report and Internal Audit tracks the progress of all recommendations and ensures the owner of the recommendation(s) is accountable to complete them in the timeline set out in the report. The Internal Audit reports are shared with Senior Management and the Audit and Finance Committee of the Board.

Completing the recommendations in the audits has brought efficiencies in many areas of the organization and brings value both internally and to our external customers through increased efficiency and effectiveness. Many of the audits have a direct impact on safely securing customer information and ensuring that the proper processes are in place to safeguard the company's assets.

The focus in Enterprise Risk Management has been in the area of ranking PowerStream's major risks and communicating those risks with mitigation strategies to Senior Management and the Board of Directors. PowerStream is following the guidelines of *ISO 31000 Risk Management – Principles and Guidelines*, to ensure the entire organization understands and participates in effective risk management practices. With a goal of being proactive, the enterprise risk program will increase PowerStream's likelihood of achieving defined strategic, project and operational objectives.

HARMONIZED SALES TAX

Prior to July 1, 2010, PowerStream paid the Ontario Provincial Sales Tax ("PST") on some of its purchases, such as materials and office supplies, and the PST formed part of the cost of these items. Many of PowerStream's costs, such as labour, contract services and legal and consulting fees were not subject to PST and therefore PST was not part of the cost.

After June 30, 2010, PowerStream began to pay the Harmonized Sales Tax ("HST") on purchases that were previously subject to the Goods and Services Tax ("GST"). PowerStream receives an input tax credit for both the federal and provincial portion of the HST, with a few exceptions.

In many cases, PowerStream now pays HST on purchases that were previously subject to only GST and not PST. In this case there is no change in costs as a result of HST since the cost before and after HST does not contain any provincial sales tax.

Where purchases were previously subject to PST, under HST the provincial portion of sales tax paid is refunded through the input tax credit and is no longer part of the cost.

PowerStream pays HST on a few items that were previously not subject to PST and have Restricted Input Tax Credits ("RITC") which results in the provincial portion of the HST not being refunded. As a result, the provincial portion of the HST remains part of the cost. According to Ontario Ministry of Finance guidance on the transition to HST, the RITCs will be in place for five years then will be phased out. This is an additional cost to PowerStream as a result of the transition to HST.

Most insurance costs will not be subject to HST but will continue to be subject to an 8% Ontario PST that is non-refundable and remains part of the cost.

PowerStream's actual costs incurred after June 30, 2010 do not contain any PST. The exceptions are the costs mentioned above, insurance and costs to which RITCs apply, where PST will remain part of the cost for the next five years.

In preparing the 2012 and 2013 capital and operating budgets underpinning this application, PowerStream was careful to take these changes into account.

Budget instructions issued to PowerStream staff indicated that sales taxes were not to be included in the budgeted cost. The Rates & Regulatory Department reviewed the budget process with staff preparing the budget and confirmed that they were careful not to include any taxes in the cost. The review revealed that budget amounts were based either on current 2011 costs or quoted costs, excluding taxes, for virtually all items.

PowerStream concludes that the 2012 and 2013 capital and operating budgets do not contain any residual embedded PST in costs.

RATE YEAR

On April 15, 2010, the Board wrote to all licensed electricity distributors and other interested parties to advise on the outcome of its consultative process "to review the need for and the implications of a potential alignment of the rate year with the fiscal year for electricity distributors (EB-2009-0423)". In that letter, the Board wrote:

> "The Board has concluded that it is appropriate to consider the merits of an alignment of the rate year with the fiscal year for a distributor on a case-by-case basis upon receipt of an application for that purpose. Such an application shall form part of a distributor's Cost of Service rate application."

In accordance with this determination by the Board, PowerStream respectfully requests that the Board make its Rate Order effective January 1, 2013. PowerStream believes that the rate impacts to all customer classes from aligning its rate year and fiscal year are acceptable.

The Board has previously approved changes to the rate year. In 2000, the Board released the Electricity Distribution Rate Handbook which adjusted the rate year to March 1 from January 1, as rates had been previously set when the rate making function was administered by Ontario Hydro. Subsequently, in 2004, the Board changed the rate year to April 1. When the 2006 Electricity Distribution Rate Handbook was released the rate year was changed once again to May 1. Since that time, the rate year has remained as May 1 for most distributors. The previous adjustments to the rate year were commonly based on administrative practices and to align distribution rate changes with commodity rate changes.

Notwithstanding past reasons for the timing of rate changes, those changes have created a material lag between the budget year underlying rate applications and the commencement of available rate financing of these budgets. Consequently, PowerStream has prepared this Application on the basis of rate year and fiscal/budget year alignment, in order that the rate-financing of investments and costs provided for in this Application are effectively concurrent with the incurrence of those investments and costs. The proposed rate and fiscal year alignment benefits both the rate payer and the utility.

Benefits to Ratepayers

As noted above, previous changes to the rate year have often been made to align with changes in the price of the commodity. Currently, the rate year is aligned with the May 1st change in commodity prices. Rate year and fiscal year alignment will offer ratepayers transparency and, with appropriate communication from the utility and the Board, a clearer understanding of the rates on which their bills are based, without the confusion of other changes in billing elements.

Additionally, electricity distributors have other billing elements, such as riders, that are implemented on dates other than May 1. Accordingly, there is no apparent ratepayer benefit in changing distribution rates and commodity rates as of the same date. Ratepayers also benefit from the utility having more certain and timely cash flow resulting from fiscal/rate year alignment. Eliminating the current lag between the budget year underlying rate applications and the commencement of available rate financing of these budgets allows for more timely and confident investment in capital and operating costs to support a sustainable distribution system and customer service delivery.

Benefits to the Utility

The alignment of rate year and fiscal year is particularly important to distributors that require financial liquidity from third party lenders. PowerStream has a significant requirement for debt capital and incurs debt in a manner, with related terms and covenants, similar to other large utilities. All of these utilities including PowerStream have public debt ratings which directly impact both the cost and availability of debt capital to support their financing requirements for distribution system infrastructure. Lenders typically base their respective decisions on the availability and relative certainty of cash flow to support business investment requirements and debt servicing. The alignment of the rate year with the fiscal year is supportive of cost effective and available financial liquidity as: i) the incurrence of investment and cost more closely aligns with cash flow; and ii) there is less regulatory uncertainty related to the approval of expenditures months after the commencement of the fiscal year.

Regulatory uncertainty in relation to the rate year/fiscal year lag also creates investment risk for a utility. There is a significant risk that, in the first effective year of a re-basing application, the Board may disallow the recovery of certain investments and costs that have been incurred in advance of its rate decision.

The alignment of the rate year and fiscal year simplifies the explanation of fiscal year results in relation to regulatory approvals of investments, costs, and return on equity. Those returns are presently computed in rate applications based on calendar year budgets. However, they are not practically available given the misalignment of the rate year and fiscal year. This creates confusion for users of financial statements and also complicates variance analyses in rate applications.

Finally, PowerStream's reporting to the Board is provided on a calendar year basis and, as such, all underlying input data into rate applications is based on the calendar year. For example, variance analyses are addressed by way of comparisons with prior years. Consequently, an alignment of the rate year and fiscal year would allow for further consistency in comparative data collection, presentation, reporting, and analysis. This would improve efficiency in utility reporting processes.

SHARED SERVICES OVERVIEW

PowerStream has three Shareholders: the City of Vaughan, the Town of Markham and the City of Barrie. PowerStream provides services to and purchases services from the City of Vaughan and the Town of Markham. Services were provided to the City of Barrie until December 31, 2011. In addition, PowerStream provides services to the Town of Bradford West Gwillimbury; these services were previously provided by the former Barrie Hydro.

None of the Shareholders owns more than 50% of PowerStream and the therefore none are affiliates as contemplated by the Board's *Affiliate Relationship Code* (the "ARC"). PowerStream, however, follows the intent of the ARC by ensuring that there are no cross subsidies.

PowerStream has accordingly entered into Shared Service Agreements that govern the terms and conditions of the provision of services to and the purchase of services from the City of Vaughan, the Town of Markham and the Town of Bradford West Gwillimbury. Copies of these agreements, which set out the basis for the pricing, are included in the following Exhibits.

A4-1-2: PowerStream and the City of Vaughan, 2011 to 2015 (Draft copy – with the City of Vaughan for execution);

A4-1-3: PowerStream and the Town of Markham, 2011 to 2013 (Executed copy attached); and

A4-1-4: PowerStream and the Town of Bradford West Gwillimbury, 2009 to 2012 (Draft copy – with the Town of Bradford West Gwillimbury for execution).

This Exhibit, A4-1-1, provides an overview of the goods and services that PowerStream purchases from and provides to the Town of Markham, the City of Vaughan and the Town of Bradford West Gwillimbury.

POWERSTREAM AND THE CITY OF VAUGHAN

Services and Products Purchased

- ***Leased facilities***

PowerStream's lease of outdoor storage space at the City of Vaughan's Joint Operations Centre will end December 31, 2012. In 2013 PowerStream will continue to lease counter and office space at the City of Vaughan Civic Centre for the provision of cashiering services.

- ***Software maintenance***

The City of Vaughan and PowerStream share licensing fees for JD Edwards Enterprise Software that each uses independently to manage their financial systems. The combined, higher volume of licenses results in a lower cost per license. In addition there is a small fee for a network link between PowerStream's Head Office and the Vaughan Civic Centre to support the cashiering services provided.

The cost of services that PowerStream purchases from the City of Vaughan are shown in Table 1, below.

Table 1: Services Purchased by PowerStream from the City of Vaughan ($)

Service	2009	2010	2011	2012	2013
Leased Facilities	731,882	286,565	133,149	136,454	10,758
Software Maintenance	37,740	38,495	39,650	40,839	42,065

Services and Products Provided

- ***Water and sewer***

PowerStream provides certain services to water and sewer customers in the City of Vaughan on behalf of the City of Vaughan. These include billing, collection, revenue management, customer account management, responses to telephone and written enquiries and the reporting of certain statistics.

- ***Payroll services***

PowerStream provides payroll services to the City of Vaughan including payroll administration (including taxes, benefits and deductions), Statistics Canada reporting, OMERS remittance and reporting and WSIB payments, as well as coordinating payroll audits and testing.

- ***Cashier services***

PowerStream provides cashier services to the City of Vaughan. These include services to process payments for water bills, municipal taxes, parking permits, licensing fees, opening and sorting night box payments and responding to customer enquires.

Table 2, below summarizes the services provided by PowerStream to the City of Vaughan.

Table 2: Services Provided by PowerStream to City of Vaughan ($)

Service	2009	2010	2011	2012	2013
Water and Sewer	1,414,367	1,439,592	1,147,000	1,181,410	1,216,850
Payroll	266,091	272,253	334,929	344,977	355,326
Cashier	235,965	240,972	242,890	250,176	257,682

The price that is charged by PowerStream for these services includes a mark-up equivalent to the weighted average cost of capital (7.3%).

POWERSTREAM AND THE TOWN OF MARKHAM

Services and Products Purchased

- ***Leased premises***

PowerStream ceased leasing premises from the Town of Markham in 2010.

- ***Cashier services***

The Town of Markham provides cashier services to PowerStream at Markham Town Hall. Customers may pay their electricity and water bills and get responses to questions about their bills and account history. Starting in 2010, PowerStream has paid the Town of Markham's cost to have a customer service agent in place as well as the cost to maintain a connection to PowerStream's Customer Information System.

The annual cost of leased facilities and cashier services purchased from the Town of Markham are summarized in Table 3 below.

Table 3: Services Purchased from the Town of Markham ($)

Service	2009	2010	2011	2012	2013
Cashier	81,930	84,388	86,920	89,527	92,213

Services and Products Provided

- ***Water and sewer***

PowerStream provides certain services to water and sewer customers in the Town of Markham on behalf of the Town of Markham. These include billing, collection, revenue management, customer account management, responses to telephone and written enquiries and the reporting of certain statistics. The price that is charged by PowerStream for these services includes an amount that is equal to PowerStream's weighted average cost of capital (7.3%).

- ***Street lighting maintenance***

PowerStream manages a tendered, third-party contract for streetlight maintenance, re-lamping programs, accident and vandalism repair, streetlight fault repairs and pole replacement. PowerStream charges a management fee for overseeing the contract. The annual amount is not fixed, but rather depends on the volume of activity.

Table 4 below summarizes the water and sewer and street lighting activities that PowerStream provides to the Town of Markham**.**

Table 4: Services Provided to the Town of Markham ($)

Service	**2009**	**2010**	**2011**	**2012**	**2013**
Water and Sewer	1,401,200	1,426,190	1,136,862	1,170,172	1,205,277
Street Lighting	965,340	1,041,443	1,186,408	1,000,000	1,000,000

POWERSTREAM AND THE CITY OF BARRIE

PowerStream provided water and sewer services to the City of Barrie until the end of 2011 at which time the City of Barrie assumed responsibility for these services. Also, up to the end of 2011, PowerStream provided water heater related services to Barrie Hydro Energy Services Inc., which is 100% owned by the City of Barrie. These services included billing of all water heater services, revenue management and collections, customer account management, telephone and written inquiry handling and certain reporting statistics. The maintenance and operational services included repairs, removals and replacements. The City of Barrie sold their water heater assets to a third party and PowerStream no longer provides these services.

POWERSTREAM AND BRADFORD WEST GWILLIMBURY

Services and Products Provided

- ***Water and sewer***

PowerStream provides certain services to water and sewer customers in the Town of Bradford West Gwillimbury on behalf of the Town of Bradford West Gwillimbury. These include billing, collection, revenue management, customer account management, responses to telephone and written enquiries and the reporting of certain statistics. The price that is charged by PowerStream for these services includes an amount that is equal to PowerStream's weighted average cost of capital (7.3%).

The annual cost of providing water and sewer service to the Town of Bradford West Gwillimbury is summarized in Table 5 below.

Table 5: Services Provided to Town of Bradford West Gwillimbury ($)

Service	2009	2010	2011	2012	2013
Water and Sewer	265,000	155,000	160,000	165,000	170,000

POWERSTREAM AND THE CITY OF VAUGHAN, 2011 TO 2015
(DRAFT COPY – WITH THE CITY OF VAUGHAN FOR EXECUTION)

SHARED SERVICES AGREEMENT made in duplicate this 1st day of January, 2011

B E T W E E N:

POWERSTREAM INC.,
(hereinafter called "**PowerStream**")

- and -

THE CITY OF VAUGHAN, (hereinafter called the "**City**")

WHEREAS on January 1, 2009, PowerStream and Barrie Hydro Distribution Inc.(Barrie Hydro) amalgamated (the "Amalgamation") in accordance with a merger agreement dated October 10th, 2008, between The Corporation of the City of Vaughan, The Corporation of the Town of Markham and the Corporation of the City of Barrie (the "**Merger Agreement**");

AND WHEREAS prior to the Amalgamation, the City and PowerStream entered into an agreement dated January 1st, 2008, providing for PowerStream to provide certain services to the City and the City to provide certain services to PowerStream (the "**Services Agreement**");

AND WHEREAS PowerStream and the City wish to terminate the Services Agreement and replace it with this Agreement as of the Effective Date to continue to provide certain services to each other for the consideration and on the terms and conditions hereinafter set forth;

NOW THEREFORE in consideration of the premises and the mutual covenants and agreements herein contained (the receipt and sufficiency of which is hereby acknowledged by each of the Parties hereto), the Parties hereto hereby covenant and agree as follows:

1. INTERPRETATION

1.1 **Definitions**. In this Agreement, including the recitals and Schedules hereto, the following words shall have the following meanings:

1.1.1 "**Affiliate**" means a body corporate which is deemed to be affiliated with another body corporate, by virtue of one of them being the subsidiary of the other or both being subsidiaries of the same body or each of them being controlled by the same person;

1.1.2 "**Affiliate Relationships Code**" means the rules issued by the Ontario Energy Board that govern the conduct of utilities as that conduct relates to their respective affiliates, as may be amended from time to time;

1.1.3 "**Agreement**" means this shared services agreement and all recitals and all Schedules attached hereto as the same may be amended, modified, supplemented, restated, or replaced from time to time;

1.1.4 "**Applicable Law**" means collectively, all applicable federal, provincial, territorial, municipal and foreign laws, statutes, ordinances, decrees, rules, regulations, by-laws, legally enforceable policies, codes, or guidelines, judicial, arbitral, administrative, ministerial, departmental or regulatory judgments, orders, decisions, directives, rulings or awards, and conditions of any grant of approval, permission, certification, consent, registration, authority or licence by any court, statutory body, self-regulatory authority, stock exchange or other Governmental Authority;

1.1.5 "**Binding Arbitration**" has the meaning ascribed thereto in Section 8.12;

1.1.6 "**Business Day**" means any day other than a day which is a Saturday, a Sunday or a statutory holiday or a civic holiday in the Province of Ontario;

1.1.7 "**City Fees**" means collectively, the charges payable by PowerStream for the provision of the City Services plus all applicable taxes, if any, in respect thereof;

1.1.8 **"City Services"** means the services provided by the City to PowerStream as set out on Schedule A and B attached hereto;

1.1.9 "**Claims**" has the meaning ascribed thereto in Section 7.2;

1.1.10 "**Confidential Information**" means the confidential, secret or proprietary information of one Party (the "**Disclosing Party**"), including but not limited to any of such information or data which is technical, financial or business in nature including customer information, and which has been or may hereafter be disclosed, directly or indirectly, to the other Party (the "**Recipient**"), either orally, in writing or in any other material form, or delivered to the Recipient;

1.1.11 "**Effective Date**" means January 1, 2011;

1.1.12 "**Extension Notice**" has the meaning ascribed thereto in Section 4.2;

1.1.13 "**Facilities**" means the facilities provided by the City to PowerStream as set out in Schedule A attached hereto;

1.1.14 "**Fees**" means collectively the City Fees and the PowerStream Fees;

1.1.15 "**Governmental Authority**" means any court, arbitrator, administrative agency, commission, or governmental or regulatory official, department, agency, body, authority or instrumentality, whether foreign, federal, state, provincial, municipal, or local, having jurisdiction over the Parties;

1.1.16 **"In Writing"** or **"Written"** means a posted letter, a facsimile transmittal or an e-mail message;

1.1.17 "**Internal Dispute Resolution**" has the meaning ascribed thereto in subsection 8.12.1;

1.1.18 **“MFIPPA”** means the *Municipal Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. M. 56;

1.1.19 “**Notice**” has the meaning ascribed thereto in Section 8.5;

1.1.20 “**Parties**” means the parties to this Agreement and “**Party**” shall mean any one of them;

1.1.21 **“PowerStream Fees”** means collectively, the charges payable by the City to PowerStream for the PowerStream Services plus all applicable taxes, if any, in respect thereof;

1.1.22 **“PowerStream Services”** means the services provided by PowerStream to the City as set out at Schedules C, D, and E;

1.1.23 “**Requested Party**” has the meaning ascribed thereto in Section 8.1;

1.1.24 “**Services**” means collectively the PowerStream Services purchased by the City from PowerStream as set out on Schedules C, D and E attached hereto and the City Services purchased by PowerStream from the City as set out on Schedule A and B, or those services agreed to in writing between the Parties from time to time;

1.1.25 “**Term**” means the term of this Agreement commencing on the Effective Date to and including the Termination Date;

1.1.26 “**Termination Date**” has the meaning ascribed thereto in Section 4.1;

1.1.27 “**Unsatisfied Party**” has the meaning ascribed thereto in Section 8.1.

1.2 **<u>Headings</u>**. The division of this Agreement into Sections and subsections and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms “**this Agreement**”, “**hereof’**, “**hereunder**” and similar expressions refer to this Agreement and not to any particular Section or other portion hereof and include any agreement supplemental hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to “**Sections**” are to sections and “**subsections**” are to subsections of this Agreement.

1.3 **<u>Extended Meanings</u>**. In this Agreement words importing the singular number only shall include the plural and vice versa, words importing any gender shall include all genders and words importing persons shall include individuals, partnerships, associations, trusts, unincorporated organisations, companies and corporations.

1.4 **<u>Currency</u>**. All references to currency herein are to lawful money of Canada unless otherwise specified.

1.5 **Schedules**. The following Schedules which are attached to this Agreement are incorporated by reference into this Agreement and are deemed to be a part of it:

City Services provided to PowerStream:

Schedule A - Facilities

Schedule B - Information Technology Services

PowerStream Services provided to City:

Schedule C - Payroll Services

Schedule D - Cashier Services

Schedule E - Water Meter Reading and Water Billing and Remittance

2. SERVICES

2.1 **Provision of Services**.

2.2 In accordance with the terms hereof, from and after the Effective Date to the Termination Date:

2.2.1 PowerStream agrees to provide and perform, at the request of the City, the Services for the benefit of the City or the City's Affiliates, as the case may be.

2.2.2 The City agrees to provide the City Services for the benefit of PowerStream or PowerStream's Affiliates, as the case may be.

2.3 **Standard of Services.** Notwithstanding the provisions of section 7.1 herein, the Parties shall perform their respective Services in a prudent, businesslike manner in accordance with the policies and service levels applicable to such Services as set out in the Schedules or such practices, policies and service levels as may be amended from time to time pursuant to Section 2.4 hereof. The Parties shall provide the Services in accordance with all Applicable Laws. Notwithstanding the foregoing, "**Applicable Laws**" shall not include any by-laws, guidelines, directions, rules or standards of the City introduced, proclaimed or implemented after the date hereof that affects the provision of the Services by PowerStream hereunder or the terms hereof.

2.4 **Amendments**. At any time during the term of this Agreement either Party may request changes in the Services that a party receives or the practices, policies or performance levels applicable to the Services received by submitting such requests (the "**Requesting Party**") In Writing to the other Party (the "**Receiving Party**"). Within a reasonable time, but in any event not more than thirty (30) Business Days after receiving written notice of a request, the Receiving Party shall advise the Requesting Party whether the change requested will have an impact on the delivery of the Services, acting reasonably, and whether or not the request will have an impact on the associated Fees and whether the Receiving Party authorizes the implementation of the change under the revised terms specified by the Requesting Party or rejects the change proposed. Minor adjustments to existing reports shall not trigger fee increases or the imposition of one-time fees. Pending the Receiving Party response, the Requesting Party shall continue to receive the applicable Services in accordance with the latest approved terms for the provision of such Services.

2.5 **Fees**.

2.5.1 City Fees paid by PowerStream shall be those as set out on Schedules A and B, or as mutually agreed upon by the Parties In Writing from time to time.

2.5.2 PowerStream Fees paid by the City shall be those as set out on Schedules C, D, and E, or as mutually agreed upon by the Parties In Writing from time to time.

2.5.3 Unless otherwise specified herein, PowerStream Fees shall be invoiced to the City on a monthly basis.

2.5.4 City Fees shall be invoiced to and shall be payable by PowerStream in accordance with the provisions of Schedule A and B.

2.5.5 The Parties agree that payment of City Fees and other charges provided for hereunder will be due and payable in arrears not later than thirty (30) days after the date of invoice.

2.5.6 All PowerStream Fees and City Fees shall comply with the requirements of the Affiliate Relationships Code.

2.6 **Co-operation by City**. The City shall co-operate with PowerStream to assist it in the provision of the Services. Without limiting the generality of the foregoing, the City shall:

2.6.1 assign a minimum of two (2) representatives of the City to co-ordinate with PowerStream the provision of the Services to the City to deal with financial and operational issues respectively;

2.6.2 prepare and provide to PowerStream, in a mutually acceptable format, all information reasonably required by PowerStream to permit proper delivery of the Services;

2.6.3 establish, incorporate and maintain as part of the practices, policies and service levels applicable to such Services, in consultation with PowerStream, operating procedures to satisfy the City's requirements for accuracy and auditing;

2.6.4 provide training, if necessary, to personnel to assist in the provision of the required information to PowerStream to permit PowerStream to provide the Services; and,

2.6.5 provide PowerStream with assistance in collecting amounts owed to the City. The City may place any of such unpaid amounts on the collector's roll and enforce any other rights or remedies of the City pursuant to section 398(2) of the *Municipal Act*, S. O. 2001, c. 25.

2.7 **Customer Information**.

2.7.1 PowerStream acknowledges that the ownership of all data in respect of water and sewer customers of the City as such data relates to: water and sewer information, water and sewer consumption history and charges, fire protection information, customer information including name, billing address, legal description, service address, the final twelve (12) months of meter readings for each customer, outstanding water and sewer invoices, customer credit and collection information, and information with regard to work orders and asset management systems is and shall remain the property of the City. PowerStream shall ensure that all of the data contemplated by this Section 2.7.1 is backed up in accordance with current PowerStream procedures and can be restored in one or two Business Days. The City acknowledges that PowerStream can only back up data collected for a maximum period of 7 years.

2.7.2 The City acknowledges that the ownership of data in respect of electricity customers whether past or present of PowerStream or any of its Affiliates is and shall remain the property of PowerStream

2.7.3 Requests for data by the City under Section 2.7.1 shall be made In Writing by an individual designated by the City to the attention of the VP Information Services at PowerStream or such other individual designated by PowerStream. PowerStream shall within one (1) Business Day advise the City of the effort required to provide such data and such data shall be provided by PowerStream to the City no later than two (2) Business Days from the date the request is made by the City or within such other, longer period of time as set out in the response from PowerStream.

2.7.4 Each Party, its employees and agents shall abide by all Applicable Laws, including the requirements of the Affiliate Relationships Code to the extent that it applies, and including Applicable Laws relating to the collection, use, retention, destruction and disclosure of any personal information which has been collected, used, retained, destroyed and disclosed in connection with the Services provided by such Party hereunder.

3. CONFIDENTIAL INFORMATION

3.1 **Confidentiality Obligation**. Commencing upon the Effective Date and continuing thereafter , each Party:

3.1.1 shall treat as confidential, keep in safe custody and not disclose to any third party any Confidential Information provided to it by the other Party; and,

3.1.2 use such Confidential Information only to the extent necessary to comply with this Agreement.

3.2 Each of the Parties shall establish and enforce procedures to protect Confidential Information disclosed to it by the other Party and shall restrict disclosure of such Confidential Information to only those employees, officers, agents and professional advisors of it and its Affiliates who need to know such information in connection with such Party's performance of this Agreement and in accordance with MFIPPA or any other applicable legislation. If a Party or its Affiliate is required by order of any Governmental Authority or Applicable Law or the rules of a stock exchange to disclose Confidential Information disclosed to it by the other Party, it shall promptly notify (if permissible) the other Party of the request for disclosure and shall cooperate with the other Party if that other Party opposes the request for disclosure and wishes to seek confidential treatment for such Confidential Information that is required to be disclosed. Each of the Parties acknowledges that no adequate remedy at law exists for a material breach or threatened material breach of this Section 3.2 the continuation of which unremedied will cause the other Party to suffer irreparable harm, and agrees that the other Party is entitled, in addition to other remedies which may be available at law or in equity, to immediate injunctive relief from any breach of this Section 3.2 and to specific performance of its rights. Promptly following the Termination Date, each Party agrees to use commercially reasonable efforts to deliver to the other Party the Confidential Information (including all electronic and other copies thereof) disclosed to it by the Disclosing Party that the Receiving Party possesses or, upon request by a Disclosing Party, the Receiving Party shall confirm In Writing from a senior officer of a Party to the Disclosing Party that such Confidential Information has been destroyed in accordance with the Disclosing Party's instructions.

3.3 The Parties agree to protect the Confidential Information in accordance with MFIPPA and the *Personal Information Protection and Electronic Documents Act* (Canada).

4. TERM.

4.1 **Term**. This Agreement will be effective as at the Effective Date and shall terminate five (5) years after the Effective Date, unless terminated earlier pursuant to Section 5.1 or extended by renewal of the term pursuant to Section 4.2 (the "**Termination Date**").

4.2 **Extension of Term**. If either Party gives notice In Writing to the other Party by not later than sixty (60) days prior to the Termination Date, requesting the continuation of Services or the provision of the City Services, as the case may be (an "**Extension Notice**") for an additional one year period, the Parties agree to negotiate, in good faith, in order to determine the terms and conditions on which such Services will be provided for a renewal term of one (1) year or such longer period as is mutually agreed to. Notwithstanding anything in this Section 4.2 to the contrary, there shall be no obligation upon any Party having been provided with an Extension Notice to extend the term of this Agreement.

5. TERMINATION.

5.1 **Termination**. This Agreement, shall terminate on the Termination Date and may be terminated prior thereto as follows:

5.1.1 by the mutual written consent of the Parties hereto;

5.1.2 by either Party effective upon not less than thirty (30) days written notice of any material breach or default of any provision or obligation of this Agreement by a Party, provided that such notice will not be effective to terminate this Agreement in the event the other Party cures the default during such notice period; and

5.1.3 immediately, by either Party if the other Party becomes insolvent or is a party to any bankruptcy or receivership proceeding or any similar action affecting the affairs, property or solvency of such Party.

5.1.4 **Termination Without Prejudice.** Any such termination of this Agreement shall be without prejudice to any other remedies which any Party may have against the other arising out of such breach of default and shall not affect any rights or obligations of any Party arising under this Agreement prior to such termination.

6. FORCE MAJEURE.

6.1 **Force Majeure**. Performance of any obligation under this Agreement, other than the payment of Fees pursuant to Section 2.5.3, 2.5.4 and 2.5.5, may be suspended by either Party without liability to the extent that an act of God, war, fire, earthquake, explosion, governmental expropriation, governmental law or regulation or any other occurrence beyond the reasonable control of such Party or labour disruption, strike or injunction (if such labour event is not caused by the bad faith or unreasonable conduct of such Party) delays, prevents, restricts, limits or renders commercially unfeasible the performance of any such obligation. The affected Party may invoke this provision by promptly notifying the other Party of the nature and estimated duration of the suspension. No Party hereto invoking this provision shall be liable for any failure to perform or any delay in the performance of its obligations in this Section 6.1.

7. DISCLAIMER, LIMIT OF LIABILITY AND INDEMNITY

7.1 **Disclaimer**. The Services provided by PowerStream are provided without any warranty whatsoever, other than as is set forth in Section 2.3 hereof. In particular, PowerStream makes no warranty as to the suitability of any of the Services for the specific purposes or needs of the City. The warranty contained in this Agreement is the only warranty made by PowerStream with respect to the Services. PowerStream specifically excludes any other warranties or conditions express or implied, including, but not limited to, implied warranties or conditions of merchantability, merchantable or satisfactory quality or fitness for a particular purpose, and those arising from a course of dealing or usage of trade.

7.2 **Indemnity by the City**. The City agrees to indemnify, defend and hold harmless PowerStream from any and all claims, litigation, damages, losses, causes of action or expenses (including legal fees and disbursements) ("**Claims**") suffered or incurred by PowerStream from third parties or otherwise in connection with:

7.2.1.1 a breach of the City's obligations under this Agreement insofar as PowerStream has complied with its obligations under this Agreement; and

7.2.1.2 any negligence on the part of the City, its employees, contractors or agents in its provision of the City Services.

7.3 Notwithstanding the provisions of Section 7.2, the City shall be under no obligation to indemnify and save harmless PowerStream from any Claims resulting from the negligence or wilful misconduct of PowerStream in its provision of the PowerStream Services hereunder.

7.4 **Indemnity by PowerStream**. PowerStream agrees to indemnify, defend and hold harmless the City from any and all Claims suffered or incurred by the City from third parties or otherwise in connection with:

7.4.1 a breach of PowerStream's obligations under this Agreement insofar as the City has complied with its obligations under this Agreement; and

7.4.2 any negligence on the part of PowerStream, its employees, contractors or agents in its provision of the Services hereunder.

7.5 Notwithstanding the provisions of Section 7.4, PowerStream shall be under no obligation to indemnify and save harmless the City from any Claims resulting from the negligence or wilful misconduct of the City in its provision of the City Services hereunder.

7.6 **Insurance**. Both Parties shall provide and keep in force a comprehensive liability insurance policy with coverage equal to or greater than Five Million Dollars ($5,000,000) (Canadian) of sufficient coverage in respect of the Services performed by it under the terms of this Agreement.

8. MISCELLANEOUS

8.1 **Audit**. The Parties shall maintain accurate and complete books and records with respect to (i) the Services provided hereunder, (ii) the Fees, and (iii) any information provided by a Party to the other Party for the provision of the Services. Each Party shall keep its accounts and records in accordance with Canadian generally accepted accounting principles from time to time approved by the Canadian Institute of Chartered Accountants (or a successor institute) with respect to the computation of Fees and other charges payable pursuant to this Agreement. Each Party shall be entitled to audit such books and records in order to confirm compliance with the terms of this Agreement. Each Party shall make such books and records available to individuals designated by the other Party and provide any assistance it may reasonably require in order to conduct audits and inspections, provided that:

8.1.1 audits and inspections shall be made at reasonable times and on at least ten (10) Business Days prior notice; and

8.1.2 audits of Fees shall be made not later than twenty four (24) months after such Fees have been paid by a Party to the other Party.

Each Party agrees to provide the other Party with reasonable facilities for such audits and inspections and copies of documents, where necessary, appropriate and permitted by law. If a Party is not satisfied with the information provided (the "**Unsatisfied Party**"), the Unsatisfied Party may retain, at its own expense, an independent auditor, to review the books and records referred to above. The Party requested to provide additional information (the "**Requested Party**") may refuse to disclose to the Unsatisfied Party or its agents any information that the Requested Party is prevented from disclosing as a result of a confidentiality obligation to another person provided that the Requested Party shall use commercially reasonable efforts to obtain consents to permit disclosure of such information if such information is reasonably required in order to conduct an audit and inspection by the Requesting Party under this Section 8.1 and the Requesting Party or its agents has requested access to such information. Each of the Parties agree that any third party conducting an audit or inspection shall be subject to the confidentiality provisions of Sections 3.1 and 3.2 and may be required by the Requested Party to enter into a confidentiality and non-disclosure agreement in form and substance reasonably acceptable to the Requested Party and each of the Parties agree that should an independent auditor be deemed by the Requested Party to be a competitor of the Requested Party, the Parties shall mutually agree to the review and audit procedures prior to such review and audit.

8.2 **Governing Law**. This Agreement shall be governed by and construed in accordance with the law of the Province of Ontario and the laws of Canada applicable therein.

8.3 **Successors**. This Agreement will enure to the benefit of and be binding on the respective successors and assigns of each of the Parties.

8.4 **Time of Essence**. Time shall be of the essence of this Agreement

8.5 **Notices**. Unless otherwise expressly provided herein, any notice, consent or other communication (a "**Notice**") given pursuant to or in connection with this Agreement shall be In Writing and shall be sufficiently given to the person to whom it is addressed if transmitted by facsimile, delivered in person to or for such person at the address of such person indicated below or at such other address as such person shall have provided in writing to the other Party in accordance with this provision. Any Notice provided in accordance with this provision shall be deemed to have been sufficiently given or made on the date on which it was so transmitted by facsimile or delivered provided that if such day is not a Business Day or delivery occurs after normal business hours of the recipient, the Notice shall be deemed given or made on the Business Day following transmission or delivery, as the case may be.

To PowerStream:

PowerStream Inc.
161 Cityview Boulevard
Vaughan, Ontario
L4H 0A9
Attention: Dennis Nolan
Executive Vice President, Corporate Services and Secretary
Fax: (905) 532-4616
E-Mail: dennis.nolan@powerstream.ca

To the City:

City of Vaughan
2141 Major Mackenzie Drive
L6A 1T1
[NTD: VAUGHAN TO INSERT]

Primary Contact:

Attention: [▪]

Fax: [▪]
E-Mail: [▪]

For agreement invoicing/payment or matters related to water & sewer services/cashiering/payroll

Attention: [▪]

Fax: [▪]
E-Mail: [▪]

For facility issues:

Attention: [▪]

Fax: [▪]
E-Mail: [▪]

For information technology services :

Attention: [▪]

Fax: [▪]
E-mail: [▪]

or to such other address as such Party shall have notified to the other Party hereto. Any communication so addressed and delivered shall be deemed to have been sufficiently given or made on the date on which it was received.

8.6 **Entire Agreement**. This Agreement, together with the recitals and the Schedules attached hereto, constitutes the entire agreement between the Parties hereto with regard to the subject matter hereof and supersedes and cancels all previous negotiations, agreements, commitments and writings in respect of the subject matter hereof. This Agreement may not be modified or amended in any respect except by written instrument signed by the Parties hereto.

8.7 **Waiver**. The failure of any Party to this Agreement at any time to require performance by the other Party of any provision hereof shall in no way affect the full right to require such performance at any time thereafter of any other provision hereof and no waiver by any Party hereof of any breach of condition, covenant or agreement shall constitute a waiver except in respect of the particular breach giving rise to such waiver. Any such waiver shall be effective only if made in writing by the Party entitled to waive the provision.

8.8 **Independent Contractor**. By virtue of this Agreement, no Party hereto constitutes any other Party hereto as its agent, partner, joint venturer, franchisee or legal representative and no Party has express or implied authority to bind any other Party hereto in any manner whatsoever. Unless otherwise contemplated in the Services or approved in writing by the other Party, no Party hereto will assume or create any obligation or responsibility whatsoever, express or implied, on behalf of or in the name of that other Party.

8.9 **Assignment**. This Agreement and the privileges herein granted shall not be assigned by either Party except with the prior written consent of the other, such consent not to be unreasonably withheld. Notwithstanding the foregoing, either party or its permitted assignee may, as security only, assign, transfer, pledge, grant a security interest in or otherwise dispose of its rights and interests under this Agreement to a trustee or lending institution, including such an assignment, transfer or other disposition upon or pursuant to the exercise of remedies by such trustee or lending institution.

8.10 **Further Assurances**. Each of the Parties hereto from time to time at the request and expense of the other Party hereto and without further consideration, will execute and deliver such other instruments of transfer, conveyance and assignment and take such further action as such other Party may require to more effectively complete any matter provided for herein.

8.11 **Severability.** Any covenant or provision hereof determined to be void or unenforceable in whole or in part will be deemed not to affect or impair the validity or enforceability of any other covenant or provision hereof and the covenants and provisions hereof are declared to be separate and distinct.

8.12 **Arbitration**.

8.12.1 In the event of any dispute or claim between the Parties, arising out of, or relating to, in any way connected with this Agreement or its interpretation or the fulfilment of the obligations of the Parties hereunder (a "**Dispute**"), such Dispute shall be referred internally by either Party by written notification to Dennis Nolan, Executive Vice President, Corporate Services and Secretary at PowerStream and [▪] at the City for resolution (the "**Internal Dispute Resolution**"). If the Dispute is not resolved within sixty (60) Business Days of a Dispute being referred to the Internal Dispute Resolution then such Dispute shall be settled by binding arbitration ("**Binding Arbitration**"). Binding Arbitration shall be conducted in accordance with the *Arbitration Act, 1991* (Ontario), as amended from time to time.

8.12.2 It shall be a condition precedent to the right of a Party to this Agreement to submit a Dispute to Binding Arbitration that such Party shall have given written notice of its intention to do so to the other Party to this Agreement and such written notice shall state the particulars of such Dispute. Within ten (10) Business Days of such notice being provided, the Parties to this Agreement shall mutually appoint a single arbitrator to determine the Dispute. The arbitrator shall fix a time, which shall not be later than ten (10) Business Days following his or her appointment, and a place in Vaughan, Ontario, for the purpose of hearing the evidence and representations of the Parties. Each of the Parties shall co-operate with the arbitrator and shall provide him or her with all information in their possession or under their control necessary or relevant to the matter being determined. Within ten (10) Business Days after the conclusion of the arbitration hearing, or such longer period as may be required by the arbitrator appointed under this subsection 8.12.2, the arbitrator shall make an award and reduce the same to writing and deliver one copy of his or her decision to each Party.

8.12.3 If the Parties fail to agree on an arbitrator within the time period specified in subsection 8.12.2 above, then, unless the parties otherwise agree, the Dispute shall be submitted to ADR Chambers for final resolution, which submission shall be by written notice which may be provided by either Party to ADR Chambers and to the other Party to this Agreement. Within five (5) Business Days following the date of any notice given by either Party pursuant to this subsection 8.12.3, an arbitrator shall be selected by random draw made by ADR Chambers. The arbitrator so selected shall perform both the settlement conference and the trial in the matter. The Parties further agree to be bound by the rules of the ADR Chambers in force from time to time.

8.12.4 There shall be no right of appeal from the arbitrator's award except in accordance with the *Arbitration Act, 1991* (Ontario). The Parties agree that a judgment upon the arbitration award may be entered in any court in Canada or any court having jurisdiction, or that an application may be made to such court for judicial recognition of the award and/or an order of enforcement thereof. The Parties agree that the arbitrator selected pursuant to subsections 8.12.2 and 8.12.3 shall determine costs (legal fees and disbursements) as part of the arbitrator's award.

8.13 **Survival**. The following Sections and or subsections will survive the expiry or termination of this Agreement: Section 2.5, Section 2.7, Section 3, Section 7, Section 8.1 and this Section 8.13.

8.14 **Counterparts**. This Agreement may be executed by the Parties hereto in several counterparts, each of which when so executed and delivered shall be an original and all such counterparts shall together constitute one and the same instrument.

IN WITNESS WHEREOF, this Agreement has been executed by the Parties hereto on the date first above written.

POWERSTREAM INC.

Per: ______________________________

Name: Dennis Nolan
Title: EVP Corporate Services & Secretary

CITY OF VAUGHAN

Per: ______________________________

Name:
Title:

Per: ______________________________

Name:
Title:

SCHEDULE A

FACILITIES PROVIDED TO POWERSTREAM

TERMS

SERVICE PROVIDED

The City agrees to provide PowerStream facility space at the following locations for the term of the Agreement, except in the case of the Joint Operations Centre which PowerStream will only be occupying until December 31, 2012 or such other period of time as agreed to between the Parties:

- Joint Operations Centre – Designated outdoor space
- Civic Centre – Designated counter space

As part of the rental fee, PowerStream will receive occupancy services consistent to the City's current operational standards. This would include services which are normally the responsibility of the tenant such as parking, access to common areas, custodial, insurance, cleaning, garbage collection, security, telephone system and long distance charges, etc.

Additional service requests related to enhanced service levels, renovations, or additional space, will require mutual agreement and may result in a fee adjustment or separate billing. Requests of this nature should be submitted by way of a work order or written request to the City's Building and Facilities Department.

PRICING

In consideration of the above, PowerStream shall pay the following annual rental rates inclusive of Maintenance and Insurance over the term of the Agreement.

Payments shall be due as per the City invoicing schedule.

	2011	**2012**	**2013**	**2014**	**2015**
Joint Operations Centre	$123,000	$126,000	0	0	0
Civic Centre – Designated Counter Space	$10,149	$10,454	$10,758	$11,062	$11,367

Civic Centre – Designated Counter Space for Cashiers 3% increase per year over 2010 fee

SCHEDULE B

INFORMATION TECHNOLOGY SERVICES PROVIDED TO POWERSTREAM

TERMS

SERVICE PROVIDED

JDE Enterprise Software License Maintenance

Currently the City pays for JDE software annual maintenance fees, which provides continuous access to JDE software fixes, news releases, etc. PowerStream currently holds an identical set of applications and equally benefits from this service. Therefore it is reasonable to share in this cost.

Network Link (WAN Services)

There is a mutual need to establish a network link between the Civic Centre and PowerStream's head office. This link is necessary for the City to provide payroll information to PowerStream for administration and processing purposes. PowerStream requires a link to access billing information in order to perform the cashiering function located at the Civic Centre. The need for this type of connection is being reviewed by both PowerStream and the City, at the end of each calendar year of the Agreement the need for this type of connection will be reviewed by the Parties and if mutually agreed that the connection is no longer required, or due to technological changes a different connection is required, a new fee will be established for this service as agreed to by both Parties.

PRICING

In consideration of the above, PowerStream shall pay the following annual amounts

	2011	**2012**	**2013**	**2014**	**2015**
JDE Enterprise Software Licence	$34,850	$35,939	$37,065	$38,126	$39,226
Network Link (WAN Services)	$4,800	$4,900	$5,000	$5,200	$5,400
TOTAL	$39,650	$40,839	$42,065	$43,326	$44,626

PRICING METHODOLOGY

Services are subcontracted and provided by external parties and should therefore be considered market value. Both Parties benefit equally from the services mentioned above and costs are shared evenly (50/50). Fees are based on forecasted inflation of 3% per year from 2010 fee.

OTHER INTERESTS

Additional service requests will require mutual agreement and may result in a fee adjustment or separate billing. Requests of this nature should be submitted by way of a work order or written request to the City's Information Technology Management Department.

SCHEDULE C

PAYROLL SERVICES

PAYROLL SERVICES PROVIDED BY POWERSTREAM TO THE CITY

SERVICE SUMMARY

PowerStream agrees to provide the following payroll services to the City for the years 2011 to 2015.

- Payroll administration
  - Payroll service for the City employees.
  - Payroll to City Council for Region of York, Hydro Vaughan Holdings Inc., Hydro Vaughan Energy Corp and Vaughan Holdings.
  - Retroactive payment processing for collective agreement ratified.
  - Payment of retiring allowances and severance packages including RRSP transfers.
  - Distribution of labour costs to the City's general ledger.
  - Special payments for cleaning allowances, long service pay, reclass pay, shift premiums, statutory holiday pay, etc.
  - Preparation of Record of Employment forms.
  - Processing of bank deposit changes and tax changes.

- Tax, benefits, and deductions administration
  - Weekly deductions and remittances for income tax, CPP, EI (4 CRA business numbers), support payments and garnishments, employee credit union, group RRSP, recreation memberships, Canada Savings Bonds, union dues (6 unions), group home and auto insurance, optional and spousal life insurance, United Way, employee computer purchase plan, clothing and uniform deductions.
  - Monthly remittances for Employer Health Tax (4 accounts), WSIB, OMERS (2 accounts).
  - Monthly and annual reporting for OMERS (2 accounts).

- Reporting
  - Monthly reporting to Statistics Canada, OMERS, Employer Health Tax, and WSIB.
  - Annual reporting for CRA (T4 and T4A's), OMERS, Employer Health Tax, WSIB, Public Sector Salary Disclosure Information, EI Premium Reduction Application.
  - Responding to HRDC requests for information regarding employment insurance claims.
  - Ad hoc reporting to department managers for budget monitoring.
  - Assist with City Financial Information Return.

- Other
  - Coordinate payroll audits by City auditors, CRA, Ministry of Finance, and WSIB.
  - Perform all acceptance testing and implement payroll computer systems changes including integration with other finance and HR systems.
  - Legislative interpretation and ensuring compliance with legislation.
  - Ensure compliance with City by-laws and six collective agreements.
  - OMERS administration (leave of absence buy-backs, termination reporting, etc.).
  - Liaise with external government organizations, banks, lawyers, etc.

COSTING METHODOLOGY

PowerStream will charge the following prices for providing the payroll services listed above to the City:

- 2011: $334,929
- 2012: $344,977
- 2013: $355,326
- 2014: $365,986
- 2015: $376,966

The prices listed above are cost based and are marked up by PowerStream's weighted average cost of capital of 7.3%. The following process was used to arrive at the costs.

1. Determined the direct costs associated with providing the service.

2. Determined the indirect costs associated with providing the service.

3. Determined what percentage of each budgetary account of the Payroll Department is attributable to providing the services.

4. Determined what costs are related only to providing the service and PowerStream wouldn't incur if it didn't provide the service.

5. Adjusted all costs for 3% inflation for years 2012, 2013, 2014 and 2015.

6. Summed all the costs related to providing the payroll services.

7. Adjusted the total cost for 7.3% in order to ensure a ROI of 7.3% as required by the ARC.

8. The adjusted amount is the price charged to the City.

SCHEDULE D

CASHIER SERVICES

CASHIER SERVICES PROVIDED BY POWERSTREAM TO THE CITY

SERVICE SUMMARY

PowerStream agrees to provide the following cashier services to the City for the years 2011 to 2015.

- Opening and sorting night box for payments
- Processing payments for:
  - Taxes
  - Parking permits
  - Permits
  - Licensing
  - Dog Tags
- Delivery of items to the City Mail Room
- Encoding all cheques in preparation for daily bank deposits
- Preparing Debit Machine, Visa/MasterCard
- Cash petty cash cheques
- Change/create float for events (Canada Day, Winder Fest, etc.)
- Prepare courier pick-up for Symcor payments
- Prepare for Brinks pick-up of daily cash deposits
- Prepare daily City blotter
- Issue City receipts
- Deliver completed/processed receipts to appropriate departments:
  - Building
  - Taxes
  - Bylaws
  - Licensing
  - Finance

- Process and accept ticket purchases for City events/offers
  - Wonderland
  - Ontario Place
  - Golf tournaments
  - Other special events

- Respond to counter inquiries (location of departments, tax due dates, etc.)

COSTING METHODOLOGY

PowerStream will charge the following prices for providing the cashier services listed above to the City:

- 2011: $242,890
- 2012: $250,176
- 2013: $257,682
- 2014: $265,412
- 2015: $273,374

The prices listed above are cost based and are marked up by PowerStream's weighted average cost of capital of 7.3%. The following process was used to arrive at the costs.

1. Determined the direct costs associated with providing the service.

2. Determined the indirect costs associated with providing the service.

3. Determined what percentage of each budgetary account of the Payments Department is attributable to providing the services.

4. Determined what costs are related only to providing the service and PowerStream wouldn't incur if it didn't provide the service.

5. Adjusted all costs for 3% inflation for years 2012, 2013, 2014 and 2015.

6. Summed all the costs related to providing the cashier services.

7. Adjusted the total cost for 7.3% in order to ensure a ROI of 7.3% as required by the ARC.

8. The adjusted amount is the price charged to the City.

The cashiering services will only be required to be performed by PowerStream until approximately September 30, 2012. Any cashiering services to be performed by PowerStream after this proposed date or in the event of cashiering services by the City on behalf of PowerStream, the Parties will amend the Agreement accordingly.

SCHEDULE E

WATER METER READING AND WATER BILLING AND REMITTANCE SERVICES PROVIDED BY POWERSTREAM TO THE CITY

Services levels currently provided will be maintained which may include those functions following.

GENERAL SERVICES PROVIDED

- **Billing of all water/sewer services.**

  - As required, PowerStream to explain the methodology used to produce estimated readings and the adjustment/correction once regular reads are collected.

  - PowerStream shall be responsible for the work quality of their meter readers.

  - PowerStream shall be responsible for submitting any work orders relating to water meters to the City and/or the City's contractor in a timely manner.

- **Revenue Management & Collections**

  - Payment by customers of water accounts are in conjunction with electricity accounts and the amounts owing are treated as one (unless prevented by the Ontario Energy Board from doing so). The Ontario Energy Board has made amendments to the Distribution System Code (DSC) that effective January 1st, 2011 or up to two (2) years from that date based on circumstances described in the amended DSC, payments must be allocated to electricity charges first and then to other charges.

  - Upon request, PowerStream shall investigate & provide account details to the City for specific customers where consumption varies from historic consumption levels.

  - PowerStream shall provide billing & collection for Waterworks customer services as per the City's approved user fee schedule for the following services:

    - Frozen meter replacement
    - Water turn on and/or turn off
    - Water meter removal, replacement and/or reinstallation
    - Water meter testing

  - PowerStream shall provide written notices to the customer to have the ARB installed or repaired.

- Coordination of appointments for repairs to water meter remote readout devices.

CUSTOMER ACCOUNT MANAGEMENT

- Resolution of Returned Mail
- Management of outgoing mail

SERVICE LEVELS

- PowerStream will include with its regular bill mailings one (1) bill insert per mailing (containing Waterworks information supplied by the municipality) at no cost. Availability is at the discretion of PowerStream. There may be third party costs associated with bill inserts.

TELEPHONE AND WRITTEN INQUIRY HANDLING

Response to telephone and written inquiries regarding water/sewer and electric will meet or exceed the mandated requirements as set out by the Ontario Energy Board:

- Telephone Response – 65% of calls answered within 30 seconds.
- Written Response to Inquiry – Within 10 business days, 80% of the time.

Annual statistics are reported to the Ontario Energy Board.

REPORTING STATISTICS

- Monthly Billing Summary - best efforts by the fifth working day and no later than the 10^{th} calendar day.

- Monthly Active Account Count List of Water Accounts best efforts by the fifth working day (broken down between residential and commercial) and no later than the 10^{th} calendar day.

Water Meter Serial Number Corrections

PowerStream shall update the water meter serial numbers in their database as provided by the City from time to time. These corrections should be merged into PowerStream's database within 20 business days of receipt.

Work Orders Statistics

- PowerStream shall provide the City monthly reports of outstanding work orders.

Customer Billing Data

PowerStream should provide customer billing data to the City in electronic format at the end of each billing month. The billing data should include the customers billed in the current month, separated into residential, general and industrial customers. Data is used in various Waterworks analyses.

PRICING

PowerStream will charge the following prices for providing the water meter reading, billing and payment & collection services listed above. The Parties will review the 2014 and 2015 prices in 2014 and 2015 at a mutually agreeable time. In the event the growth in the annual number of accounts exceeds 7% in either of 2014 or 2015, adjustments to pricing for those years will be made accordingly, subject to the mutual agreement of the Parties.

- 2011: $1,147,000
- 2012: $1,181,410
- 2013: $1,216,850
- 2014: $1,253,360
- 2015: $1,290,960

The prices listed above are cost based and are marked up by PowerStream's weighted average cost of capital of 7.3%. The following process was used to arrive at the costs. The meter reading service is obtained form a competitive bidding process.

1. Determined the direct costs associated with providing the service.

2. Determined the indirect costs associated with providing the service.

3. Determined what percentage of each budgetary account of the various Customer Services Departments are attributable to providing the services.

4. Determined what costs are related only to providing the service and PowerStream wouldn't incur if it didn't provide the service.

5. Adjusted all costs for 3% inflation for years 2012, 2013, 2014 and 2015.

6. Summed all the costs related to providing the water services.

7. Adjusted the total cost for 7.3% in order to ensure a ROI of 7.3% as required by the ARC.

8. The adjusted amount is the price charged by PowerStream to the City.

POWERSTREAM AND THE TOWN OF MARKHAM, 2011 TO 2013
(EXECUTED COPY ATTACHED)

SHARED SERVICES AGREEMENT made in duplicate this 1st day of January, 2011

B E T W E E N:

POWERSTREAM INC.,
(hereinafter called "**PowerStream**")

\- and -

THE CORPORATION OF THE TOWN OF MARKHAM,
(hereinafter called the "**Town**")

WHEREAS on January 1, 2009, PowerStream and Barrie Hydro Distribution Inc.(Barrie Hydro) amalgamated (the "Amalgamation") in accordance with a merger agreement dated October 10th, 2008, between The Corporation of the City of Vaughan, The Corporation of the Town of Markham and the Corporation of the City of Barrie (the "**Merger Agreement**");

AND WHEREAS prior to the Amalgamation, the Town and PowerStream entered into an agreement dated January 1st, 2008, providing for PowerStream to provide certain services to the Town and the Town to provide certain services to PowerStream (the "**Services Agreement**");

AND WHEREAS PowerStream and the Town wish to terminate the Services Agreement and replace it with this Agreement as of the Effective Date to continue to provide certain services to each other for the consideration and on the terms and conditions hereinafter set forth;

NOW THEREFORE in consideration of the premises and the mutual covenants and agreements herein contained (the receipt and sufficiency of which is hereby acknowledged by each of the Parties hereto), the Parties hereto hereby covenant and agree as follows:

1. INTERPRETATION

1.1 **<u>Definitions</u>**. In this Agreement, including the recitals and Schedules hereto, the following words shall have the following meanings:

1.1.1 "**Affiliate**" means a body corporate which is deemed to be affiliated with another body corporate, by virtue of one of them being the subsidiary of the other or both being subsidiaries of the same body or each of them being controlled by the same person

1.1.2 "**Affiliate Relationships Code**" means the rules issued by the Ontario Energy Board that govern the conduct of utilities as that conduct relates to their respective affiliates, as may be amended from time to time.

1.1.3 "**Agreement**" means this shared services agreement and all recitals and all Schedules attached hereto as the same may be amended, modified, supplemented, restated, or replaced from time to time;

1.1.4 "**Applicable Law**" means collectively, all applicable federal, provincial, territorial, municipal and foreign laws, statutes, ordinances, decrees, rules, regulations, by-laws, legally enforceable policies, codes, or guidelines, judicial, arbitral, administrative, ministerial, departmental or regulatory judgments, orders, decisions, directives, rulings or awards, and conditions of any grant of approval, permission, certification, consent, registration, authority or licence by any court, statutory body, self-regulatory authority, stock exchange or other Governmental Authority;

1.1.5 "**Binding Arbitration**" has the meaning ascribed thereto in Section 8.12;

1.1.6 "**Business Day**" means any day other than a day which is a Saturday, a Sunday or a statutory holiday or a civic holiday in the Province of Ontario;

1.1.7 "**Claims**" has the meaning ascribed thereto in Section 7.2;

1.1.8 "**Confidential Information**" means the confidential, secret or proprietary information of one Party (the "**Disclosing Party**"), including but not limited to any of such information or data which is technical, financial or business in nature including customer information, and which has been or may hereafter be disclosed, directly or indirectly, to the other Party (the "**Recipient**"), either orally, in writing or in any other material form, or delivered to the Recipient;

1.1.9 "**Effective Date**" means January 1, 2011;

1.1.10 "**Extension Notice**" has the meaning ascribed thereto in Section 4.2;

1.1.11 "**Fee Review Date**" has the meaning ascribed thereto in subsection 2.5.3;

1.1.12 "**Fees**" means collectively the Town Fees and the PowerStream Fees;

1.1.13 "**Governmental Authority**" means any court, arbitrator, administrative agency, commission, or governmental or regulatory official, department, agency, body, authority or instrumentality, whether foreign, federal, state, provincial, municipal, or local, having jurisdiction over the Parties;

1.1.14 **"In Writing"** or **"Written"** means a posted letter, a facsimile transmittal or an e-mail message;

1.1.15 "**Internal Dispute Resolution**" has the meaning ascribed thereto in subsection 8.12.1;

1.1.16 **"MFIPPA"** means the *Municipal Freedom of Information and Protection of Privacy Act,* R.S.O. 1990, c. M. 56.

1.1.17 "**Notice**" has the meaning ascribed thereto in Section 8.5;

1.1.18 **"Parties"** means the parties to this Agreement and **"Party"** shall mean any one of them.

1.1.19 **"PowerStream Fees"** means collectively, the charges payable by the Town to PowerStream for the provision of the services set out on Schedules B and C attached hereto, plus all applicable taxes, if any, in respect thereof;

1.1.20 **"PowerStream Services"** means the services provided by PowerStream to the Town as set out at Schedules B and C;

1.1.21 **"Requested Party"** has the meaning ascribed thereto in Section 8.1;

1.1.22 **"Services"** means collectively the PowerStream Services purchased by the Town from PowerStream as set out on Schedules B and C attached hereto and the Town Services purchased by PowerStream from the Town as set out on Schedule A, or those services agreed to in writing between the Parties from time to time;

1.1.23 **"Term"** means the term of this Agreement commencing on the Effective Date to and including the Termination Date;

1.1.24 **"Termination Date"** has the meaning ascribed thereto in Section 4.1;

1.1.25 **"Town Fees"** means collectively, the charges payable by PowerStream for the provision of the Services as set out in Schedule A attached hereto, plus all applicable taxes, if any, in respect thereof;

1.1.26 **"Town Services"** means the services provided by the Town to PowerStream as set out on Schedule A attached hereto;

1.1.27 **"Unsatisfied Party"** has the meaning ascribed thereto in Section 8.1.

1.2 **Headings**. The division of this Agreement into Sections and subsections and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms **"this Agreement"**, **"hereof"**, **"hereunder"** and similar expressions refer to this Agreement and not to any particular Section or other portion hereof and include any agreement supplemental hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to **"Sections"** are to sections and **"subsections"** are to subsections of this Agreement.

1.3 **Extended Meanings**. In this Agreement words importing the singular number only shall include the plural and vice versa, words importing any gender shall include all genders and words importing persons shall include individuals, partnerships, associations, trusts, unincorporated organisations, companies and corporations.

1.4 **Currency**. All references to currency herein are to lawful money of Canada unless otherwise specified.

1.5 **Schedules**. The following Schedules which are attached to this Agreement are incorporated by reference into this Agreement and are deemed to be a part of it:

Town Services provided to PowerStream:

Schedule A	-	Cashier Services at Markham Town Hall

Services Purchased from PowerStream by the Town:

Schedule B	-	Water Meter Reading and Billing
Schedule C	-	Street Lighting Services

2. SERVICES

2.1 **Provision of Services**.

2.2 In accordance with the terms hereof, from and after the Effective Date to the Termination Date:

2.2.1 PowerStream agrees to provide and perform, at the request of the Town, the Services for the benefit of the Town or the Town's Affiliates, as the case may be.

2.2.2 The Town agrees to provide the Town Services for the benefit of PowerStream or PowerStream's Affiliates, as the case may be.

2.3 **Standard of Services**. Notwithstanding the provisions of section 7.1 herein, the Parties shall perform their respective Services in a prudent, businesslike manner in accordance with the policies and service levels applicable to such Services as set out in the Schedules or such practices, policies and service levels as may be amended from time to time pursuant to Section 2.4 hereof. The Parties shall provide the Services in accordance with all Applicable Laws. Notwithstanding the foregoing, "**Applicable Laws**" shall not include any by-laws, guidelines, directions, rules or standards of the Town introduced, proclaimed or implemented after the date hereof that affects the provision of the Services by PowerStream hereunder or the terms hereof.

2.4 **Amendments**. At any time during the term of this Agreement either Party may request changes in the Services that a party receives or the practices, policies or performance levels applicable to the Services received by submitting such requests (the "Requesting Party") in writing to the other Party (the "Receiving Party"). Within a reasonable time, but in any event not more than thirty (30)

Business Days after receiving written notice of a request, the Receiving Party shall advise the Requesting Party whether the change requested will have an impact on the delivery of the Services, acting reasonably, and whether or not the request will have an impact on the associated Fees and whether the Receiving Party authorizes the implementation of the change under the revised terms specified by the Requesting Party or rejects the change proposed. Minor adjustments to existing reports shall not trigger fee increases or the imposition of one-time fees. Pending the Receiving Party response, the Requesting Party shall continue to receive the applicable Services in accordance with the latest approved terms for the provision of such Services.

2.5 <u>**Fees**</u>.

2.5.1 Town Fees paid by PowerStream shall be those as set out on Schedules A, or as mutually agreed upon by the Parties in writing from time to time.

2.5.2 PowerStream Fees paid by the Town shall be those as set out on Schedules B and C, or as mutually agreed upon by the Parties in writing from time to time.

2.5.3 The Parties shall review the PowerStream Fees in respect of Schedule C only on an annual basis, prior to or on November 1st (the "**Fee Review Date**") for the following calendar year. If the Parties are unable to agree on the adjustments to the PowerStream Fees within thirty (30) days of the Fee Review Date then the dispute shall be settled by the dispute resolution procedure in accordance with Section 8.12 herein.

2.5.4 Unless otherwise specified herein, PowerStream Fees shall be invoiced to the Town on a monthly basis. The final invoice sent by PowerStream to the Town for Streetlight Maintenance Services only, shall adjust the annual Fees to reflect actual rather than budgeted costs.

2.5.5 Town Fees shall be invoiced to and shall be payable by PowerStream in accordance with the provisions of Schedule A.

2.5.6 The Parties agree that payment of Town Fees and other charges provided for hereunder will be due and payable in arrears not later than thirty (30) days after the date of invoice.

2.5.7 All PowerStream Fees and Town Fees shall comply with the requirements of the Affiliate Relationships Code.

2.6 <u>**Co-operation by Town**</u>. The Town shall co-operate with PowerStream to assist it in the provision of the Services. Without limiting the generality of the foregoing, the Town shall:

2.6.1 assign a minimum of two (2) representatives of the Town to co-ordinate with PowerStream the provision of the Services to the Town to deal with financial and operational issues respectively;

2.6.2 prepare and provide to PowerStream, in a mutually acceptable format, all information reasonably required by PowerStream to permit proper delivery of the Services;

2.6.3 establish, incorporate and maintain as part of the practices, policies and service levels applicable to such Services, in consultation with PowerStream, operating procedures to satisfy the Town's requirements for accuracy and auditing;

2.6.4 provide training, if necessary, to personnel to assist in the provision of the required information to PowerStream to permit PowerStream to provide the Services; and,

2.6.5 provide PowerStream with assistance in collecting amounts owed to the Town. The Town may place any of such unpaid amounts on the collector's roll and enforce any other rights or remedies of the Town pursuant to section 398(2) of the *Municipal Act*, S. O. 2001, c. 25.

2.7 **Customer Information**.

2.7.1 PowerStream acknowledges that the ownership of all data in respect of water and sewer customers of the Town as such data relates to: water and sewer information, water and sewer consumption history and charges, fire protection information, customer information including name, billing address, legal description, service address, the final twelve (12) months of meter readings for each customer, outstanding water and sewer invoices, customer credit and collection information, and information with regard to work orders and asset management systems is and shall remain the property of the Town. PowerStream shall ensure that all of the data contemplated by this Section 2.7.1 is backed up in accordance with current PowerStream procedures and can be restored in one or two Business Days. The Town acknowledges that PowerStream can only back up data collected for a maximum period of 7 years.

2.7.2 The Town acknowledges that the ownership of data in respect of electricity customers whether past or present of PowerStream or any of its Affiliates is and shall remain the property of PowerStream

2.7.3 Requests for data by the Town under Section 2.7.1 shall be made In Writing by an individual designated by the Town to the attention of the VP Information Services at PowerStream or such other individual designated by PowerStream. PowerStream shall within 1 Business Day advise the Town of the effort required to provide such data and such data shall be provided by PowerStream to the Town no later than 2 Business

Days from the date the request is made by the Town or within such other, longer period of time as set out in the response from PowerStream.

2.7.4 Each Party, its employees and agents shall abide by all Applicable Laws, including the requirements of the Affiliate Relationships Code to the extent that it applies, and including Applicable Laws relating to the collection, use, retention, destruction and disclosure of any personal information which has been collected, used, retained, destroyed and disclosed in connection with the Services provided by such Party hereunder.

3. CONFIDENTIAL INFORMATION

3.1 **Confidentiality Obligation**. Commencing upon the Effective Date and continuing thereafter , each Party:

3.1.1 shall treat as confidential, keep in safe custody and not disclose to any third party any Confidential Information provided to it by the other Party; and,

3.1.2 use such Confidential Information only to the extent necessary to comply with this Agreement.

3.2 Each of the Parties shall establish and enforce procedures to protect Confidential Information disclosed to it by the other Party and shall restrict disclosure of such Confidential Information to only those employees, officers, agents and professional advisors of it and its Affiliates who need to know such information in connection with such Party's performance of this Agreement and in accordance with MFIPPA or any other applicable legislation. If a Party or its Affiliate is required by order of any Governmental Authority or Applicable Law or the rules of a stock exchange to disclose Confidential Information disclosed to it by the other Party, it shall promptly notify (if permissible) the other Party of the request for disclosure and shall cooperate with the other Party if that other Party opposes the request for disclosure and wishes to seek confidential treatment for such Confidential Information that is required to be disclosed. Each of the Parties acknowledges that no adequate remedy at law exists for a material breach or threatened material breach of this Section 3.2 the continuation of which unremedied will cause the other Party to suffer irreparable harm, and agrees that the other Party is entitled, in addition to other remedies which may be available at law or in equity, to immediate injunctive relief from any breach of this Section 3.2 and to specific performance of its rights. Promptly following the Termination Date, each Party agrees to use commercially reasonable efforts to deliver to the other Party the Confidential Information (including all electronic and other copies thereof) disclosed to it by the Disclosing Party that the Receiving Party possesses or, upon request by a Disclosing Party, the Receiving Party shall confirm in writing from a senior officer of a Party to the Disclosing Party that such

Confidential Information has been destroyed in accordance with the Disclosing Party's instructions.

3.3 The Parties agree to protect the Confidential Information in accordance with MFIPPA and the *Personal Information Protection and Electronic Documents Act* (Canada).

4. TERM.

4.1 **Term**. This Agreement will be effective as at the Effective Date and shall terminate three (3) years after the Effective Date, unless terminated earlier pursuant to Section 5.1 or extended by renewal of the term pursuant to Section 4.2 (the "**Termination Date**").

4.2 **Extension of Term**. If either Party gives notice in writing to the other Party by not later than sixty (60) days prior to the Termination Date, requesting the continuation of Services or the provision of the Town Services, as the case may be (an "**Extension Notice**") for an additional one year period, the Parties agree to negotiate, in good faith, in order to determine the terms and conditions on which such Services will be provided for a renewal term of one year or such longer period as is mutually agreed to. Notwithstanding anything in this Section 4.2 to the contrary, there shall be no obligation upon any Party having been provided with an Extension Notice to extend the term of this Agreement.

5. TERMINATION.

5.1 **Termination**. This Agreement, shall terminate on the Termination Date and may be terminated prior thereto as follows:

5.1.1 by the mutual written consent of the Parties hereto;

5.1.2 by either Party effective upon not less than thirty (30) days written notice of any material breach or default of any provision or obligation of this Agreement by a Party, provided that such notice will not be effective to terminate this Agreement in the event the other Party cures the default during such notice period; and

5.1.3 immediately, by either Party if the other Party becomes insolvent or is a party to any bankruptcy or receivership proceeding or any similar action affecting the affairs, property or solvency of such Party.

5.1.4 **Termination Without Prejudice.** Any such termination of this Agreement shall be without prejudice to any other remedies which any Party may have against the other arising out of such breach of default and shall not affect any rights or obligations of any Party arising under this Agreement prior to such termination.

6. FORCE MAJEURE.

6.1 **Force Majeure**. Performance of any obligation under this Agreement, other than the payment of Fees pursuant to Sections 2.5.4, 2.5.5 and 2.5.6, may be suspended by either Party without liability to the extent that an act of God, war, fire, earthquake, explosion, governmental expropriation, governmental law or regulation or any other occurrence beyond the reasonable control of such Party or labour disruption, strike or injunction (if such labour event is not caused by the bad faith or unreasonable conduct of such Party) delays, prevents, restricts, limits or renders commercially unfeasible the performance of any such obligation. The affected Party may invoke this provision by promptly notifying the other Party of the nature and estimated duration of the suspension. No Party hereto invoking this provision shall be liable for any failure to perform or any delay in the performance of its obligations in this Section 6.1.

7. DISCLAIMER, LIMIT OF LIABILITY AND INDEMNITY

7.1 **Disclaimer**. The Services provided by PowerStream are provided without any warranty whatsoever, other than as is set forth in Section 2.3 hereof. In particular, PowerStream makes no warranty as to the suitability of any of the Services for the specific purposes or needs of the Town. The warranty contained in this Agreement is the only warranty made by PowerStream with respect to the Services. PowerStream specifically excludes any other warranties or conditions express or implied, including, but not limited to, implied warranties or conditions of merchantability, merchantable or satisfactory quality or fitness for a particular purpose, and those arising from a course of dealing or usage of trade.

7.2 **Indemnity by the Town**. The Town agrees to indemnify, defend and hold harmless PowerStream from any and all claims, litigation, damages, losses, causes of action or expenses (including legal fees and disbursements) (“**Claims**”) suffered or incurred by PowerStream from third parties or otherwise in connection with:

7.2.1.1 a breach of the Town’s obligations under this Agreement insofar as PowerStream has complied with its obligations under this Agreement; and

7.2.1.2 any negligence on the part of the Town, its employees, contractors or agents in its provision of the Town Services.

7.3 Notwithstanding the provisions of Section 7.2, the Town shall be under no obligation to indemnify and save harmless PowerStream from any Claims resulting from the negligence or wilful misconduct of PowerStream in its provision of the PowerStream Services hereunder.

7.4 **Indemnity by PowerStream**. PowerStream agrees to indemnify, defend and hold harmless the Town from any and all Claims suffered or incurred by the Town from third parties or otherwise in connection with:

7.4.1 a breach of PowerStream's obligations under this Agreement insofar as the Town has complied with its obligations under this Agreement; and

7.4.2 any negligence on the part of PowerStream, its employees, contractors or agents in its provision of the Services hereunder.

7.5 Notwithstanding the provisions of Section 7.4, PowerStream shall be under no obligation to indemnify and save harmless the Town from any Claims resulting from the negligence or wilful misconduct of the Town in its provision of the Town Services hereunder.

7.6 **Insurance**. Both Parties shall provide and keep in force a comprehensive liability insurance policy with coverage equal to or greater than Five Million Dollars ($5,000,000) (Canadian) of sufficient coverage in respect of the Services performed by it under the terms of this Agreement.

8. MISCELLANEOUS

8.1 **Audit.** The Parties shall maintain accurate and complete books and records with respect to (i) the Services provided hereunder, (ii) the Fees, and (iii) any information provided by a Party to the other Party for the provision of the Services. Each Party shall keep its accounts and records in accordance with Canadian generally accepted accounting principles from time to time approved by the Canadian Institute of Chartered Accountants (or a successor institute) with respect to the computation of Fees and other charges payable pursuant to this Agreement. Each Party shall be entitled to audit such books and records in order to confirm compliance with the terms of this Agreement. Each Party shall make such books and records available to individuals designated by the other Party and provide any assistance it may reasonably require in order to conduct audits and inspections, provided that:

8.1.1 audits and inspections shall be made at reasonable times and on at least ten (10) Business Days prior notice; and

8.1.2 audits of Fees shall be made not later than twenty four (24) months after such Fees have been paid by a Party to the other Party.

Each Party agrees to provide the other Party with reasonable facilities for such audits and inspections and copies of documents, where necessary, appropriate and permitted by law. If a Party is not satisfied with the information provided (the "**Unsatisfied Party**"), the Unsatisfied Party may retain, at its own expense, an independent auditor, to review the books and records referred to above. The Party requested to provide additional information (the "**Requested Party**") may refuse to disclose to the Unsatisfied Party or its agents any information that the Requested Party is prevented from disclosing as a result of a confidentiality obligation to another person provided that the Requested Party shall use commercially reasonable efforts to obtain consents to permit disclosure of such information if such information is reasonably required in order to conduct an audit and inspection by the Requesting Party under this Section 8.1 and the Requesting Party or its agents has requested access to such information. Each of the Parties agree that any third party conducting an audit or inspection shall be subject to the confidentiality provisions of Sections 3.1 and 3.2 and may be required by the Requested Party to enter into a confidentiality and non-disclosure agreement in form and substance reasonably acceptable to the Requested Party and each of the Parties agree that should an independent auditor be deemed by the Requested Party to be a competitor of the Requested Party, the Parties shall mutually agree to the review and audit procedures prior to such review and audit.

8.2 **Governing Law**. This Agreement shall be governed by and construed in accordance with the law of the Province of Ontario and the laws of Canada applicable therein.

8.3 **Successors**. This Agreement will enure to the benefit of and be binding on the respective successors and assigns of each of the Parties.

8.4 **Time of Essence**. Time shall be of the essence of this Agreement

8.5 **Notices**. Unless otherwise expressly provided herein, any notice, consent or other communication (a "**Notice**") given pursuant to or in connection with this Agreement shall be in writing and shall be sufficiently given to the person to whom it is addressed if transmitted by facsimile, delivered in person to or for such person at the address of such person indicated below or at such other address as such person shall have provided in writing to the other Party in accordance with this provision. Any Notice provided in accordance with this provision shall be deemed to have been sufficiently given or made on the date on which it was so transmitted by facsimile or delivered provided that if such day is not a Business Day or delivery occurs after normal business hours of the recipient, the Notice shall be deemed given or made on the Business Day following transmission or delivery, as the case may be.

To PowerStream:

PowerStream Inc.
161 Cityview Boulevard
Vaughan, Ontario
L4H 0A9
Attention: Dennis Nolan
Executive Vice President, Corporate Services and Secretary
Fax: (905) 532-4616
E-Mail: dennis.nolan@powerstream.ca

To the Town:

The Corporation of the Town of Markham
Anthony Roman Centre
101 Town Centre Boulevard

Markham, Ontario
L3R 9W3
For Financial:
Attention: Joel Lustig
Treasurer
Fax: 905-479-7769
E-Mail: jlustig@markham.ca

For Operation Issues:
Attention: Paul Ingham
Director, Operations
Fax: 905-940-1550
E-Mail: pingham@markham.ca

For Waterworks Operational issues:
Attention: Peter Loukes
Director, Environmental Services
Fax: 905-479-7766
E-Mail: ploukes@markham.ca

or to such other address as such Party shall have notified to the other Party hereto. Any communication so addressed and delivered shall be deemed to have been sufficiently given or made on the date on which it was received.

8.6 **Entire Agreement**. This Agreement, together with the recitals and the Schedules attached hereto, constitutes the entire agreement between the Parties hereto with regard to the subject matter hereof and supersedes and cancels all previous negotiations, agreements, commitments and writings in respect of the subject matter hereof. This Agreement may not be modified or amended in any respect except by written instrument signed by the Parties hereto.

8.7 **Waiver**. The failure of any Party to this Agreement at any time to require performance by the other Party of any provision hereof shall in no way affect the full right to require such performance at any time thereafter of any other provision hereof and no waiver by any Party hereof of any breach of condition, covenant or agreement shall constitute a waiver except in respect of the particular breach giving rise to such waiver. Any such waiver shall be effective only if made in writing by the Party entitled to waive the provision.

8.8 **Independent Contractor**. By virtue of this Agreement, no Party hereto constitutes any other Party hereto as its agent, partner, joint venturer, franchisee or legal representative and no Party has express or implied authority to bind any other Party hereto in any manner whatsoever. Unless otherwise contemplated in the Services or the Town Services or approved in writing by the other Party, no Party hereto will assume or create any obligation or responsibility whatsoever, express or implied, on behalf of or in the name of that other Party.

8.9 **<u>Assignment</u>**. This Agreement and the privileges herein granted shall not be assigned by either Party except with the prior written consent of the other, such consent not to be unreasonably withheld. Notwithstanding the foregoing, either party or its permitted assignee may, as security only, assign, transfer, pledge, grant a security interest in or otherwise dispose of its rights and interests under this Agreement to a trustee or lending institution, including such an assignment, transfer or other disposition upon or pursuant to the exercise of remedies by such trustee or lending institution.

8.10 **<u>Further Assurances</u>**. Each of the Parties hereto from time to time at the request and expense of the other Party hereto and without further consideration, will execute and deliver such other instruments of transfer, conveyance and assignment and take such further action as such other Party may require to more effectively complete any matter provided for herein.

8.11 **<u>Severability</u>**. Any covenant or provision hereof determined to be void or unenforceable in whole or in part will be deemed not to affect or impair the validity or enforceability of any other covenant or provision hereof and the covenants and provisions hereof are declared to be separate and distinct.

8.12 **<u>Arbitration</u>**.

8.12.1 In the event of any dispute or claim between the Parties, arising out of, or relating to, in any way connected with this Agreement or its interpretation or the fulfilment of the obligations of the Parties hereunder (a "**Dispute**"), such Dispute shall be referred internally by either Party by written notification to Dennis Nolan, Executive Vice President, Corporate Services and Secretary at PowerStream and Andy Taylor, Chief Administrative Officer at the Town for resolution (the "**Internal Dispute Resolution**"). If the Dispute is not resolved within 60 Business Days of a Dispute being referred to the Internal Dispute Resolution then such Dispute shall be settled by binding arbitration ("**Binding Arbitration**"). Binding Arbitration shall be conducted in accordance with the *Arbitration Act, 1991* (Ontario), as amended from time to time.

8.12.2 It shall be a condition precedent to the right of a Party to this Agreement to submit a Dispute to Binding Arbitration that such Party shall have given written notice of its intention to do so to the other Party to this Agreement and such written notice shall state the particulars of such Dispute. Within ten (10) Business Days of such notice being provided, the Parties to this Agreement shall mutually appoint a single arbitrator to determine the Dispute. The arbitrator shall fix a time, which shall not be later than ten (10) Business Days following his or her appointment, and a place in Vaughan, Ontario, for the purpose of hearing the evidence and representations of the Parties. Each of the Parties shall co-operate with the arbitrator and shall provide him or her with all information in their possession or under their control necessary or relevant to the matter being determined. Within ten (10) Business Days after the conclusion of the arbitration hearing, or such longer period as may be required by the arbitrator appointed under this subsection 8.12.2, the arbitrator shall make an award and reduce the same to writing and deliver one copy of his or her decision to each Party.

8.12.3 If the Parties fail to agree on an arbitrator within the time period specified in subsection 8.12.2 above, then, unless the parties otherwise agree, the Dispute shall be submitted to ADR Chambers for final resolution, which submission shall be by written notice which may be provided by either Party to ADR Chambers and to the other Party to this Agreement. Within five (5) Business Days following the date of any notice given by either Party pursuant to this subsection 8.12.3, an arbitrator shall be selected by random draw made by ADR Chambers. The arbitrator so selected shall perform both the settlement conference and the trial in the matter. The Parties further agree to be bound by the rules of the ADR Chambers in force from time to time.

8.12.4 There shall be no right of appeal from the arbitrator's award except in accordance with the *Arbitration Act, 1991* (Ontario). The Parties agree that a judgment upon the arbitration award may be entered in any court in Canada or any court having jurisdiction, or that an application may be made to such court for judicial recognition of the award and/or an order of enforcement thereof. The Parties agree that the arbitrator selected pursuant to subsections 8.12.2 and 8.12.3 shall determine costs (legal fees and disbursements) as part of the arbitrator's award.

8.13 **Survival.** The following Sections and or subsections will survive the expiry or termination of this Agreement: Subsections 2.5.1, 2.5.2, 2.5.4 to 2.5.7 inclusive, Section 2.7, Sections 3.1, 3.2, 3.3, Sections 7.1 to 7.5 inclusive, Section 8.1, and this Section 8.13.

8.14 **Counterparts**. This Agreement may be executed by the Parties hereto in several counterparts, each of which when so executed and delivered shall be an original and all such counterparts shall together constitute one and the same instrument.

IN WITNESS WHEREOF, this Agreement has been executed by the Parties hereto on the date first above written.

POWERSTREAM INC.

Per: ______________________________

Name: Dennis Nolan
Title: EVP Corporate Services & Secretary

THE CORPORATION OF THE TOWN OF MARKHAM

Per: ______________________________

Mayor Frank Scarpitti

APPROVED AS TO FORM
2/17/12 AMR
TOWN SOLICITOR

Per: ______________________________

Clerk Kimberley Kitteringham

APPROVED TOWN OF MARKHAM
COUNCIL ✓ RESOLUTION # 8
CMTE G.C. REPORT # 1
BY-LAW # DATE DEC. 14/10
KB

SCHEDULE "A"

TOWN SERVICES

CASHIER SERVICES AT MARKHAM TOWN HALL

Terms and Pricing

This Schedule conveys the service expectations and service deliverables for the Town of Markham in its delivery of cashiering services to PowerStream beginning on January, 1, 2011, and lasting for the three-year term of this contract. All of the service expectations listed below will be accompanied by full training and refresher training provided by PowerStream, as required including documentations.

Service Expectations

On a daily basis, Town Cashiering staff will be required to do the following:

- Open for business at 8:30am
- Log into PowerStream's Customer Information System and Log off from PowerStream's Customer Information System when appropriate and in any event at close of business
- Accept payments related to PowerStream by cheque, by cash, by Interac from customers and occasionally from Field Customer Service Representatives who have collected
- Input payments into PowerStream's cash management system
- Set aside any post-dated cheques and forward them to PowerStream's Head Office
- Day-End, Month-End and Year-End routines as determined by PowerStream will be broadcast to Town Cashiering staff
- Town staff or customer to advise PowerStream at the Head office location in Vaughan of payments made by customers who are at risk of disconnection or deserve to be reconnected once they have made their payments
- Prepare courier packages which could include customer related enquiries
- Prepare deposits for armoured courier pickup at a generally specified time each day during regular working hours
- Answer basic questions related to customer bills on account history and basic industry issues; any payment arrangements will be made through PowerStream's Head Office
- Close the cashier service at 4:30pm
- Balance payment batches as often as necessary throughout the day
- For any shortages, the Town of Markham will be responsible for the cost of the outage amount
- Print each posted and balanced payment batch summary and copies of the matching deposit slips and send via courier to PowerStream's Head Office
- Any correspondence, PAP/EPP applications, name change information, copies of deposit slips, new service applications and the like should be couriered to PowerStream's head Office at the next opportunity
- Prepare daily separate armoured courier pickup acknowledgements for both cash and cheques

Deliverables

PowerStream will provide:

- Deposit bags
- Deposit slips
- Armoured Courier service
- Staff training and documentation
- Any customer related information or rate schedules
- Point of sale Interac Machines including ribbons, rolls plus PowerStream receipts
- 3 "Paid" Stamps
- 3 "Entered" Stamps
- One "Deposit to the Credit of PowerStream Inc." Stamp

The Town of Markham will provide:

- Staff to handle the payment and customer service expectations of customers and the Town of Markham
- Cooperation to determine the source and correction of any errors
- A telephone programmed to call toll-free to PowerStream's Head Office for priority support on issues of importance especially including issues requiring customers to be reconnected or to avoid being disconnected
- A display space for a few customer related information pieces plus water and electricity rate schedules
- A local printer to be able to print screens for enquiring customers and for batch backup

Annual Pricing

- 2011 annual cost $86,920
- Add 3% for wage/increases/inflation for cost of $89,527 in 2012 and $92,213 in 2013
- Provided that if the actual costs for the Interac line and one hot line go up by more than 3%, the annual pricing for these two items only shall increase by 3% plus the actual increase over 3%

SCHEDULE "B"

POWERSTREAM SERVICES

WATER METER READING AND BILLING

Services levels currently provided will be maintained which may include those functions following.

GENERAL SERVICES PROVIDED

Billing of all water/sewer services

- As required, PowerStream to explain the methodology used to produce estimated readings and the adjustment/correction once regular reads are collected.
- PowerStream shall be responsible for the work quality of their meter readers.
- PowerStream shall be responsible for submitting any work orders relating to water meters to the Town and/or Town's contractor in a timely manner.
- All water meter reading.
- Billing of all water/sewer services.
- Bill calculation usage exception review; dollar value exception review.

REVENUE MANAGEMENT & COLLECTIONS

- Payment by customers of water accounts are in conjunction with electricity accounts and the amounts owing are treated as one (unless prevented by the Ontario Energy Board from doing so. The Ontario Energy Board has made amendments to the Distribution System Code (DSC) that effective January 1st, 2011 or up to two (2) years from that date based on circumstances described in the amended DSC, payments must be allocated to electricity charges first and then to other charges.
- Upon request, PowerStream shall investigate & provide account details to the Town for specific customers where consumption varies from historic consumption levels.
- PowerStream shall provide billing & collection for Waterworks customer services as per the Town's approved user fee schedule for the following services:

- Frozen meter replacement
- Water turn on and/or turn off
- Water meter removal, replacement and/or reinstallation
- Water meter testing

- o PowerStream shall provide written notices to the customer to have the ARB installed or repaired
- o Coordination of appointments for repairs to water meter remote readout devices
- o Collection action applies to accounts that remain unpaid beyond the due date and may result in the disconnection of electricity service.
- o Failure to pay for the water/sewer service arrears does not necessarily result in water/sewer service disconnection.
- o Back-billing for water/sewer services where applicable, will be actively pursued. Complex back-billing/adjustments are to be approved by the Town and responses to disputes that cannot be resolved by PowerStream are to come from the Town. A normal Town of Markham contact for such cases is required.
- o PowerStream acts as the billing and collection *agent* on behalf of the Town of Markham and as such cannot accept bad debt water losses. Such losses will be charged back to the Town of Markham annually by deduction from the proceeds of water/sewer revenues collected.
- o PowerStream will assist the Town of Markham to tax-roll for unpaid water and sewer arrears as provided under the *Municipal Act, 2001, S.O. 2001* by transferring the water and sewer arrears to the owner of the property at which the services are provided.
- o Reporting of invalid or missing remote meter numbers and serial numbers.
- o Follow-up as required with both Water Works (Town of Markham) and the customer.
- o Reporting of missing or bypassed water meters.
- o Bad debt write- off list.

CUSTOMER ACCOUNT MANAGEMENT

- Resolution of Returned Mail
- Management of outgoing mail
- Set up and maintenance of customer account information.
- Set up of customer moving in and out information.

SERVICE LEVELS

- PowerStream will include with its regular bill mailings one (1) bill insert per mailing , containing information supplied by the Town at no cost. Availability is at the discretion of PowerStream. There may be third party costs associated with bill inserts.
- Frequency of all water meter readings and billings will be based on PowerStream's reading and billing cycles which are currently bi-monthly for residential accounts and monthly for commercial accounts.
- PowerStream will provide one rate-change adjustment per calendar year at no cost. Rate changes will normally be applied in the month of January. Pro-rating of bills resulting from rate changes or rate increases applied at any other time of the year will be provided at an additional cost.
- A minimum of 30 calendar day's written notice is required for water/sewer rate increases to be incorporated to the CIS to commence on the first day of the month as determined by the Town. More than 30 calendar days notice is welcome.

TELEPHONE & WRITTEN INQUIRY HANDLING

Response to telephone and written inquiries regarding water/sewer and electric will meet or exceed the mandated requirements as set out by the Ontario Energy Board:

- Telephone Response – 65% of calls answered within 30 seconds.
- Written Response to Inquiry – Within 10 business days, 80% of the time.

Annual statistics are reported to the Ontario Energy Board.

REPORTING STATISTICS

- Monthly Billing Summary and Accruals - best efforts by the fifth working day and no later than the 10th calendar day.

- o Monthly Active Account Count List of Water Accounts best efforts by the fifth working day (broken down between residential and commercial) and no later than the 10th calendar day
- o Monthly Account and Consumption List (electronic file received by Waterworks)

Water Meter Serial Number Corrections

PowerStream shall update the water meter serial numbers in their database as provided by the Town from time to time. These corrections should be merged into PowerStream's database within 20 business days of receipt.

Work Orders Statistics

PowerStream shall provide the Town monthly reports of outstanding work orders.

Customer Billing Data

PowerStream should provide customer billing data to the Town in electronic format at the end of each billing month. The billing data should include the customers billed in the current month, separated into residential, general and industrial customers. Data is used in various Waterworks analyses.

REMITTANCE & PRICING

PowerStream will charge the following prices for providing the water meter reading, billing and payment and collection services. A review of prices based on actual accounts will be made at the end of Q1 of the following year of each year of the Agreement. Any adjustment of prices based on this review would require the consent of both PowerStream and the Town.

All amounts billed in a calendar month shall be remitted to the Town no later than the 10th day of the following month, by electronic funds transfer. PowerStream shall be entitled to deduct 1/12th the annual cost set out below from each monthly remittance of the water accounts billed in the previous month.

- 2011: $1,136,862
- 2012: $1,170,172
- 2013: $1,205,277

The prices listed above are cost based and are marked up by PowerStream's weighted average cost of capital of 7.3%. The following process was used to arrive at the costs. The meter reading service is obtained from a competitive bidding process.

1. Determined the direct costs associated with providing the service.

2. Determined the indirect costs associated with providing the service.

3. Determined what percentage of each budgetary account of the various Customer Services Departments are attributable to providing the services.

4. Determined what costs are related only to providing the service and PowerStream wouldn't incur if it didn't provide the services.

5. Adjusted all prices for 3% inflation for years 2012 and 2013.

6. Summed all the costs related to providing the water services.

7. Adjusted the total cost for 7.3% in order to ensure a ROI of 7.3% as required by the ARC.

8. The adjusted amount is the price charged to the Town of Markham.

SCHEDULE "C"

POWERSTREAM SERVICES

Street Lighting Services Provided by PowerStream Inc. to the Town of Markham

SERVICE SUMMARY

Street Lighting Services for the Town of Markham is broken into five categories:

1. Street Light Maintenance
   a. Replacement of defective fixtures
   b. Burned out lights and ballasts
   c. Damaged poles and hardware
2. Re-lamping Program
   a. Replace all street light bulbs in 1 selected area out of the 5 geographic based on a 5 year area rotation cycle.
3. Accident (e.g. hit by car) and Vandalism
   a. Repair of broken street light poles.
   b. Repair of damaged hardware.
   c. Excludes damages where costs are recovered through insurance or by direct payment.
4. Street Light Faults
   a. Locating cable failure.
   b. Contracting labour to expose underground cable.
   c. Repairing damaged or faulty cables.
5. Pole Replacement (not a service covered in the street light contract).
   a. Replace aging poles as a part of the maintenance process.

TERM

Notwithstanding Section 4.1 of the Agreement, the Street Lighting Services shall be provided by PowerStream for a one (1) year term from January 1, 2011 to December 31, 2011. Thereafter, the term for Street Lighting Services may be renewed for three (3) additional one (1) year terms, upon written notice from the Town to PowerStream (as approved by the Town's Chief Administrative Officer).

COSTING METHODOLOGY

PowerStream will obtain pricing through a competitive bidding process in order to get the lowest cost for Town of Markham. PowerStream will manage the contract to ensure that service standards and quality are maintained. A contract management fee of 20% will be charged.

Pricing is estimated at $1,000,000 per year (including contract management fee) based on the experience in 2009 and 2010 and a Forecast for 2011. The actual costs will be charged.

Costs

	2009	2010	2011
Total	**$965,340**	**$978,765**	**$1,000,000**

POWERSTREAM AND THE TOWN OF BRADFORD WEST GWILLIMBURY, 2009 TO 2012 (DRAFT COPY – WITH THE TOWN OF BRADFORD WEST GWILLIMBURY FOR EXECUTION).

SHARED SERVICES AGREEMENT made in duplicate this 1st day of December, 2009

B E T W E E N:

POWERSTREAM INC.,
(hereinafter called "**PowerStream**")

- and -

THE CORPORATION OF THE TOWN OF BRADFORD WEST GWILLIMBURY,
(hereinafter called the "**Municipality**")

WHEREAS on January 1, 2009, PowerStream and Barrie Hydro Distribution Inc.(Barrie Hydro) amalgamated in accordance with a merger agreement dated October 10, 2008 between The Corporation of the City of Vaughan, The Corporation of the Town of Markham and the Corporation of the City of Barrie, (the "**Merger Agreement**");

AND WHEREAS prior to the Amalgamation, the Municipality and Barrie Hydro Energy Services Inc. entered into an agreement dated December 1, 2006, providing for Barrie Hydro Energy Services to implement and co-ordinate the billing and collection of water rates on behalf of the Municipality (the "**Services Agreement**");

AND WHEREAS pursuant to subsection 5.2 (4) of the Merger Agreement, all contracts listed on Schedule Appendix "B" 2(29) of the Merger Agreement, which includes the Services Agreement, are to satisfy the requirements of the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the Ontario Energy Board and as may be revised from time to time (the "**Affiliate Relationships Code**");

AND WHEREAS PowerStream and the Municipality wish to enter into an agreement to replace the Services Agreement with this Shared Services Agreement in order for PowerStream to continue to provide certain services to the Municipality for the consideration and on the terms and conditions hereinafter set forth;

NOW THEREFORE in consideration of the premises and the mutual covenants and agreements herein contained (the receipt and sufficiency of which is hereby acknowledged by each of the Parties hereto), the Parties hereto hereby covenant and agree as follows:

1. INTERPRETATION

1.1 **Definitions**. In this Agreement, including the recitals and Schedules hereto, the following words shall have the following meanings:

1.1.1 "**Affiliate**" means a body corporate which is deemed to be affiliated with another body corporate, by virtue of one of them being the subsidiary of the other or both being subsidiaries of the same body or each of them being controlled by the same person;

1.1.2 “**Affiliate Relationships Code**” means that as described in the third recital of this Agreement;

1.1.3 “**Agreement**” means this shared services agreement and all recitals and all Schedules attached hereto as the same may be amended, modified, supplemented, restated, or replaced from time to time;

1.1.4 “**Applicable Law**” and “**Applicable Laws**” means collectively, all applicable federal, provincial, territorial, municipal and foreign laws, statutes, ordinances, decrees, rules, regulations, by-laws, legally enforceable policies, codes, or guidelines, judicial, arbitral, administrative, ministerial, departmental or regulatory judgments, orders, decisions, directives, rulings or awards, and conditions of any grant of approval, permission, certification, consent, registration, authority or licence by any court, statutory body, self-regulatory authority, stock exchange or other Governmental Authority;

1.1.5 “**Binding Arbitration**” has the meaning ascribed thereto in Section 8.12;

1.1.6 “**Business Day**” means any day other than a day which is a Saturday, a Sunday or a statutory holiday or a civic holiday in the Province of Ontario;

1.1.7 “**Claims**” has the meaning ascribed thereto in Section 7.1;

1.1.8 “**Confidential Information**” means the confidential, secret or proprietary information of one Party (the “**Disclosing Party**”), including any of such information or data which (a) the Disclosing Party is obligated, under contract or law, to keep confidential and (b) is technical, financial or business in nature, and which has been or may hereafter be disclosed, directly or indirectly, to the other Party (the “**Recipient**”), either orally, in writing or in any other material form, or delivered to the Recipient;

1.1.9 “**Disclosing Party**” has the meaning ascribed thereto in Section 3.2;

1.1.10 “**Effective Date**” means the date of this Agreement – December 1, 2009;

1.1.11 “**Extension Notice**” has the meaning ascribed thereto in Section 4.2;

1.1.12 “**Fee Review Date**” has the meaning ascribed thereto in subsection 2.5.2;

1.1.13 “**Fees**” means the charges for the provision of the Services as set out in Schedule ‘A’, plus all applicable sales or service taxes;

1.1.14 “**Governmental Authority**” means any court, arbitrator, administrative agency, commission, or governmental or regulatory official, department, agency, body, authority or instrumentality, whether foreign, federal, state, provincial, municipal, or local, having jurisdiction over the Parties;

1.1.15 **“In Writing”** or **“Written”** means a posted letter, a facsimile transmittal or an e-mail message;

1.1.16 “**Internal Dispute Resolution**” has the meaning ascribed thereto in subsection 8.12.1;

1.1.17 **“MFIPPA”** means the *Municipal Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. M. 56;

1.1.18 “**Notice**” has the meaning ascribed thereto in Section 8.4;

1.1.19 “**Parties**” means the parties to this Agreement and “**Party**” shall mean any one of them;

1.1.20 “**Receiving Party**” has the meaning ascribed thereto in Section 3.2;

1.1.21 “**Requested Party**” has the meaning ascribed thereto in Section 8.1;

1.1.22 “**Services**” means the services purchased by the Municipality from PowerStream as set out on Schedule A;

1.1.23 “**Term**” means the term of this Agreement commencing on the Effective Date to and including the Termination Date;

1.1.24 “**Termination Date**” has the meaning ascribed thereto in Section 4.1;

1.1.25 **“PowerStream Fees”** means collectively, the charges payable by the Municipality to PowerStream for the provision of the services set out on Schedule A plus all applicable taxes, if any, in respect thereof as may be amended from time to time; and

1.1.26 “**Unsatisfied Party**” has the meaning ascribed thereto in Section 8.1.

1.2 **Headings**. The division of this Agreement into Sections and subsections and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms “**this Agreement**”, “**hereof**”, “**hereunder**” and similar expressions refer to this Agreement and not to any particular Section or other portion hereof and include any agreement supplemental hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to “**Sections**” are to sections and “**subsections**” are to subsections of this Agreement.

1.3 **Extended Meanings**. In this Agreement words importing the singular number only shall include the plural and vice versa, words importing any gender shall include all genders and words importing persons shall include individuals, partnerships, associations, trusts, unincorporated organisations, companies and corporations.

1.4 **<u>Currency</u>**. All references to currency herein are to lawful money of Canada unless otherwise specified.

1.5 **<u>Schedules</u>**. The following Schedules which are attached to this Agreement are incorporated by reference into this Agreement and are deemed to be a part of it:

Services Purchased from PowerStream by the Municipality:

Schedule A - Water Meter Reading and Billing

2. SERVICES

2.1 **<u>Provision of Services</u>**.

2.2 In accordance with the terms hereof, from and after the Effective Date to the Termination Date PowerStream agrees to provide and perform, at the request of the Municipality, the Services for the benefit of the Municipality or the Municipality's Affiliates, as the case may be.

2.3 **<u>Standard of Services</u>.** Notwithstanding the provisions of section 7.1 herein, PowerStream shall provide the Services in a professional manner and in accordance with the policies and service levels applicable to such Services. PowerStream shall provide the Services in accordance with all Applicable Laws. Notwithstanding the foregoing, "**Applicable Laws**" shall not include any by-laws, guidelines, directions, rules or standards of the Municipality introduced, proclaimed or implemented after the date hereof that affects the provision of the Services by PowerStream hereunder or the terms hereof.

2.4 **<u>Amendments</u>**. At any time during the term of this Agreement the Municipality may request changes in the Services that the Municipality receives or the practices, policies or performance levels applicable to the Services received by the Municipality by submitting such requests in writing to PowerStream. Within a reasonable time, but in any event not more than thirty (30) Business Days after receiving written notice of a request, PowerStream shall advise the Municipality whether the change requested will have an impact on the delivery of the Services, acting reasonably, and whether or not the request will have an impact on the associated Fees. In the event there is no impact and subject to the mutual agreement of the Parties, a change request will be implemented. However, if there is an impact, PowerStream may reject the change request. Minor adjustments to existing reports shall not trigger fee increases or the imposition of one-time fees. Subject to the mutual agreement of the Parties, the Municipality shall receive the Services set out in a change request in accordance with the latest approved terms for the provision of such Services.

2.5 **Fees**.

2.5.1 PowerStream Fees paid by the Municipality shall be those as set out in Schedule A or as mutually agreed upon by the Parties in writing from time to time.

2.5.2 The Parties shall review in accordance with Schedule A the PowerStream Fees once on an annual basis and such review shall occur prior to or on November 1st (the "**Fee Review Date**") for the following calendar year. If the Parties are unable to agree on the adjustments to the PowerStream Fees within thirty (30) days of the Fee Review Date then the dispute shall be settled by the dispute resolution procedure in accordance with Section 8.12 herein.

2.5.3 Unless otherwise specified herein, PowerStream Fees shall be invoiced to the Municipality on a monthly basis in accordance with Schedule A.

2.5.4 All PowerStream Fees shall comply with the requirements of the Affiliate Relationships Code.

2.6 **Co-operation by Municipality**. The Municipality shall co-operate with PowerStream and provide PowerStream with reasonable assistance in the provision of the Services. Without limiting the generality of the foregoing, the Municipality shall:

2.6.1 assign a minimum of two (2) representatives of the Municipality to co-ordinate with PowerStream the provision of the Services to the Municipality and to deal with financial and operational issues respectively;

2.6.2 prepare and provide to PowerStream, in a mutually acceptable format, all information reasonably required by PowerStream to permit proper delivery of the Services;

2.6.3 establish, incorporate and maintain as part of the practices, policies and service levels applicable to such Services, in consultation with PowerStream, operating procedures to satisfy the Municipality's requirements for accuracy and auditing;

2.6.4 provide training, if necessary, to personnel of PowerStream to assist in the provision of the required information to PowerStream to permit PowerStream to provide the Services; and

2.6.5 provide PowerStream with assistance in collecting amounts owed to the Municipality. The Municipality may place any of such unpaid amounts on the collector's roll and enforce any other rights or remedies of the Municipality pursuant to section 398(2) of the *Municipal Act*, S. O. 2001, c. 25.

2.7 **Customer Information**.

2.7.1 PowerStream acknowledges that the ownership of all data in respect of water and sewer customers of the Municipality as such data relates to: water and sewer information, water and sewer consumption history and charges, fire protection information, customer information including name, billing address, legal description, service address, the final twelve (12) months of meter readings for each customer, outstanding water and sewer invoices, customer credit and collection information, and information with regard to work orders and asset management systems is and shall remain the property of the Municipality. PowerStream shall ensure that all of the data contemplated by this Section 2.7.1 is backed up in accordance with current PowerStream procedures and can be restored in 1-2 Business Days. The Municipality acknowledges that PowerStream can only back up data collected over a maximum period of 7 years.

2.7.2 The Municipality acknowledges that the ownership of data in respect of electricity customers of PowerStream or any of its Affiliates is and shall remain the property of PowerStream.

2.7.3 Intentionally deleted.

2.7.4 Requests for data by the Municipality under Section 2.7.1 shall be made in writing, which may include electronic mail, by an individual designated by the Municipality to the attention of the VP Information Services at PowerStream or such other individual designated by PowerStream. PowerStream shall within 1 Business Day advise the Municipality of the effort required to provide such data and such data shall be provided by PowerStream to the Municipality no later than two (2) Business Days from the date the request is made by the Municipality or within such other reasonably time as may be agreed by the Parties. Each Party, its employees and agents shall abide by all Applicable Laws, including the requirements of the Affiliate Relationships Code to the extent that it applies, related to the collection, use, retention, destruction and disclosure of any personal data which has been collected, used, retained, destroyed and disclosed in connection with the Services .

3. CONFIDENTIAL INFORMATION

3.1 **Confidentiality Obligation**. Commencing upon the Effective Date and continuing thereafter, each Party:

3.1.1 shall treat as confidential, keep in safe custody and not disclose to any third party any Confidential Information provided to it by the other Party; and

3.1.2 use such Confidential Information only to the extent necessary to comply with this Agreement.

3.2 Each of the Parties shall establish and enforce procedures to protect Confidential Information disclosed to it by the other Party and shall restrict disclosure of such Confidential Information to only those employees, officers, agents and professional advisors of it and its Affiliates who need to know such information in connection with such Party's performance of this Agreement and in accordance with the *Municipal Freedom of Information and Protection of Privacy Act* R.S.O. 1990, CHAPTER m.56 ("**MFIPPA**") or any other applicable legislation. If a Party or its Affiliate is required by order of any Governmental Authority or Applicable Law or the rules of a stock exchange to disclose Confidential Information disclosed to it by the other Party, it shall promptly notify the other Party of the request for disclosure and shall cooperate with the other Party if that other Party opposes the request for disclosure and wishes to seek confidential treatment for such Confidential Information that is required to be disclosed. Each of the Parties acknowledges that no adequate remedy at law exists for a material breach or threatened material breach of this Section 3.2 the continuation of which unremedied will cause the other Party to suffer irreparable harm, and agrees that the other Party is entitled, in addition to other remedies which may be available at law or in equity, to immediate injunctive relief from any breach of this Section 3.2 and to specific performance of its rights. Promptly following the Termination Date, each Party agrees to use commercially reasonable efforts to deliver to the other Party (the "**Disclosing Party**") the Confidential Information (including all electronic and other copies thereof) disclosed to it (the "**Receiving Party**") by the Disclosing Party that the Receiving Party possesses or, upon request by a Disclosing Party, the Receiving Party shall confirm to the Disclosing Party that such Confidential Information has been destroyed in accordance with the Disclosing Party's instructions but, in no event if such Confidential Information is not returned to the Disclosing Party or destroyed in accordance with its instructions, such Confidential Information shall not be disclosed by the Receiving Party to any other person. Notwithstanding the forgoing, (i) PowerStream acknowledges that the Municipality and its Affiliates are subject to MFIPPA and PowerStream agrees to act in accordance with applicable provincial laws relating to privacy as they apply to the provision of the Services by PowerStream; and (ii) the Municipality acknowledges that PowerStream and its Affiliates are subject to the *Personal Information Protection and Electronic Documents Act* (Canada) and the Municipality agrees to act in accordance with Applicable Laws.

4. TERM.

4.1 **Term**. This Agreement will commence on the Effective Date and shall terminate three (3) years after the Effective Date (the "**Term**"), unless terminated earlier pursuant to Section 5.1 or extended by renewal of the term pursuant to Section 4.2 (the "**Termination Date**").

4.2 **Extension of Term**. If either Party gives notice in writing to the other Party by not later than sixty (60) days prior to the Termination Date, requesting the continuation of Services, as the case may be (an "**Extension Notice**") for an additional one year period, the Parties agree to negotiate, in good faith, in order to determine the terms and conditions on which such Services will be provided for a renewal term of one year or such longer period as is mutually agreed to. Notwithstanding anything in this Section 4.2 to the contrary, there shall be no obligation upon any Party having been provided with an Extension Notice to extend the term of this Agreement.

5. TERMINATION.

5.1 **Termination**. This Agreement shall terminate on the Termination Date and may be terminated prior thereto as follows:

5.1.1 by the mutual written consent of the Parties hereto;

5.1.2 by either Party effective upon not less than eighteen (18) months written notice to the other Party;

5.1.3 by either Party effective upon not less than thirty (30) days written notice of any material breach or default of any provision or obligation of this Agreement by a Party, provided that such notice will not be effective to terminate this Agreement in the event the other Party cures the default during such notice period; and

5.1.4 immediately by either Party if the other Party becomes insolvent or is a party to any bankruptcy or receivership proceeding or any similar action affecting the affairs, property or solvency of such Party.

5.1.5 **Termination Without Prejudice.** Any such termination of this Agreement shall be without prejudice to any other remedies which any Party may have against the other arising out of such breach of default and shall not affect any rights or obligations of any Party arising under this Agreement, at law or in equity, prior to such termination.

6. FORCE MAJEURE.

6.1 **Force Majeure**. Performance of any obligation under this Agreement, other than the payment of Fees pursuant to Section, may be suspended by either Party without liability to the extent that an act of God, war, fire, earthquake, explosion, governmental expropriation, governmental law or regulation or any other occurrence beyond the reasonable control of such Party or labour disruption, strike or injunction (if such labour event is not caused by the bad faith or unreasonable conduct of such Party) delays, prevents, materially restricts or limits the performance of any such obligation, provided that the Party affected shall at all times make commercially reasonable efforts to perform its obligations. The affected Party may invoke this provision by promptly notifying the other Party of the nature and estimated duration of the suspension. No Party hereto invoking this provision shall be liable for any failure to perform or any delay in the performance of its obligations in this Section 6.1.

7. DISCLAIMER, LIMIT OF LIABILITY AND INDEMNITY

7.1 **Indemnity by the Municipality**. The Municipality agrees to indemnify, defend and hold harmless PowerStream its shareholders, officers, directors, employees, agents, contractors or subcontractors (the "**PowerStream Indemnitees**") from any and all claims, litigation, damages, losses, causes of action or expenses (including legal fees and disbursements) (a **"Claim"** or "**Claims**") suffered or incurred by the PowerStream Indemnitees from third parties or otherwise in connection with:

7.1.1. a breach of the Municipality's obligations under this Agreement insofar as PowerStream has not contributed to such Claim;

7.2 Notwithstanding the provisions of Section 7.1, the Municipality shall be under no obligation to indemnify and save harmless PowerStream Indemnitees from any Claims resulting from the negligence or wilful misconduct of PowerStream in its provision of the Services hereunder.

7.3 **Indemnity by PowerStream**. PowerStream agrees to indemnify, defend and hold harmless the Municipality its officers, directors, employees, agents, contractors or subcontractors (the "**Municipality's Indemnitees**") from any and all Claims suffered or incurred by the Municipality from third parties or otherwise in connection with:

7.3.1 a breach of PowerStream's obligations under this Agreement which causes a Claim, insofar as the Municipality has not contributed to such Claim; and

7.3.2 any negligence on the part of PowerStream, its employees, contractors or agents in its provision of the Services hereunder.

7.4 Notwithstanding the provisions of Section 7.13, PowerStream shall be under no obligation to indemnify and save harmless Muncipality's Indemnitees from any Claims resulting from the negligence or wilful misconduct of Municipality in its provision of the Services hereunder.

7.5 **Insurance**. PowerStream shall provide and keep in force a comprehensive liability insurance policy with coverage equal to or greater than Five Million Dollars ($5,000,000) (Canadian) of sufficient coverage in respect of the Services performed by it under the terms of this Agreement, which shall include, at a minimum, business Automobile Liability Insurance covering all vehicles used in connection with the Services covering bodily injury and property damage combined with automobile insurance.

8. MISCELLANEOUS

8.1 **Audit**. PowerStream shall maintain accurate and complete books and records with respect to (i) the Services provided hereunder, (ii) the PowerStream Fees, and (iii) any information provided by the Municipality to PowerStream for the provision of the Services. Each Party shall keep its accounts and records in accordance with Canadian generally accepted accounting principles from time to time approved by the Canadian Institute of Chartered Accountants (or a successor institute) with respect to the computation of Fees and other charges payable pursuant to this Agreement. Each Party shall be entitled to audit such books and records in order to confirm compliance with the terms of this Agreement. Each Party shall make such books and records available to individuals designated by the other Party and provide any assistance it may reasonably require in order to conduct audits and inspections, provided that:

8.1.1 audits and inspections shall be made at reasonable times and on at least ten (10) Business Days prior notice; and

8.1.2 audits of Fees shall be made not later than twenty four (24) months after such Fees have been paid by a Party to the other Party.

Each Party agrees to provide the other Party with reasonable facilities for such audits and inspections and copies of documents, where necessary, appropriate and permitted by law. If a Party is not satisfied with the information provided (the "**Unsatisfied Party**"), the Unsatisfied Party may retain, at its own expense, an independent auditor, to review the books and records referred to above. The Party requested to provide additional information (the "**Requested Party**") may refuse to disclose to the Unsatisfied Party or its agents any information that the Requested Party is prevented from disclosing as a result of a confidentiality obligation to another person provided that the Requested Party shall use commercially reasonable efforts to obtain consents to permit disclosure of such information if such information is reasonably required in order to conduct an audit and inspection by the Requesting Party under this Section 8.1 and the Requesting Party or its agents has requested access to such information. Each of the Parties agree that any third party conducting an audit or inspection shall be subject to the confidentiality provisions of Sections 3.1 and 3.2 and may be required by the Requested Party to enter into a confidentiality and non-disclosure agreement in form and substance reasonably acceptable to the Requested Party and each of the Parties agree that should an independent auditor be deemed by the Requested Party to be a competitor of the Requested Party, the Parties shall mutually agree to the review and audit procedures prior to such review and audit.

8.2 **Governing Law**. This Agreement shall be governed by and construed in accordance with the law of the Province of Ontario and the laws of Canada applicable therein.

8.3 **Successors**. This Agreement will enure to the benefit of and be binding on the respective successors and assigns of each of the Parties.

8.4 **Time of Essence**. Time shall be of the essence of this Agreement.

8.5 **<u>Notices</u>**. Unless otherwise expressly provided herein, any notice, consent or other communication (a "**Notice**") given pursuant to or in connection with this Agreement shall be in writing and shall be sufficiently given to the person to whom it is addressed if transmitted by facsimile, delivered in person to or for such person at the address of such person indicated below or at such other address as such person shall have provided in writing to the other Party in accordance with this provision. Any Notice provided in accordance with this provision shall be deemed to have been sufficiently given or made on the date on which it was so transmitted by facsimile or delivered provided that if such day is not a Business Day or delivery occurs after normal business hours of the recipient, the Notice shall be deemed given or made on the Business Day following transmission or delivery, as the case may be.

To PowerStream:

PowerStream Inc.
161 Cityview Boulevard
Vaughan, Ontario
L4H 0A9
Attention: Dennis Nolan
Executive Vice President, Corporate Services and Secretary
Fax: (905) 532-4616
E-Mail: dennis.nolan@powerstream.ca

To the Municipality:

The Corporation of the Town of Bradford West Gwillimbury
100 Dissette Street, Units 7 & 8, PO Box 100
Bradford ON
L3Z 2A7

For Financial matters:
Attention: Ian Goodfellow
Fax: (905) 775-4472
E-Mail: igoodfellow@townofbwg.com

For Waterworks Operational issues:
Attention: Ed O'Donnel
Fax: (905) 778-2070
E-Mail: eodonnell@townofbwg.com

or to such other address as such Party shall have notified to the other Party hereto. Any communication so addressed and delivered shall be deemed to have been sufficiently given or made on the date on which it was received.

8.6 **<u>Entire Agreement</u>**. This Agreement, together with the recitals and the Schedules attached hereto, constitutes the entire agreement between the Parties hereto with regard to the subject matter hereof and supersedes and cancels all previous negotiations, agreements, commitments and writings in respect of the subject matter hereof. This Agreement may not be modified or amended in any respect except by written instrument signed by the Parties hereto.

8.7 **<u>Waiver</u>**. The failure of any Party to this Agreement at any time to require performance by the other Party of any provision hereof shall in no way affect the full right to require such performance at any time thereafter of any other provision hereof and no waiver by any Party hereof of any breach of condition, covenant or agreement shall constitute a waiver except in respect of the particular breach giving rise to such waiver. Any such waiver shall be effective only if made in writing by the Party entitled to waive the provision.

8.8 **<u>Independent Contractor</u>**. By virtue of this Agreement, no Party hereto constitutes any other Party hereto as its agent, partner, joint venturer, franchisee or legal representative and no Party has express or implied authority to bind any other Party hereto in any manner whatsoever. Unless otherwise contemplated in the Services or the Facilities or approved in writing by the other Party, no Party hereto will assume or create any obligation or responsibility whatsoever, express or implied, on behalf of or in the name of that other Party.

8.9 **<u>Assignment</u>**. This Agreement and the privileges herein granted shall not be assigned by either Party except with the prior written consent of the other, such consent not to be unreasonably withheld.

8.10 **<u>Further Assurances</u>**. Each of the Parties hereto from time to time at the request and expense of the other Party hereto and without further consideration, will execute and deliver such other instruments of transfer, conveyance and assignment and take such further action as such other Party may require to more effectively complete any matter provided for herein.

8.11 **<u>Severability</u>.** Any covenant or provision hereof determined to be void or unenforceable in whole or in part will be deemed not to affect or impair the validity or enforceability of any other covenant or provision hereof and the covenants and provisions hereof are declared to be separate and distinct.

8.12 **<u>Arbitration</u>**.

8.12.1 In the event of any dispute or claim between the Parties, arising out of, or relating to, in any way connected with this Agreement or its interpretation or the fulfilment of the obligations of the Parties hereunder (a "**Dispute**"), such Dispute shall be referred internally by either Party by written notification to Dennis Nolan, Executive Vice President, Corporate Services and Secretary at PowerStream and Jay Currier, Town Manager at the Municipality for resolution (the "**Internal Dispute Resolution**"). If the

Dispute is not resolved within 60 Business Days of a Dispute being referred to the Internal Dispute Resolution then such Dispute shall be settled by binding arbitration ("**Binding Arbitration**"). Binding Arbitration shall be conducted in accordance with the *Arbitration Act, 1991* (Ontario), as amended from time to time.

8.12.2 It shall be a condition precedent to the right of a Party to this Agreement to submit a Dispute to Binding Arbitration that such Party shall have given written notice of its intention to do so to the other Party to this Agreement and such written notice shall state the particulars of such Dispute. Within ten (10) Business Days of such notice being provided, the Parties to this Agreement shall mutually appoint a single arbitrator to determine the Dispute. The arbitrator shall fix a time, which shall not be later than ten (10) Business Days following his or her appointment, and a place in Vaughan, Ontario, for the purpose of hearing the evidence and representations of the Parties. Each of the Parties shall co-operate with the arbitrator and shall provide him or her with all information in their possession or under their control necessary or relevant to the matter being determined. Within ten (10) Business Days after the conclusion of the arbitration hearing, or such longer period as may be required by the arbitrator appointed under this subsection 8.12.2, the arbitrator shall make an award and reduce the same to writing and deliver one copy of his or her decision to each Party.

8.12.3 If the Parties fail to agree on an arbitrator within the time period specified in subsection 8.12.2 above, then, unless the parties otherwise agree, the Dispute shall be submitted to ADR Chambers for final resolution, which submission shall be by written notice which may be provided by either Party to ADR Chambers and to the other Party to this Agreement. Within five (5) Business Days following the date of any notice given by either Party pursuant to this subsection 8.12.3, an arbitrator shall be selected by random draw made by ADR Chambers. The arbitrator so selected shall perform both the settlement conference and the trial in the matter. The Parties further agree to be bound by the rules of the ADR Chambers in force from time to time.

8.12.4 There shall be no right of appeal from the arbitrator's award except in accordance with the *Arbitration Act, 1991* (Ontario). The Parties agree that a judgment upon the arbitration award may be entered in any court in Canada or any court having jurisdiction, or that an application may be made to such court for judicial recognition of the award and/or an order of enforcement thereof. The Parties agree that the arbitrator selected pursuant to subsections 8.12.2 and 8.12.3 shall determine costs (legal fees and disbursements) as part of the arbitrator's award.

8.13 **Survival**. The following Sections and or subsections will survive the expiry or termination of this Agreement: Section 2.5, Section 2.7, Section 3, Section 7, Section 8.1 and this Section 8.13.

8.14 **Counterparts**. This Agreement may be executed by the Parties hereto in several counterparts, each of which when so executed and delivered shall be an original and all such counterparts shall together constitute one and the same instrument.

IN WITNESS WHEREOF, this Agreement has been executed by the Parties hereto on the date first above written.

POWERSTREAM INC.

Per: ______________________________

Name: Dennis Nolan
Title: EVP Corporate Services & Secretary

THE CORPORATION OF THE TOWN OF BRADFORD WEST GWILLIMBURY

Per: ______________________________

Name:
Title:

Per: ______________________________

Name:
Title:

SCHEDULE “A”

WATER METER READING AND BILLING

Services levels currently provided will be maintained which may include those functions following.

GENERAL SERVICES PROVIDED

Billing of all water/sewer services

- Be responsible for the work quality and accuracy of their meter readers.
- Read all accessible water meters on every billing cycle. PowerStream will estimate a water reading(s) if access to a water meter or remote reading device is not available.
- Explain to customers the methodology used to produce estimated readings and the adjustment/correction once regular reads are collected, as required.
- Review all edit/exception reports based on set points and making corrections or adjustments as required in a timely manner.
- PowerStream shall be responsible for submitting any work orders relating to water meters to the Municipality and/or Municipality’s contractor within two (2) business days of becoming aware of a need to repair a water meter.
- Billing of all water/sewer services at the rates provided by the Town on an annual basis. Billing services includes supply of bill stock, out envelopes and return envelopes. PowerStream Fee is to also include bill printing, stuffing and printer consumable costs.
- Remit proceeds of the water/sewer billings on the 10th day of every month.

REVENUE MANAGEMENT & COLLECTIONS

- Payment by customers of water accounts are in conjunction with electricity accounts and the amounts owing are treated as one (unless prevented by the Ontario Energy Board from doing so). The Ontario Energy Board has made amendments to the Distribution System Code (DSC) that effective January 1st, 2011 or up to two (2) years from that date based on circumstances described in the amended DSC, payments must be allocated to electricity charges first and then to other charges.
- Upon request, PowerStream shall investigate & provide account details to the Municipality, in a timely manner, for specific customers where consumption varies from historic consumption levels.

- PowerStream shall provide billing & collection for Waterworks customer services as per the Municipality's approved user fee schedule for the following services:

    - Frozen meter replacement
    - Water turn on and/or turn off
    - Water meter removal, replacement and/or reinstallation
    - Water meter testing

- Failure to pay for the water/sewer service arrears does not necessarily result in water/sewer service disconnection.

- Back-billing for water/sewer services where applicable, will be actively pursued. Complex back-billing/adjustments are to be approved by the Municipality and responses to disputes that cannot be resolved by PowerStream are to come from the Municipality. A normal Town of Bradford contact for such cases is required.

- PowerStream acts as the billing and collection *agent* on behalf of the Municipality and as such cannot accept bad debt water losses. Such losses will be charged back to the Municipality annually by deduction from the proceeds of water/sewer revenues collected.

- PowerStream will assist the Municipality to tax-roll for unpaid water and sewer arrears as provided under the *Municipal Act, 2001, S.O. 2001* by transferring the water and sewer arrears to the owner of the property at which the services are provided.

- Reporting of invalid or missing remote meter numbers and serial numbers.

- Follow-up as required with both Water Works (Municipality) and the customer.

- Reporting of missing or bypassed water meters.

- Bad debt write- off list.

CUSTOMER ACCOUNT MANAGEMENT

- Resolution of Returned Mail

- Management of outgoing mail

- Set up and maintenance of customer account information.

- Set up of customer moving in and out information.

- Offer customer service at a minimum of 8.5 hours a day/5 days a week/52 weeks a year excluding weekends and recognized PowerStream holidays and closings.

SERVICE LEVELS

- PowerStream will include with its regular bill mailings one (1) bill insert per mailing, containing information supplied by the Municipality at no cost. Availability is at the discretion of PowerStream. There may be third party costs associated with bill inserts.

- Frequency of all water meter readings and billings will be based on PowerStream's reading and billing cycles which are currently bi-monthly for residential accounts and monthly for commercial accounts.

- PowerStream will provide one rate-change adjustment per calendar year at no cost. Rate changes will normally be applied April 1st of each year. Pro-rating of bills resulting from rate changes or rate increases applied at any other time of the year will be provided at an additional cost.

- A minimum of thirty (30) calendar day's written notice is required for water/sewer rate increases to be incorporated to the CIS to commence on the first day of the month as determined by the Municipality. More than thirty (30) calendar days notice is welcome.

TELEPHONE & WRITTEN INQUIRY HANDLING

Response to telephone and written inquiries regarding water/sewer and electric will meet or exceed the mandated requirements as set out by the Ontario Energy Board:

- Telephone Response – 65% of calls answered within 30 seconds.

- Written Response to Inquiry – Within 10 business days, 80% of the time.

Annual statistics are reported to the Ontario Energy Board.

REPORTING STATISTICS

- Monthly Billing Summary and Accruals - best efforts by the fifth working day and no later than the 10th calendar day.

- Monthly Active Account Count List of Water Accounts best efforts by the fifth working day (broken down between residential and commercial) and no later than the 10th calendar day

- Monthly Account and Consumption List (electronic file received by Waterworks)

Water Meter Serial Number Corrections

PowerStream shall update the water meter serial numbers in their database as provided by the Municipality from time to time. These corrections should be merged into PowerStream's database within twenty (20) business days of receipt.

Work Orders Statistics

PowerStream shall provide the Municipality monthly reports of outstanding work orders.

Customer Billing Data

PowerStream should provide customer billing data to the Municipality in electronic format at the end of each billing month. The billing data should include the customers billed in the current month, separated into residential, general and industrial customers. Data is used in various Waterworks analyses.

REMITTANCE & PRICING

PowerStream will charge the following prices for providing the water meter reading, billing and payment and collection services listed above. An adjustment based on actual accounts will be made at the end of Q1 2011 for 2011 and at the end of Q1 2012 for 2012.

All amounts billed in a calendar month shall be remitted to the Municipality no later than the 10^{th} day of the following month, by electronic funds transfer. PowerStream shall be entitled to deduct $1/12^{th}$ the annual cost set out below from each monthly remittance of the water accounts billed in the previous month.

Remittance of amounts billed will be made on an interim basis as follows;

PowerStream reads residential accounts bi-monthly and commercial accounts monthly. PowerStream will forward an interim payment to the Municipality for off-cycle months. This will be accomplished by settling an estimated residential monthly billing, based upon the actual of the previous month. The settlement for the on-cycle billing will be a reconciliation of actual residential billing less the prior month's residential estimate.

Example:
January 2010 - All of the Municipality will be read and billed for a one month period (last monthly billing).

February 2010 - Off-Cycle Residential. Settle residential with the Municipality using a monthly estimate based on the billed residential dollars in January. Commercial accounts will be the actual amount billed.

March 2010 - All of the Municipality read. Residential settlement will be a reconciliation based upon the residential estimate for February. (March residential actual less estimated February residential.) Commercial accounts will be the actual amount billed.

April 2010 - Off-Cycle Residential. Settle residential with the Municipality using an estimate based on the billed residential dollars in March. Commercial accounts will be the actual amount billed.

<u>Pricing</u>

*__Bi-Monthly Manual Meter Reading – Bi Monthly Bill Calculation – Residential__

Monthly Manual Meter Reading – Monthly Bill Calculation – General Service

- 2010: $155,000
- 2011: $160,000
- 2012: $165,000

CAPITAL INVESTMENT PROCESS

PowerStream's Capital Investment Process is guided by its Asset Investment Strategy ("AIS") and utilizes the following five steps, on an annual basis:

Step One: Business Units develop their initial five year capital plans as part of the annual capital planning cycle consistent with the Asset Investment Strategy.

Step Two: A Corporate Five Year Plan is developed based on the submitted business unit five year plans as part of the capital planning cycle.

Step Three: Business units prepare detailed budgets and business cases for projects in year one and year two of their five year plans as part of the annual budget process.

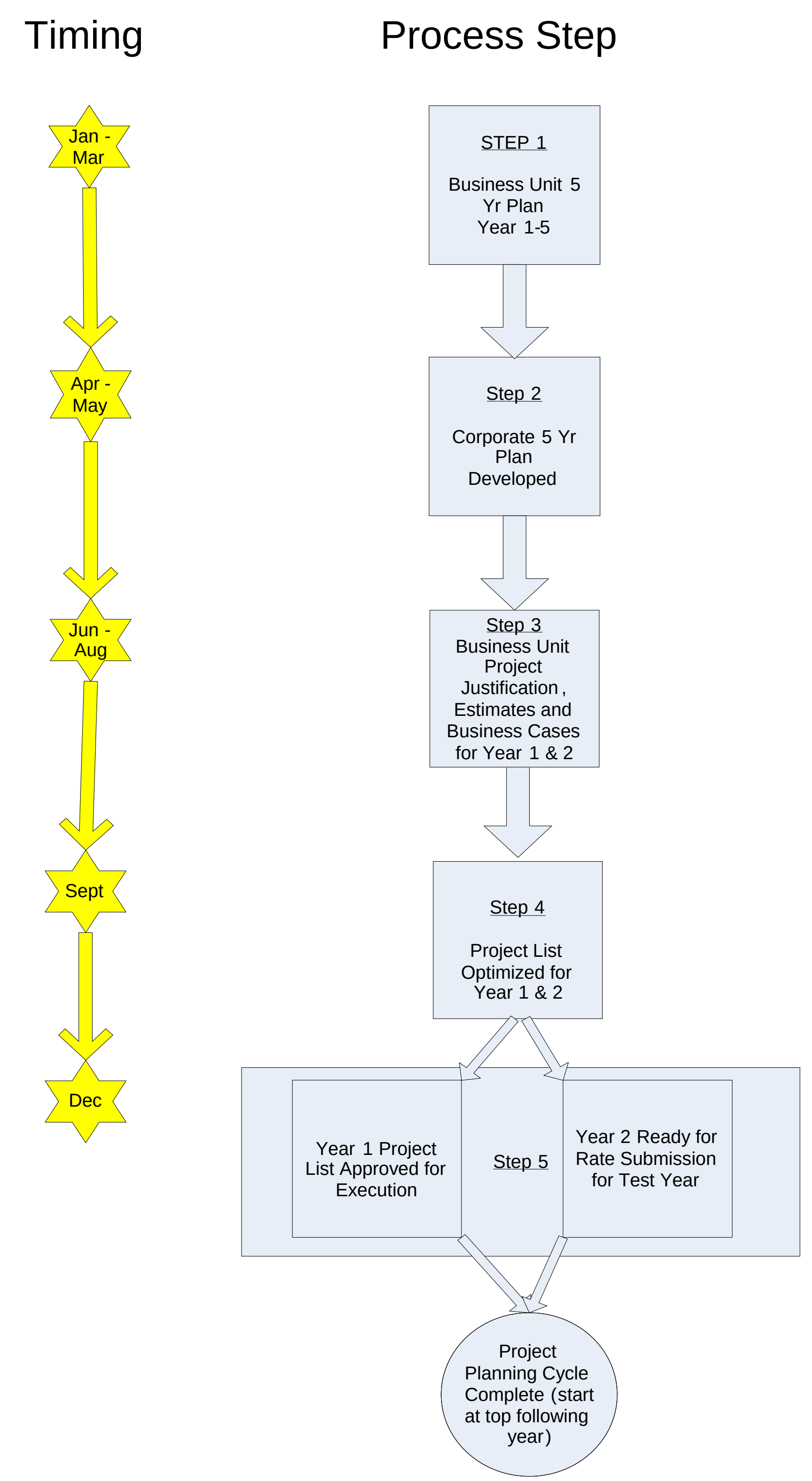
Step Four: The year one and year two detailed budgets for all business units are prioritized through the "Optimizer" process.

Step Five: Approved and prioritized projects for year one are readied for execution in the next business year and approved and prioritized projects for year two are readied for incorporation in a rate application (as required by the OEB schedule).

These five steps are shown in the following Figure 1 alongside a calendar to indicate the approximate timing of each step.

The detailed activities in each step are discussed in the following pages.

Figure 1 - PowerStream's Capital Budget Process and Planning Cycle



Step One – Business Unit Five Year Capital Plans

PowerStream's Capital Investment Process incorporates both a five year forward looking plan and the build up of a two year detailed plan. Business units that have major capital expenditures put together their own five year departmental plans. Early in the calendar year a request is sent out by the Engineering Services division to all business units in PowerStream to prepare five year capital plans. These plans are developed over the January to March period and submitted to the Engineering Services division for review and consolidation. These five year plans serve as the starting base for the development of the Corporate Five Year Plan.

The business unit five year capital plans serve four purposes: i) assist business units in their future planning and enable the business units to provide a solid two year budget; ii) forms the basis of the information provided in a rate application for the forward looking years; iii) provides the Finance team with information for their financial planning and iv) provides for smoother, more consistent capital spending year over year.

Business units provide details in their five year plans on forecast capital spending requirements and describe the process by which they have determined the capital spending requirement. Specific projects and costs identified in the plans are generally preliminary and the projects identified in the plans may or may not be approved for execution at this point.

In this rate application the five year plan from the Engineering Planning department is included as Exhibit B1, Tab 2, Schedule 2. Engineering Planning identifies the majority of controllable construction projects within the organization to maintain the distribution assets of the company. The five year capital plan for Engineering Planning is a key component of the company's Asset Management Planning process. The company's Asset Management Planning process is discussed in Exhibit B1, Tab 1, Schedule 2.

The categories that PowerStream uses to plan its capital expenditures are detailed in Appendix A to this exhibit.

Step Two – Corporate Five Year Capital Plan

The business unit five year plans are summarized into a Corporate Five Year Plan. The information is combined from the following business units:

- Engineering Planning
- Distribution Design
- Operations
- Lines
- Supply Chain Services
- Smart Grid & Metering
- Information Services
- Capital Budget Supervisor (Misc. Capital)

A copy of the June, 2011 Corporate Five Year Plan is in Exhibit B1, Tab 2 Schedule 1.

The information in the Corporate Five Year Plan is used by the Finance Department in their financial models to consider affordability. In addition, information in the five year plan is used in rate planning for the forward looking years, i.e. 2014 and 2015.

Step Three – Budgets for Years One and Two

Once the Corporate Five Year Plan is complete, the detailed build of the two year budget begins which will eventually become the bridge year and the test year capital expenditure forecasts. The projects identified in the first two years of the five year plan forms the basis for the capital projects put forth for the two year plan. For each project the following information is provided: identification information, justification, resource requirements, and estimated costs. For projects less than $500,000 the information is input into a database and the information forms a “mini-business case” for each project. For any specific project (non-program) that is greater than $500,000 a full business case is provided and submitted for approval.

Step Four – Determining the Portfolio of Projects

Once project identification is complete, the business units in conjunction with the Capital Budget Supervisor answer a series of questions about each project. The questions asked are aligned with PowerStream's Asset Investment Strategy ("AIS"). The answers to the questions form the basis for scoring both the value of the project to the corporation and the risk to the corporation if the project is not completed in the planned year. The Capital Budget Supervisor participates with the business units across the organization in answering the questions to ensure consistent interpretation of the questions and answers.

Once the questions on the projects are all answered, the data on the projects is compiled and loaded into "Optimizer". Optimizer is a proprietary software tool purchased by PowerStream from UMS Group. Optimizer is an Excel based software tool that takes the capital portfolio, the value and risk scores given to each project, the cost for each project, and a budget envelope and then calculates an optimum project list for the overall budget envelope. The Optimizer tool is capable of running several scenarios with the project list being optimized for the least amount of risk, optimized for the most amount of value or optimized for the most value at the least amount of risk. All capital projects in the corporation are run through the Optimizer tool with projects from IT, fleet, station construction and lines construction being considered through the same tool.

With the output from various scenarios from the Optimizer software, PowerStream's Optimizer team has discussions as to which projects will be approved as part of the two year capital budget. Members of the Optimizer team include key senior leaders from each of the business units who have major capital spend across the corporation, Rates & Regulatory and Organizational Effectiveness.

Deriving the capital budget follows both a top down and bottom up approach. The high level budget envelope is developed as a joint effort among the Finance, Rates & Regulatory and Engineering departments. The Finance department uses the output from the Corporate Five Year Plan in a financial model to determine affordability and impact on financial soundness and customers. As a result, a target budget envelope is determined. The Optimizer team uses the target budget envelope as a starting point in deliberations. Various scenarios are run through

Optimizer, both below and above the targeted envelope. The value and risk level between the scenarios is considered. The Optimizer team provides feedback on the feasibility of the target budget envelope and adjustments to the envelope are made and a final decision is reached after discussion amongst the Optimizer team and the applicable business unit representatives.

Step Five – Final Capital Project Portfolio

The final list approved by the Optimizer team forms the basis for the two year capital budget. The first year of the capital plan is approved by the PowerStream's Executive Management Team (EMT) and Board of Directors for execution for the following year. The second year of the two year plan is also approved by the PowerStream's EMT and Board of Directors and forms the basis of the information provided in a rate case for the test year.

It is reasonably expected, although not a certainty that the majority of the projects identified in the second year of the two year plan will become approved projects in the first year of the subsequent year's two year plan. Business units have the ability to put forward changed, new or alternative projects based on new information garnered during the year. Projects are rescored each year to determine if value or risk has changed. Optimization of projects may also change based on updates to the Asset Investment Strategy ("AIS").

PowerStream's Asset Investment Strategy

PowerStream's Asset Investment Strategy ("AIS") is the framework for decision making for the capital expenditure program. This investment and risk framework is built into the Optimizer tool and process. The AIS helps define the portfolio of investments that will achieve the Company's strategic value expectations within the company's defined risk tolerance boundaries. This includes providing guidance to make effective short-term (one year) and long-term (two to five years) investment decisions, and to maximize the value of the assets to the company

Within PowerStream's AIS, strategic value is defined as the array of business objectives (called AIS objectives) that the company must consider to achieve the overall corporate business strategy and objectives. These business objectives are aligned to the overall corporate strategy and objectives and success is measured against a series of success criteria. See Table 1 below for a listing of the AIS objectives and success criteria. The objectives are quantified as more than simply a financial or dollar value consideration and extend beyond why we are in business, in an attempt to quantify the most critical considerations that drive the company's ability to remain in business and effectively service customers. The AIS objectives and success criteria are reviewed annually to ensure continued alignment with the overall corporate business strategy and objectives.

PowerStream's AIS, defines risk in its broadest terms, primarily, but not exclusively, in terms of strategic, financial and operational (or technical) risk. The risks considered are quantified for each element used in defining AIS strategic value and are a result of direct or indirect loss due to failed internal processes, people, systems, work practices, or, from external events. Risk is viewed from the perspective of both probability and consequence.

Table 1

AIS Objectives and Success Criteria

AIS Objectives	Success Criteria for each Objective
Business Excellence	Compliance
	Employee Satisfaction
	Operational Excellence
Customer Satisfaction	Index of Reliability
	Customer Satisfaction
	Service Quality Indicators
	Capacity
Financial	Hard & Soft Savings
	Revenue Recovery Factors
Health & Safety	Health & Safety
	Employee Wellness
Environmental Sustainability	Environmental Impact

APPENDIX A

SUMMARY DESCRIPTION OF MAJOR CATEGORIES OF CAPITAL EXPENDITURES

PowerStream sorts its capital investments into four major categories and a number of sub-categories. Summary descriptions of the major categories are as follows:

Sustainment Capital – Sustainment Capital is defined to include projects that replace or enhance capital assets to maintain the reliability of the distribution system so that it will continue to function within established performance standards. Sub categories include: Emergency/ Restoration; Replacement Programs; Sustainment Driven Lines Projects; Transformer/Municipal Station Projects; and Emerging PowerStream Projects.

Development Capital – this major category includes projects that involve system expansion or relocation due to growth and/or to satisfy external demands. Sub categories include: Subdivisions/Services; Road Authority Projects; Growth Driven Transformer/Municipal Stations; Growth Driven Lines Projects; Emerging Development Capital; and Distributed Generation.

Operations Capital – this major category includes projects that support the day-to-day operations of PowerStream. Sub categories include: Buildings; Fleet; Metering; Spare Parts; Tools; Information/Communication Systems; Emerging Operations and Interest Capital.

Capital Deferral Account – this category includes capital projects which are recovered through deferral account mechanisms. Expenditures include Smart Meters, Smart Grid and Renewable Generation.

DETAILED CATEGORY AND SUB-CATEGORY DESCRIPTIONS

Following is a detailed description of the categories and sub-categories of capital spending used at PowerStream.

SUSTAINMENT CAPITAL

Sustainment Capital is defined to include projects that replace/enhance capital assets to maintain the reliability of the distribution system so that it will continue to function within established performance standards. In general, this includes the replacement of overhead and underground lines, system reconfigurations, voltage conversions, upgrading of equipment (not primarily for expansion of capacity), planned asset replacements based on the results of the Asset Condition Assessment ("ACA") process (poles, transformers, distribution switchgear, underground primary cables, station circuit breakers and reclosers). Sustainment capital is further broken down into a number of sub-categories as described below.

Replacement Program

This sub-category covers the replacement of overhead wires, underground cables and station equipment as identified as needing replaced through the ACA process. PowerStream's ACA process is described in Exhibit B1, Tab 2, Schedules 3 and 4. These yearly programs include: Wood Pole Replacement program; Underground Cable Injection program; Underground Switchgear Replacement program; Underground Cable Replacement program; Station Circuit Breaker Replacement program; and Other replacement programs (Pole Line, Switches, Arresters, Station Transformer, Capacitor, Reactor, Station Structure)

Sustainment Driven Lines Projects

This sub-category is for those projects that are not capacity driven (i.e. load growth related), but are required to sustain the distribution system and ensure reliability. These projects are identified through technical studies or through an identified reliability need. Included in this category are: Voltage Conversion Projects; System Re-configuration Projects; Radial Supply Remediation Projects; Distribution Automation Projects; Reliability Driven Projects; Fault Indicator Installation and Replacement program.

Emergency / Restoration

This sub-category covers capital costs of repair and restoration of the distribution system. Work is required as a result of on-going power outages or identified through inspection as needing repair due to a hazardous safety condition or potential imminent failure. The work is divided into programs, specifically, Replacement of Failed Distribution Equipment; Replacement of Distribution Equipment due to Storm Events; Replacement of Distribution Equipment due to Accidents and Joint Use Pole Removal.

Replacement of Failed Distribution Equipment covers the emergency replacement of all failed equipment within PowerStream's distribution system due to unexpected failure. These failures generally result in power interruptions to our customers and the failed equipment is removed and replaced with serviceable electrical equipment restoring power.

Replacement of Distribution Equipment due to Storm Events covers replacement of major distribution equipment damaged during storm events including poles, transformers, lines, services, and switching devices. The distribution components replaced are necessary to restore power to our customers and restore the operating system to safe working conditions. The projection for this capital budget item is estimated based on the past five years of historical spending due to the year over year variability in severe weather patterns.

Replacement of Distribution Equipment due to Accidents covers the cost associated with replacement of major equipment damaged by vehicle accidents and foreign interference. The replacement costs are tracked and where possible collection is made from the party causing the damage to PowerStream's distribution equipment. Costs recovered from third parties are attributable to revenue.

Joint Use Pole Removal covers the removal of poles that recently had joint use facilities removed. During the process of pole replacements there is a lag time for joint use parties to relocate their attachments to PowerStream's new pole. Historically, this time has taken several months and even years. Due to the time lag the original work orders associated with the pole replacement have been closed.

Transformer / Municipal Stations

This sub-category is for those Municipal Stations ("MS" – stations that transform from 44kV or 27.6 kv to a lower distribution voltage such as 13.8 kV) and Transformer Stations ("TS" – stations greater than 100 MVA that transform from high voltages 230 kV to 27.6 kV) projects that are not capacity driven, but are required to sustain PowerStream's fleet of eleven TS's and fifty-four MS's. Sustainment activities include projects to: replace worn out equipment, improve reliability, enhance operability & maintainability, and to improve & maintain safety.

Emerging Sustainment Capital

This sub-category covers sustainment projects that are unforeseen. Despite the best efforts of the budget team to identify all of the capital requirements for the budget year, there are projects that arise after the budget has been approved. Projects are typically required due to an unforeseen circumstance or were missed during budget preparation but if not completed in the current year would have a negative impact on the day-to-day operation of the distribution system. Every effort is made to defer the projects to the next budget year. Project leaders requesting to tap into these funds are required to have appropriate approval prior to work commencing.

DEVELOPMENT CAPITAL

Development Capital is defined to include projects that enable system expansion required as a result of customer growth and relocation projects due to municipal and regional requirements as a result of growth in the communities served by PowerStream. Development Capital is further broken down into a number of sub-categories as described below.

Subdivision / Services

This sub-category covers the costs to connect new customers to the system. The work is divided into programs as follows: Layouts; New Services; New Subdivisions; and Secondary Services.

Layouts consist of work to make ready the system for new residential infill services, upgrading of residential services and small commercial services. A layout is completed for each customer.

The customer's service could be underground or overhead and is the connection from the main plant on the boulevard to the building. Costs are shared between the customer and PowerStream. In accordance with the Distribution System Code ("DSC"), the LDC is required to provide the customer with a basic connection allowance for each residential service. This basic connection credit equates to 30m of an overhead service and 10m of an underground service.

New Services consists of new and/or upgraded primary services to industrial, commercial and institutional customers. These services are normally underground from the existing distribution or sub-transmission system and up to and including the padmount transformer. Typically customers contribute 100% of the cost for new services. In accordance with the DSC, these services are considered a connection and are 100% recoverable (deemed as 'Lies Along' – these are new services where facilities exist to service the customers).

New Subdivisions consist of the primary and secondary underground cables as well as transformers installed to the street line of each lot within a new residential "greenfield" subdivision development. In accordance with the DSC, the development cost is subject to an economic model to determine the LDC share and the Developer share based on revenues from the development. Up to 2012 upstream costs are included in the economic model. With this rate application upstream charges are removed for the test year, 2013, and going forward.

Secondary underground services are installed from the street to the meter base for each lot. This work allows for the connection of the secondary service to the padmount transformer which in turn provides power to the customer's unit. These services are installed as the houses within the development are built and are normally installed within five years of the new subdivision being installed. In accordance with the DSC, these service costs are put through the economic model and shared at time of the OTC.

Road Authority Projects

As communities within PowerStream's service territory continue to grow, it is accompanied by road construction, re-alignment and widening of existing roads as well as the installation of new water and sewer infrastructure. This development work is controlled by Provincial, Regional and Municipal authorities. Because PowerStream's distribution system is located on the road allowance, at the request of the road authority, it must be relocated to accommodate this development work. Each year, PowerStream reviews the five and ten year road authority plans for development to identify where distribution system conflicts exist and to budget for resolution of these conflicts. The majority of these projects involve relocating portions of the distribution system. These projects are usually cost shared with the road authority. This sub-category covers the costs for these relocations.

Growth Driven Transformer / Municipal Station Projects

This sub-category covers construction projects of new or upgrade of existing transformer and municipal station capital projects that PowerStream must complete to provide sufficient capacity to supply new customers and load growth from existing customers. Every year PowerStream prepares a load forecast and studies the system to identify capacity short falls and recommends projects to ensure sufficient capacity for customer load growth demands.

Growth Driven Lines Projects

This sub-category covers construction of new or upgrade of existing distribution or subtransmission lines that PowerStream must complete to provide sufficient feeder and component capacity to supply new customers and load growth from existing customers. PowerStream uses the load forecast and studies the system to identify capacity short falls and recommends projects to ensure sufficient capacity for customer load growth demands.

Emerging Development Capital

This sub-category covers large customer projects due to the customer’s emerging needs throughout the year. Projects are typically required due to either a relocation required by a customer or the expansion of the distribution system for the customer. In the case of relocations, the customer typically pays 100% of the costs. In the case of a required expansion of the distribution system, costs are shared as per the requirements of the Distribution System Code (“DSC”) and PowerStream’s Conditions of Service (“COS”).

Distributed Generation Connections

This sub-category covers the costs to connect new distributed generation customers to the system. In accordance with the Distribution System Code, these costs are shared by the customer and PowerStream. The customer is responsible to cover the cost of connection. PowerStream will cover system expansion costs at or below a distributed generation customer's renewable energy expansion cap.

OPERATIONS CAPITAL

Operations Capital is defined to include projects that support the day-to-day operation of PowerStream. Operations Capital is further broken down into a number of sub-categories as described below.

Metering

This sub-category involves the installation or replacement of meters. The work involves the upgrades or replacement of wholesale or retail meters and includes the following: Wholesale Meter Upgrades; Failed Meter/Transformer Replacements; Meter Re-verifications and Smart Meters.

Wholesale Meter Upgrades consists of projects to upgrade PowerStream Wholesale Meters. PowerStream is directly connected to the Independent Electrical System Operator ("IESO") grid at several points. Each of these connection points entails a wholesale metering point and meter. Normally upgrades are required due to requirements set out by the IESO.

Failed Meter/Transformer Replacements consists of the replacement of meters, wire, instrument transformers and associated test equipment for revenue billing meter systems which periodically fail. When a revenue meter fails replacement must take place as soon as possible to minimize the time that customer energy consumption data is lost.

Meter Re-verifications are required due to regulations under the Electricity and Gas Inspection Act enforced by Measurement Canada to ensure that all revenue meters meet strict accuracy and operational standards over the life of the meter. The process of removing and testing the meter is referred to as re-verification. The meter re-verifications are not, as of yet, required on smart meters.

Smart Meter deployment has been a primary focus of PowerStream since 2006 when the Provincial Government mandated the replacement of the electromechanical billing meters with the new Smart Meter and Advanced Meter Infrastructure ("AMI") two-way communication system. The costs for installation of the Smart Meters were covered under Smart Meter deferral accounts prior to 2012. Going forward capital spending associated with Smart Meters are covered in this category and support the continued functioning of the newly installed system.

Suite Meters consists of costs for PowerStream to install either a new suite metering system or for PowerStream to install a Bulk Meter system in residential condominiums or commercial/retail buildings. Builders/developers of residential/condominium housing and industrial/commercial/in stitutional buildings have a choice to have their premises bulk metered (single meter) by PowerStream and individually meter customers on their own or have PowerStream supply/install individual suite metering. PowerStream will also replace existing bulk billing meter systems totalizing energy consumption for the entire condo/apartment building with individual unit metering through negotiation and agreements with building owners.

Upgrade of 2.5 Element Meters is a program to upgrade existing two and one half (2.5) element meters to the more modern three (3) element meters. The older fuse link test blocks often have fuses operate or open which causes loss of potential to the meter, which in turn causes the meter to inaccurately (under-recording) measure the actual energy consumed. The result is lost revenue that may go undetected for long periods of time until a meter inspection reveals the fuse operation.

Fleet

This sub-category involves the purchase in three vehicle classifications: Heavy Duty; Light/Medium and Miscellaneous

PowerStream has forty-three heavy duty units including aerial devices and radial boom derricks for work on distribution lines.

PowerStream has 156 light/medium units such as vans, pickups and automobiles used across the organization by various roles such as Line Supervisors, Sub-foreman, Line Technicians, Inspectors, Locaters etc.

PowerStream has sixty miscellaneous units including pole trailers, general use trailers, tension machines and forklifts. These units are either used to move material around or assist in the distribution line work.

A vehicle is considered for replacement based on an expected life. PowerStream has established an expected life for each class of vehicle. Replacement is determined by achieving years of use, mileage or hours of use as per manufacturer's recommendations for replacement. This expected life replacement approach is in keeping with industry practice and is important to assist PowerStream's ability to forecast vehicle spending, assist PowerStream in achieving a lower risk of catastrophic vehicle failure and enhancing PowerStream's ability to negotiate long term procurement contracts with vendors and realize savings.

Tools

This sub-category involves the purchase of tools that are required for the ongoing operation, construction, maintenance, and repair of the distribution system. Tools include power measuring equipment, cutters and crimpers; relay testing equipment, communications testing equipment, meter testing equipment and locating equipment. These purchased tools replace worn out or broken tools used by the staff on a daily basis for their work.

Buildings

This sub-category involves the purchase, replacement or rehabilitation of major assets related to one of PowerStream's three main centres of operation at Patterson Rd. in Barrie, Addiscott in Markham, and Cityview in Vaughan.

The Patterson Rd. facility in Barrie was built in 1990. The Cityview Blvd. facility in Vaughan was primarily constructed in 2007 and ready for occupancy in early 2008 and the Addiscott facility in Markham was primarily constructed in 2009 and ready for occupancy in early 2010.

Relevant projects include changes to: exterior (i.e. pavement, fencing, lighting, stores yard); interior (i.e. furniture); mechanical (i.e. Plumbing); structural (i.e. windows, doors, wall partitions); and HVAC (Heating & air conditioning);

Information / Communication Systems

This sub-category consists of new projects or upgrades to PowerStream's information technology or communication systems across the organization

In 2011 PowerStream engaged KPMG to facilitate the development of a business driven Information Services ("IS") Strategic Plan. The process involved extensive input from the management and executive teams and resulted in development of five strategic initiatives. Subsequently, a list of projects which support the achievement of the strategy was developed and prioritized by the senior management. The result was a five year IS Roadmap and Investment Plan. Projects are categorized into the five strategic initiatives as follows: Developing Information Capital; Delivering Outstanding Customer Service; Achieving Operational Excellence; Building a Foundation for Innovation and Maintain our Infrastructure.

Projects within "Developing Information Capital" will enable PowerStream to develop, retain and share corporate knowledge. The evolution of Smart metering and the convergence of Operational Networks with IS networks is resulting in exponential growth of data. Establishing an enterprise data model and standards will facilitate the transformation of data into valuable and trusted corporate information upon which business decisions are based.

Projects within "Outstanding Customer Service" will give PowerStream the ability to provide customers, the rate payers, with the best possible service at the lowest cost. While it is recognised that every dollar invested is ultimately to benefit the customer, this category describes those investments which have a direct impact on PowerStream's customer. These projects are aimed to provide modern and valuable customer services and include a New CIS implementation and customer facing process improvements.

Projects within "Achieving Operational Excellence" are aimed towards applications and initiatives that improve business processes primarily through automation. During the past PowerStream has experienced rapid growth through mergers and acquisitions, PowerStream's processes have evolved either by merging and adapting multiple processes or by simply adopting a process from a former company. The same methodology was applied to applications which supported the processes. While this strategy was successful in quickly bringing companies together, it didn't take full advantage of scale or opportunities to apply new technology. New applications to support operational excellence include an Enterprise Asset Management System, a Workforce Management Solution, and hardware and software to support a mobile workforce solution.

Projects within "Building a Foundation for Innovation Investments" are geared toward improving how Information Services serves the corporation. Initiatives include development and update of an Information Services Governance framework to ensure that alignment with business units remains strong and the development and update of Enterprise Architecture Standards to help manage the growing requirement to add and integrate new systems and data sources.

Projects within "Maintain our Infrastructure" are required to maintain and keep up-to-date PowerStream's computer assets including both hardware and application software.

- **Hardware** – PowerStream has personal computers distributed amongst three locations including selected field personnel. PowerStream utilizes a centralized printing model as much as possible. High capacity multi-function printers are also located throughout the various offices. There are additional stand-alone or small workgroup printers to meet specific needs. In addition, PowerStream's has a large number of servers to manage the applications and data. Annual funding is required to replace any equipment which no longer meets minimum requirements. Minimum requirements are dictated either by unacceptable performance, or lack of compatibility with applications or other systems. PowerStream continuously looks for opportunities to extend the lifecycle of hardware and software.
- **Application Software** – PowerStream's major application systems include: an Enterprise Resource Planning ("ERP") system JD Edwards Enterprise; a Customer information System ("CIS"), T&W Information Systems; a Geographic Information System ("GIS") ESRI; an Outage Management System, Responder; a Design System, Designer; SCADA Survalent; a Station Information System, Cascade. PowerStream utilizes the Microsoft Office suite, SharePoint, and Exchange mail for general desktop use. Telecom support includes a Voice over Internet Protocol ("VOIP") telephone system; and hardware to support fibre connectivity between all work centres and several sub-stations. Upgrades to existing applications are considered necessary when there is lack of vendor support; lack of compatibility

with versions used by business partners and customers; new features are available which provide additional functionality to improve efficiency; or lack of compatibility with new software or hardware.

Purchase of Spare Equipment

This sub-category is for the purchase of key equipment in stations that will be held in reserve and used for system spares in the event that a failure of the key equipment occurs.

Emerging Operations Capital

This sub-category covers monies for operations projects that are unforeseen. Despite the best efforts of the budget team to identify all of the capital requirements for the budget year, there are projects that arise after the budget has been approved. Projects are typically required due to an unforeseen circumstance or were missed during budget preparation but if not completed in the current year would have a negative impact on the day-to-day operation of the distribution system. Every effort is made to defer the projects to the next budget. Project leaders requesting to access these funds are required to have appropriate approval prior to work commencing.

Interest Capitalization

This sub-category covers monies for interest capitalization. Under Internal Financial Reporting Standards ("IFRS"), interest capitalization is defined as the borrowing costs that are directly attributable to the acquisition or construction of a qualifying asset cost. A qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use. PowerStream has determined this period of time as those projects that span over four months in duration. To assist in project management these costs are tracked in one category within the capital budget.

CAPITAL DEFERRAL ACCOUNT

The Capital Deferral Account includes capital projects which are recovered through deferral account mechanisms. Expenditures include smart meters, smart grid and distributed generation.

Smart Meters

PowerStream initiated its smart meter program in 2006 as mandated through regulation by the OEB. PowerStream completed implementation of its smart meter program in 2011. All capital costs for the installation of the meters, communications infrastructure and back office hardware and software were included in this deferral account. Recovery of these costs was achieved through separate smart meter rate applications in 2010 and 2011. Effective 2012 smart meter installations and related capital activity will be part of the capital budget reporting process. Costs will no longer be tracked in a deferral account.

Smart Grid

Expenditures in the smart grid deferral account are for smart grid projects that would not have been completed in the normal course of PowerStream's everyday business and are pilots of new technology that may be considered for incorporation into the grid or are pilots to understand the impact of new technologies such as the Electric Car.

Renewable Generation

Expenditures in the renewable generation deferral account are for capital projects that support and facilitate the connection of renewable generation customers. Projects typically are to support a WiMax communication infrastructure for the distributed generation customers and changes to substation infrastructure to decrease short circuit values so customers can be connected.

ASSET MANAGEMENT PLANNING AND INFORMATION MANAGEMENT PROCESSES

PowerStream's Asset Management Planning Process

PowerStream's Asset Investment Strategy ("AIS") is key to the decision making process to ensure that effective short and long term investment decisions are made, which maximize the value of the assets to the company. As part of the overall process of making informed decisions, the Company makes use of disciplined policies, standards and processes, for maintaining the assets of the Company. These policies, standards and processes effectively form PowerStream's Asset Management Planning process.

There are several key components making up PowerStream's Asset Management Planning process. These components are described in this rate application as follows:

- Inspections and Maintenance Practices – Exhibit D1, Tab 2, Schedule 1
- Capital expenditure planning:
    - Capital Investment Process – Exhibit B1, Tab1, Schedule 1
    - Asset Management Planning and Information Management Process - Exhibit B1, Tab1, Schedule 2
    - Corporate Five Year Capital Plan – Exhibit B1, Tab 2, Schedule 1
    - Engineering Five Year Capital Plan – Exhibit B1, Tab 2, Schedule 2
    - Asset Condition Assessment – Exhibit B1, Tab 2, Schedule 3 & 4
    - Green Energy Act Plan – See Exhibit B2, Tab 1, Schedule 1 & 2
    - Capital Financing Processes –Exhibit E, Tab 1, Schedule 1
- Information Management Process – part of this Exhibit

PowerStream's Asset Management process continues to evolve and recent focus has been two-fold. First, bringing to a common level, for all predecessor utilities, the practices, guidance and directives for managing distribution and station asset condition information and understanding of required capital spend for renewal of aging assets. Second, ensuring a robust capital planning and budgeting process for all capital spending in the corporation, including optimizing all capital using the same "lens". The planned future focus is to ensure operations and maintenance spending on assets is more fully documented with equitable practices between the predecessor entities. Also, life-cycle costs will be more fully taken into consideration.

Powerstream's Information Management Process

Information Management as it relates to asset data is the development, execution and supervision of plans, policies, programs and practices that control, protect, deliver and enhance the value of asset data. For the purposes of this section, asset data relates to electrical distribution plant in the field (stations, poles wires, transformers, switches, etc.).

Access to PowerStream's asset data is a fundamental need of engineering and operating personnel to ensure that timely, informed decisions can be made on design and operating issues. Network performance is directly linked to the timely availability and accuracy of asset data.

The primary sources of asset data are PowerStream's Supervisory Control and Data Acquisition ("SCADA") system, Geographical Information System ("GIS") system (coupled to an Outage Management System ("OMS")), Cascade system, station drawing records and FileNexus (a data repository).

SCADA – Supervisory Central and Data Acquisition

PowerStream's SCADA system provides "real time" asset data on certain key assets that are in the field (e.g. stations, automated switches, wholesale smart meters). The key assets allow the system control operators to monitor asset status and performance and to configure the distribution system on an ongoing basis in order to optimize system performance and the supply of power to PowerStream's customers. Typical data collected through SCADA is operational related and includes information such as equipment status (on/off), power flow (amps) and alarms related to mission critical station equipment (relay triggers).

SCADA data is archived and provides a historical record of system performance that allows for detailed engineering and operating analysis to provide future direction and plans for improving system performance.

SCADA real time data is available to operations and engineering staff through the corporate networks via a web browser. Archived SCADA data will be available to users through a data historian application located on the corporate network.

Geographical Information System

PowerStream's Geographical Information System ("GIS") holds both locational and attribute data on the electrical distribution assets within PowerStream's territory. PowerStream's GIS data is relied upon by many departments within the organization for operational, maintenance and design requirements.

The GIS department receives data from multiple sources which is subsequently captured in the GIS. This process ensures an accurate record of the electrical distribution network and connectivity is available. In addition, there are a number of attributes associated with each asset that are also recorded. The information can then be queried and extracted to satisfy specific requests for information (e.g. electrical connectivity, age of assets, testing records, etc.).

Maintenance of GIS records is controlled by the GIS Department. The GIS Department has instituted processes and procedures to capture, update and maintain PowerStream's electrical distribution asset data. All GIS data entry including, but not limited to, new plant, attribute updates, plant removal and any other spatial data must be completed in the ESRI ArcFM environment following a version management convention (ESRI ArcFM is a vendor name). All versions are put through a quality assurance and quality control process by a senior GIS employee before posting to the GIS production environment.

The majority of GIS information input (70%) is from capital programs that result in additions of plant to the distribution system. Examples of this are drawings pertaining to new subdivisions, new commercial and residential installations and capital works on roads.

In PowerStream South (predecessor PowerStream territory), an Asset Tracking Form ("ATF") is used to capture individual asset information. This is a paper based system. The function of the ATF is to provide a standard form to capture asset information gathered by the Lines & Construction staff in PowerStream South. Lines & Construction staff complete the ATF for asset installations, removals and inspections of major equipment such as transformer, switchgears, switches, poles, and splices. Upon completion of the ATF, a copy is sent to the GIS Department. The GIS Department updates the required database systems with the attribute information.

In PowerStream North (predecessor Barrie Hydro territory), the Barrie Attribute Tool ("BAT") is utilized. This is an electronic system. Forms are input to a web hosted database. The information is then sent electronically to the GIS department. At this point the corporate GIS is updated with the BAT information. The BAT also serves as an asset history tool. The database can be queried against for historical asset information in report form. Plans are in place to harmonize PowerStream North and South to a common web based asset tracking tool in 2012.

The remaining 30% of GIS information input comes from operational sources (e.g. open points on feeders, discrepancy verification), maintenance sources (e.g. attribute information arising from inspection or maintenance), and other discrete sources (e.g. joint use, street lighting, land base, orthoimaging, etc).

Outage Management System

The Outage Management System ("OMS") utilizes the GIS connectivity model and inputs from: smart meters, SCADA, Customer Information System ("CIS"), Interactive Voice Recognition ("IVR") and manual input to provide dynamic system and outage information and status. Outage calls, whether input automatically (as in smart meters) or manually, are automatically grouped together as appropriate and predictive device operation is generated. This application brings together multiple operational inputs and provides a dynamic picture of PowerStream's distribution network performance. Reliability performance statistics are generated from the OMS.

Asset performance reports (e.g. operations performance reports) are produced on a regular basis and are provided to senior management for information and review. Outage notification alerts and other reliability related notifications are produced in real time as required.

Cascade

Cascade is a Computerized Maintenance Management System ("CMMS"). This application aids in the efficient and timely maintenance of PowerStream's station assets. Cascade receives real-time operational SCADA data, inspection data, test data, equipment diagnostic data (and many other inputs) for the Transformer Stations and Municipal stations. Cascade data is input, used and accessed by operational groups such as our Station Maintenance and Protection and Control sections.

Handheld field devices or computer notebooks are used to upload and download data to/from the database for operational field use. Advanced algorithms in the Cascade software generate preventative maintenance orders and alerts based on operating conditions.

Station Drawing Repository

The Station Drawing Depository ("SDR") holds data, predominately reference drawings, related to PowerStream's station facilities. Engineering drawings pertaining to PowerStream's transformer stations and municipal stations are relied on by both the Engineering and Operations departments who reference Station drawings during their day to day work. One common set of electronically stored drawings, controlled in a managed database, ensures accurate and efficient creation, editing, modification and access to Stations Drawings.

The Stations Design department leads the preparation and issue of design, construction, and as-built drawings for PowerStream's Transformer Stations ("TS"), Municipal Stations ("MS'), and Telecommunication Network ("Telecom"). These drawings, once issued, are electronically stored in the SDR which is located on a file management system (SharePoint).

The types of drawings residing in the Stations Drawing Repository are: System Drawings (communication drawings, etc.); Transformer Stations; Municipal Stations; and Control Centres.

The process to add, modify, delete drawings in the SDR is strictly controlled and administered by the Station Design department. Through the SDR, stakeholders in engineering and operations can access draft drawings, construction drawings, "as-built" drawings and archived (obsolete) drawings.

FileNexus

FileNexus is a data repository that holds lines project construction drawings for new services, new subdivisions, new construction projects, line relocations and line rehabilitations. Engineering drawings are relied upon by design, construction and operations staff in their day-do-day work. One common place for storage is used so approved drawings, as-built drawings and any related documents to projects are available for access.

The process to add, modify, delete drawings is laid out as part of the process flow for each type of work and stage of work completion. Through FileNexus design, construction and operations staff access the drawings through various stages of project completion.

RATE BASE OVERVIEW

Table 1 below summarizes PowerStream's rate base from 2009, the last Cost of Service ("COS") rebasing for PowerStream, to 2013, the Test Year for the current COS Application. These are combined amounts for both the legacy PowerStream (South) and former Barrie Hydro (Barrie), which amalgamated January 1, 2009.

Table 1: Rate Base 2009 to 2013 ($Millions)

	CGAAP			**MIFRS**			
Rate Base	**PS Total 2009 Actual**	**PS Total 2010 Actual**	**PS Total 2011 Actual**	**PS Total 2011 Actual**	**PS Total 2012 Forecast**	**PS Total 2013 Forecast**	**Change from 2009 Actual**
Opening PP&E NBV	$ 535.1	$ 539.5	$ 613.2	$ 613.2	$ 659.9	$ 695.0	$ 159.9
Closing PP&E NBV	$ 539.5	$ 613.2	$ 651.9	$ 659.9	$ 695.0	$ 740.9	$ 201.4
PP&E - Average NBV	**$ 537.3**	**$ 576.3**	**$ 632.5**	**$ 636.5**	**$ 677.4**	**$ 717.9**	**$ 180.7**
Working Capital Allowance	$ 102.2	$ 112.2	$ 122.0	$ 123.8	$ 117.1	$ 122.7	$ 20.4
Rate base	$ 639.5	$ 688.5	$ 754.6	$ 760.3	$ 794.5	$ 840.6	**$ 201.1**
Green Energy Capital					$ 0.5	$ 0.5	$ 0.5
PP&E Transitional Amount	$ -	$ -	$ -	$ (0.5)	$ (1.7)	$ (2.6)	$ (2.6)
Adjusted Rate base	**$ 639.5**	**$ 688.5**	**$ 754.6**	**$ 759.9**	**$ 793.2**	**$ 838.5**	**$ 199.0**
PP&E Transitional Amount	$ -	$ -	$ -	$ (0.9)	$ (2.6)	$ (2.6)	

Prior to amalgamation, PowerStream filed a COS rate application for 2009 and Barrie filed a COS rate application for 2008. Actual results for 2009 are on a total basis for the amalgamated entity. These factors make comparison of the most recent Board Approved to Actual rate base amounts difficult. This comparison is discussed below under the title "Board Approved vs. Actual".

As can be seen in Table 1, PowerStream's rate base has increased from $639.5 million in 2009 to $838.5 million in the 2013 test year, an increase of $199.0 million. This is made up of:

- an increase of $180.7 million in the Property Plant and Equipment ("PP&E") Average Net Book Value ("NBV");
- an increase in Working Capital Allowance ("WCA") of $20.4 million;

- an increase of $0.5 million for the Renewable Enabling and Smart Grid capital investments in deferral accounts up to December 31, 2011 for approval and inclusion in rate base; and
- an adjustment to PP&E of $2.6 million reduction for the International Financial Reporting Standards ("IFRS") PP&E Transitional Amount.

These changes are discussed below.

PP&E Average NBV

The change in rate base arising from the PP&E Average NBV is summarized in Table 2 below:

Table 2: Change in PP&E Average NBV ($Million)

Closing PP&E NBV	$ 740.9
Opening PP&E NBV	$ 539.5
Change *	**$ 201.4**
Add 2009 averaging impact	$ 2.2
less 2013 averaging impact	$ (23.0)
Rate base impact	**$ 180.7**

The Property Plant and Equipment ("PP&E") Net Book Value ("NBV") amounts are net of contributed capital and accumulated depreciation.

Details of the change in PP&E NBV can be found in Exhibit B1, Tab 1, Schedule 7, "In Service Additions".

Working Capital Allowance ("WCA")

The change in the WCA amount accounts for $14.3 million of the increase in rate base. This is driven by the increase in the cost of power, increase in distribution expenses and offset by the reduction in the working capital allowance from 15% to 13%.

The Working Capital Allowance is discussed further in Exhibit B3, Tab 1, Schedule 1, "Working Capital Overview".

Green Energy Capital

PowerStream is applying for disposition of the costs to December 31, 2011, related to the Green Energy Act ("GEA") initiative by the Provincial Government, tracked in the following deferral accounts:

1531 Renewable Connection Capital Deferral Account

1532 Renewable Connection OM&A Deferral Account

1534 Smart Grid Capital Deferral Account

1535 Smart Grid OM&A Deferral Account

The Green Energy Capital amount represents the capital additions in accounts 1531 and 1534 to December 31, 2011, net of accumulated of accumulated depreciation to December 31, 2012, as summarized below in Table 3

Table 3: Summary of Green Energy Capital Amount ($000)

Total Additions to Dec 31/11	**Net**
Account 1531 - Gross	$ 524.8
Less Provincial Recovery	$ (493.3)
Account 1531 – direct benefit	$ 31.5
Account 1534	$ 476.8
Total cost	**$ 508.3**
2010 amortization	$ 3.5
2011 amortization	$ 16.3
2012 Amortization	$ 25.7
Accumulated amortization	**$ 45.5**
Net Book Value	**$ 462.8**

The above Green Energy capital NBV amount of $0.5 million has been added to rate base as of December 31, 2012.

The amount shown for 1531 Renewable Connection Capital Deferral Account, represents the direct benefit amount for PowerStream's customers and is net of the amount that PowerStream is seeking for recovery through the Independent Electricity System Operator ("IESO") under Ontario Regulation 330/09 section 3.

The Green Energy Act Plan can be found in Exhibit B2, Tab 1, Schedule 2. More information on the Green Energy Act Plan deferral accounts, disposition, planned spending and funding rate adders can be found in Exhibit B2, Tab 1, Schedule 1.

IFRS PP&E Transitional Amount:

PowerStream filed for its previous COS rates under Canadian Generally Accepted Accounting Principals ("CGAAP"). In 2012 PowerStream adopted International Financial Reporting Standards ("IFRS") for financial reporting purposes.

The adoption of IFRS required the restatement of 2011 balances under IFRS. PowerStream has followed the Board's guidance and tracked the differences in PP&E between CGAAP and OEB Modified IFRS ("MIFRS") in account 1575 for 2011. The differences for 2012 have been forecast for the purpose of this rate Application.

PowerStream has determined that the value of PP&E at December 31, 2012 under CGAAP would be $2.6 million lower than the PP&E under MIFRS. This amount has been deducted from rate base in calculating revenue requirement.

The impacts of IFRS and the differences in PP&E recorded in account 1575 are discussed in Exhibit A3, Tab 1, Schedule 5.

Board Approved vs. Actual:

Table 4 compares the most recent Board Approved Rate Base Amounts to Actual.

Table 4: Board Approved vs. Actual Rate Base ($000)

	CGAAP				
Rate Base	**Barrie 2008 Board Approved**	**South 2009 Board Approved**	**Combined Board Approved**	**Combined 2009 Actual**	**Variance**
PP&E - Average NBV	$ 130,388	$ 457,087	$ 587,475	$ 537,273	$ 50,202
Working Capital Allowance	$ 19,466	$ 69,727	$ 89,193	$ 102,209	$ (13,016)
Rate base	**$ 149,854**	**$ 526,814**	**$ 676,668**	**$ 639,482**	**$ 37,186**

Actual PP&E values were lower mainly as a result of the merger and a delay in the in-service date of Markham Transformer # 4.

The amalgamation of Barrie Hydro Distribution Inc. and PowerStream Inc. was approved by the OEB in December 2008 and effective January 1, 2009. Several large purchases were avoided as a result of the merger and the ability to share resources between the two predecessor utilities.

CAPITAL EXPENDITURES OVERVIEW

Overall, the total capital expenditures have varied from 2007 to 2013 with consistent levels being sustained through to 2011. The exception to this was in 2009 when additional funds were required to build the new Markham TS#4 and supporting distribution infrastructure. Increases in total capital expenditure are required for both 2012, the bridge year, and 2013, the test year. In 2012, the increase is in large part due to an increase in Operations Capital to fund a new Customer Information System ("CIS"). Increases in 2013 can be attributed to an increase in Sustainment Capital to support increased infrastructure replacement and rehabilitation, an increase in Developmental Capital for subdivisions, road authority projects and electrical distribution infrastructure projects to supply customer load growth and an increase in Operations Capital to fund the new CIS.

The details of the Capital Expenditures for the period 2007 to 2013 are shown in Table 1 below.

Table 1:

Capital Expenditures 2007 to Test Year 2013								
PROJECT DESCRIPTION	**2007 Actual (CGAAP)**	**2008 Actual (CGAAP)**	**2009 Actual (CGAAP)**	**2010 Actual (CGAAP)**	**2011 Actual (CGAAP)**	**2011 Actual (MIFRS)**	**2012 Bridge Year (MIFRS)**	**2013 Test Year (MIFRS)**
Sustainment Capital								
Replacement Program	$3,863,657	$4,629,272	$4,451,046	$5,219,180	$3,886,039	$3,254,511	$6,967,807	$7,979,035
Sustainment Driven Lines Projects	$6,457,421	$7,040,850	$8,437,575	$6,663,891	$10,681,906	$8,284,920	$9,919,810	$23,238,712
Emergency / Restoration	$3,114,168	$3,589,697	$4,203,755	$8,673,251	$7,504,452	$7,082,363	$9,100,468	$9,527,350
Transformer / Municipal Stations	$1,457,915	$714,605	$948,688	$1,407,008	$3,492,638	$3,268,289	$1,123,370	$2,673,187
Emerging Sustainment Capital	$2,353,154	$3,122,060	$2,281,720	$1,549,473	$1,072,112	$949,866	$2,824,959	$2,847,386
Total Sustainment Capital	$17,246,315	$19,096,482	$20,322,784	$23,512,802	$26,637,146	$22,839,950	$29,936,414	$46,265,670
Development Capital								
Subdivision / Services	-$15,811	$1,412,727	$7,508,430	$3,939,167	$7,878,391	$4,822,559	$9,469,121	$11,672,797
Road Authority Projects	$3,697,004	$1,088,679	$3,942,432	$5,922,934	$8,910,456	$7,218,612	$6,298,918	$13,044,233
Additional Capacity (Transformer / Municipal Stations)	$2,710,298	$6,574,963	$10,772,075	$1,784,948	$150,524	$113,508	$727,500	$5,983,906
Growth Driven Lines Projects	$2,348,220	$1,535,358	$11,926,518	$4,992,351	$7,825,726	$7,038,310	$4,024,577	$6,544,575
Emerging Development Capital	$200,346	$644,866	$858,309	$611,790	$1,032,240	$626,419	$540,569	$435,371
Distributed Generation Connections	$0	$0	$23,941	$79,931	$32,210	-$86,236	$0	$0
Total Development Capital	$8,940,057	$11,256,592	$35,031,705	$17,331,122	$25,829,548	$19,733,172	$21,060,685	$37,680,882
Operations Capital								
Metering	$1,935,577	$2,799,149	$2,045,082	$2,909,300	$3,144,545	$2,167,753	$2,582,260	$2,619,518
Fleet	$2,099,231	$2,626,258	$3,933,516	$3,059,001	$1,172,758	$1,154,496	$2,037,200	$2,932,600
Tools	$466,984	$354,050	$326,514	$457,226	$640,137	$629,865	$712,810	$596,576
Buildings	$20,993,737	$4,931,129	$4,846,822	$1,308,312	$176,551	$173,385	$864,930	$221,372
Information / Communication Systems	$1,996,988	$3,345,827	$2,498,400	$5,546,874	$4,528,148	$4,419,136	$18,422,910	$22,396,999
Purchase of Spare Equipment	$0	$3,345,554	$3,099,128	$321,634	-$228,589	-$228,721	$66,000	$127,654

Capital Expenditures 2007 to Test Year 2013								
PROJECT DESCRIPTION	**2007 Actual (CGAAP)**	**2008 Actual (CGAAP)**	**2009 Actual (CGAAP)**	**2010 Actual (CGAAP)**	**2011 Actual (CGAAP)**	**2011 Actual (MIFRS)**	**2012 Bridge Year (MIFRS)**	**2013 Test Year (MIFRS)**
Emerging Operations Capital	$2,341,273	$2,020,446	$944,198	$1,171,867	$768,100	$742,961	$686,770	$120,120
Interest Capitalization	$1,374,013	$850,187	$1,390,473	$1,674,195	$573,560	$340,287	$330,000	$1,317,372
Total Operations Capital	$31,207,803	$20,272,599	$19,084,132	$16,448,410	$10,775,210	$9,399,162	$25,702,880	$30,332,211
Total Capital Expenditure	$57,394,175	$50,625,673	$74,438,621	$57,292,334	$63,241,903	$51,972,285	$76,699,979	$114,278,763
Capital Deferral Accounts								
Smart Meters	$10,536,450	$6,610,918	$17,195,703	$26,731,788	$1,526,739	$1,406,008	$0	$0
Smart Grid	$0	$0	$0	$192,265	$284,912	$281,174	$1,250,000	$650,000
Renewable Generation	$0	$0	$0	$54,046	$470,772	$468,795	$756,361	$77,250
Total Capital Deferral Accounts	$10,536,450	$6,610,918	$17,195,703	$26,978,099	$2,282,423	$2,155,977	$2,006,361	$727,250

Sustainment Capital

PowerStream has increased monies for Sustainment Capital each year. As a result of completing Asset Condition Assessments, PowerStream has recognized the need to increase spending to ensure the infrastructure is renewed appropriately to ensure a reliable system for customers. A large number of assets that were installed in the 1970's and early 1980's, are greater than 30 years old and are at or near end of life. As such, planned replacement and rehabilitation of poles, switches, switchgear and underground cable have been increased. Planned replacement is necessary as these assets are critical to system integrity and unplanned failures result in significant customer outages and could result in a significant potential public hazard.

The largest increase in Sustainment Capital for 2013 can be attributable to rehabilitation of underground cable. PowerStream has significant underground cable which was installed during the 1970's and early 1980's and is now at end of life. This cable is an early generation of cable with a shorter life span than the new cable being installed today. Outages as a result of cable faults on the early generation of cable have been increasing and sections of cable which failed during 2011 could not be repaired. Replacement was the only option. Troubleshooting cable problems generally takes significant time and results in extended outages for impacted customers.

PowerStream has started replacement of the cable in specific subdivisions and has piloted the injection of the cable[1] to extend life. Based on the Asset Condition Assessment of the underground cable PowerStream needs to increase spending on these rehabilitations. The amount proposed for 2013 is at a level, which if sustained over the next 20 years, will result in appropriate rehabilitation of the early generation of underground cable. PowerStream has significantly more of the next generation cable that was installed during the late 1980's and 1990's which is expected to be at its end of life 20-30 years from now.

Also to be noted is the increase in funds from 2007 required for Emergency/Restoration. This sub-category covers capital costs of repair and restoration of the distribution system. Work is

[1] The injection of cable is a process where a compound is injected into the cable jacket. The compound fills in the gaps in the jacket, hardens and prevents water from finding its way to the core of the cable and causing a fault.

required as a result of on-going power outages or identified through inspection as needing replacement due to a hazardous safety condition or potential imminent failure. Costs have increased since 2007 with a significant increase in 2010. The general increase can be attributed to PowerStream's efforts to better identify proactively problems with the system through identification of worst performing feeders and inspection practices. The inspections have identified the need to replace additional assets.

Development Capital

The requirement for Development Capital over the past few years has generally increased each year. There are three main drivers to these changes. The first driver is the increased requirement to relocate plant as requested by Road Authorities. The Municipalities and Regions have increased their infrastructure projects and those projects have impacted PowerStream, requiring PowerStream to relocate an increased amount of pole lines.

A second driver of the increase in Development Capital is the funds required for subdivisions and new services. The "ups and downs" of the historical costs for subdivisions have been impacted by the timing of receipt of the capital contribution from the developers compared to timing of construction. PowerStream keeps track of lots issued for construction. The number of lots issued for construction has steadily increased each year. Additional sewer capacity is expected to come on line in 2013 so the increase in lots is expected to continue. Additional increases in funds for 2012 and 2013 can be attributed to costing changes. Changes were made in the economic model to adopt best practices between the former Barrie Hydro and former PowerStream impacting 2012 and 2013. In addition, consistent with the Distribution System Code ("DSC"), with this rate application, upstream costs can no longer be put in the model resulting in a further increase in PowerStream's share of the costs to install subdivisions in 2013.

A third driver of the changes in Development Capital is the funds required for specific projects to construct new facilities to support load growth. Although load growth has slowed, what remains is concentrated in areas where land is available for "greenfield" development. PowerStream prudently plans the system to utilize the existing facilities as much as possible to service the new developments but in certain areas new facilities are required due to technical constraints on the existing distribution system.

In 2009 Markham TS#4 was constructed with some associated feeders. 2009 also saw the construction of feeders out of Armitage TS to support the re-development of the Distribution System in Northern York Region with the installation of Holland Landing TS. Due to these projects, 2009 had increased costs compared to other years. Specific lines projects and station projects required for load growth has remained relatively steady since 2010 with an increase expected in 2013. During 2013 two major projects are required in Barrie which will result in an increase in costs. One is the construction of a new substation and the other is construction of a new 44 kV feeder from Midhurst TS to south Barrie.

Operations Capital

The spending on Operations Capital has varied from year to year. The variances can be attributed to differing specific large project needs in a given year. Spending in 2007 to 2009 was impacted by the construction of the new Head Office at Cityview and new Operations centre at Addiscott. Spending in the bridge year, 2012 and the test year, 2013 are impacted by the work on a new CIS to be in-service by the end of the second quarter of 2014.

Capital Deferral Account

The requirement for Capital Deferral Account spending has resulted from three programs. The first program is Smart Meters. PowerStream completed installations of Smart Meters in 2011. The second program is Renewable Generation. The needs required for Renewable Generation are covered in the Green Energy Plan (“GEA”) Plan (Exhibit B2, Tab 1, Schedule 2). Similarly, the third program is Smart Grid which is also covered in the GEA Plan.

The expenditures for Barrie (North) and PowerStream South are detailed separately for purposes of comparison to rate cases, see Exhibit B1, Tab 1, Schedule 6 for 2008 Barrie and for 2009 PowerStream. All other expenditures are combined for purposes of comparison to the test year.

See Exhibit B1, Tab 1, Schedule 6 for detailed year-over-year capital spending variance analysis. Projects greater than $750,000 in the bridge year 2012 and test year 2013 are summarized in “Investment Summary Documents” in Exhibit B1, Tab 1, Schedule 8.

MAJOR PROJECTS OVERVIEW

This exhibit highlights two major projects.

New Operations Centre

In 2010 PowerStream moved from two Operations Centres, one in Vaughan and one in Markham, to a new single location in Markham. It was challenging to find a suitable location with access to major highways and where outdoor storage of material and equipment would be allowed. The following evidence explains the rationale for the consolidation to a single site, the options and the financial impacts.

Customer Information System Project

In 2011, PowerStream purchased an Oracle Customer Information System ("CIS") to replace the existing T&W CIS system that is no longer viable. A Request for Proposal ("RFP") was issued to select a vendor to integrate the system, which is the largest cost in the project. The following evidence outlines the need, the alternatives considered and the rationale for the selected approach. Note that the new CIS system is expected to be in service by the end of the second quarter of 2014.

NEW OPERATIONS CENTRE

PROJECT OVERVIEW

PowerStream was required to replace the Markham Operations Centre, which served the eastern part of the legacy PowerStream service territory, due to the termination of the short term lease at 8100 Warden Avenue.

PowerStream engaged a real estate consultant to identify available sites for a replacement Markham/East Operations Centre. The site would need to accommodate PowerStream's need for indoor parking of utility vehicles and outside storage of poles, transformers and other electrical equipment. As well it would need to be situated to allow quick response time to PowerStream's service area. To minimize disruption to operations, PowerStream was looking to purchase or obtain a longer term lease (fifteen years or more).

The search considered existing buildings and sites available for development. The search concentrated on the Markham and Richmond Hill areas as these locations were central to the service area to be covered.

Most potential sites identified were determined not to viable because outside storage was not permitted or was very limited.

In the course of this search, it became apparent that there were very limited options for an Operations Centre site. There were no existing buildings available that met PowerStream's requirements and most new development in the Markham and Richmond Hill area was restricted to "prestige" business parks which do not allow the type of Operations Centre required by PowerStream.

PowerStream management was also concerned that a similar situation could arise with the existing Vaughan Joint Operations Centre ("JOC"). The JOC was at a site owned by the City of Vaughan ("City") and shared with the City operations departments. PowerStream had a short term lease with the City, whereby either party could terminate the lease upon twelve months notice. It was clear that as the City continues to grow, its operational departments would require more of the site and at some point the City would require the space occupied by PowerStream and terminate the lease. PowerStream management considered this likely to happen within five to ten years.

PowerStream considered another option to combine the East Operations Centres into a combined Operations Centre and the JOC. From an operational and cost perspective there were benefits to a consolidated service centre.

After consideration of the options available, it was determined that a new consolidated Operations Centre, for the South service territory, which would allow the company to combine all field operations in one site while providing high levels of service to customers, was preferred. This would ensure the organization's future operating needs were secured, while providing the most prudent financial outcome.

A search for suitable sites for a consolidated Operations Centre for the south service territory was conducted by a real estate consultant, CRESA Partners ("CRESA"). Several potential sites for a consolidated service centre were identified: the "Salt Dome" at Dufferin and Highway 407 in Vaughan ("Dome"), Addiscott Court, at Highway 407 and Highway 404 in Markham ("Addiscott") and the Elgin Mills Business Park at Highway 404 and Elgin Mills in Richmond Hill.

Further investigation of these sites took place. Further discussions regarding the Richmond Hill site revealed that PowerStream's requirements for outside storage would not be allowed.

This left Addiscott and the Dome as the remaining potential sites. Both sites were well located to provide quick access to the service territory due to their proximity to highway 407 and a north-south 400 series highway (404 and 400 respectively). Both sites allowed the outside storage required and had sufficient space. Both sites were adjacent to PowerStream owned transformer stations.

PowerStream found there were considerable obstacles and uncertainty regarding development of the Dome site due to ownership of the required parcels of land by several parties. It was also concluded that the land value at the Dome would be more costly compared to the Markham location.

CRESA continued to search for sites for either option, but did not find any suitable sites for either a replacement east Operations Centre or for a consolidated Operations Centre.

The Addiscott site was deemed to be the preferred site. The owner of the Addiscott site was not interested in selling this property, only leasing. Developers are typically not interested in selling as there can be financial benefits to leasing rather than selling and recognizing any gain on sale. Many developers prefer to retain ownership of the land and the potential for further appreciation. The owner offered to design and build an Operations Centre to PowerStream's specifications at 80 Addiscott Court in Markham and offer a long term lease of 25 years.

PowerStream obtained approval to enter into negotiations for a long term lease. These negotiations resulted in a 25 year lease with purchase and lease renewal options.

PowerStream took possession of Addiscott as of January 1, 2010 and completed consolidation of its two operating centres in the South service territory into a consolidated Operations Centre as of March 2010.

Project Need

In 2004, PowerStream was formed by the amalgamation of Hydro Vaughan, Markham Hydro, and Richmond Hill Hydro. In 2005, PowerStream purchased and amalgamated with Aurora Hydro Connections Limited ("Aurora Hydro").

In an attempt to establish the most efficient and effective operational strategy, PowerStream reduced the number of Operations Centres from three to two after the 2004 amalgamation by closing the Richmond Hill Hydro Operations Centre. Similarly after the purchase of Aurora Hydro in November 2005, the Aurora Hydro Operations Centre was closed in May 2006.

The Operations Centres that remained open to accommodate PowerStream's service territory were the JOC located at 2800 Rutherford Road in Vaughan, and 8100 Warden Avenue ("Warden") in Markham. These facilities were leased from the City of Vaughan and the Town of Markham ("TOM"), respectively.

In order to secure PowerStream's operating requirements, management attempted to negotiate long-term leases with both parties. However neither party was willing to commit to a long term lease arrangement, preferring to keep the option to use these sites to meet their future municipal needs. In the summer of 2007, the TOM notified PowerStream that it was exercising the right under the agreement to terminate the lease with PowerStream for the Warden location.

PowerStream retained CRESA Partners real estate consultants to assist with the lease or purchase of a replacement facility for the Markham operations centre. No suitable properties were available for purchase or lease in the required timeframe for vacating the Warden location. The lack of suitable sites was largely due to restrictions regarding outdoor storage, which PowerStream requires for poles, transformers and switchgear. Another key consideration was that the location must allow ready access to the service territory to allow service levels to be met.

As a temporary solution, PowerStream obtained a short term lease and moved the Markham service centre operations to 550 Cochrane Drive (“Cochrane”). Due to the lack of outside storage space at this location, PowerStream was required to continue using the outdoor storage at the former Warden location, while continuing to explore the market for a more suitable long-term facility. However, the Town of Markham stipulated that the company’s use of the Warden location for outdoor storage requirements was only available for a period of up to two years to allow PowerStream to find a longer term solution. Thus, the organization was faced with the pressing task of securing a long-term facility to properly accommodate the firm’s operational needs.

SERVICE CENTER ALTERNATIVES CONSIDERED

In 2008 PowerStream was operating out of two facilities: one at the JOC in Vaughan and a temporary location at Cochrane in Markham. In addition, since no outdoor storage was available at the temporary site Cochrane site, PowerStream was using the outdoor storage space at 8100 Warden Avenue as an interim solution. The TOM had advised PowerStream that this outdoor storage facility would not be available beyond 2009.

The Cochrane location was a temporary measure due to the requirement to vacate the Warden location in Markham. However, it was not sustainable in the long-run due to less than satisfactory space, a lack of a covered garage space for line vehicles (mainly "bucket" trucks) and the lack of outdoor storage.

The Vaughan JOC was shared between PowerStream and several operating departments of the City of Vaughan. PowerStream was concerned that it would be asked to vacate the Vaughan facility in the future as the City's needs increased at that site. PowerStream considered the immediate need for a suitable Markham operations centre and the likelihood that in within the next five to ten years it would be required to replace the Vaughan facility.

PowerStream continued to work with CRESA to find a long term solution to its operating centre requirements in its South (York Region) service territory.

The following key criteria were used to evaluate the options for PowerStream's South operating centre facilities:

- Minimize disruptions to operational capability (minimum lease of 15 years);
- Economically viable – most cost effective option
- Meet service level requirements.
- Opportunity for improved efficiencies

DESCRIPTION OF ALTERNATIVES

The following two alternatives were identified and considered.

<u>Alternative #1: Two Operation Centres – Markham and Vaughan</u>

This alternative considered the purchase or long term lease of a facility to replace the Markham operations centre formerly at 8100 Warden Avenue, which was temporarily moved to the Cochrane location.

PowerStream continued to work with CRESA to find a suitable facility for purchase or long term lease in the Markham area. The search continued to show that no suitable existing facilities were available for purchase or lease in the eastern part of PowerStream's service territory, largely due to restrictions on outdoor storage. Nor were there any suitable properties available for purchase where a suitable Operations Centre could be constructed.

PowerStream was concerned that the availability of suitable sites for an operations centre would be even more unlikely when it was time to replace the Vaughan JOC.

<u>Alternative #2: One Consolidated Operation Centre</u>

Faced with the scarce availability of suitable sites in York Region, PowerStream began to consider the benefits of combining current operations into a consolidated Operations Centre for the South service territory.

Moving to a consolidated site would create opportunities for increased efficiencies in terms of staffing, fleet requirements, management travel time and safety stock. Consolidating the two service centres offered many intangible advantages. This also offered the advantage of helping to unify the corporate culture and business processes. A combined site would bring the operations staff together and facilitate better management through this integration, as has occurred in other areas where PowerStream's work forces have been brought together.

PowerStream worked with CRESA to procure land and facilities for purchase or long term lease to meet the criteria for a consolidated operations centre for the South. After an extensive search and review, it was determined that there were two possible sites.

- Lands owned by Bloorguard Investments ("Bloorguard") at Addiscott Court (Highway 404 an 407) in Markham;
- The "Salt Dome" site located on Dufferin Street at Highway 407 in Vaughan, and partially owned by the City of Vaughan.

A third site in Richmond Hill had been identified as a potential site but had to be eliminated as the outside storage required by PowerStream was not permitted.

The Addiscott and Salt Dome locations were ideal for the purposes of a service centre for several reasons. First, they were close to Highway 407 and, therefore, a large portion of the service territory could be easily accessed via highways to minimize response times. Second, the locations were both easily accessible for large vehicles, and large enough to house an operations centre and outdoor storage. Finally, they both provided proximity to current or future planned transformer stations.

The availability of the Salt Dome facility, particularly with respect to timing, was uncertain. There are various owners of the land that comprised the site. Preliminary research indicated that if the owners of the land were to sell, their asking price would likely be $1.6 to $1.8 million per acre. Due to the multiple land ownership, it was not clear that it would be possible to assemble a parcel of the necessary size.

No other suitable sites had been identified, leaving Addiscott as the preferred option. PowerStream worked with CRESA to negotiate favourable lease terms with Bloorguard.

ANALYSIS OF ALTERNATIVES

<u>Alternative #1: Two Operation Centres – Markham and Vaughan</u>

Due to the nature of PowerStream's business, it is essential to be able to continue operations in a seamless fashion without interruption, and uphold a high level of service to the communities served. By continuing to operate out of two operations centres in the South, PowerStream would continue to bear significant tenant risk. In addition, neither of the facilities had sustainable outdoor storage.

If this alternative were pursued, PowerStream would have to build an operating facility for Markham alone, and continue to use the current facility in Vaughan. However, it is assumed that the organization would need to build a new service centre in Vaughan to replace the leased facility within ten years.

CRESA estimated based on construction costs and land prices, two separate facilities would cost approximately $17 million each, based on seven acres of land valued at $6 million and construction costs of $11 million. This translates to an annualized payment of $1,352,000 based on the typical capitalization rate used by lessors.

This option assumes that two separate seven acre sites would be available, one in Markham now and eventually a second one in Vaughan. This was not the case during the project due to the lack of available land appropriately zoned for PowerStream's uses. The scarcity of suitable sites was expected to get worse in the future due to the continuing development in the PowerStream South service territory.

<u>Alternative #2: One Consolidated Operations Centre</u>

After evaluating the options based on the established criteria for PowerStream's operating centre needs, it became evident that this alternative met the criteria and facilitated the execution of PowerStream's long-term operational strategy. The following table compares how the organization's requirements would be addressed by a consolidated operating facility.

Table 1 – PowerStream's Service Centre Requirements and Solutions Provided by Acquiring a Consolidated Operating Facility.

Service Centre Requirements	Solutions Provided by Acquiring a Consolidated Operating Facility
Ensures long-term operational viability of the company (over minimum of 15 years)	PowerStream will either pursue a long-term lease (i.e. 25 year lease) with an ownership option, or outright ownership
Economically viable - most cost effective option	This option is the most cost effective compared to having to build two smaller centres
Opportunity for improved efficiencies	Opportunities for efficiencies related to staffing, vehicle utilization, safety stock and management travel
Has minimal impact on service levels	Analysis indicates minimal impact on service levels

In addition to satisfying the desired criteria, this alternative would also eliminate the dependency on multiple landlords, the uncertainty associated with short-term leases (12 months notice to terminate lease), help streamline operations, increase efficiency, and ultimately secure PowerStream's long-term operating requirements.

PowerStream's management conducted a cost comparison of alternative #1 (two operations centres) versus alternative #2 (consolidated operations centre) over a 25 year time horizon. In the analysis, it was assumed that the temporary Markham site would be replaced and that the current Vaughan site would either no longer be available to PowerStream or be outgrown in ten years, and require replacement at that time. The analysis associated with the consolidated operating facility involved leasing the consolidated service centre over the same forecasted time horizon. The following table is a summary of the net present values ("NPV") associated with the leasing costs for each of the service facility scenarios, assuming a time horizon of 25 years.

Table 2 – NPV Analysis of the Service Centre Alternatives

	NPV ($millions)
Alternative #1 Two Operations Centres – Markham and Vaughan - Build smaller service centre in Markham immediately, retain existing Vaughan operations centre and replace in ten years	$ 33.8
Alternative #2 One Consolidated Operations Centre - Addiscott Court Markham lease	$ 30.4

The only available option meeting PowerStream's requirements was the long term lease of Addiscott. This option also was financially prudent compared to the two separate centres option as determined by the NPV analysis. As noted earlier, the Dome, the other site considered for a consolidated operations centre, would be more costly due to higher land costs if land assembly were even feasible.

Therefore, given that consolidating PowerStream's South operations centres is cost-effective, the Addiscott site suits the firm's operational needs, and land in York region is in short supply, PowerStream's management received approval to proceed with negotiating a long term lease of Addiscott.

PowerStream received a proposal from Bloorguard, in which they offered to build an operations centre for PowerStream and provide a 25 year capital lease. In turn, PowerStream requested to purchase the land and facility from Bloorguard immediately. Bloorguard declined to sell the 12 acre site at that time.

PowerStream worked with CRESA Partners to negotiate favourable lease terms. The final lease agreement included a 25 year capital lease, a purchase option at the end of year 25, first right of purchase if the owner sells before the end of the lease and two five year term lease renewal options. PowerStream also purchased two acres of adjacent land needed for a transformer station in Markham. No other suitable land was available for purchase.

The lease rates negotiated with Bloorguard were:

- Years 1-10: $2,286,011
- Years 11-20: $2,457,011
- Years 21-25: $2,621,011

ACCOUNTING TREATMENT AND VALUES

PowerStream followed the Canadian Institute of Chartered Accountants ("CICA") Handbook section 3065 Leases to determine the proper accounting treatment for the long term lease on the Addiscott Operations Centre. PowerStream's account treatment of this lease was reviewed by the company's external auditor and accepted as the correct accounting treatment under Canadian Generally Accepted Accounting Principles ("CGAAP").

As required by CICA 3065.73, it was necessary to consider the land and building separately. The lease payments were allocated between the land and building in proportion to their respective fair market value at the lease inception. The fair market value ("FMV") of the land was based on the price per acre paid for the adjoining lot which was purchased for a new transformer station. This resulted in a FMV for the land of $11.4 million. The FMV of the building was determined based on a construction cost estimate by a consulting engineering firm of $19.0 million. The total FMV for the operations centre was $30.4 million. This resulted in the following allocation of the lease payment between land and building.

Annual lease amounts	Total	Land	Building
Years 1 to 10	2,286,011	856,100	1,429,911
Years 11 to 20	2,457,011	920,138	1,536,873
Years 21 to 25	2,621,011	981,555	1,639,456

It was determined that the land portion of the lease is an operating lease. Accordingly the land portion of the lease payment has been included under rent in the Operating, Maintenance and Administrative costs. The building portion of the lease was determined to be a capital lease and recorded in account 2005 Property under Capital Leases at the net present value of the lease payments related to the Building of $18.3 million.

CUSTOMER INFORMATION SYSTEM PROJECT

SUMMARY

PowerStream will implement a new Oracle based Customer Information System (“CIS”) to replace the existing T&W Info-Systems Ltd. CIS system (“T&W”) that dates back to the 1970s. In November of 2011 PowerStream’s Board of Directors approved a purchase agreement for the Oracle Customer Care and Billing CIS (“CC&B”) solution. In February of 2012 PowerStream purchased Oracle’s CIS Custom Components for the Ontario Market (“CCOM”). PowerStream is currently conducting a Request for Proposal (“RFP”) process for selection of a system integrator.

PROJECT OVERVIEW

The new CIS is one element of PowerStream’s documented five year Information System (“IS”) Strategy which is aligned with its corporate strategy and supports PowerStream’s objectives particularly in the areas of growth and integration with new and emerging technologies. PowerStream’s overall IS Strategy is key to achieving the IS mission which states:

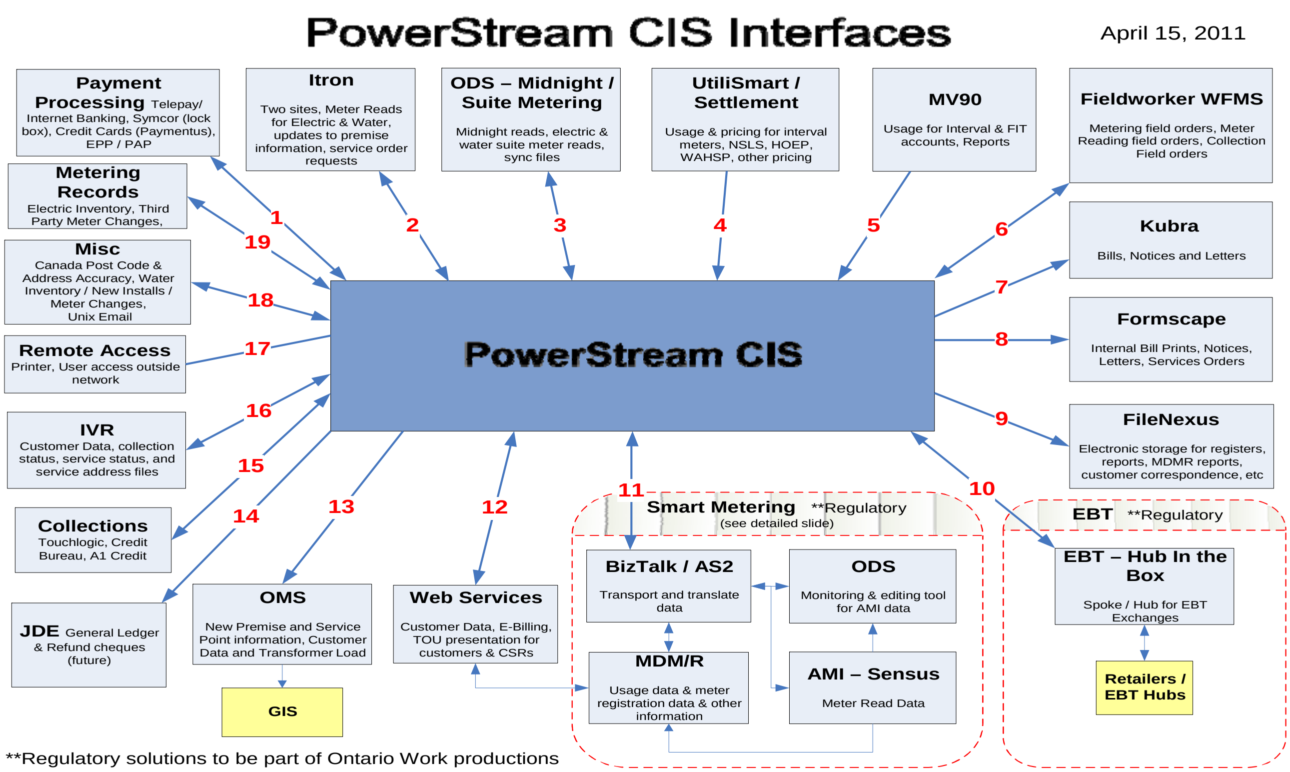
> “PowerStream will use information technology as an enterprise asset to enable and automate our business. Through the use of technology, PowerStream will sustain its leadership position in the industry by providing the best value and service to our customers, shareholders, and employees.”

The CIS is a critical and comprehensive business system for PowerStream. The CIS provides the full meter-to-cash applications required to meet one of the core business mandates of providing account management, billing, collections, payments, and meter management/meter reading functionality for over 330,000 electricity customers within PowerStream’s service territory. It also is a hub system providing inbound and outbound information to approximately twenty other interface systems both internal and external to PowerStream.

The new CIS will satisfy all of the functions of the existing T&W system, increase productivity and provide PowerStream with a platform to meet the needs of its customers and the changing industry. Oracle's CC&B solution will allow PowerStream to transform its current business by standardizing and integrating processes across the enterprise to help increase automation and productivity, improve customer service, and reduce operational risk. The CC&B system will provide customers with the ability to more easily access information and tools necessary to self-manage relationships and enable better energy decisions, thereby achieving two of the CIS project's key objectives: to 1) reduce cost to serve by lowering the number of calls to the customer care center; and 2) supply customers with the information and ability to better manage electricity usage and enroll in energy efficiency programs. The CC&B system will deliver more up-to-date customer information, a more user-friendly interface, and better workflow automation capabilities for improving customer interactions.

The major cost components of the new CIS system are the system hardware and software, internal resources, consulting and legal costs and the cost for integration of the CIS with PowerStream's existing processes and systems. Approximately two-thirds of the costs are for system integration. As noted earlier, the selection of a system integrator is taking place through a full RFP process. The system integrator plays a key role in integrating the twenty interfaces noted in Figure 1, below, with the Oracle CC&B solution by providing expertise in areas that include data conversion, business process requirements and design, testing training, organizational change management, cutover and transition and business continuity.

Figure 1: CIS Interfaces



The new CIS system is planned to be in service in by the end of Q2, 2014. The capital and OM&A cash costs associated with this project are outlined in Table 1 below.

Table 1: CIS Cost

CIS Replacement Project - Cost Breakdown							
(Taxes and Staff Overhead Burdens NOT Included)							
			Capital			OM&A	
Software License& Hardware			2012	2013	2014	2012	2013
		$5,133,160	$4,253,160	$605,000	$275,000	$578,844	$578,844
Internal Staff & Resource Costs							
		$4,166,934	$1,491,588	$1,726,192	$949,155		
Legal - Consulting - Other Misc.							
		$3,194,605	$1,399,464	$1,208,644	$586,497		
Integration							
		$22,000,000	$5,500,000	$12,100,000	$4,400,000		
TOTAL PROJECT COST		$34,494,699	$12,644,212	$15,639,836	$6,210,652		

The following sections of this evidence outline the CIS project need, alternatives considered, an assessment of the alternatives, an outline of the alternative selected, benefits of the new system and information on next steps in PowerStream's CIS implementation.

PROJECT NEED

PowerStream's current CIS is a legacy system that was created by T&W Info-Systems Ltd. in the 1970s. Prior to the creation of PowerStream each of the three initial predecessor utilities (Markham Hydro, Hydro Vaughan, and Richmond Hill Hydro) utilized different versions of this system to perform their billing and collection services. Upon creation of PowerStream in 2004, the systems were merged to one system. In 2006, further modifications were made to accommodate the acquisition of Aurora Hydro. The merger with Barrie Hydro in 2009 resulted in further changes. The implementation of smart meters and time of use ("TOU") rates also necessitated changes.

The CIS software is owned by PowerStream and supported by its Information Systems Division ("IS") which manages the T&W vendor that is onsite at the head office. T&W provides programming and software support to the CIS system and has provided significant support services in order to meet the ever changing needs of PowerStream's customers, demands of the Ontario electricity market and utility growth.

There are, however three significant risks associated with the current system that have caused the need to explore a more modern, robust and technically advanced system. The existing T&W CIS system has reached its limitations and cannot be kept running; integration with new and emerging technologies is restrictive; and the detailed knowledge base for this system is limited.

The risks mentioned above and the realization that eventually a new CIS System would be needed to facilitate future objectives has been known for some time. In 2007, PowerStream participated (as an observer) in a joint large municipal utility discovery process involving Toronto Hydro, Enersource, Hydro Ottawa, Horizon Utilities and London Hydro, so as to become familiar with CIS products available that may be suitable for PowerStream's future needs. This exercise ultimately resulted in both Toronto Hydro and Enersource pursuing a new CIS based on Oracle platforms which are both currently in production. Horizon implemented an Oracle System. Hydro Ottawa is implementing an Oracle system. London Hydro selected an SAP system. Participation in this joint discovery group provided PowerStream with insight with regard to evaluating CIS solutions, developing an associated business case, preparing and conducting the Request for Proposal ("RFP") and solution implementation.

PROJECT TIMING

PowerStream had been involved in growth activities since its inception in 2004 initially and subsequently with further expansion involving Aurora Hydro, Barrie Hydro and most recently a partnership with Collus (pending regulatory approval). In addition to this growth activity PowerStream was actively involved in efforts regarding smart meter deployment, CIS system connectivity with the Provincial Meter Data Management and Repository ("MDM/R") and implementation of TOU rates during the 2008 to 2011 period. Therefore contemplating a new CIS during this heightened period of activity was not practical and it was decided to keep the T&W system operating as long as possible.

In 2010 as part of PowerStream's planning process it was identified that there would be a period of stability leading into 2011 and that a window of opportunity and period of relative stability would present itself in 2012 to late 2013 allowing a practical period of time in which a new CIS could be installed. Coupled with this was the awareness that a number of key personnel that would be instrumental in a new CIS implementation would become eligible for retirement, with some eligible as early as 2012. Therefore it was prudent to proceed with this initiative while PowerStream still had the highly specialized knowledge under its employ.

ALTERNATIVES CONSIDERED

Introduction

In 2007, a discovery process was initiated by PowerStream to become familiar with CIS products that may be suitable for its needs. PowerStream participated as an observer in a joint large municipal utility discovery process involving Toronto Hydro, Enersource, Hydro Ottawa, Horizon Utilities, and London Hydro. This resulted in a joint venture between Toronto Hydro and Enersource to pursue a new CIS. Enersource and Toronto Hydro are "live" with their systems based on an Oracle platform. Learnings were gained by PowerStream related to evaluating CIS solutions, development of an IT business case, preparation for the RFP, and implementation of the solution.

The discovery process that was undertaken determined that there are only two suitable system solutions available to enable PowerStream to meet its business objectives. The two systems are Oracle's CC&B and SAP. Both systems are widely used throughout North America and are equally capable of producing similar performance. The primary differentiator between the two solutions is their ability to provide the functionality necessary to meet the regulatory requirements unique to the Ontario electricity market. Other considerations are the ability to meet business requirements, ability to integrate to existing business systems and interfaces, ease of integration, functionality, and ease of use.

PowerStream also participated in discussions with Hydro Ottawa in 2010 and 2011 to review the feasibility of partnering in a joint CIS venture and explore potential cost sharing and synergy opportunities. It was determined that differences in processes and interfaces would not permit a joint implementation. However, the two utilities plan to maintain close relationships to assist each other during an almost parallel implementation period. As an example of this relationship Ottawa Hydro provided information on their RFP process that proved to be valuable to PowerStream in setting up their RFP process for selection of a system integrator.

In the third quarter of 2011, following PowerStream's discussions and feasibility review with Hydro Ottawa, PowerStream made the decision to pursue a CIS replacement on its own. It has included this initiative as one of four primary objectives in its corporate strategy, and this is the primary focus of its formalized IS strategy. To date PowerStream has assigned two Project Co-Sponsors and a Core Implementation Team to head up this initiative.

As part of its due diligence, PowerStream participated in a hands-on demonstration of London Hydro's SAP system which represents the other main alternative to Oracle offered in the marketplace supporting utilities the same size as (or larger than) PowerStream. In addition, PowerStream had hosted presentations from both Oracle and SAP to allow them an opportunity to demonstrate their respective products and provide approximate costs. Finally, PowerStream has remained abreast of the trends and developments amongst the largest Local Distribution Companies ("LDC"s) in Ontario, all of whom are either contemplating, proceeding with or have already implemented state of the art CIS's.

As a result of PowerStream's learning process there were three main alternatives for the replacement of PowerStream's CIS identified. These were;

Continuation of the status quo;

Implementing an Oracle based CIS; and

Implementing a SAP based CIS.

DESCRIPTION OF ALTERNATIVES

Alternative 1 – Status Quo

The core of PowerStream's CIS is the T&W system that has been in place since the 1980's (originally designed in the 1970's) with customized modifications to meet growth and regulatory/business requirements. Continuing with this system is an alternative for PowerStream. The CIS is owned by PowerStream and supported by both its in-house IS division and the remaining eight staff of the T&W vendor who are managed through the IS division. PowerStream is the only remaining significant client of T&W. T&W provides programming and system support of the CIS system and has provided support to meet growth and regulatory requirements.

PowerStream has identified several risks associated that make the current system not viabie. These include the lack of documentation by T&W; significant customization of the system over the years primarily to accommodate growth through mergers with others and regulatory requirements; its inability to efficiently accommodate future changes as a result of past customization; changing business processes; and integration of emerging technologies. Compounding this matter is the fact that with the lack of documentation, there is no easy way of fixing this system without pulling key knowledgeable staff off of normal duties. Another key risk associated with the current system is the age of T&W's principal, Dr. Yu Tu, who is past normal retirement age but continues to lead the support of the system and retains the knowledge of the core programming.

PowerStream's customer satisfaction can be expected to remain stable but will be at risk of deterioration when compared to other large LDCs that have implemented more comprehensive up-to-date systems that contain more customer care and self-serve abilities than exists with the T&W system. PowerStream's annual maintenance and capital costs can be expected to increase as new modifications are required to be made to an already highly customized system.

Alternative 2: Oracle Based CIS

This alternative results in the replacement of the existing T&W system with Oracle's Customer Care and Billing ("CC&B") solution. Oracle is one of the market leaders (the other being SAP) in the provision of CIS software to utilities of a size and scope of operation similar to and larger than PowerStream. They have an extensive client base in North America. Locally, Oracle's CC&B product is installed at Enersource and at Toronto Hydro. Hydro Ottawa is currently in the process of upgrading to the Oracle CC&B solution.

Oracle offers modern functions with new service features available to customers. It is designed to operate with easily updatable templates which are configurable to meet the specific requirements of a given client. It will be easy to install, modify, and support compared to older CIS offerings such as T&W. The software reflects best practices at the process level so process improvements will also be a benefit of implementation. In addition, there will be reduced time and cost benefit if "process templates" that have already been developed by Enersource and Toronto Hydro in their implementations are usable by PowerStream.

Oracle has Custom Components for the Ontario Marketplace, known as CCOM, which has been purchased by PowerStream, that is embedded in its CC&B product to provide the ability to perform transactions according to meet the needs of the Ontario regulatory requirements.

PowerStream's financial systems operate on a JD Edwards platform which is an Oracle based and supported system. Using Oracle's CC&B CIS solution makes integration to PowerStream's financial system less complicated compared to integration to an SAP based CIS system.

Alternative 3: SAP Based CIS

This alternative results in the replacement of the existing T&W system with SAP's CIS solution. SAP is one of the market leaders (the other being Oracle) in the provision of CIS software to utilities of a size and scope of operation similar to and larger than

PowerStream. They have an extensive client base in North America. Locally, SAP's product is installed at London Hydro and is being implemented at Hydro One. Hydro One recently completed an RFP and is planning to implement an SAP CIS solution which is consistent with its previous implementation of SAP products for its work management and finance systems.

SAP has some similar features to the Oracle offering but the SAP product does not have specific components to allow operation in the Ontario market. In addition, information was not readily available from SAP on potential process improvement benefits or details on the cost of the product.

ASSESSMENT OF ALTERNATIVES

Alternative 1 – Status Quo

Key risks to continuing with the T&W system were identified in the description of the Status Quo alternative and include the age of the system, the lack of documentation, inability to expand much beyond current capabilities, and the age of T&W's principal, Dr. Yu Tu, who leads the support of the system and retains the knowledge of the core programming.

In addition, PowerStream needs custom reports and the ability to make ad hoc requests in the CIS system. Currently this type of analysis requires custom programming by T&W which is often a lengthy and expensive process.

The T&W system is no longer viable.

Alternative 2: Oracle based CIS

The Oracle solution has several key advantages over the Status Quo and the SAP alternative. One of the key advantages to this alternative is that the Oracle CIS system includes established CCOM modules as part of its CC&B system.

In addition, in a review of CIS systems used in the industry it was found that Oracle is the same system currently used by Toronto Hydro and Enersource with plans underway by Hydro Ottawa to implement a system upgrade to the same Oracle platform. If PowerStream moved to the Oracle platform the opportunity arises to create a joint users group with the other three large LDCs which will provide a more efficient way to implement future system enhancements and changes as directed by the OEB. This user group would represent over 1.5 million customers in Ontario and will allow PowerStream to more effectively work with its peers to understand and implement regulatory changes. An additional benefit of working as a group utilizing CCOM is that costs associated with modifying the product due to regulatory changes could be shared.

As a result of PowerStream and Hydro Ottawa proceeding with an implementation in an almost parallel time frame, PowerStream was able to receive a significant price reduction on the CC&B product from Oracle. The savings on the capital cost of the Oracle CC&B and related support over the first 5 years of ownership is approximately $1 million.

This new system will allow PowerStream to take advantage of, and more easily integrate with, new and emerging technologies associated with customer self serve options and smart grid related initiatives some of which have already been explored by other Oracle users mentioned above.

PowerStream staff have explored both the Oracle and SAP systems in actual working situations and have concluded that Oracle provides a more streamlined and user friendly environment compared to SAP from both an implementation and an operational perspective.

Alternative 3: SAP Based CIS

SAP does not, at this time have the comparable custom modules for the Ontario marketplace similar to Oracle nor were they able to provide an order of magnitude in terms of cost. Capital and annual maintenance costs were not available from SAP at the information session hosted by PowerStream or upon further discussions. Oracle has provided significant discounts on its software license while SAP could not provide a pricing range or order of magnitude to PowerStream unless they were first engaged to conduct a "Value Engineering" exercise of the PowerStream organization. As an alternative, SAP referred PowerStream to a consultant that had extensive experience in SAP implementation work. PowerStream met with the consultant to discuss potential risks, integration experiences and seek an order of magnitude in terms of expected costs. The outcome of the meeting confirmed that while SAP might be equivalent in terms of cost of the CIS product, integration would be more complex, and the system lack pre-developed functions to deal with the Ontario market.

The SAP alternative has a higher risk due to more complex interface requirements in relation to other PowerStream systems (e.g. PowerStream's JD Edwards Financial System is an Oracle based system) and the requirement to fully build out custom components for the Ontario marketplace similar to what is already available for Oracle's CIS.

Also, as mentioned above, PowerStream staff has explored both the Oracle and SAP systems in actual working situations. PowerStream met with London Hydro to discuss their recent implementation of an SAP CIS and to view the active system. A similar discovery meeting was held with Hydro One staff who were, at the time, at the front end of an SAP implementation. These discovery meetings concluded that Oracle provides a more streamlined and user friendly environment compared to SAP from both an implementation and operational perspective.

SELECTED ALTERNATIVE

A decision has been made to base PowerStream's new CIS System on the Oracle CC&B platform accompanied by Oracle's Custom CCOM (Alternative 2). The proposed Oracle -based CIS alternative is the best solution for PowerStream.

Identified Benefits

In addition to the issues previously identified, the Oracle product has the following key benefits / advantages.

The Oracle solution would allow PowerStream to participate in a joint users group allowing for more effective and efficient implementation of future enhancements to meet operational needs as well as regulatory changes. In addition, this user group will represent over 1.5 million customers in Ontario and will allow PowerStream to more effectively work with its peers to understand and implement regulatory changes.

This new up-to-date solution will increase employee satisfaction through a much improved user interface and ease of use within a windows based environment and much improved system abilities compared to the existing CIS. Processes within the new system are more efficient and automated thereby reducing the number of manual processes which lead to user frustration, thus improving overall efficiency and satisfaction.

The new Oracle based CIS will be more easily integrated with new and emerging technologies especially related to web based and mobile customer self-serve offerings which will have a direct and positive impact on customer satisfaction. The system also offers more cross functional ability which will enable more effective and efficient access to data that can be utilized by staff when dealing with complex escalated inquiries or through customer self-serve applications. This will lend itself towards providing customers with shorter turnaround times on inquiries and resolving billing exceptions thus improving service quality.

The Oracle product offers a number of predefined reports and the ability to conduct more effective ad hoc reports compared to the existing system. This will allow for the ability to drill deeper into processes in order to conduct custom analytics that will be used as part of PowerStream's efforts towards continuous improvement and cost savings.

The Oracle CC&B CIS will position PowerStream to migrate existing customers on to a platform which offers functionality that enables enhanced customer contact preferences and enhanced customer contact channels, something that is not available in T&W today.

The new system will reduce the need to increase future staff resources due to the inherent efficiencies and improved functionality built into the system. The CC&B system provides a platform where PowerStream can optimize core business processes and thereby supports the implementation of process improvement methodologies that drive efficiency and effectiveness of core CIS processes. The CC&B platform also positions PowerStream to accommodate potential future customer growth.

The affects to the environment are minimal and potentially positive. Initially there may be an increase in the use of paper during the implementation and stabilization phase. However, over time, the use of paper, especially in regard to exception reports, could be reduced. Future paper usage will also be reduced as a result of the system being more adaptable to emerging technologies therefore allowing PowerStream to leverage electronic communication technologies especially as they relate to service orders and collections notices. This will reduce dependency on high speed printers and therefore reduce the environmental impacts inherent with this type of equipment.

NEXT STEPS

The PowerStream Board of Directors approved a "Special Resolution", dated November 21, 2011, for the amount of $3.3 million (plus applicable sales tax) to purchase the ORACLE Customer Care and Billing (CC&B) Software License and Associate Program Components and related one year support. This approval was requested in order to take advantage of significant cost savings that can be achieved by completing a purchase agreement between PowerStream and Oracle by November 30, 2011. Subsequently, as part of the approved 2012 Capital budget for the CIS Replacement project, Oracle's CCOM was purchased in February of 2012.

An RFP was developed and released for bids in late 2011 in order to secure the services of a Systems Integrator to assist PowerStream in implementing the CC&B product. A recommendation for a vendor is scheduled to be prepared by the end of April, 2012 and finalization of the terms and conditions with the successful candidate completed by the end of May 2012. The targeted implementation or "Go Live" date of the new system is scheduled by the end of Q2 2014

At the present time efforts are underway to complete the development of an appropriate project governance structure. The organizational configuration of the internal implementation team has been completed and recruitment of staff to backfill those identified to participate on the project is underway.

1 **CAPITAL EXPENDITURES – DETAILED VARIANCE ANALYSIS**

2 **2008 Barrie Hydro Actual versus 2008 Barrie Board Approved**

3 Table 1 below shows the 2008 capital expenditures approved in the 2008 Barrie Hydro rate
4 application compared to the actual 2008 capital expenditures for Barrie Hydro.

Table 1
Barrie 2008 Actual Comparison To 2008 Barrie Approved

ID #	Project ID	2008 Approved CGAAP	2008 Actual CGAAP	Difference
1	2008 Subdivision Servicing	$2,132,000	-$311,262	-$2,443,262
2	Residential Services	$300,000	$426,529	$126,529
3	General Service Connections	$100,000	-$242,210	-$342,210
3B	Northern Ethanol Plant	$1,850,000	$0	-$1,850,000
4	City Road Relocation Projects - (Appendix A1)	$1,600,000	-$305,626	-$1,905,626
5	Transformer Betterment	$600,000	$785,281	$185,281
6	44kV Switch Automation Upgrades	$510,000	$398,482	-$111,518
7	Pole Replacements	$506,800	$700,343	$193,543
8	MS835 (Mill Street) Upgrade	$500,000	$0	-$500,000
9	Belle Isle Feeder 1 Upgrade	$400,000	$0	-$400,000
10	Underground Primary Cable Betterment	$300,000	$602,634	$302,634
11	Essa Road Concrete Pole Rehab	$250,000	$0	-$250,000
11B	Pole Betterment - Park Side	$0	$251,447	$251,447
12	Miscellaneous Substation Projects	$250,000	$123,626	-$126,374
13	2007 Carryover (Work in Progress)	$200,000	-$84,649	-$284,649
14	Mill / Nolan Feeder Balancing and Contingency	$172,000	$0	-$172,000
15	MS415 F4 Conductor Upgrade	$165,000	$48,124	-$116,876
16	13.8kV Switch Installations (LBGO)	$150,000	$210,239	$60,239
17	Protection Upgrade	$150,000	$15,637	-$134,363
18	PCB Removals	$130,014	$105,191	-$24,823
19	2009 Pre-Design Capital	$75,000	$62,612	-$12,388
20	Pole Testing	$75,000	$69,297	-$5,703
21	Lightning Arresters	$60,000	$0	-$60,000
22	Vault Betterment	$50,000	$24,120	-$25,880
23	Unplanned Minor Capital Upgrades	$50,000	$98,691	$48,691

Table 1
Barrie 2008 Actual Comparison To 2008 Barrie Approved

ID #	Project ID	2008 Approved CGAAP	2008 Actual CGAAP	Difference
	Project Total	**$10,575,814**	**$2,978,506**	**-$7,597,308**
27	Building	$57,000	$122,726	$65,726
28	Office Equipment	$75,375	$33,130	-$42,245
29	Computer Hardware	$726,000	$111,647	-$614,353
30	Computer Software	$1,915,000	$79,373	-$1,835,627
31	Vehicles	$893,575	$474,300	-$419,275
32	Miscellaneous Equipment	$175,275	$93,616	-$81,659
33	Meters	$150,000	$157,146	$7,146
34	Supervisory Control and Data Acquistion	$51,250	$0	-$51,250
	Purchased Capital	**$4,043,475**	**$1,071,938**	**-$2,971,537**
	TOTAL	**$14,619,289**	**$4,050,444**	**-$10,568,845**

In summary, the $10.6 million decrease between the actual capital spending in 2008 vs. the Board approved amounts is primarily due to changing customer requirements ($6.4 million) and the decision to put certain projects on hold due to a pending merger ($2.9 million). Details are as follows:

Purchased Capital - During 2008 Barrie Hydro entered into discussion on merging with PowerStream. As a result of these discussions a number of 2008 capital projects were put on hold and resulted in a savings of $2.9 million. These projects included: Computer Hardware – hardware for a new ERP system; computer software – software for a new Enterprise Resopurce Planning (“ERP”) system; Vehicle – purchase of one large bucket truck; Supervisory Control and Data Acquisition (“SCADA”) – changes to the SCADA system. The system related projects were put on hold due to the need to merge systems and processes with those of PowerStream.

2008 Subdivision Servicing –The actual gross spending on subdivisions was similar to the approved rate application. The net actual cost was below the approved due to timing of receipt of capital contributions.

North0ern Ethanol Plant – An ethanol plant was planning on locating in Barrie. The load requirements were significant. Capital funding was planned to service this customer's needs, and then the project was abandoned by the customer.

Residential Services – This category is for capital spending to upgrade facilities to support service upgrades by customers or to support infill residential lot construction. The level of activity and actual expenditures were greater than anticipated.

General Service Connections – This category represents capital spending to provide service to Industrial, Commercial and Institutional ("ICI") customers. Typically these customers pay 100% for servicing. Additional funds are provided in the budget for upgrades to the distribution system required to connect customers that are not recoverable from the customer under the Distribution System Code ("DSC"). In 2008, none of the new ICI connections required upgrades to the distribution system. There were a number of projects in 2008 where money was received and recorded as a reduction in current capital spending but the majority of construction and costs took place and were recorded in 2009.

City Road Relocation Projects – The municipal portion of City Road Relocation projects are billed on completion of the projects. Monies are reflected in the capital budget upon billing. In 2007, there were a number of road relocation projects that were not billed until 2008. As a result capital contributions recorded in 2008 were high as billings from both 2007 and 2008 projects were included. Processes were changed in 2008 so that projects were billed in a timelier manner.

Projects Re-Optimized – The capital expenditure project list for the 2008 rate case was developed in spring 2007. Consistent with Barrie Hydro budgeting processes, in late fall 2007 the project list was re-optimized. Barrie Hydro had improved the budget optimization process and a number of needs had changed. The re-optimization process drove a number of changes. Projects that were removed or reduced included: MS 835 Upgrade; Belle Isle Feeder 1 Upgrade; Essa Road Concrete Pole Rehab; Mill/Nolan Feeder Balancing and Contingency; Lightning Arresters; and Substation Projects. Projects added or increased included:; Pole Betterment on Parkside Drive; Increase to Transformer Betterment; Increase to Pole Replacements; and Increase to Underground Primary Cable Betterment.

44 KV Switch Automation Upgrades – Due to internal resource constraints one less switch was completed then planned.

2007 Carryover Work – This represents expected spending to complete projects commencing in the prior year. Actual carry over from 2007 was less than expected. In addition, there was a development charge for Penetanguishene, part of PowerStream North, that was recorded against a 2007 Penetanguishene project completed in 2008. The majority of costs were record in 2007 but the entire development charge was applied and recorded as a reduction of capital spending in 2008.

2009 PowerStream Actual versus 2009 Board Approved

Table 2 below shows the 2009 capital expenditures approved in the 2009 PowerStream approved expenditures compared to the actual 2009 capital expenditures for PowerStream. Barrie Hydro expenditures are not included.

Table 2

PowerStream 2009 Actual vs. to 2009 Approved

PROJECT DESCRIPTION	2009 Approved CGAAP	2009 Actual CGAAP	Difference
Sustainment Capital			
Pole or Line Replacements/Upgrades	$4,454,000	$3,530,297	-$923,703
Transformer Station Enhancements/Upgrades	$3,232,000	$4,410,208	$1,178,208
Asset Condition Assessment Program	$5,339,000	$1,883,075	-$3,455,925
Distribution System Voltage Conversions	$3,465,000	$2,847,508	-$617,492
Switchgear Replacements/Upgrades/Refurbishments	$1,239,000	$1,521,070	$282,070
Cable Replacement	$333,000	$1,102,684	$769,684
Load transfers From Other LDC's	$0	$408,262	$408,262
Distribution Transformer Enhancements/Upgrades/Refurbishment	$261,000	$232,965	-$28,035
Load Interrupter Switch Replacement	$409,000	$153,668	-$255,332
Distributor Station Enhancement/Upgrades	$472,000	$139,876	-$332,124
Unforeseen Capital Projects	$414,000	$770,829	$356,829
Total Sustainment Capital	**$19,618,000**	**$17,000,441**	**-$2,617,559**
Development Capital			
Transformer Stations-Additional Capacity	$22,771,000	$21,467,790	-$1,303,210
Residential Subdivisions	$5,019,000	$5,131,273	$112,273

Table 2 PowerStream 2009 Actual vs. to 2009 Approved			
PROJECT DESCRIPTION	**2009 Approved CGAAP**	**2009 Actual CGAAP**	**Difference**
Distribution System Plant Re-Location	**$5,892,000**	**$2,406,413**	**-$3,485,587**
New Commercial Services	**$181,000**	**$724,771**	**$543,771**
Distribution Stations - Additional Capacity	**$0**	**$93,489**	**$93,489**
New Overhead or Underground Lines	**$6,742,000**	**$392,326**	**-$6,349,674**
Unforeseen Capital Projects	**$414,000**	**$186,999**	**-$227,001**
Total Development Capital	**$41,019,000**	**$30,403,060**	**-$10,615,940**
Operations Capital			
System Operation Automation	**$1,819,000**	**$1,564,892**	**-$254,108**
Unplanned Equipment Replacement	**$1,678,000**	**$3,434,031**	**$1,756,031**
Suite-Metering Costs	**$1,086,000**	**$1,785,988**	**$699,988**
Fleet	**$887,000**	**$3,923,857**	**$3,036,857**
Wholesale Meters	**$256,000**	**$25,842**	**-$230,158**
Tools	**$310,000**	**$325,713**	**$15,713**
Smart Grid Program	**$505,000**	**$0**	**-$505,000**
Meter Re-Verification and Replacement Program	**$390,000**	**$228,230**	**-$161,770**
Asset Condition Assessment Model Development	**$25,000**	**$23,588**	**-$1,412**
Geographic Information System	**$101,000**	**$461,388**	**$360,388**
Conservation & Demand Management - Smart Meter Pilot	**$0**	**$0**	**$0**
System Control Room	**$0**	**$0**	**$0**
Storm Damage To Distribution System	**$617,000**	**$687,384**	**$70,384**
Conservation & Demand Management - Load Control Devices	**$0**	**$0**	**$0**
Total Operations Capital	**$7,674,000**	**$12,460,912**	**$4,786,912**
Other Miscellaneous Capital			
Information Technology Enhancements	**$823,000**	**$1,120,485**	**$297,485**
Customer Information System Enhancements	**$1,351,000**	**$487,428**	**-$863,572**
Financial System Enhancements	**$303,000**	**$128,625**	**-$174,375**
New Computer Equipment/Replacement	**$800,000**	**$504,614**	**-$295,386**
New Head Office	**$381,000**	**$4,944,902**	**$4,563,902**
Software Purchase	**$297,000**	**$274,696**	**-$22,304**
Interest Capitalization	**$0**	**$1,387,058**	**$1,387,058**
Total Other Miscellaneous Capital	**$3,955,000**	**$8,847,808**	**$4,892,808**
Total Capital Expenditure	**$72,266,000**	**$68,712,221**	**-$3,553,779**
Capital Deferral Accounts			
Smart Meters	**$12,975,000**	**$15,451,128**	**$2,476,128**

Table 2 PowerStream 2009 Actual vs. to 2009 Approved			
PROJECT DESCRIPTION	2009 Approved CGAAP	2009 Actual CGAAP	Difference
Total Capital Deferral Accounts	$12,975,000	$15,451,128	$2,476,128Table 2

In total during 2009 actual expenditures on capital (including deferral accounts) was $84.1 M. The actual spending was consistent with the $85.2 requested in PowerStream's rate application.

Differences between actual capital spending in 2009 and the Board Approved amounts are as follows:

- Sustainment capital is $2.6 million below the Board Approved amount. Spending was less in the majority of categories. The Transformer Station Enhancements/Upgrades increased by $1.2 million due to the purchase of a spare power transformer that cost more than budgeted. Certain planned categories of spending were reduced as a result of re-prioritizing the activities of both Barrie Hydro and PowerStream.

- Development capital is $10.6 million below the Board Approved amount. Spending was less in the majority of categories. Of significance is the $3.5 million decrease in Distribution System Plant Re-Location. This category is for road relocations requested by road authorities. This is driven by customer requests and was less than expected. Additional significance is the $1.3 million reduction in the Transformer Stations-Additional Capacity. In 2009 the plan was to complete the construction of Markham Transformer Station ("TS") #4. The construction was completed in 2010 and resulted in less spending in 2009. Lastly, there is a $6.3 million decrease in New Overhead or Underground Lines. In 2009 it was planned to construct feeders out of Markham TS#4 and feeders out of Armitage TS. These projects ran into difficulties in the design stage and were not constructed until 2010.

- Operations capital was $4.8 million above the Board Approved amount. Two drivers of the increase included: increase in emergency replacements (Unplanned Equipment Replacement) of $1.8 million; and an increase in fleet purchases of $3 million.

Additional trucks were identified as needing replacement after the rate case was put forth.

- Miscellaneous capital was $4.9 million above the Board Approved amount. The two main contributing factors lead to this increase. The first was an increase in interest capitalization. The impact on interest capitalization for Markham TS#4 was not taken into consideration at budget time. The second factor was the start of construction of the new operations centre (Addiscott) in Markham. In 2008 PowerStream signed a long term lease for a new operations centre to serve the South service territory (predecessor PowerStream territory). In filing its 2009 Cost of Service filing, PowerStream did not include any spending related to the new operations centre as it did not appear likely that it would be in service in 2009. This centre was constructed by the landlord to PowerStream's specifications and was completed in January 2010. The lease term commenced January 1, 2010. In order to facilitate the consolidation of the two South operations centres into one as soon as possible after the start of the lease, PowerStream started to equip the building in late 2009.

- The last category, Smart Meter, expenditures were higher than planned and resulted in an increase of $2.5 million more than the Board Approved amount.

2008 Actual versus 2007 Actual

Table 3 below compares the capital expenditures in 2008 to capital expenditures in 2007. Expenditures include both Barrie Hydro and PowerStream South.

Table 3
Capital Expenditure 2008 Actual Comparison to 2007 Actual

PROJECT DESCRIPTION	2007 Actual CGAAP	2008 Actual CGAAP	Difference
Sustainment Capital			
Replacement Program	$3,863,657	$4,629,272	$765,614
Sustainment Driven Lines Projects	$6,457,421	$7,040,850	$583,429
Emergency / Restoration	$3,114,168	$3,589,697	$475,528
Transformer / Municipal Stations	$1,457,915	$714,605	-$743,311
Emerging Sustainment Capital	$2,353,154	$3,122,060	$768,906

Table 3

Capital Expenditure 2008 Actual Comparison to 2007 Actual

PROJECT DESCRIPTION	2007 Actual CGAAP	2008 Actual CGAAP	Difference
Total Sustainment Capital	**$17,246,315**	**$19,096,482**	**$1,850,167**
Development Capital			
Subdivision / Services	**-$15,811**	**$1,412,727**	**$1,428,538**
Road Authority Projects	**$3,697,004**	**$1,088,679**	**-$2,608,325**
Additional Capacity (Transformer / Municipal Stations)	**$2,710,298**	**$6,574,963**	**$3,864,665**
Growth Driven Lines Projects	**$2,348,220**	**$1,535,358**	**-$812,863**
Emerging Development Capital	**$200,346**	**$644,866**	**$444,520**
Distributed Generation Connections	**$0**	**$0**	**$0**
Total Development Capital	**$8,940,057**	**$11,256,592**	**$2,316,535**
Operations Capital			
Metering	**$1,935,577**	**$2,799,149**	**$863,572**
Fleet	**$2,099,231**	**$2,626,258**	**$527,027**
Tools	**$466,984**	**$354,050**	**-$112,934**
Buildings	**$20,993,737**	**$4,931,129**	**-$16,062,608**
Information / Communication Systems	**$1,996,988**	**$3,345,827**	**$1,348,839**
Purchase of spare equipment	**$0**	**$3,345,554**	**$3,345,554**
Emerging Operations Capital	**$2,341,273**	**$2,020,446**	**-$320,827**
Interest Capitalization	**$1,374,013**	**$850,187**	**-$523,827**
Total Operations Capital	**$31,207,803**	**$20,272,599**	**-$10,935,204**
Total Capital Expenditure	**$57,394,175**	**$50,625,673**	**-$6,768,502**
Capital Deferral Accounts			
Smart Meters	**$10,536,450**	**$6,610,918**	**-$3,925,532**
Smart Grid	**$0**	**$0**	**$0**
Renewable Generation	**$0**	**$0**	**$0**
Total Capital Deferral Accounts	**$10,536,450**	**$6,610,918**	**-$3,925,532**

Significant changes from 2008 compared to 2007 are as follows:

Sustainment

In 2008 the increase in Replacement programs is primarily due to additional pole and transformer replacements in the Barrie service area. The budgets for the two programs were increased during the optimization of the capital project list. Similarly, funding increased for the Sustainment projects due to the completion of an underground subdivision rehabilitation on Martin Grove Rd. (Vaughan). In the Emergency/Restoration category in 2008 there was an increase in equipment failures which were discovered on emergency trouble calls or inspections of assets. With respect to Transformers and Municipal Stations, in 2008 there was a decrease as no large projects were required. In the Emerging Sustainment Capital category there was increased spending as more sustainment work was undertaken in 2008 due to several unanticipated projects. These unanticipated projects in 2008 included: switchgear replacements; insulator replacements; two circuit extension at Leslie St. (Markham) and Vandorf Side-road (Aurora); pole line upgrade at Hwy 27 (Vaughan).

Development

Gross servicing costs for subdivisions and associated services and ICI customers in 2008 were greater than 2007 due to increased customer requests. Net costs were lower in 2008 due to timing of capital contributions towards the subdivisions and ICI projects. Road Authority Projects activity in 2008 was similar to 2007. However there was a large amount of 2007 costs for the Barrie service area billed in 2008 reducing net capital expenditures in 2008. In 2008 there was more growth driven capital (i.e. Transformers and Municipal Stations) spending. Significant projects in 2008 included: upgrade of three Aurora Municipal Stations and the start of construction of Markham TS#4. With respect to Growth Driven Lines Projects, there were fewer significant projects in 2008. In 2008 there was more emerging work required including a significant project involving a pole line upgrade at Huntington Rd. (Vaughan).

Operations

Metering costs increased in 2008 related mainly to the meter re-verification program. Fleet costs increased in 2008 as additional vehicles were purchased compared to 2007 reflecting the normal cycle of vehicle replacement. As an offset tool spending was reduced in Barrie in 2008 due to the potential merger;

In 2007 construction of the new head office and control room for PowerStream at Cityview Blvd. (Vaughan) was started. Construction was completed in early 2008 with staff moving into the building in February 2008. In the Information/Communication Systems areas there were significant projects in 2008 as compared to 2007 that resulted in increased costs. They included: funds for business continuity planning, changes to the Geographical Information System ("GIS") system including the purchase of an outage management system.

The Asset Condition Assessment review completed in 2007 on the condition of PowerStream's power transformers recommended that PowerStream should inventory two spare power transformers in case of a failure. One was purchased in 2008 and the other in 2009. In the Emerging Operations there were fewer projects required in 2008.

As a result of the majority of construction for the Cityview Head Office Facility occurring in 2007, interest capitalization was higher in that year as compared to 2008.

Capital Deferral

There was reduced spending in 2008 for smart meters compared to 2007.

1 **2009 Actual versus 2008 Actual**

2 Table 4 below compares the actual capital expenditures in 2009 to actual capital expenditures in
3 2008. Expenditures include both Barrie Hydro and PowerStream South.

Table 4
Capital Expenditure 2009 Actual Comparison to 2008 Actual

PROJECT DESCRIPTION	2008 Actual CGAAP	2009 Actual CGAAP	Difference
Sustainment Capital			
Replacement Program	$4,629,272	$4,451,046	-$178,226
Sustainment Driven Lines Projects	$7,040,850	$8,437,575	$1,396,725
Emergency / Restoration	$3,589,697	$4,203,755	$614,058
Transformer / Municipal Stations	$714,605	$948,688	$234,084
Emerging Sustainment Capital	$3,122,060	$2,281,720	-$840,340
Total Sustainment Capital	$19,096,482	$20,322,784	$1,226,302
Development Capital			
Subdivision / Services	$1,412,727	$7,508,430	$6,095,704
Road Authority Projects	$1,088,679	$3,942,432	$2,853,752
Additional Capacity (Transformer / Municipal Stations)	$6,574,963	$10,772,075	$4,197,112
Growth Driven Lines Projects	$1,535,358	$11,926,518	$10,391,160
Emerging Development Capital	$644,866	$858,309	$213,443
Distributed Generation Connections	$0	$23,941	$23,941
Total Development Capital	$11,256,592	$35,031,705	$23,775,112
Operations Capital			
Metering	$2,799,149	$2,045,082	-$754,067
Fleet	$2,626,258	$3,933,516	$1,307,258
Tools	$354,050	$326,514	-$27,535
Buildings	$4,931,129	$4,846,822	-$84,307
Information / Communication Systems	$3,345,827	$2,498,400	-$847,427
Purchase of spare equipment	$3,345,554	$3,099,128	-$246,426
Emerging Operations Capital	$2,020,446	$944,198	-$1,076,248
Interest Capitalization	$850,187	$1,390,473	$540,286
Total Operations Capital	$20,272,599	$19,084,132	-$1,188,467
Total Capital Expenditure	$50,625,673	$74,438,621	$23,812,947
Capital Deferral Accounts			
Smart Meters	$6,610,918	$17,195,703	$10,584,785
Smart Grid	$0	$0	$0

Table 4 Capital Expenditure 2009 Actual Comparison to 2008 Actual			
PROJECT DESCRIPTION	**2008 Actual CGAAP**	**2009 Actual CGAAP**	**Difference**
Renewable Generation	**$0**	**$0**	**$0**
Total Capital Deferral Accounts	**$6,610,918**	**$17,195,703**	**$10,584,785**

Significant changes from 2009 compared to 2008 are as follows:

Sustainment

In 2009 there was an increase in Sustainment Driven Lines projects due to an increase in identified assets needing replacement. Significant projects included a new pole line installation at Esna Park (Markham), Belcourt underground rehabilitation project (Markham), and pole upgrade at Huntington Rd. (Vaughan). In addition, in 2009 there was an increase in emergency replacement capital due to increased failed equipment, and in the Emerging Sustainment Capital category there was a reduced requirement for unanticipated capital.

Development

There was an increase in subdivision servicing in 2009 compared to 2008 due to an increase in customer requests resulting in increased net costs.

The amount of road authority work completed in 2009 was similar to that completed in 2008; however net costs increased. Net costs in 2009 were as expected. 2008 net costs were lower than expected due to late billing of capital contributions for 2007. PowerStream has since corrected this timing issue and now uses progress payments to ensure the capital contributions for road authority work are recorded in the year the work is completed.

In 2009 there was more growth driven capital spending (i.e. Transformer / Municipal Stations) due to substantive completion of Markham TS#4. Significant projects in 2009 included: start of construction of the new Park Place Municipal Station ("MS") in Barrie and the construction of Markham TS#4. Growth Driven Lines Projects increased spending in 2009 was due to new feeders being installed out of the new Markham TS#4 and new feeders being installed and change in feeder configuration out of Armitage TS (Aurora supply) to accommodate changes that resulted from the construction of Holland TS.

Also, in 2009 there was more emerging work due to increased customer's requirements.

Operations

In 2009 there was a decrease related to the meter re-verification program and wholesale metering program. Also in 2009 there were additional vehicles purchased compared to 2008 as part of the regular replacement schedule and consistent with fleet replacement guideline.

Information / Communication Systems reduced spending in 2009 as no large projects were implemented while in 2008 there were three larger projects including business continuity planning, changes to the GIS system including the purchase of an outage management system.

The Asset Condition review completed in 2007 on the condition of PowerStream's power transformers recommended that PowerStream should inventory two spare transformers in case of failure. One was purchased in 2008 and the other in 2009. The project costs in 2009 were less than 2008.

There were fewer emerging projects that were required in 2009 and interest capitalized amounts increased in 2009 due to an increase in 2009 capital spending compared to 2008.

Capital Deferral

There was increased spending in 2009 for smart meters compared to 2008. This increase was consistent with the project plan.

<u>2010 Actual versus 2009 Actual</u>

Table 5 below compares the actual capital expenditures in 2010 to actual capital expenditures in 2009. Expenditures include both Barrie and PowerStream South.

Table 5
Capital Expenditure 2010 Actual Comparison to 2009 Actual

PROJECT DESCRIPTION	2009 Actual CGAAP	2010 Actual CGAAP	Difference
Sustainment Capital			
Replacement Program	$4,451,046	$5,219,180	$775,268
Sustainment Driven Lines Projects	$8,437,575	$6,663,891	-$1,768,986
Emergency / Restoration	$4,203,755	$8,673,251	$4,469,823

Table 5
Capital Expenditure 2010 Actual Comparison to 2009 Actual

PROJECT DESCRIPTION	2009 Actual CGAAP	2010 Actual CGAAP	Difference
Transformer / Municipal Stations	$948,688	$1,407,008	$458,320
Emerging Sustainment Capital	$2,281,720	$1,549,473	-$728,590
Total Sustainment Capital	$20,322,784	$23,512,802	$3,205,835
Development Capital			
Subdivision / Services	$7,508,430	$3,939,167	-$3,563,268
Road Authority Projects	$3,942,432	$5,922,934	$1,985,349
Additional Capacity (Transformer / Municipal Stations)	$10,772,075	$1,784,948	-$8,969,860
Growth Driven Lines Projects	$11,926,518	$4,992,351	-$6,915,049
Emerging Development Capital	$858,309	$611,790	-$245,143
Distributed Generation Connections	$23,941	$79,931	$56,029
Total Development Capital	$35,031,705	$17,331,122	-$17,651,942
Operations Capital			
Metering	$2,045,082	$2,909,300	$867,497
Fleet	$3,933,516	$3,059,001	-$868,210
Tools	$326,514	$457,226	$131,235
Buildings	$4,846,822	$1,308,312	-$3,530,740
Information / Communication Systems	$2,498,400	$5,546,874	$3,052,480
Purchase of spare equipment	$3,099,128	$321,634	-$2,772,526
Emerging Operations Capital	$944,198	$1,171,867	$229,182
Interest Capitalization	$1,390,473	$1,674,195	$285,952
Total Operations Capital	$19,084,132	$16,448,410	-$2,605,131
Total Capital Expenditure	$74,438,621	$57,292,334	-$17,051,238
Capital Deferral Accounts			
Smart Meters	$17,195,703	$26,731,788	$9,536,086
Smart Grid	$0	$192,265	$192,264
Renewable Generation	$0	$54,046	$54,046
Total Capital Deferral Accounts	$17,195,703	$26,978,099	$9,782,396

Significant changes from 2010 compared to 2009 are as follows:

Sustainment

In 2010 there was an increase in replacement programs for key distribution equipment. This increase was a result of recommendations from the Asset Condition Assessments on those distribution assets. This increase was more than offset by the Sustainment Driven Lines Program where in 2010 there was a decrease in sustainment driven lines projects due to fewer projects being optimized for completion in 2010.

In 2010 there was an increase in the emergency / restoration program. Emergency replacements of key assets in PowerStream North (predecessor Barrie Hydro territory) were previously captured within the replacement programs. As a result of the merger, practices were harmonized and the emergency asset replacements were re-categorized into this category. In addition to this change there was an increase in required replacements of leaking transformers and failed switchgear which were identified through inspection programs.

In 2010 there was a decrease in sustainment driven projects for transformer and municipal stations due to fewer projects being optimized for completion in 2010.

Also in 2010 there was a reduced requirement for emerging sustainment capital due to fewer unanticipated projects arising.

Development

Costs for subdivisions and services were less in 2010 compared to 2009 as a result of fewer subdivisions being constructed in that year.

The amount of road authority work increased in 2010. The increase can be attributed to infrastructure spending by municipalities requiring pole relocations.

In 2010 there were no major projects for transformer and municipal stations related to growth and as a result the cost in this category were significantly lower versus 2009. Markham TS #4 construction was completed in early 2010. In 2010 there was a decrease in growth driven lines projects as a result of the completion in 2009 of projects related to Markham TS#4 and Armitage TS.

Emerging development work was less in 2010 as there was less emerging work due to customer's requirements.

Operations

In 2010 there was an increase in spending with respect to metering as a result of additional condominiums being converted to smart suite metering.

Fleet expenditures in 2010 were lower compared to 2009 as part of the regular replacement schedule and consistent with fleet replacement guideline.

There was a reduction in spending in 2010 in Building category compared to 2009. In 2010 construction was completed on PowerStream's new Addiscott Operations Centre. The majority of the spending for the project occurred in 2009 resulting in increased costs in 2009.

There was an increase in Information / Communication Systems spending in 2010 due to an increase in various projects in several departments across the organization. Significant projects included: upgrades to the CIS system, new IVR phone system; upgrade of AS400 system; upgrade of communication infrastructure; upgrade to software and data related to the GIS system.

In 2010 no major spare equipment was required and resulted in reduced spending for spare equipment compared to 2009.

The amounts increased for interest capitalization in 2010 due to Markham TS #4. It was anticipated that Markham TS#4 would be put in service in 2009. However Markham TS#4 did not go into service until April 2010. Interest accumulated for the additional four months in 2010.

Capital Deferral

The smart metering installations continued in 2010 with an increase in the numbers of meters installed compared to 2009. In 2010 smart meters were installed in PowerStream North.

In 2010 two smart grid initiatives were undertaken. A pilot program to install digital fault indicators to test the viability of the digital indicators and an electrical vehicle trial to understand the characteristics and potential affect of electrical vehicles on the distribution system.

2011 Actual versus 2010 Actual

Table 6 below compares the actual 2011 (CGAAP) capital expenditures in 2011 to actual capital expenditures in 2010 (CGAAP). Expenditures include both Barrie Hydro and PowerStream South.

Table 6
Capital Expenditure 2011 Actual (CGAAP) Comparison to 2010 Actual (CGAAP)

PROJECT DESCRIPTION	2010 Actual CGAAP	2011 Actual - CGAAP	Difference
Sustainment Capital			
Replacement Program	$5,219,180	$3,886,039	-$1,333,140
Sustainment Driven Lines Projects	$6,663,891	$10,681,906	$4,018,015
Emergency / Restoration	$8,673,251	$7,504,452	-$1,168,799
Transformer / Municipal Stations	$1,407,008	$3,492,638	$2,085,629
Emerging Sustainment Capital	$1,549,473	$1,072,112	-$477,361
Total Sustainment Capital	$23,512,802	$26,637,146	$3,124,344
Development Capital			
Subdivision / Services	$3,939,167	$7,878,391	$3,939,223
Road Authority Projects	$5,922,934	$8,910,456	$2,987,522
Additional Capacity (Transformer / Municipal Stations)	$1,784,948	$150,524	-$1,634,424
Growth Driven Lines Projects	$4,992,351	$7,825,726	$2,833,375
Emerging Development Capital	$611,790	$1,032,240	$420,450
Distributed Generation Connections	$79,931	$32,210	-$47,721
Total Development Capital	$17,331,122	$25,829,548	$8,498,426
Operations Capital			
Metering	$2,909,300	$3,144,545	$235,244
Fleet	$3,059,001	$1,172,758	-$1,886,243
Tools	$457,226	$640,137	$182,911
Buildings	$1,308,312	$176,551	-$1,131,761
Information / Communication Systems	$5,546,874	$4,528,148	-$1,018,726
Purchase of spare equipment	$321,634	-$228,589	-$550,223
Emerging Operations Capital	$1,171,867	$768,100	-$403,767
Interest Capitalization	$1,674,195	$573,560	-$1,100,635
Total Operations Capital	$16,448,410	$10,775,210	-$5,673,200
Total Capital Expenditure	$57,292,334	$63,241,903	$5,949,569

Table 6
Capital Expenditure 2011 Actual (CGAAP) Comparison to 2010 Actual (CGAAP)

PROJECT DESCRIPTION	2010 Actual CGAAP	2011 Actual - CGAAP	Difference
Capital Deferral Accounts			
Smart Meters	**$26,731,788**	**$1,526,739**	**-$25,205,049**
Smart Grid	**$192,265**	**$284,912**	**$92,647**
Renewable Generation	**$54,046**	**$470,772**	**$416,726**
Total Capital Deferral Accounts	**$26,978,099**	**$2,282,423**	**-$24,695,676**

Significant changes from 2011 compared to 2010 are as follows:

Sustainment

Replacement Programs decreased in 2011 compared to 2010 as a result of resourcing constraints.

Sustainment Driven Lines Projects increased in 2011 due to an increase in cable rehabilitation projects including cable injection and replacement. Also increasing in costs in 2011 versus 2010 were the Sustainment Transformer /Municipal Stations costs as a result of an increased focus on station sustainment type projects. Major projects included: soil testing and remediation at various TS / MS locations; new capacitor banks at Vaughan TS#2 required by the Independent Electricity System Operator ("IESO"); and remediation of corrosive sulphur in transformer oil at Richmond Hill TS #1.

Emergency / Restoration decreased in 2011 compared to 2010 as fewer individual assets required replacing on an emergency basis.

Development

Subdivision lots serviced in 2011 increased compared to 2010 due to an increase in customer requests.

The amount of road authority work in 2011 was greater than 2010 due to an increase in customer requests.

In 2011 there were no major projects for transformer and municipal stations related to growth as compared to 2010.

In 2011 there was an increase in growth driven lines projects due to an identified need to support increased load growth in specific areas of PowerStream's territory. Major projects included new feeders from Markham TS #4, 44 kV line extension on Bayview Ave. (Aurora supply) and feeder extension on Centre Street (Vaughan).

Operations

In 2011 there was a decrease in fleet costs. There were fewer vehicles purchased in 2011 compared to 2010 as part of the regular replacement schedule and consistent with fleet replacement guideline. In the Tools category there were additional tools and equipment purchased by the stations and lines groups to replace aged equipment and embrace new technologies.

There was a reduction in spending in the Building category in 2011 compared to 2010 as there were no major projects required in 2011.

Information / Communication Systems spending levels in 2011 were similar to 2010 with a modest reduction in projects.

Minimal spare equipment was purchased in 2011. Adjustments were made in 2011 for PST recovery for prior equipment purchases resulting in negative net cost.

Interest Capitalization amounts decreased in 2011. Interest amounts in 2011 were less than 2010 as there were no major projects, such as Markham TS #4, that attracted interest in 2011 compared to 2010.

Capital Deferral

The smart metering installations were substantially completed in 2010 and as a result cost were lower in 2011

In 2011 the two smart grid initiatives started in 2010 were continued. In addition, in 2011 a WiMax system was installed to facilitate real time communications with distributed generators.

2011 Actual CGAAP versus 2011 Actual MIFRS

Table 7 below compares the actual 2011 (CGAAP) capital expenditures in 2011 to actual capital expenditures in 2011 (MIFRS). Expenditures include both Barrie Hydro and PowerStream South.

Table 7

Capital Expenditure 2011 Actual (MIFRS) Comparison to 2011 Actual (CGAAP)

PROJECT DESCRIPTION	2011 Actual CGAAP	2011 Actual MIFRS	Difference
Sustainment Capital			
Replacement Program	$3,886,039	$3,254,511	-$631,528
Sustainment Driven Lines Projects	$10,681,906	$8,284,920	-$2,396,985
Emergency / Restoration	$7,504,452	$7,082,363	-$422,088
Transformer / Municipal Stations	$3,492,638	$3,268,289	-$224,349
Emerging Sustainment Capital	$1,072,112	$949,866	-$122,246
Total Sustainment Capital	$26,637,146	$22,839,950	-$3,797,196
Development Capital			
Subdivision / Services	$7,878,391	$4,822,559	-$3,055,832
Road Authority Projects	$8,910,456	$7,218,612	-$1,691,844
Additional Capacity (Transformer / Municipal Stations)	$150,524	$113,508	-$37,016
Growth Driven Lines Projects	$7,825,726	$7,038,310	-$787,416
Emerging Development Capital	$1,032,240	$626,419	-$405,821
Distributed Generation Connections	$32,210	-$86,236	-$118,446
Total Development Capital	$25,829,548	$19,733,172	-$6,096,375
Operations Capital			
Metering	$3,144,545	$2,167,753	-$976,791
Fleet	$1,172,758	$1,154,496	-$18,262
Tools	$640,137	$629,865	-$10,272
Buildings	$176,551	$173,385	-$3,166
Information / Communication Systems	$4,528,148	$4,419,136	-$109,012
Purchase of spare equipment	-$228,589	-$228,721	-$132
Emerging Operations Capital	$768,100	$742,961	-$25,139
Interest Capitalization	$573,560	$340,287	-$233,273
Total Operations Capital	$10,775,210	$9,399,162	-$1,376,047
Total Capital Expenditure	$63,241,903	$51,972,285	-$11,269,619

Table 7 Capital Expenditure 2011 Actual (MIFRS) Comparison to 2011 Actual (CGAAP)			
PROJECT DESCRIPTION	**2011 Actual CGAAP**	**2011 Actual MIFRS**	**Difference**
Capital Deferral Accounts			
Smart Meters	**$1,526,739**	**$1,406,008**	**-$120,731**
Smart Grid	**$284,912**	**$281,174**	**-$3,738**
Renewable Generation	**$470,772**	**$468,795**	**$-1,977**
Total Capital Deferral Accounts	**$2,282,423**	**$2,155,977**	**-$126,446**

Significant changes from CGAAP 2011 compared to MIFRS 2011 were due to differences in burden allocation. For a full discussion of the impacts of changing from CGAAP to MIFRS see Exhibit A3, Tab 1, Schedule 5.

Sustainment

In general, the Sustainment category was moderately impacted by MIFRS. Under CGAAP outside labour attracted an engineering burden which under MIFRS was removed. The labour was only one component of the costs in the majority of the sub-categories within Sustainment. The exception was the Sustainment Driven Lines Projects where a substantive amount of the work was completed by outside contractors supplying both material and labour. Under CGAAP the material and labour attracted an engineering burden which was removed under MIFRS.

Development

In general the Development category was only moderately impacted by MIFRS. Similarly to the Sustainment category under CGAAP outside labour attracted an engineering burden which under MIFRS was removed. The labour was only one component of the costs in the majority of the sub-categories within Sustainment. The exception was the Subdivisions / Services where a substantive amount of the work was completed by outside contractors supplying both material and labour. Under CGAAP the material and labour attracted an engineering burden which was removed under MIFRS.

Operations

The Operations category was not impacted significantly by MIFRS. Most of the monies within Operation are for inside labour, purchases of tools and equipment or non construction purchased services which were not impacted by burden changes under MIFRS. The exception would be metering where outside metering staff attract reduced burdens under MIFRS.

Capital Deferral

The Capital Deferral accounts were moderately impacted by MIFRS as a result of the reduced burdens on outside labour.

2012 Bridge Year (MIFRS) versus 2011 Actual (MIFRS)

Table 8 below compares the capital expenditures in the Bridge Year 2012 forecast compared to actual MIFRS spending in 2011. Expenditures include both Barrie and PowerStream South.

Table 8

Capital Expenditure Bridge Year 2012 (MIFRS) Comparison to 2011 (MIFRS)

PROJECT DESCRIPTION	2011 Actual - MIFRS	2012 Bridge Year (MIFRS)	Difference
Sustainment Capital			
Replacement Program	$3,254,511	$6,967,807	$3,713,296
Sustainment Driven Lines Projects	$8,284,920	$9,919,810	$1,634,890
Emergency / Restoration	$7,082,363	$9,100,468	$2,018,105
Transformer / Municipal Stations	$3,268,289	$1,123,370	-$2,144,919
Emerging Sustainment Capital	$949,866	$2,824,959	$1,875,093
Total Sustainment Capital	$22,839,950	$29,936,414	$7,096,464
Development Capital			
Subdivision / Services	$4,822,559	$9,469,121	$4,646,562
Road Authority Projects	$7,218,612	$6,298,918	-$919,694
Additional Capacity (Transformer / Municipal Stations)	$113,508	$727,500	$613,992
Growth Driven Lines Projects	$7,038,310	$4,024,577	-$3,013,733
Emerging Development Capital	$626,419	$540,569	-$85,850
Distributed Generation Connections	-$86,236	$0	$86,236
Total Development Capital	$19,733,172	$21,060,685	$1,327,513
Operations Capital			
Metering	$2,167,753	$2,582,260	$414,507

Table 8 Capital Expenditure Bridge Year 2012 (MIFRS) Comparison to 2011 (MIFRS)			
PROJECT DESCRIPTION	**2011 Actual - MIFRS**	**2012 Bridge Year (MIFRS)**	**Difference**
Fleet	$1,154,496	$2,037,200	$882,704
Tools	$629,865	$712,810	$82,945
Buildings	$173,385	$864,930	$691,545
Information / Communication Systems	$4,419,136	$18,422,910	$14,003,774
Purchase of spare equipment	-$228,721	$66,000	$294,721
Emerging Operations Capital	$742,961	$686,770	-$56,191
Interest Capitalization	$340,287	$330,000	-$10,287
Total Operations Capital	$9,399,162	$25,702,880	$16,303,718
Total Capital Expenditure	$51,972,285	$76,699,979	$24,727,694
Capital Deferral Accounts			
Smart Meters	$1,406,008	$0	-$1,406,008
Smart Grid	$281,174	$1,250,000	$968,826
Renewable Generation	$468,795	$756,361	$287,566
Total Capital Deferral Accounts	$2,155,977	$2,006,361	-$149,616

Significant changes from 2012 compared to 2011 are as follows:

Sustainment

In 2012 there is an increase in replacement programs due to an increase in the pole replacement program.

Sustainment Driven Lines Projects increased in 2012 compared to 2011 due to an increase in subdivision rehabilitation and cable rejuvenation projects.

Emergency / Restoration program increased in 2012. With increased focus on inspections and worst performing feeders additional assets are required to be replaced as problems are discovered.

In 2012 there is a decrease in the sustainment project related to Transformer/Municipal stations compared to 2011. Through the Optimizer process it was decided that other projects within the corporation had higher priority.

In the Emergency Sustainment Capital category in 2011 there were a number of emerging U/G cable replacements required. This is the first time PowerStream had experienced the need to replace cable on an unplanned basis. Sections of cable that are thirty years old are failing and cannot be repaired. Due to these failures PowerStream has budgeted additional funds in emerging for unplanned U/G cable replacements.

Development

In 2012 there is an increase for subdivisions. Based on discussions with developers and municipalities extra lots are anticipated in 2012 compared to 2011. In addition, during 2011 merged practices for subdivision costing were implemented. Consistent with the Distribution System Code ("DSC") basic connection costs were included in the economic model (Appendix B of the DSC, section Capital Costs, item (e)). As a result of the implementation the costs increased for PowerStream.

Additional Capacity (Transformer / Municipal Stations) costs increased due to the purchase of a piece of property and subsequent design completion for a new Municipal Station in PowerStream North (predecessor Barrie Hydro Territory) to be constructed in 2013. The substation is required as two neighbouring substations in the area were at capacity in the summer of 2011.

In 2012 there is a reduced requirement for Growth Driven Lines Projects compared to 2011.

Operations

In 2012 PowerStream will start installation of Buttonville TS metering for compliance of IESO requirements. As a result the costs in metering have increased compared to 2011.

In 2011 no large vehicles / fleet purchases were made. In 2012, consistent with replacement policies, two large vehicles are to be replaced, one Aerial Device and one Digger Derrick resulting in increased costs.

Building costs are increased in 2012 compared to 2011. Additional projects are required to accommodate enhanced security at PowerStream's Addiscott and Patterson Rd. buildings. In addition, the yard in the PowerStream North facility required renovations to accommodate increased storage needs and update of the security in the yard. Lastly, PowerStream's Cityview office in Vaughan is at capacity. Additional funds are allocated to accommodate staff moves to an alternative location.

PowerStream is implementing a new Customer Information System ("CIS") which by itself represents $12.9 M of the additional spending in this category. The existing system dates back to the 1970's, has been significantly modified and customized and has reached its limits in terms of future capacity and abilities to integrate with new technologies. The new CIS is a key element of PowerStream's five year IT strategy. The project will start in 2012 and will go live in 2014. The increase in costs in Information / Communication Systems in 2012 compared to 2011 is due to the first phase of the CIS implementation

Capital Deferral

The smart metering installations were completed in 2011.

In 2012 there are a number of Smart Grid pilots. Major projects include: continued work on the electric vehicle trial; implementation of a grid energy management program and home energy trials (behind the meter SG Applications).

In 2012 two major projects are required to support connection of distribution generators, resulting in an increased spending for Renewable Generation for 2012. The projects include the completion of the installation of the WiMax communication system and installation of equipment to reduce fault current at Markham TS#1 and Markham TS #2.

2013 Test Year versus 2012 Bridge Year

Table 9 below compares the capital expenditures in the Test Year 2013 (MIFRS) forecast compared to the capital expenditures forecast in the Bridge Year 2012 (MIFRS). Expenditures include both Barrie and PowerStream South.

Table 9

Capital Expenditures Test Year 2013 Compared to Bridge Year 2012

PROJECT DESCRIPTION	2012 Bridge Year (MIFRS)	2013 Test Year (MIFRS)	Difference
Sustainment Capital			
Replacement Program	$6,967,807	$7,979,035	$1,011,228
Sustainment Driven Lines Projects	$9,919,810	$23,238,712	$13,318,902
Emergency / Restoration	$9,100,468	$9,527,350	$426,882
Transformer / Municipal Stations	$1,123,370	$2,673,187	$1,549,817
Emerging Sustainment Capital	$2,824,959	$2,847,386	$22,427
Total Sustainment Capital	$29,936,414	$46,265,670	$16,329,256
Development Capital			
Subdivision / Services	$9,469,121	$11,672,797	$2,203,676
Road Authority Projects	$6,298,918	$13,044,233	$6,745,315
Additional Capacity (Transformer / Municipal Stations)	$727,500	$5,983,906	$5,256,406
Growth Driven Lines Projects	$4,024,577	$6,544,575	$2,519,998
Emerging Development Capital	$540,569	$435,371	-$105,198
Distributed Generation Connections	$0	$0	$0
Total Development Capital	$21,060,685	$37,680,882	$16,620,197
Operations Capital			
Metering	$2,582,260	$2,619,518	$37,258
Fleet	$2,037,200	$2,932,600	$895,400
Tools	$712,810	$596,576	-$116,234
Buildings	$864,930	$221,372	-$643,558
Information / Communication Systems	$18,422,910	$22,396,999	$3,974,089
Purchase of spare equipment	$66,000	$127,654	$61,654
Emerging Operations Capital	$686,770	$120,120	-$566,650
Interest Capitalization	$330,000	$1,317,372	$987,372
Total Operations Capital	$25,702,880	$30,332,211	$4,629,331
Total Capital Expenditure	$76,699,979	$114,278,763	$37,578,784

Table 9

Capital Expenditures Test Year 2013 Compared to Bridge Year 2012

PROJECT DESCRIPTION	2012 Bridge Year (MIFRS)	2013 Test Year (MIFRS)	Difference
Capital Deferral Accounts			
Smart Meters	**$0**	**$0**	**$0**
Smart Grid	**$1,250,000**	**$650,000**	**-$600,000**
Renewable Generation	**$756,361**	**$77,250**	**-$756,361**
Total Capital Deferral Accounts	**$2,006,361**	**$727,250**	**-$1,356,361**

Significant changes from 2013 compared to 2012 are as follows:

Sustainment

In 2013 there is an increase in replacement programs due to a continued increase in the pole replacement program and switch gear replacement program. PowerStream has been increasing funds for these two programs in the last number of years. This is in response to the results from pole testing undertaken, inspection of the switch gear, completing Asset Condition Assessments and identified requirement to increase the annual programs. It is believed that 2013 funding levels are appropriate for the foreseeable future, excepting allowances cost increases for labour, labour saving devices and material. See the Asset Condition Assessment, Exhibit B1, Tab 2, Schedules 3 and 4 and the Engineering Five Year plan, Exhibit B1, Tab 2, Schedule 2 for additional information.

In 2013 there is an increase in Sustainment Driven Lines Projects spending compared to 2012. In 2013 there is a major focus on cable rehabilitation. This includes both replacing underground cable and injecting the underground cable. Since 2009 PowerStream has been completing Asset Condition Assessments on various major equipment. In 2011 the review was completed for the underground cable including a review of the underground cable for acquired utilities. In addition, since 2009 PowerStream has been investigating and testing various cable injection methods. As a result of the review it is necessary to increase both the amount of cable injected and replacements.

PowerStream has significant underground cable which was installed during the 1970's and early 1980's is now at end of life. This cable is an early generation of cable with a shorter life span than the new cable being installed today. Outages as a result of cable faults on the early generation of cable have been increasing and sections of cable which failed during 2011 could not be repaired. Replacement was the only option. Troubleshooting cable problems generally takes significant time and results in extended outages for impacted customers.

It is believed that 2013 funding levels are appropriate for the foreseeable future, excepting allowances cost increases for labour, labour saving devices and material. See the Asset Condition Assessment, Exhibit B1, Tab 2, Schedules 3 and 4 and the Engineering Five Year plan, Exhibit B1, Tab 2, Schedule 2 for additional information. PowerStream has significantly more of the next generation cable that was installed during the late 1980's and 1990's which is expected to be at its end of life 20-30 years from now.

In 2013 the number of Sustainment Transformer/Municipal Station projects has been increased. A minimal number of projects were completed in 2012. Through a re-optimization it was deemed that projects could be delayed one year but not continued years due to their value and increased risks. Major projects include the addition of oil containment systems at six substations; automatic feeder restoration at two transformer stations and the replacement of transformer bushing at a transformer station.

Development

In 2013 there is an expected increase for subdivisions. PowerStream keeps track of lots issued for construction. The number of lots issued for construction has steadily increased each year. Additional sewer capacity is expected to come on line in York Region in 2013 so the increase in lots is expected to continue. Discussions with developers and municipalities confirm that increased subdivision construction is anticipated in 2013 compared to 2012. In addition to the increase in servicing requirements, PowerStream has upstream charges in the current economic model. Consistent with the DSC (Appendix B, section Capital Costs, (d.1)) once PowerStream completes this rate application we will no longer include upstream charges in the economic model calculation. This will result in fewer contributions from developers and increased costs for PowerStream in the test year, 2013.

There is an increase cost in 2013 compared to 2012 for Road Authority projects. Projects have been identified for 2013 based on information from the Municipalities and York Region. Of significant impact is the requirement to relocate PowerStream plant due to requirements from the York Region Rapid Transit ("YRRT"). The YRRT is a high volume transit corridor that will be built across some sixty kilomentres within PowerStream's service territory. The transportation corridors have been identified as urban growth and high density intensification areas under the "Places to Grow" initiative by the Provincial Government. On these two corridors there is a desire by the Municipalities to place the electrical distribution assets underground when relocation is required. Based on a review of technical issues related to intensification, zero setback zoning and their associated issues with both safe limits of approach during construction and for building maintenance once completed, PowerStream has agreed to contribute funds towards the underground relocation in locations where buildings are being constructed tight to the lot line adjacent to the boulevard where pole lines exist.

There are increased costs in 2013 compared 2012 with respect to Transformer / Municipal Stations. In 2013 a new substation will be constructed in Barrie to reduce the loading on two neighbouring substations that were at capacity during the summer of 2011. In addition, it is anticipated that the Ontario Power Authority ("OPA") study for south York Region and subsequent Environmental Assessment for a new south Transformer Station will be completed. PowerStream will purchase property for a new south Transformer Station as soon as the Environmental Assessment is completed to ensure the property is secured. Additional information on the requirement for both substations can be found in the Engineering Five Year Plan, Exhibit B1, Tab 2, Schedule 2.

In 2013 there is an increase in spending on Growth Driven Lines Projects compared to 2012 due to the completion of two projects that commenced in 2012. In 2012 construction of infrastructure to support an additional 44 kV feeder from Midhurst TS will be started. Phase 2 will be completed in 2013. In 2012 a pole line installation on Dufferin Street will be started. Phase 2 will be completed in 2013. The requirement of these two projects is discussed in the Engineering Five Year Plan, Exhibit B1, Tab 2, Schedule 2.

Although load growth has slowed much of the load growth is concentrated in areas where land is available for greenfield development. PowerStream prudently plans the system to utilize the existing facilities as much as possible to service the new developments but in certain areas new facilities are required due to technical constraints on the existing distribution system.

Operations

In 2013 there is a planned increase in fleet replacements compared to 2012. The increase can be attributable to a planned increase in replacements of Light/Medium duty vehicles as part of the regular replacement schedule and consistent with fleet replacement guideline. Building Costs will decrease in 2013 compared to 2012 as fewer projects are required compared to 2012.

Information/Communication Systems – PowerStream is implementing a new Customer Information System ("CIS"). The project will start in 2012 and be completed in 2014. The largest amount of budget required is during 2013 ($16.7 M), resulting in an increase in spending in 2013 compared to 2012.

Capital Deferral

The smart metering installations were completed in 2011 and there is reduced costs for Smart Grid in 2013 compared to 2012 as there are fewer projects identified.

Costs for Renewable Generation are reduced in 2013 compared to 2012. The installation of the WiMax system will be complete. Only upgrades to transformer station wiring and protection will be required in 2013.

<u>Forecast 2014 & 2015 compared to 2013 Test Year</u>

Table 10 below compares the forecast capital expenditures in future years 2014 & 2015 compared to 2013. Expenditures include both Barrie and PowerStream South.

Table 10

Capital Expenditures Future 2014 & 2015 Compared to 2013

PROJECT DESCRIPTION	2013 Test Year (MIFRS)	Future 2014 (MIFRS)	Future 2015 (MIFRS)
Sustainment Capital			

Table 10

Capital Expenditures Future 2014 & 2015 Compared to 2013

PROJECT DESCRIPTION	2013 Test Year (MIFRS)	Future 2014 (MIFRS)	Future 2015 (MIFRS)
Replacement Program	$7,979,035	$8,054,000	$8,028,000
Sustainment Driven Lines Projects	$23,238,712	$23,702,000	$24,114,000
Emergency / Restoration	$9,527,350	$10,517,000	$10,794,000
Transformer / Municipal Stations	$2,673,187	$5,773,000	$4,288,000
Emerging Sustainment Capital	$2,847,386	$1,300,000	$1,300,000
Total Sustainment Capital	$46,265,670	$49,346,000	$48,524,000
Development Capital			
Subdivision / Services	$11,672,797	$11,410,000	$13,420,000
Road Authority Projects	$13,044,233	$19,555,398	$12,258,498
Additional Capacity (Transformer / Municipal Stations)	$5,983,906	$9,398,000	$21,414,000
Growth Driven Lines Projects	$6,544,575	$6,502,000	$10,028,000
Emerging Development Capital	$435,371	$220,000	$230,000
Distributed Generation Connections	$0	$23,000	$16,000
Total Development Capital	$37,680,882	$47,108,398	$57,366,498
Operations Capital			
Metering	$2,619,518	$1,842,000	$1,992,000
Fleet	$2,932,600	$3,000,000	$3,000,000
Tools	$596,576	$544,000	$491,000
Buildings	$221,372	$149,000	$223,000
Information / Communication Systems	$22,396,999	$12,750,714	$8,197,000
Purchase of spare equipment	$127,654	$30,000	$30,000
Emerging Operations Capital	$120,120	$500,000	$500,000
Interest Capitalization	$1,317,372	$1,430,300	$1,149,900
Total Operations Capital	$30,332,211	$20,246,017	$15,582,900
Total Capital Expenditure	$114,278,763	$116,700,415	$121,473,398
Capital Deferral Accounts			
Smart Meters	$0	$0	$0
Smart Grid	$650,000	$350,000	$350,000

Table 10

Capital Expenditures Future 2014 & 2015 Compared to 2013

PROJECT DESCRIPTION	2013 Test Year (MIFRS)	Future 2014 (MIFRS)	Future 2015 (MIFRS)
Renewable Generation	$77,250	$61,800	$51,500
Total Capital Deferral Accounts	$727,250	$411,800	$401,500

Forecast significant changes for 2014 and 2015 compared to the test year 2013 are as follows:

Sustainment

Levels of Sustainment capital are expected to be similar in 2014 and 2015 compared to the test year 2013. Based on review of Asset Condition Assessments it is believed that monies required to sustain and replace assets in PowerStream's distribution system and transformer stations are at a level in 2013 that can be sustained in the foreseeable future and result in an appropriate level of replacement to effectively replace aging assets.

Development

Levels of Development capital are expected to increase in both 2014 and 2015. Subdivision and servicing for new customers is expected to increase as the number of new lots is increasing as well as the number of layouts. There are lands available in the south for continued development. Road Authority projects are expected to increase in 2014 and 2015 as a result of York Region Rapid Transit ("YRRT") projects. YRRT is expected to construct new rapid transit lanes on Yonge Street from Highway 7 to Major Mackenzie Drive which is anticipated to require significant pole relocations for PowerStream. Anticipated projects required to support continued load growth include a new substation in Barrie in 2014 and the construction of a new Transformer Station in the south. The Transformer Station construction is anticipated to be across 2013 through to 2016 with an anticipated in-service end of 2016. The plan is to purchase property in 2013, prepare lands, purchase major equipment, and construct the station in the 2014-2016 period. Feeder construction will begin in 2015 to meet the 2016 in-service date.

Operations

Levels of Operations capital are expected to decrease in 2014 and then again in 2015 compared to 2013. The changes in anticipated spending are result of PowerStream's business driven Information Systems Strategic Plan. The plan calls for PowerStream to focus its efforts in 2012, 2013 and 2014 on implementing a new Customer Information System (CIS). Spending in 2014 decreases as a result of the completion of the CIS. Consistent with PowerStream's Information Systems Strategic Plan spending will continue in 2015 due to the planned implementation of a new Asset Management System.

Capital Deferral

Capital Deferral spending is anticipated to be at similar levels in 2014 and 2015 as in the test year 2013.

IN SERVICE ADDITIONS

The change in the net book value ("NBV") of Property, Plant & Equipment ("PP&E") from 2009, the last Cost of Service ("COS") rebasing for PowerStream, to 2013, the test year for the current COS Application is summarized in Table 1 below.

Table 1: PP&E NBV Change 2010 to 2013 ($Millions)

	CGAAP December 31, 2009	MIFRS December 31, 2013	Change	Add MIFRS NBV Adj.	Total Change
Gross Cost	$ 1,396	$ 1,121	$ (274)	$ (680)	$ 405
Contributed Capital	$ (260)	$ (276)	$ (15)	$ 63	$ (78)
Net Cost	**$ 1,135**	**$ 846**	**$ (290)**	**$ (617)**	**$ 327**
Accumulated Depreciation	$ (596)	$ (105)	$ 491	$ 617	$ (126)
Net Book Value (NBV)	**$ 539**	**$ 741**	**$ 201**	**$ -**	**$ 201**

Since the 2009 rebasing year, there have been net additions to PP&E of $327 million, after deducting contributed capital. The net additions result from additions of $365 million less dispositions of $38 million.

Under the International Financial Reporting Standards 1 ("IFRS1") election, as at January 1, 2011, Gross Cost was deemed to be the opening NBV under Canadian GAAP ("CGAAP") and reduced by the amount of accumulated depreciation; accumulated depreciation was set to $0. As a result to get the total change in the period, it is necessary to add this adjustment back to the difference between the closing (MIFRS Dec. 31, 2013) and opening (CGAAP Dec. 31, 2009) balances. See Exhibit A3, Tab 1, Schedule 5 for more information regarding the impacts of MIFRS.

Under MIFRS, PP&E includes intangible assets previously classified as fixed assets, namely Land Rights and Computer Software. PP&E amounts have been adjusted to reflect in service assets by removing Work-in-Process ("WIP"). Detailed fixed asset continuity schedules are provided in Exhibit B1, Tab 2, Schedule 5.

Table 2 below summarizes the Capital Expenditure ("CAPEX") described in the Capital Expenditures Overview and Detailed Variance Analysis sections (Exhibit B1, Tab 1, Schedule 6) and the adjustment of opening and closing WIP to arrive at the in service additions to be included in PP&E for determination of rate base.

Table 2: CAPEX, WIP and Disposition Summary ($Millions)

Description	Amount
Capital Expenditures 2010	$ 57
Capital Expenditures 2011	$ 52
Capital Expenditures 2012	$ 77
Capital Expenditures 2013	$ 114
CAPEX 2010 to 2013	**$ 300**
2010 Approved Smart meters	$ 19
2011 Approved Smart meters	$ 22
Addiscott capital lease	$ 18
Other Items not in CAPEX	$ 6
+ opening WIP	$ 59
- closing WIP	$ (59)
Additions	**$ 365**
Dispositions	$ (38)
Net Additions	**$ 327**

The totals in Table 2 include additions for 2010 based on CGAAP plus additions for 2011 to 2013 based on MIFRS. Differences between CGAAP and MIFRS for 2011 and 2012 are tracked in the IFRS PP&E Transitional Amount account 1575 which is shown as a separate adjustment to rate base.

The CAPEX amounts represent spending for the year and do not take into account WIP. PP&E additions are adjusted to recognize WIP and only include in-service additions.

The CAPEX reports keep deferral account spending, such as smart meters and smart grid, separate. As deferral account amounts are recognized in PP&E upon approval by the Ontario Energy Board ("OEB"), these have been excluded from the CAPEX amounts. Approved deferral account amounts are shown separately. Leases are not included in the CAPEX report so the capital lease is also added separately. Similarly a few other items, such as major spare parts in inventory, are not recorded in the CAPEX report, but are recorded in PP&E.

As shown in Table 2 above, net additions to PP&E of $327 million are the result of additions of $365 million less dispositions of $38 million. Table 3 provides a summary of the $365 million in additions, net of contributed capital, taking into account opening and closing WIP.

Table 3: Summary of PP&E Additions ($Millions)

Description	Amount
Sustainment Capital	
Replacement Program	$ 23.4
Sustainment Driven Lines Projects	$ 47.7
Emergency / Restoration	$ 33.1
Transformer / Municipal Stations	$ 8.1
Emerging Sustainment Capital	$ 8.6
Total Sustainment Capital	**$ 120.9**
Development Capital	
Subdivision / Services	$ 30.9
Road Authority Projects	$ 31.3
Additional Capacity (Transformer / Municipal Stations)	$ 22.3
Growth Driven Lines Projects	$ 26.6
Emerging Development Capital	$ 2.4
Distributed Generation Connections	$ 0.0
Total Development Capital	**$ 113.6**
Operations Capital	
Metering (Non- Smart Meter Program)	$ 10.3
Fleet	$ 10.3
Tools	$ 2.3
Buildings	$ 5.3
Information / Communication Systems	$ 23.8
Purchase of spare equipment	$ 6.5
Emerging Operations Capital	$ 2.9
Interest Capitalization	$ 4.0
Total Operations Capital	$ 65.5
Sub-total Capital Additions	**$ 300.0**
Smart Meters approved in 2010 and 2011	$ 41.2
Addiscott Operating Center Lease	$ 18.3
Other items not in CAPEX report	$ 5.6
Total Additions	**$ 365.1**

The need to replace aging plant, particularly underground cable and poles, is driving the spending on Sustainment Capital.

Growth continues to drive spending on Development Capital, with the need to add new transformer stations and feeders, invest in new subdivision infrastructure and the relocation of plant to accommodate road widening and other work by Municipalities and Regions.

Spending on Operations Capital is attributable to many different requirements. Metering spending is driven in large part by the Independent Electricity Electricity System Operator ("IESO") metering requirements and the need to acquire new wholesale meters. Fleet spending is mainly for replacement of aging vehicles. There has been considerable spending on Information and Communications Systems. Major projects include upgrading of the AS400 computer, an integrated voice response system ("IVR"), expansion of the Geographic Information System ("GIS") and billing system upgrades.

Smart meter additions of $41 million were approved in PowerStream's 2010 Smart Meter Cost Recovery Application (EB-2010-0209) and 2011 Smart Meter Cost Recovery Application (EB-2011-0128).

The lease on the Addiscott Operations Center building has been determined to be a capital lease under both CGAAP and IFRS. For more information see Exhibit B1, Tab 1, Schedule 5.

Although included in capital spending, WIP of $59 million has been excluded from the calculation of PP&E and rate base, as it will not be in service by the end of 2013. This includes $35 million for spending on a new transformer station in Vaughan, a new municipal station in Barrie and a new Customer Information and Billing System (CIS) that will not be in service as of December 31, 2013.

There was $59 million in WIP at December 31, 2009 which has gone into service and been added to the PP&E amount. This WIP included $42 million for new stations and feeders, a spare power transformer and furniture and equipment for a new operations center.

Dispositions of $38 million consists mainly of the cost of stranded meters of $33.3 million, which along with accumulated depreciation of $20.5 million for a NBV of $12.8 million, which has been transferred from PP&E to the smart meter deferral account 1555. The remaining balance of dispositions consists mostly of the cost of vehicle dispositions.

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	Pole Replacement Program
Project Classification:	Sustainment
Capital Expenditure Net of Contributed Capital Amount	2012 - $2,806,713; 2013 - $4,038,806
In-service date:	Poles installed throughout the planning period

Need:

To replace at various locations in PowerStream's service territory deteriorated wood poles so as to maintain system reliability, customer service performance standards and public safety at various locations in PowerStream's service territory. The candidates for replacement are determined on a prioritized basis, based on pole condition and remaining strength.

Summary:

This project includes the replacement of wood poles at various locations throughout PowerStream's service area. Every year PowerStream analyzes the pole testing, inspection program and asset condition assessment results to prioritize the pole replacement candidates. Pole testing results identify the specific wood poles that have deteriorated to a point where their remaining structural strengths are inadequate for their intended function. Poles are a critical component of the distribution system, as a number of pieces of equipment are attached to them (such as conductors, transformers, switches, street lights, telecommunication attachments, etc.). As a pole's physical condition and structural strength deteriorate, the pole may become inadequate for its intended function, and should be replaced to maintain the integrity of the distribution system, customer service standards and public safety.

Results:

Deteriorated poles are replaced with new poles, which will maintain system reliability, customer service performance standards, and public safety.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 1.1 M	$ 1.7 M	$ 1.6 M	$ 1.2M	$ 2.8 M	$ 4.0 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	Submersible Transformer Replacement
Project Classification:	Sustainment
Capital Expenditure Net of Contributed Capital Amount:	2012 - $996,115; 2013 - $1,501,844
In-service date:	Replacements completed throughout the planning period

Need:

To replace obsolete submersible transformers at various locations in PowerStream's service territory with new units to provide a safer work environment, maintain system reliability and customer service performance standards.

Summary:

This is a multi-year project which began in 2009. The project addresses the operational and safety concerns with respect to obsolete submersible transformers over a number of years, with a completion date of 2016.

PowerStream has a number of submersible transformer unit locations where the historical design and installation criteria no longer provide sufficient access for field staff to perform safe switching operations. The retro-fitting work, involves the replacement of submersible transformers with switchable padmount transformers that will facilitate safe operational work practices for the field staff.

Results:

Obsolete submersible units will be replaced with padmount transformers which will address current operational and safety concerns. This project will maintain system reliability and customer service performance standards.

1 **Planned Annual Expenditures (net of contributed capital):**

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 135 K	$ 129 K	$ 1.1 M	$ 1.0M	$ 996 K	$ 1.5 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	Planned Distribution Switchgear Replacement
Project Classification:	Sustainment
Capital Expenditures Net of Contributed Capital Amount:	2012 – $ 585,465; 2013 - $1,159,625
In-service date:	Switchgear installed throughout the planning period

Need:

Replace deteriorated distribution switchgear units at various locations in PowerStream's service territory with new units to maintain system reliability and customer service performance standards.

Summary:

This project includes the replacement of distribution switchgear units at various locations in PowerStream's service territory. A number of distribution switchgear units have been identified by PowerStream's Asset Condition Assessment ("ACA") Model as needing replacement due to age and condition.

The locations and priority are determined based on the benefit/cost ratio results from the ACA Model, and discussion and feedback among Lines, System Control, and System Planning staff.

The distribution switchgear units are critical components of PowerStream's distribution system. As these units get older, their functional capability deteriorates, and they need to be replaced to maintain the integrity of the distribution system. Planned replacement is preferred to replacing on an emergency basis which typically results in an unplanned outage.

Results:

Deteriorated distribution switchgear units are replaced with new units, which will maintain system reliability and customer service performance standards.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	n/a	$ 1.4 M	$ 648 K	$ 611 K	$ 585 K	$ 1.2 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title: Underground Cable Replacement

Project Classification: Sustainment

Capital Expenditures Net of Contributed Capital Amount: 2013 - $11,147,459

In-service date: Specific projects in-service in 2013

Need:

It has been identified through PowerStream's Asset Condition Assessment ("ACA") that underground primary cables that have reached the end of their reliable service life be replaced to maintain system reliability and customer service performance standards. Failure to address this issue will result in increasing annual costs associated with emergency repair/replacement of failing cable with an associated decline in customer service performance standards.

Summary:

This project includes the replacement of 47 km of underground primary cable at various locations in PowerStream's service territory. The cable replacement locations are selected and prioritized based on a number of qualitative and quantitative asset criteria such as cable age, cable condition, failure history, diagnostic testing results, customer service impacts, and criticality of the cable to the distribution system.

Results:

End-of-life cables are replaced with new cables, which will maintain system reliability and customer service performance standards.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 1.2 M	$ 1.0 M	$ 4.1 M	$ 3.1M	$ 3.7 M	$ 11.1 M

** For comparison purposes monies have been included for specific underground cable replacement projects completed in 2009 to 2012

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	Underground Cable Injection
Project Classification:	Sustainment
Capital Expenditures Net of Contributed Capital Amount	2012 – $554,392; 2013 - $3,984,835
In-service date:	Specific sites completed throughout the planning period

Need:

To perform cable injection work so as to rejuvenate old and deteriorated underground primary cable. The cable injection process and technology will extend the life of a cable, thus maintain system reliability and customer service performance standards at various locations in PowerStream's service territory. Failure to address this issue will result in increasing annual costs associated with emergency repair/replacement of failing cable with an associated decline in customer service performance standards.

Summary:

This project includes cable injection work on 57 km of underground primary cable at various locations in PowerStream's service territory. The cable injection candidates are selected and prioritized based on a number of qualitative and quantitative asset criteria such as cable age, failure history, diagnostic testing results, condition of neutral wires, number of splices, customer service impacts and criticality of the cable to the distribution system.

The cable injection process will inject silicone fluid down the strands of the cable. The silicone fluid will diffuse out of the strands through the strand shield and into the insulation, thereby counteracting the effects of cable insulation aging by increasing the dielectric strength of the cable insulation and thus extending the life of the cable. Cable injection is a preferred alternative to replacement as there is beneficial net present value of cable injection in comparison to replacement.

Results:

Old and deteriorated underground primary cables are rejuvenated and their useful life is extended, which will maintain system reliability and customer service performance standards.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 128 K	$ 24 K	$ 359 K	$ 324 K	$ 600 K	$ 4.0 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title: Romfield Subdivision Cable Rehabilitation

Project Classification: Sustainment

Capital Expenditures Net of Contributed Capital Amount: 2012 - $1,879,539; 2013 - $1,755,272

In-service date: Phase 2 – October 2012; Phase 3 – October 2013

Need:

To replace of end-of-life underground cable (which is currently 40 years old) and obsolete submersible transformers to maintain system reliability and customer service performance standards in the Romfield Subdivision area in Markham.

Summary:

This project is the second phase of a 5-phase project. Phase 1 is being completed in 2011. Phase 3, 4, and 5 are proposed for completion in 2013, 2014, and 2015 respectively.

In the Romfield Subdivision area in Markham the underground cable is over 40 years old and has failed numerous times in the last few years. The submersible transformers are obsolete and cannot be switched when energized.

Results:

End-of-life underground cable and obsolete transformers are replaced with new components, which will maintain system reliability and customer service performance standards in the Romfield Subdivision.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$0	$0	$1.6 M	$ 1.2 M	$1.9M	$1.8M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title: Flowervale Subdivision Cable Rehabilitation

Project Classification: Sustainment

Capital Expenditures Net of Contributed Capital Amount 2012 - $1,783,819

In-service date: Phase 3 – October 2012

Need:

To replace end-of-life underground cable (which is currently 39 years old) and obsolete submersible transformers to maintain system reliability and customer service performance standards in the Flowervale Subdivision area in Markham.

Summary:

This project is in the final phase of a 3-phase project. Phase 1 and 2 were completed in 2010 and 2011 respectively.

The underground cable is 39 years old and has failed numerous times in the last few years. Cable test report indicates the cable is at end-of-life. The submersible transformers are obsolete and cannot be switched when energized.

Results:

End-of-life underground cable and obsolete transformers are replaced with new components, which will maintain system reliability and customer service performance standards to the Flowervale Subdivision.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$0	$ 789 K	$ 1.2 M	$ 954 K	$ 1.8 M	$0

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	Distribution Automation Switch/Reclosers
Project Classification:	Sustainment
Capital Expenditures Net of Contributed Capital Amount	2012 - $812,615; 2013 - $1,037,166
In-service Date:	Switches installed throughout the planning period

Need:

Distribution Automation Switches / Reclosers are proposed at several new locations in the system. The new switches / reclosers are required to improve system reliability on poorly performing feeders as well as for load balancing of selected feeders within the system. The existing switches are deemed end of life and are required to be replaced.

Summary:

Automated Switches / Reclosers are key components of the distribution system. The Distribution Automation Switches / Reclosers, which are remotely controlled devices (via SCADA), will provide for the rapid transfer of customer loads in planned and emergencies situations. Operational efficiencies are gained from not having to dispatch work crews to manually switch devices in the field.

Results:

Automated Switches / Reclosers are key components of the distribution system. This project will allow for the rapid transfer of load between feeders or stations during emergency situations. It will provide a real time system reading to Control Room Operators, eliminate the risks associated with manual switching, allows for an increase in asset utilization through flexible load transfers and will help to sectionalize the feeders so as to minimize the customers affected during an outage.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 854 K	$ 32 2K	$ 704 K	$ 607 K	$ 813 K	$ 1.0 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	Unscheduled Replacement of Failed Distribution Equipment
Project Classification:	Sustainment Capital
Capital Expenditures Net of Contributed Capital Amount	2012 - $5,104,844; 2013 - $5,337,269
In-service date:	Equipment is replaced throughout the planning period

Need:

This expenditure covers replacement of equipment, poles, conductors, devices and transformers, within our distribution system due to unexpected failure or expected imminent failure as discovered through inspection. The equipment must be replaced so that power can be restored and the reliability of the distribution system maintained.

Summary:

LDC's must restore power when an outage occurs. This expenditure is to remove and replace equipment for unplanned failure of poles, conductors, devices and transformers in the distribution system that are causing interruption of power to customers. Equipment may also be replaced due to identified safety hazards that must immediately be taken care of or replaced if imminent failure is expected as identified through inspection. The equipment is removed and replaced with new equipment.

This budget is prepared based on historical data of previous years with consideration for changed practices for tracking costs.

Results:

Restore power when an outage occurs and make the equipment safe due to an identified safety hazard.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 2.3 M	$ 8.6 M	$ 6.7 M	$ 5.9 M	$ 5.1 M	$ 5.3 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title: Unscheduled Replacement of Failed Switchgears

Project Classification: Sustainment Capital

Capital Expenditures Net of Contributed Capital Amount 2012 - $1,674,662; 2013 - $1,763,293

In-service date: Switchgears replaced throughout the planning period

Need:

This expenditure covers the replacement of switchgears within PowerStream's service territory due to unexpected failure or expected imminent failure as discovered through inspection. The switchgears must be replaced so that power can be restored and the reliability of the distribution system maintained.

Summary:

LDC's must restore power when an outage occurs. This expenditure is for i) unplanned failure of switchgears in the system causing interruption of power to customers and/or ii) the unplanned replacement of switchgear due to safety hazards and iii) replace switchgears when through inspection risk of imminent failure is identified. This equipment is removed and replaced with new electrical equipment.

This budget is prepared based on historical data of previous years. Switchgear replacements have been increasing and for 2012 going forward the replacements will be budgeted separately from general Unscheduled Replacement of Failed Distribution Equipment.

Results:

Restore power when an outage occurs and make the equipment safe as required.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	n/a	n/a	n/a	n/a	$ 1.7 M	$ 1.8 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	Planned Station Circuit Breaker Replacement at Vaughan TS2
Project Classification:	Sustainment
Capital Expenditure Net of Contributed Capital Amount	2012 - $ 1,518,003
In-service date:	November 2012

Need:

The Vaughan TS2 (also named Torstar TS) circuit breakers have been identified by the Asset Condition Assessment ("ACA") model as requiring replacement due to age, condition and historical failures. In addition, the circuit breakers are considered "obsolete" in that they are no longer built or supported by the manufacturer.

In addition to being obsolete, the existing HKSA 2000 Amp transformer circuit breakers at Vaughan TS#2 have the same design defect as the HKSA transformer circuit breakers that have failed at Vaughan TS#1 (also named Greenwood TS) in 2009. An investigation of these failures has shown that the Transient Recovery Voltage rating of the transformer breakers at Vaughan TS#1 was inadequate for their application as transformer circuit breakers.

The existing 9 circuit breakers on the "A" bus will be replaced with new HD-4 circuit breakers. In phase 1 of the project the "B" bus breakers were replaced in 2011.

Summary:

8 of the 17 circuit breakers at Vaughan TS#2 have been replaced in 2011 with new HD-4 circuit breakers. This project is to replace the remaining 9 circuit breakers. Switchgear breaker cells will be modified to accommodate the physical configuration of the new circuit breakers. The 9 circuit breakers to be replaced are on the "A" Bus, including:

- The 6 feeder breakers for the M1, M3, M5, M7, M9 and M11 feeders
- The bus tie breaker between the "A" and "B" 28kV Busses, and
- The 2 transformer breakers on the "A" Bus, designated as T1A & T2A

Results:

This project addresses the inadequate transient recovery voltage problem with the HKSA 2000 Amp transformer circuit breakers, the obsolescence problem with all 9 breakers and the condition of the breakers as identified through the ACA model. The result will be to improve the reliability of the electrical supply for the City of Vaughan and to remove the risk of rating related circuit breakers failure at Vaughan TS#2.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$0	$0	$ 1.4 M	$ 1.3M	$ 1.5 M	$0

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	Planned Station Circuit Breaker Replacement at Richmond Hill TS#1
Project Classification:	Sustainment
Capital Expenditures Net of Contributed Capital Amount	2013 - $ 909,096
In-service date:	November 2013

Need:

The Richmond Hill TS#1 (also named Lazenby 1 TS), transformer and bus tie circuit breakers have been identified by the Asset Condition Assessment ("ACA") model as requiring replacement due to age, condition and historical failures. The circuit breakers are considered "obsolete" in that they are no longer built or supported by the manufacturer.

In addition to being obsolete, the existing HKSA 2000 Amp transformer circuit breakers at Richmond Hill TS#1 have the same design defect as the HKSA transformer circuit breakers that have failed at Vaughan TS#1 (also named Greenwood TS) in 2009. An investigation of these failures has shown that the Transient Recovery Voltage rating of the transformer breakers at Vaughan TS#1 was inadequate for their application as transformer circuit breakers.

The existing 5 circuit breakers on the "A" bus will be replaced with new HD-4 circuit breakers.

Summary:

It is proposed to replace 5 circuit breaker units on the "A" bus at Richmond Hill TS#1 in 2013, consisting of 4 transformer breakers and 1 bus tie breaker. Switchgear breaker cells will be modified to accommodate the physical configuration of the new circuit breakers. The 5 circuit breaker units are listed below:

- The bus tie breaker between the "A" and "B" 28kV Busses
- The 2 transformer breakers on the "A" Bus, designated as T1A & T2A, and
- The 2 transformer breakers on the "B" Bus, designated as T1B & T2B

Results:

This project addresses the inadequate transient recovery voltage problem with the HKSA 2000 Amp transformer circuit breakers, the obsolescence of all 5 breakers and the condition of the breakers as identified through the ACA model. The result will improve the reliability of the electrical supply for the Town of Richmond Hill and to remove the risk of rating related circuit breakers failure at Richmond Hill TS#1.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$0	$0	$0	$0	$0	$ 909 K

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	Oil Containment Systems for Municipal Stations
Project Classification:	Sustainment
Capital Expenditure Net of Contributed Capital Amount	2013 - $883,261
In-service date:	Sites completed throughout 2013

Need:

The Ontario Ministry of Environment's ("MOE") requires PowerStream be responsible for the clean-up of any oil spills caused from our transformer stations. Fines may be applied for unintended release of oil to the environment as a result of equipment failure or other reasons. In order to mitigate this risk PowerStream has undertaken to install an oil containment system for each municipal station transformer in order to reduce the potential risk of environmental damage.

Summary:

Utilities operate a number of oil filled equipment, such as transformers, and have a responsibility to restrict accidental oil spills from contaminating the surrounding areas. This has lead utilities to install oil containment systems around power transformers in stations to prevent a failed unit from leaking or spilling oil into the surrounding environment.

PowerStream has initiated a program to install the "SorbWeb" containment system around the transformers at all existing municipal stations ("MS's"). The SorbWeb system is recognized by the Ministry of Environment to allow snowmelt and rainwater to permeate into the subsoil but effectively trap oil in a multi-layered geocomposite material surrounding the transformer.

To date, PowerStream has completed eleven SorbWeb installations at MS's. The plan is to retrofit the remaining thirty MS's by installing oil containment systems each year. The MS's are prioritized based on their potential impact to environmentally sensitive areas. Six installations are planned for 2013. Each SorbWeb retrofit takes approximately two to three weeks to install.

Results:

The installation of the SorbWeb oil containment system at PowerStream's above mentioned municipal stations is a proactive means of mitigating the potentially high costs of oil spills into the surrounding area that could result from a transformer failure.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$0	$ 255 K	$0	$0	$0	$ 883 K

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	Emerging Cable Replacement Projects
Project Classification:	Sustainment
Capital Expenditures Net of Contributed Capital Amount:	2012 - $1,967,787; 2013 - $1,969,889
In-service Date:	Specific projects completed throughout the planning period

Need:

Underground cable and splice failures are the leading cause of outages in the Defective Equipment Category. The planned Cable replacement program, which targets particular cable segments based on age, condition and outage information, systematically addresses replacement of this asset category over time. Each year planned projects are identified and submitted for capital funding during the budget approval process.

In some cases cable sections not identified for replacement in a particular budget year may begin to fail to the point where repair is no longer a viable or reliable option and security of supply is put at high risk. At this point the cable needs to be replaced immediately and is treated as an Emerging project. This could happen at any time during the course of the year.

Summary:

These projects address the replacement of cables which are deemed either un-repairable or need to be replaced immediately in order to maintain operations. The replacement decision is based on cable test data, failure analysis data and a review of the impact the cable section has on the security of supply to the local area and/or overall system.

Funding for these underground cable replacements has, in the past been funded through Emerging PowerStream Initiated projects. In 2011 the requirement for unforeseen replacements has emerged. Based on this experience PowerStream is expecting an increased requirement for funds to immediately replace sections of cable. As such, PowerStream, going forward is going to track this category of projects separately and has increased funds for anticipated required replacements.

Results:

This project addresses cable replacements which have an immediate impact to operations and are essential to restore supply.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$0	$0	$ 700 K	$ 646 K	$ 2.0 M	$ 2.0 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title: Emerging PowerStream Initiated Projects

Project Classification: Sustainment

Capital Expenditures Net of Contributed Capital Amount $857,172 / year

In-service date: During 2012 & 2013 per project requirements

Need:

Emerging projects are typically projects that are required to maintain system integrity that arise during the year but were not foreseen at budgeting time. The risk of delaying the projects to the next budget year is seen as too great.

Summary:

The capital budget build each year begins in May with Project Owners identifying required projects. Project Owners must identify projects by the end of August for the following two years execution. Once projects are identified, there is a freeze put on project identification and changes to the project list that is approved by the Board and subsequently executed. This process assists in timely approvals and project execution. One issue with this process is any new projects that come forth cannot be considered for execution until the following year. However, there are projects where the risk is deemed to great to wait until the following year for execution. As such, there are monies set aside each year for unforeseen, emerging, projects that arise during the year.

Projects in this category are for construction capital and are typically required to maintain system integrity and reliability. Monies for emerging projects are estimated based on historical patterns. Monies have been reduced for 2012 compared to 2011 as a new Emerging category was developed to account for specific projects to replace failed sections of Underground Cable.

Results:

The emerging projects initiated will improve system reliability.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 2.3 M	$ 1.5 M	$ 1.1 M	$ 987 K	$ 857 K	$ 857 K

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title: New Subdivision Development

Project Classification: Development

Capital Expenditures Net of Contributed Capital Amount 2012 - $5,616,262; 2013 - $7,532,534

In-service date: Specific subdivisions in-service throughout the planning period

Need:

To covers the costs of new green field subdivisions developments. Upon request and in accordance with the Distribution System Code ("DSC"), PowerStream provides an Offer to Connect to Developers for the installation of new plant to service a new subdivision.

Summary:

New subdivisions consist of the primary cable, transformers and secondary to the street line of each lot within a new residential subdivision development. In accordance with the DSC, the development cost is put through an economic model to determine the LDC share of costs and the Developer share based on revenues from the development. Up until the end of 2012 upstream costs are included in the economic model. In accordance with the DSC the upstream costs from 2013 forward, the test year, have been removed thereby resulting in PowerStream's costs increasing.

Results:

To service developer requests for residential subdivision in accordance with the DSC.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 6.0 M	- $ 652 K	$ 4.1 M	$ 3.1 M	$ 5.6 M	$ 7.5 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title: Secondary Services

Project Classification: Development

Capital Expenditures Net of Contributed Capital Amount 2012 - $1,310,849; 2013 - $1,478,189

In-service date: Services installed throughout the planning period

Need:

To cover costs for a customer's service connection from the property line to meter base.

Summary:

Secondary underground services are installed from the service tails at the street line to the meter base for each lot. This work allows for the connection of the secondary service to the pad mount transformer which in turn provides power to the customer's house. The secondary underground services are installed as the houses within the development are built and are normally installed within five years of the new subdivision electrical infrastructure being installed.

In accordance with Distribution System Code ("DSC"), these service costs are put through the economic model and shared when the Offer to Connect is entered into with the Developer. The Developer is appropriately given credit for the required basic connection charge in accordance with the DSC.

Results:

New customer's electrical residential service gets energized as requested.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	n/a	n/a	$ 1.5 M	$ 1.2 M	$ 1.3 M	$ 1.5 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title: Layouts

Project Classification: Development

Capital Expenditures Net of Contributed Capital Amount: 2012 – $742,178; 2013 - $805,567

In-service date: Layouts completed throughout the planning period

Need:

To cover the costs to respond to a customer's request for a service in an infill lot or a customer's request to upgrade their existing electrical service.

Summary:

Layouts consist of work to make ready the system for new residential infill services, upgrading of residential services and small commercial services. A layout is completed for each customer. The customer's service could be underground or overhead and is the connection from the main plant on the boulevard to the building.

Costs are shared between the customer and PowerStream. In accordance with the Distribution System Code ("DSC"), the LDC is required to provide the customer with a basic connection allowance for each residential service.

Results:

Customer's electrical residential service gets energized as requested.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 401 K	$ 924 K	$ 922 K	$ 668 K	$ 742 K	$ 806 K

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title: Road Authority Projects

Project Classification: Development

Capital Expenditures Net of Contributed Capital Amount 2012 - $6,298,918M; 2013 - $13,044,233

In-service date: Specific projects in-service throughout the planning period

Need:

Road authority projects are projects that are initiated by a Region, Town or Municipality. If there are hydro conflicts with the road project, PowerStream has to relocate the plant out of the proposed road and back to the new boulevard. PowerStream generally pays 60-70% of the costs with the Region, Towns or Municipalities paying for 50% of labour and labour saving devices for the relocation.

Summary:

Road authority projects that require relocation are estimated based on historical data, with input from the Municipal, Town and Regional plans.

The following projects are expected for 2012:

- Keele St - Steeles Ave to Hwy 407
- Hwy 7 - Warden Ave to Sciberras
- Olde Bayview Ave / Sunset Beach Road
- Snively Street / Drynoch Ave
- Richmond Hill Main Street Phase 1
- Richmond Hill Main Street Phase 2
- Rodick Road Phase 2
- YRRT – Hwy7 – Bayview to Warden

The following projects for expected for 2013:

- Rutherford Road, Jane to Keele St
- Rutherford Road, Keele to Dufferin St

- Weston Road, Hwy 7 to Rutherford Rd
- Barrie – Mapleview Drive – Huronia to Country Lane
- Bradford – Thornton St. & Fredrick St.
- Penetanguishene – Maria St.
- YRRT – Hwy 7 – Hwy 400 to Yonge St.

Results:

The Regions and local Municipalities and Towns require PowerStream to relocate the distribution system to accommodate road works. The projects will be completed as required.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 3.9 M	$ 5.9 M	$ 9.1 M	$ 7.5 M	$ 6.3 M	$ 13.0 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	New Sandringham MS
Project Classification:	Development
Capital Expenditures Net of Contributed Capital Amount	$4,483,907
In-service Date:	April 2014

Need:

This project is to provide capacity relief to two existing Municipal Substations (“MS”), Huronia MS and Big Bay Point MS, located in south-east Barrie. The summer peaks for these two stations have exceeded their transformer base ratings for the past two summers.

Planning information obtained from the City of Barrie indicates that an additional 8 MVA of new load will need to be supplied in the area over the next five years.

Summary:

This project involves the construction of a 44 -13.8 kV, 20MVA, 4-Feeder substation including a short (approx. 1km) 44kV line section to supply the station and four short (approx. 300m) 13.8 kV feeder egress cables.

This new station will be electrically connected with the other stations in the area, through existing distribution facilities.

The added capacity will be utilized for servicing planned growth in the area as well as to ensure that adequate backup supply capacity is available in the event of a station contingency (i.e. loss of transformer).

Results:

This project addresses the loading issues at two existing substations and provides capacity for future growth in south-east Barrie. Additionally the added capacity will provide operational flexibility (i.e. for system maintenance and emergency restoration) within the supply area.

1 **Planned Annual Expenditures (net of contributed capital):**

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 0	$ 0	$ 0	$ 0	$ 700 K	$ 3.8 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	Vaughan TS#4 Land Purchase
Project Classification:	Development
Capital Expenditures Net of Contributed Capital Amount	2013 - $2,200,000
In-service date:	New Transformer Station In-Service May 2016

Need:

The purpose of this project is to purchase land for the future construction of Vaughan Transformer Station 4 ("VTS#4"). The station will provide 170 MVA of new capacity through twelve new 27.6kV feeders that will be integrated into the distribution system. VTS#4 will service future load growth in the Vaughan area. In addition, VTS#4 will off-load some existing feeders in Vaughan which in turn will provide feeder capacity to our Richmond Hill service territory.

Summary:

This project involves the purchase of approximately two acres of land (80Mx100M), preferably near a Hydro One 230kV transmission corridor. The exact location is yet to be determined however PowerStream is currently participating in a York Region Electricity Supply Study, led by the Ontario Power Authority. PowerStream's load forecast indicates the need for a new station to be in service by 2016, in order to meet summer peak demand. The Class EA process for siting the station will begin in 2012. Design and construction of VTS#4 will take up to three years. For successful project completion land is required to be purchased in 2013.

Results:

This project will allow PowerStream to start the design and construction of VTS#4, in order to meet an in service date of 2016. VTS#4 will provide additional system capacity for future load growth as well as backup capacity for operational and reliability purposes.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2.2 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	Midhurst TS Mapleview Drive – New 44kV Express Feeder from Midhurst to south-west end of Barrie
Project Classification:	Development
Capital Expenditures Net of Contributed Capital Amount	$5,720,425
In-service Date:	Stage 1 – November 2012, Stage 2 - December 2013

Need:

To provide capacity relief to two existing 44 kV Feeders, Midhurst TS 23M5 and Barrie TS 13M5 and increase supply capacity and reliability to the south-west part of the City of Barrie.

The south-west part of Barrie is bounded by Harvie Rd. to the north, Salem/Lockhart Rd. to the south, Welham Rd. to the east and Hwy. 27/Veterans Dr. to the west. The 2011 summer peak load within this boundary was approximately 76 MVA. In the next twelve months, this area will see two new data centers with approximately 10 MVA of new load. Both data centers have indicated an ultimate load of 20 MVA each.

The south-west part of the City of Barrie is currently being supplied by three 44 kV feeders; Midhurst TS 23M5; Barrie TS 13M5 and 13M6.

The existing 44 kV feeders in this area cannot support the projected load beyond 2013 and therefore capacity relief is required.

Summary:

This project involves the construction of an express 44 kV feeder, approximately 20 km in length, from Midhurst TS to the south-west part of the City of Barrie. The construction will be carried out in two stages. Stage one will take place in 2012 and it will be from Midhurst TS to Livingstone St. Stage two will take place in 2013 and it will go from Sunnidale Rd. via Ferndale Dr. to Mapleview Dr. East.

Results:

This project will address feeder capacity constraints in the south-west part of the City of Barrie and allow for the additional new load of the data centers described above. The addition of this new feeder and its associated tie points, with other feeders, will improve operational flexibility (i.e. backup supply and system maintenance purposes) to this area of the city.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 0	$ 0	$ 0	$ 0	$ 1.5 M	$ 4.2 M

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title: Install two circuits on Dufferin Street

Project Classification: Development

Capital Expenditures Net of Contributed Capital Amount $1,291,809

In-service date: May 2013

Need:

To service future load growth in the Thornhill area. In addition, this project will reduce load on local feeders (36M7 & 51M2) that are either over-loaded or near capacity and reduce load on Vaughan TS#1. The feeder extension will serve to supply back-up power to customers in the area, in the event of a system contingency.

Summary:

This project involves the construction / extension of two feeders (20M23 and 20M24 feed from Vaughan TS#1 Expansion) via an overhead pole line on Dufferin to Center Street. These two feeders will tie into existing circuits on Center St, east of Dufferin St that connect to the Thornhill area. Historical loading information shows that existing feeders 36M7 and 51M2, in the Thornhill area, are currently loaded beyond PowerStream's loading guidelines. Vaughan TS#1 is fully loaded and at risk if new load growth is added. Load relief is required. Project construction will begin in late 2012 with planned completion in 2013.

This project will help reduce load on feeders (36M7 & 51M2) and Vaughan TS#1. In addition, feeders 20M23/M24 will serve as ties between Vaughan TS#1 and Vaughan TS#1 Expansion. This will allow load transfers between stations in the event of a system contingency, reducing the risk of customer outages.

Results:

This project addresses loading issues for two feeders both in the short term and long term and reduces the risk of customer outages due to feeder/station loading issues.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 0	$ 0	$ 0	$ 0	$ 638 K	$ 654 K

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	New Suite Metering
Project Classification:	Operations Capital
Capital Expenditures Net of Contributed Capital Amount	$892,554 / year
In-service date:	Specific sites in-service throughout the planning period

Need:

This project provides a means for PowerStream to install revenue meters in each condo unit of the high rise condominium building marketplace throughout its service territory.

Summary:

As land availability declines in PowerStream's service territory, developers have turned to building high rise condominiums to meet the growing demand for residential & commercial accommodation. Each high rise condo project represents an opportunity to increase PowerStream's customer base by several hundred customers by installing revenue meters for each condo unit. In the past a single bulk meter at the service entrance (representing a customer count of one) was the preferred option. With the electricity market opening, individual suite metering is PowerStream's preferred option.

PowerStream has successfully installed condominium (or suite) meters in high rise condo buildings for the past five years, averaging approximately 1,500 units per year. These installations have increased PowerStream's customer base by 2.5% over that period, or 0.5% per year of organic customer growth.

This suite metering business is not without competition. Third party "meter service providers" lobby condo developers offering financial incentives to the developer to install the third party metering equipment. PowerStream's strategy to meet this competition is to secure the commitment of the developer as early as possible in the building planning stage. Although a challenge, PowerStream has been quite successful in this effort to date. Failure of PowerStream to compete in this competitive and growing marketplace would mean the loss of this important organic growth component.

Results:

The addition of approximately 1,500 new customers each year from the growing condominium sector in PowerStream's service territory. This will become increasingly more important as more developers enter the high rise condominium market.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 1.5 M	$ 1.6 M	$ 2.0 M	$ 1.3 M	$ 893 K	$ 893 K

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title:	Buttonville Metering Upgrade
Project Classification:	Operations Capital
Capital Expenditures Net of Contributed Capital Amount	$1,202,718
In-service date:	November 2013

Need:

This project is required to make PowerStream compliant with the Independent Electricity System Operator ("IESO") Rules for Wholesale Metering Installations and compliance with PowerStream's Ontario Energy Board ("OEB") issued license. This installation is required to be installed by the end of 2013.

Summary:

This project will involve installing new two current and voltage transformers in the Hydro One Networks Inc. ("HONI") owned transformer station located in Markham. New steel support structures will be installed on new concrete bases to support the metering transformers. This option utilizes the existing metering and related equipment already installed inside the station, re-directing the secondary wiring to connect to the new current transformer/potential transformer ("CT/PT") equipment connected to the 230 kV Bus. Project construction will start in 2012 with planned completion in 2013.

PowerStream metering staff would rely on HONI resources to design and construct this project as this is a HONI requirement. PowerStream staff would order the new CT/PT equipment for installation by HONI. Commissioning of the completed project would be a joint responsibility between the two companies.

Results:

This project is required for compliance with IESO Market Rules and PowerStream's OEB License. Failure to do so would result in sanctions from the IESO and fines up to $240,000 per year.

1 **Planned Annual Expenditures (net of contributed capital):**

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 0	$ 0	$ 0	$ 0	$ 502 K	$ 701 K

POWERSTREAM – INVESTMENT SUMMARY DOCUMENT

Project Title: Light /Medium duty & Misc. Classification Vehicle Replacements and associated accessories

Project Classification: Operations Capital

Capital Expenditures Net of Contributed Capital Amount 2012 – $748,000; 2013 - $1,738,000

In-service date: Vehicle purchases completed throughout the planning period.

Need:

This project covers the costs of acquisition of Light and Medium duty and miscellaneous vehicle replacements including their accessories.

Summary:

PowerStream has 156 light/medium vehicles and sixty miscellaneous units for use across the organization. PowerStream has established an expected life for each class of vehicle or unit. Expected life is determined by years of use, mileage or hours of use as per manufacturer's recommendations for replacement. A vehicle is considered for replacement upon reaching expected life. A specific vehicle's replacement may be deferred based on additional considerations for replacement such as on-going maintenance costs and utilization.

The budgeted amount covers the replacement of vehicles required to be replaced in the given year.

Results:

Vehicles replaced at end of life resulting in reliable vehicles for staff that depend upon the vehicles to perform their duties efficiently and safely.

Planned Annual Expenditures (net of contributed capital):

Year	2009 Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge	2013 Test
Total Costs	$ 3.9 M	$ 2.9 M	$ 558 K	$ 558 K	$ 748 K	$ 1.7 M

POWERSTREAM INVESTMENT SUMMARY DOCUMENT

Project Title:	Customer Information System (CIS) Replacement
Project Classification:	Operations Capital
Capital Expenditures Net of Contributed Capital Amount:	$34,500,000
In-service date:	June 2014

Need:

To replace the existing T&W Customer Information System ("CIS") that dates back to the 1970's with a new Oracle based CIS. There are three significant risks associated with the current system that have caused the need to explore a more modern, robust and technically advanced system for PowerStream to meet its Corporate Strategy aspirations. The existing T&W CIS system has i) reached its limitations in terms of future capacity, ii) its integration with new and emerging technologies is restrictive and iii) the detailed knowledge base for this system is limited.

Summary:

The CIS is a critical and comprehensive business system for PowerStream. The CIS provides the full meter-to-cash applications required to meet one of the core business mandates of providing account management, billing, collections, payments, and meter management/meter reading functionality for over 330,000 electricity customers within PowerStream's service territory. It also is a hub system providing inbound and outbound information to approximately twenty other interface systems both internal and external to PowerStream. In addition, the CIS also enables PowerStream to provide water billing services to its two primary shareholders, The City of Vaughan and Town of Markham as well as to one of its stakeholders, the Town of Bradford.

The new Oracle based CIS will be more easily integrated with new and emerging technologies especially related to web based and mobile customer self-serve offerings which will have a direct impact on customer satisfaction. The system also offers more cross functional ability which will enable more effective and efficient access to data that can be utilized by staff when dealing with complex escalated inquiries or through customer self-serve applications. This will lend itself towards providing customers with shorter turnaround times on inquiries and resolving billing exceptions thus improving service quality.

The Oracle solution would allow PowerStream to participate in a joint users group allowing for more effective and efficient implementation of future enhancements to meet operational needs as well as regulatory changes. In addition, this user group will represent over 1.5M customers in Ontario and will allow PowerStream to more effectively assist the Board in understanding the impacts of their regulatory changes.

This new up-to-date solution will increase employee satisfaction through a much improved user interface and ease of use within a windows based environment and much improved system abilities compared to the existing CIS. Processes within the new system are more efficient and automated thereby reducing the number of manual processes which lead to user frustration, thus improving overall efficiency and satisfaction.

The Oracle product offers a number of predefined reports and the ability to conduct more effective had hoc reports compared to the existing system. This will allow the ability to drill deeper into processes in order to conduct custom analytics that will be used as part of PowerStream’s efforts towards continuous improvement and cost savings.

The Oracle Customer Care and Billing (“CC&B”) CIS will position PowerStream to migrate existing customers on to a platform which offers functionality that enables enhanced customer contact preferences and enhanced customer contact channels, something that is not available in the T&W CIS today.

The new system will reduce the need to increase future staff resources due to the inherent efficiencies and improved functionality built into the system. CC&B system provides a platform where PowerStream can optimize core business processes and thereby supports the implementation of process improvement methodologies that drive efficiency and effectiveness of core CIS processes. The CC&B platform also positions PowerStream to accommodate potential future customer growth.

For a detailed discussion of the alternatives considered and the assessment of those alternatives please see Exhibit B1, Tab 1, Schedule 5.

Results:

A new Oracle based CIS that provides a current system that will more easily meet the strategic objectives of PowerStream compared to the present CIS system. It eliminates the key risks of single vendor, limited support resources and allows for the capacity required to enable system growth which is limited with the current legacy CIS system. The new CIS is one element of PowerStream's documented five year Information System Strategy which is and supports a more modern, robust and technically advanced system for PowerStream.

Planned Annual Expenditures (net of contributed capital):

Year *($ millions)*	**2009 Actual**	**2010 Actual**	**2011 Actual**	**2011 MIFRS Actual**	**2012 Bridge**	**2013 Test**	**2014 Forecast**
Total Costs	$ 0	$ 0	$ 0	$ 0	$ 12.6M	$15.6M	$6.2M

Corporate Five Year Capital Plan

2012 – 2016

Prepared by: S. Cunningham & T. D'Onofrio

June 30, 2011

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CORPORATE FIVE YEAR CAPITAL PLAN

1.0 Summary

As part of PowerStream's Capital Budget process and planning cycle, business units have developed five year capital plans for the years 2012 – 2016. The plan presented here summarizes the business unit five year capital plans into one corporate capital plan for the same years. In addition, this document highlights PowerStream's Asset Investment Strategy and PowerStream's Capital Budget Process and Planning Cycle.

2.0 PowerStream's Asset Investment Strategy

The goal of PowerStream's Asset Investment Strategy is to effectively define the portfolio of investments that will achieve the company's strategic value expectations, within the company's defined risk tolerance boundaries. This includes: making effective short-term (one-year) and long-term (two to five year) investment decisions, to maximize the value of the assets to the company, and developing and implementing disciplined policies, processes, and standards for maintaining the assets of the company.

Within the context of PowerStream's Asset Investment Strategy, strategic value is defined as the array of important considerations that the company must consider to maintain it's short-term and long-term viability. These considerations are expressed in terms of a series of weighted critical strategic objectives and success criteria which are linked and aligned to the overall corporate business strategy. See Exhibit 1 for the strategic objectives, success criteria and their weightings. The objectives are quantified as more than simply a financial or dollar value consideration and extend beyond why we are in business, in an attempt to quantify the most critical considerations that drive the company's ability to remain in business. The strategic objectives, success criteria and their weighting are reviewed annually to ensure continued alignment with the overall corporate business strategy.

Within the context of PowerStream's Asset Investment Strategy risk is defined in its broadest terms, primarily, but not exclusively, in terms of strategic, financial and operational (or technical) risk. The risks considered are quantified for each element used in defining strategic value and are a result of direct or indirect loss due to failed internal processes, people, systems, work practices, or, from external events. Risk is viewed from the perspective of both probability and consequence.

Exhibit 1 – Strategic Objectives, Success Criteria and Their Weighting

Business Excellence	**26.2%**	Compliance	52.5%	13.7%
		Employee Satisfaction	14.2%	3.7%
		Operational Excellence	33.4%	8.8%
Customer Satisfaction	**31.9%**	IOR	41.7%	13.3%
		Customer Satisfaction	26.9 %	8.6 %
		SOI	12.1%	3.9%
		Capacity	19.3%	6.1%
Financial	**20.1%**	Hard & Soft Savings	25.0%	5.0 %
		Revenue Recovery Factors	75.0%	15.1%
Health & Safety	**15.1%**	Health & Safety	66.7%	10.1%
		Employee Wellness	33.3%	5.0%
Environmental Sustainability	**6.7%**	Environmental Impact	100%	6.7%

3.0 Overview of PowerStream's Capital Budget Process and Planning Cycle

PowerStream's Capital Budget process incorporates both a five year forward looking plan and the "build up" of a two year detailed plan. The five year plan is completed at the beginning of the year. Business units that have major capital spend put together their own five year departmental plans. These five year departmental plans are then summarized into a Corporate Five Year Plan (this plan).

The five year plan serves three purposes: assists business units in their forward thinking and enable the business units to provide a solid two year budget; form the basis of the information provided in a rate application for the forward looking years; and provides the finance team with information for their financial scenario planning.

Once the five year plans are complete, the creation of the two year capital plan begins. The projects identified in the first two years of the five year plans form the basis for the capital projects put forth for the two year plan. The project owners provide for each project: identification information, justification, resource requirements, and estimated costs. The information is inputted in a sequel database and the information forms a "mini-business case" for each project. For any specific project (non-program) that is greater than $500K the project owner provides a full business case and ensures approval of the business case.

Once project owners have completed project identification, the business unit owner (Manager) in conjunction with the Capital Budget Supervisor answers a series of questions about each project. The questions asked are aligned with PowerStream's Asset Investment Strategy described above. The answers to the questions form the basis for scoring both the value of the project to the corporation and the risk to the corporation if the project is not completed in the planned year. The Capital Budget Supervisor participates with the business unit owners across the corporation in answering the questions to ensure consistent interpretation of the questions and answers.

Once the questions on the projects are all answered, the data on the projects is compiled and loaded into Optimizer. Optimizer is an Excel based software tool that takes the capital portfolio, the value and risk scores given to each project, the financial dollars of each project, and a targeted spend level and then mathematically calculates an optimum project list that is for the targeted spend level. The tool is capable of running several scenarios with the project list being optimized for the least amount of risk, optimized for the most amount of value or optimized for the most amount of value and the least amount of risk combined. All projects in the corporation are run through this process with projects from IS, fleet, station construction and lines construction being considered through the same "lens".

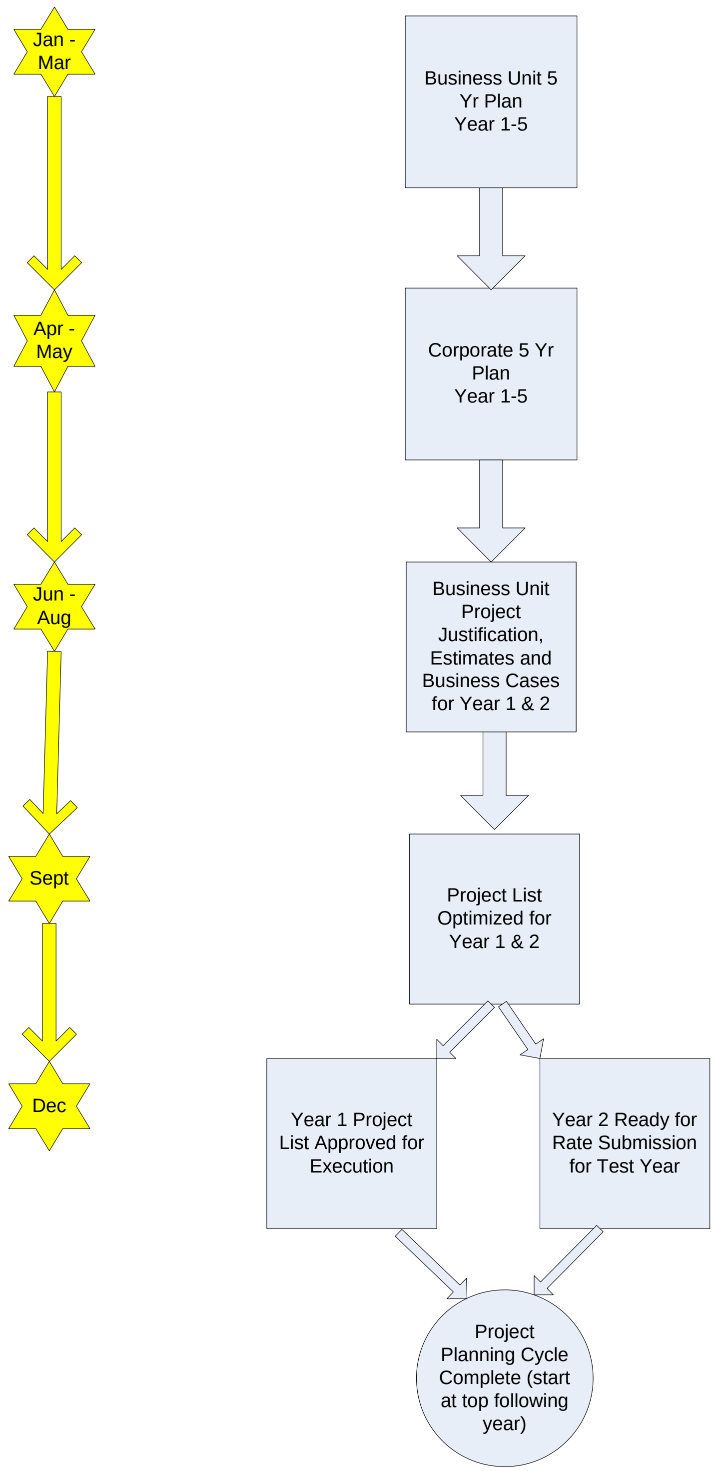
With the output from various scenarios from the Optimizer software PowerStream's Optimizer team has discussions as to which projects will be approved as part of the two year capital budget. Generally, the projects that are identified through Optimizer as adding the most value for given dollar or having the most risk if not completed in the given year, are approved. Members of the

Optimizer team include key senior leaders from each of the business units who have major capital spending.

The final project list approved by the Optimizer team forms the basis for the two year capital plan. The first year of the capital plan is approved by the Board for execution in the following year. The second year of the two year plan forms the basis of the information provided in a rate case for the test year.

Exhibit 2 depicts the capital budget process and planning cycle beginning with updating the five year plan at the beginning of each year. It is expected that the majority of the projects identified in the second year of the two year plan will be approved in the first year of the subsequent year's two year plan. Business units have the ability to put forward changed, new or alternative projects based on new information garnered during the year. Optimization of projects may also change based on updates to the Asset Investment Strategy.

Exhibit 2 - PowerStream's Capital Budget Process and Planning Cycle



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4.0 Description of Major Capital Categories

PowerStream has sorted its capital investments into three major categories and a number of sub-categories. Three are described below. A detailed list of the sub-categories is in Exhibit 3.

Sustainment Capital – This major category includes projects that replace asset infrastructure that is at end of life or projects that enable improved safety, reliability or efficiency in the operation of the distribution system. Sub categories include: Emergency Restoration; Replacement Programs; Sustainment Driven Lines Projects; Transformer/Municipal Station Projects; and Emerging PowerStream Projects.

Development Capital – This major category includes projects that involve system expansion or relocation due to growth and/or to satisfy external demands. Sub categories include: Subdivisions/Services; Road Authority Projects; Growth Driven Transformer/Municipal Stations; Growth Driven Lines Projects; Emerging Development Capital; and Distributed Generation.

Operations Capital – This major category includes projects that support the day-to-day operations of PowerStream. Sub categories include: Buildings; Fleet; Metering; Spare Parts; Tools; Information/Communication Systems; Emerging Operations and Interest Capital.

Exhibit 3 – Major and Sub-Categories for Capital Budget	
1. Sustainment Capital	
1a	Replacement Program
1b	Sustainment Driven Lines Projects
1c	Emergency / Restoration
1d	Transformer / Municipal Stations
1e	Emerging Sustainment Capital
2. Development Capital	
2a	Subdivision / Services
2b	Road Authority Projects
2c	Growth Driven Transformer / Municipal Stations - Additional Capacity
2d	Growth Driven Lines Projects
2e	Emerging Development Capital
2g	Distributed Generation Connections
3. Operations Capital	
3a	Metering (Non- Smart Meter Program)
3b	Fleet
3c	Tools
3d	Buildings
3e	Information / Communication Systems
3f	Purchase of spare equipment
3g	Emerging Operations Capital
3i	Interest Capitalization

5.0 PowerStream's 5 Year Capital Plan

Exhibit 4 is the capital plan for the year's 2012 to 2016. The information is combined from the following business unit reports:

- Engineering Planning
- Distribution Design
- Operations
- Lines
- Supply Chain Services
- Smart Grid & Metering
- Information Services
- Capital Supervisor (Misc. Capital)

All reports give a general description of the work required for their business unit. Included in each of the business unit reports is a description of the methodology used to determine spending requirements. Project costs are aligned to the major capital categories described above.

Exhibit 4 - Five Year Capital Plan ($ K)

Rate Category	2012	2013	2014	2015	2016
Sustainment					
Emergency / Restoration	9790	10251	10517	10794	11080
Replacement Program	7830	8682	8054	8028	8394
Sustainment Driven Lines Projects	11295	23792	23702	24114	23066
Transformer/Municipal Station	7536	7694	5773	4288	5290
Emerging Sustainment	1300	1300	1300	1300	1300
TOTAL SUSTAINMENT	37751	51719	49346	48524	49130
Development					
Subdivisions/Services	10300	9880	11410	13420	15440
Road Authority Projects	4200	11970	4460	4340	4160
Emerging Development Capital	340	201	220	230	240
Distributed Generation Connections	840	35	23	16	16
Growth Driven Transformer/Municipal Stations	3106	6448	9398	21414	2134
Growth Driven Lines Projects	7458	14518	6502	10028	19631
TOTAL DEVELOPMENT	26244	43052	32013	49448	41621
Operations					
Buildings	643	21	149	223	106
Fleet	3000	3000	3000	3000	3000
Information / Communication Systems	13809	12143	5919	8197	8524
Metering	2092	2092	1842	1992	1942
Spare Parts	230	130	30	30	0
Tools	698	550	544	491	517
Emerging Operations Capital	500	500	500	500	500
Interest Capitalization	1000	1000	1000	1000	1000
TOTAL OPERATIONS	21972	19436	12984	15433	15589
TOTAL	85967	114207	94343	113405	106340

Five Year Capital Plan

Engineering Planning
(System Planning and Stations)

2012 – 2016

Prepared by: Engineering Planning
January 20, 2012

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1.0 GENERAL SUMMARY

This report describes the capital plan recommended by the Engineering Planning Division (System Planning & Standards Department, and Stations Design & Construction Department). The capital plan covers the five years 2012, 2013, 2014, 2015, and 2016.

The capital projects are required to:

- Prepare the distribution system for new load growth.
- Maintain system reliability and customer service.
- Replace aging, end-of-life equipments based on the results of the Asset Condition Assessment ("ACA") process.

The structures of the summary tables are described below.

First, the capital projects are categorized and summarized by the following:

- Sustainment Capital
- Development Capital
- Operations Capital

Second and third, the capital projects are also categorized and summarized by the following sub-categories:

1a. Replacement Program

<u>Overhead Plant Asset Replacement</u>

- Pole Replacement
- Other Overhead Plant Asset Replacement

<u>Underground Plant Asset Replacement</u>

- Cable Replacement
- Cable Injection
- Underground Transformer Replacement

- Underground Switchgear Replacement
- Other Underground Plant Asset Replacement

Stations Plant Asset Replacement

- Station Circuit Breaker Replacement
- Other Station Plant Asset Replacement

1b. Sustainment Driven Lines Projects

Lines Projects (not capacity driven)

- Conversion Projects
- System Reconfiguration Projects
- Radial Supply Remediation Projects
- Distribution Automation Projects
- Reliability Driven Projects
- Safety, Environment Driven Projects at Lines
- Compliance to External Directives / Standards at Lines

1d. Transformer / Municipal Stations (not capacity driven)

Station Projects at TS (not capacity driven)

- Station Projects at TS (not capacity driven)
- Safety, Environment Driven Projects at TS
- Compliance to External Directives / Standards at TS
- Distribution Automation at TS

Station Projects at MS (not capacity driven)

- Station Projects at MS (not capacity driven)
- Safety, Environment Driven Projects at MS

- Compliance to External Directives / Standards at MS
- Distribution Automation at MS

2c. Growth Driven Transformer / Municipal Stations – Additional Capacity

Growth Driven Station Projects at TS

- Growth Driven Station Projects at TS

Growth Driven Station Projects at MS

- Growth Driven Station Projects at MS

2d. Growth Driven Lines Projects

Growth Driven Lines Projects

- Growth Driven Lines Projects

The definitions for the above categories are included in Section 3 of the report.

The proposed capital projects for the five years are listed in Appendix A.

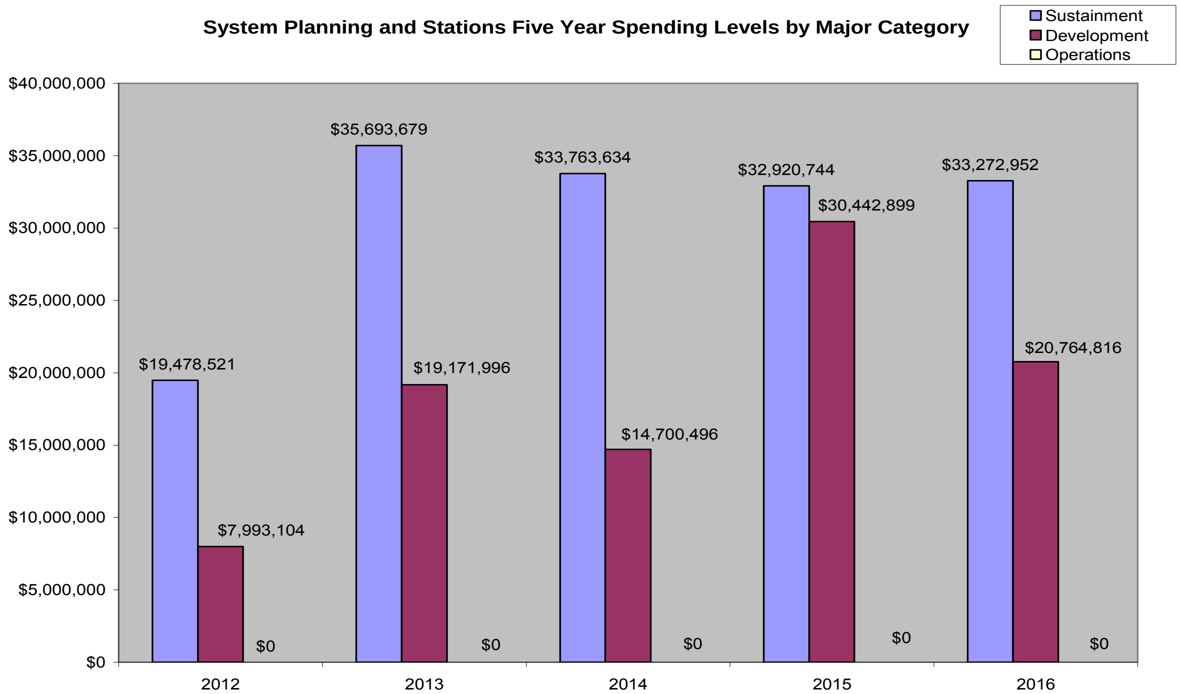
This document covers the controllable capital projects for both the distribution and stations assets in the corporation, and therefore it is a key component of the corporation's Asset Management Plan.

It should be noted that, as future emerging issues arise, the scope, cost, timing, and priority of individual projects will be adjusted accordingly.

On an annual basis, each of the proposed projects for the upcoming budget year will be submitted, reviewed and approved according to PowerStream annual budget review and approval process. As a result, the Five Year Capital Plan will be monitored, revisited and revised every year, or as often as required.

1.1 Funding Requirements

The forecasts for the funding requirements are summarized below.



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PowerStream - Capital Work Plan from Planning and Stations							
1. Sustainment Capital							
Category		**2012**	**2013**	**2014**	**2015**	**2016**	**5 Yr. Total**
1a	Replacement Program	$10,996,930	$25,655,359	$25,978,472	$26,705,952	$25,518,482	**$114,855,194**
1b	Sustainment Driven Lines Projects	$5,787,292	$6,115,176	$5,331,776	$5,254,175	$5,569,275	**$28,057,694**
1d	Transformer / Municipal Station Projects (not capacity-driven)	$2,694,299	$3,923,144	$2,453,386	$960,617	$2,185,195	**$12,216,641**
	Total Sustainment:	**$19,478,521**	**$35,693,679**	**$33,763,634**	**$32,920,744**	**$33,272,952**	**$155,129,529**
2. Development Capital							
Category		**2012**	**2013**	**2014**	**2015**	**2016**	**5 Yr. Total**
2c	Growth Driven Transformer / Municipal Stations - Additional Capacity	$1,834,517	$6,153,692	$9,177,896	$20,614,899	$1,134,216	**$38,915,219**
2d	Growth Driven Lines Projects	$6,158,587	$13,018,304	$5,522,600	$9,828,000	$19,630,600	**$54,158,091**
	Total Development:	**$7,993,104**	**$19,171,996**	**$14,700,496**	**$30,442,899**	**$20,764,816**	**$93,073,310**
3. Operations Capital							
Category		**2012**	**2013**	**2014**	**2015**	**2016**	**5 Yr. Total**
	Total Operations:	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grand Total							
		2012	**2013**	**2014**	**2015**	**2016**	**5 Yr. Total**
	Grand Total:	**$27,471,625**	**$54,865,675**	**$48,464,129**	**$63,363,642**	**$54,037,767**	**$248,202,838**

2

2.0 INTRODUCTION AND PURPOSE

This report provides a summary listing and funds requirement of the proposed capital projects for the five year period between 2012 and 2016. The projects are proposed by two departments within the Engineering Planning division: System Planning & Standards Department, and Station Design & Construction Department.

Each project is organized by the following categories:

- Major Categories (total of 3)
- Sub-Categories (total of 5)
- Minor Categories (total of 9)
- Sub-Minor Categories (total of 27)

There are cases where a project is driven by and provides benefit to more than one category. In those cases, the final category will be determined based on the primary driver and primary benefit of the project.

The report is organized as follows:

- Section 1 provides the general summary.
- Section 2 explains the purpose and structure of the report.
- Section 3 provides explanation of all categories.
- Section 4 describes the methodology and process used to determine the proposed spending levels.
- Section 5 describes the process used for capital project justification and budget approval.
- Section 6 describes the proposed capital projects in detail.
- Section 7 provides the summary of the five year capital plan.
- Section 6 (Appendix A) provides the listing of all individual capital projects of the five year capital plan.

3.0 CATEGORY DEFINITIONS

The categories are listed in the following table, and described below.

Categories for Five Year Capital Plan		
1. Sustainment		
1a Replacement Program		
	1. Overhead Plant Asset Replacement Programs	
		1.1 Pole Replacement
		1.2 Other OH Plant Asset Replacement (Switch, OH Transformer, Insulator)
	2. Underground Plant Asset Replacement Programs	
		2.1 Cable Replacement
		2.2 Cable Injection
		2.3 UG Transformer Replacement
		2.4 UG Switchgear Replacement
		2.5 Other UG Plant Asset Replacement
	3. Station Plant Asset Replacement Programs	
		3.1 Station Circuit Breaker Replacement
		3.2 Other Station Plant Asset Replacement
1b Sustainment Driven Lines Projects		
	4. Lines Projects (not capacity driven)	
		4.1 Conversion Projects
		4.2 System Reconfiguration Projects
		4.3 Radial Supply Remediation Projects
		4.4 Distribution Automation Projects
		4.5 Reliability Driven Projects
		4.6 Safety, Environment Driven Projects at Lines
		4.7 Compliance to External Directives / Standards at Lines
1d Transformer / Municipal Station Projects (not capacity driven)		
	5. Station Projects at TS (not capacity driven)	
		5.1 Station Projects at TS (not capacity driven)
		5.2 Safety, Environment Driven Projects at TS
		5.3 Compliance to External Directives / Standards at TS
		5.4 Distribution Automation at TS
	6. Station Projects at MS (not capacity driven)	
		6.1 Station Projects at MS (not capacity driven)
		6.2 Safety, Environment Driven Projects at MS
		6.3 Compliance to External Directives / Standards at MS
		6.4 Distribution Automation at MS
2. Development		
2c Growth Driven Transformer / Municipal Stations - Additional Capacity		
	8. Growth Driven Station Projects at TS	
		8.1 Growth Driven Station Projects at TS
	9. Growth Driven Station Projects at MS	
		9.1 Growth Driven Station Projects at MS
2d Growth Driven Lines Projects		
	10. Growth Driven Lines Projects	
		10.1 Growth Driven Lines Projects
3. Operations		

3.1 Major Categories

Sustainment Capital

This category includes projects that replace asset infrastructure that is at end of life or projects that enable improved safety, reliability or efficiency in the operation of the distribution system. Capital projects included in this Engineering Planning Five Year Capital Plan are:

- Replacement Programs
- Sustainment Driven Lines Projects
- Transformer/Municipal Station Projects (not capacity driven)

Development Capital

This category includes projects that involve system expansion or relocation due to growth and/or to satisfy external demands. Capital projects included in this Engineering Planning Five Year Capital Plan are:

- Growth Driven Transformer/Municipal Station Projects
- Growth Driven Lines Projects

Operations Capital

This category includes projects that support the day-to-day operations of PowerStream.

This Engineering Planning Five Year Capital Plan does not include any funding requirements for Operations Capital.

3.2 Sub-Categories

1a. Replacement Program

This category mainly covers the replacement of distribution and station assets. It includes the following:

- Overhead Plant Asset Replacement
- Underground Plant Asset Replacement
- Station Plant Asset Replacement

Overhead Plant Asset Replacement

This category mainly covers the replacement of Overhead Plant Assets using the ACA. It includes the following:

- Wood Pole Replacement
- Other Overhead Plant Asset Replacement (Switch, Transformer, Insulator)

These programs are described below:

Wood Pole Replacement

This category will cover all work performed under the planned pole replacement program.

Wood poles are critical component of the distribution system as many types of equipment are attached to them (conductors, transformers, switches, street lights, telecommunication attachments, etc.). As a pole's physical condition and structural strength deteriorate, the pole may become inadequate for its intended function, and should be replaced to maintain the integrity of the distribution system.

Every year, on a prioritized basis with data acquired from the pole testing program, a number of poles are proposed for replacement due to the pole conditions and remaining strength.

Other Overhead Plant Asset Replacement (Switch, Transformer, Insulator)

Under this category the following capital work will be discussed:

- Overhead Transformer Replacement
- Overhead Hubbell AB Chance Switch Replacement

Overhead Transformer Replacement

PowerStream will operate the overhead transformers on a run-to-failure approach. It was determined that proactive replacement of overhead transformers is not cost effective based on the fact that the risk and consequences of failure are low, and PowerStream presently has sufficient capability and effective process and procedures to manage these asset failures at the current failure rate.

Overhead Hubbell AB Chance Switch Replacement

This category covers costs associated with the Hubbell AB Chance Switch Replacement project.

Lines Department has raised a safety concern about the performance of the existing overhead Hubbell AB Chance brand of switches in PowerStream North. The switches with cracking porcelain insulator may develop flashover which will result in power outage, damage to adjacent equipment, and present a safety risk to Lines staff when they are required to operate these switches.

Underground Plant Asset Replacement

This category mainly covers the replacement of Underground Plant Assets using the ACA Process, and includes the following:

- Underground Cable Replacement
- Underground Cable Injection
- Underground Transformer Replacement
- Underground Switchgear Replacement
- Other Underground Plant Assets Replacement (Splice, Vault, Duct Bank)

These programs are described below:

Underground Cable Replacement

PowerStream has approximately 7,836 km of underground primary cable length, the vast majority of which is direct buried and the rest is in duct. As the cable gets older and the condition deteriorates, it will fail. Initially PowerStream can repair or replace the faulted cable segment under reactive emergency response. But if the cable fails too often, it will result in unacceptable service to the customer, and unacceptable repair costs to PowerStream. PowerStream will prioritize and replace end-of-life cable to maintain system reliability.

Underground Cable Injection

Currently, PowerStream is experimenting with Cable Injection technology to gain more experience. This plan is developed based on the assumption that Cable Injection is a viable option for a certain quantity of cable. As the cable gets older, the cable insulation may develop a premature aging process caused by a phenomenon known as "water treeing". Water trees will reduce the breakdown strength of the insulation and eventually lead to cable failure. The Cable Injection process will inject silicone chemicals down the strands of the cable, which will improve the strength of the insulation, and therefore extend the life of the cable.

Underground Transformer Replacement

PowerStream will operate the padmount transformers on a run-to-failure approach. It was determined that proactive replacement of underground transformers is not cost effective based on the fact that the risk and consequences of failure are low, and PowerStream presently has sufficient capability and effective process and procedures to manage these asset failures at the current failure rate.

In 2008 System Control identified ninety-one submersible equipment locations to be retrofitted to meet a new operations switching procedure. The existing submersible unit design and installation do not provide sufficient access to allow the field staff to perform switching operations under normal and emergency situations, thus reducing customer service and reliability level to the affected customers. The retro-fitting work, including installation of switches, splice out, replace submersible transformer with padmount transformer, change to switchable transformer, will make the design and installation similar with the majority of other existing locations in the system, facilitating normal work procedures for the field staff.

Underground Switchgear Replacement

As the existing distribution switchgear population aging and deteriorating, some units will need to be replaced to maintain the integrity of the distribution system. On a prioritized basis, based on the results of the inspection, maintenance, and analysis, a number of switchgear units will be selected for planned replacement. This category will cover costs for planned switchgear replacements and not emergency replacement (i.e. replacement after the switchgear unit has already failed).

Other Underground Plant Assets Replacement (Splice, Vault, Duct Bank)

No other underground plant asset specific replacement is recommended at this time.

Station Plant Asset Replacement

This category mainly covers the replacement of Station Plant Asset using the ACA Process, and includes the following:

- Station Circuit Breaker Replacement
- Other Station Plant Asset Replacement (Transformer, Primary Switch, Capacitor, Reactor, Structure)

These programs are described below:

Station Circuit Breaker Replacement

Station circuit breakers are automated switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions. Circuit breakers are required to operate infrequently, however, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage.

A number of station circuit breaker units (mostly ABB Type HKSA and Outdoor GEC Type OX36) have been identified by the ACA Model as needing replacement, mostly due to age, condition, obsolescence, and historical failures.

Other Station Plant Asset Replacement (Transformer, Primary Switch, Capacitor, Reactor, Structure)

Under this category the following capital work will be discussed:

- 230 kV Switches
- Primary Switches
- Station Reactors
- Station Capacitors
- MS Transformers

- TS Transformers

230 kV Switches

This asset group consists of transmission and station air break switches at TS's. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements.

Primary Switches

This asset group consists of station air break and fused switches at MS's. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements.

Station Reactors

This asset group consists of reactors at stations. The primary function of reactors is to limit the short circuit current of a line when there is short circuit. It can also be used to absorb reactive power, or as part of filtering circuit.

Station Capacitors

This asset group consists of capacitors at stations. The primary function of capacitors is to improve the quality of the electrical supply and the efficient operation of the power system. The major applications include power factor improvement and voltage regulation.

MS Transformers

This asset group consists of MS transformers at MS's. The MS transformers are used to step down the sub-transmission voltage or higher distribution voltage to lower distribution voltage levels.

TS Transformers

This asset group consists of TS transformers at TS's. The TS transformers are used to step down the transmission voltage to distribution voltage levels.

1b. Sustainment Driven Lines Projects

This category mainly covers the Lines projects that are not capacity driven. It includes the following:

- Lines Projects (not capacity driven)

<u>Lines Projects (not capacity driven)</u>

This category is mainly for those projects that are not capacity driven, but are required to sustain the distribution system. It includes the following:

- Conversion Projects
- System Re-configuration Projects
- Radial Supply Remediation Projects
- Distribution Automation Projects
- Reliability Driven Projects
- Safety, Environment Driven Projects at Lines
- Compliance to External Directives / Standards at Lines

These projects are described below:

Voltage Conversion Projects

PowerStream has a number of MS providing supply feeders at 13.8 kV and 8.32 kV levels.

In general, 13.8 kV and 8.32 kV systems have higher distribution losses than do the higher voltage systems such as 27.6 kV systems.

Another operations issue of the 13.8 kV and 8.32 kV MS's is that some MS's have a single transformer and long single feeder which make power outage restoration difficult, and as a result have a negative impact on system reliability. Some existing cases are listed below:

- Rainbow MS: single transformer with a long single 13.8 kV feeder.
- Elder MS: single transformer with two long 8.32 kV feeders on the same pole line.
- Concord MS: single transformer.

- King MS: single transformer with a long single 8.32 kV feeder.

Remediation projects are formulated to convert the affected areas to 27.6 kV supply system in phases and to decommission the MS.

System Re-configuration Projects

System Planning, in consultation with System Control and Lines, will recommend projects to resolve feeder load balancing and load transfer capability under normal and emergency situations. Operations and safety issues will be considered.

Radial Supply Remediation Projects

The vast majority of PowerStream distribution system is designed as an open loop system with multiple interconnections between the feeders. Under this supply scheme, when feeder A is out of service, an adjacent feeder B may be able to pick up a portion of feeder A's load, subject to feeder B's capacity and other operations constraints. As a result, the extent of customer interruptions can be reduced. This will have a positive impact to system reliability.

In some areas of PowerStream service territory, however, there are locations where customers only have radial supply, whereas there is only one path between the customers and the source of supply. Under this supply scheme, when the source of supply is out of service, the downstream customers will have total service interruptions as there are no alternate supplies available. As a result, these customers will experience longer outages. This will have a negative impact to system reliability.

The remediation projects are formulated based on the following criteria:

- Number of customers and the length of radial supplies
- Requirements from System Control
- Total kVA load connected
- Feasibility to remediate

Distribution Automation Projects

Although in general distribution automation will improve power outage restoration and therefore system reliability, PowerStream cannot justify the automation of the whole distribution system due to the high costs. As a result, decision on quantity and location of automation equipment must be made on a case-to-case basis and be guided by the following three criteria:

- Criterion 1: Economic Consideration: the cost of a distribution automation project must be less than the benefit of the reliability improvement, calculated using customer interruption frequency and duration.
- Criterion 2: Feeder Loading Consideration: to facilitate back-up and emergency load transfer, distribution automation equipment must be installed so that the feeder segment loading can be limited to a certain threshold, based on specific feeder configuration.
- Criterion 3: System Control Consideration: to facilitate control room operations, distribution automation equipment must be installed based on specific feeder operating conditions.

Reliability Driven Projects

On the on-going basis the reliability performance, at the system, feeder, and component levels, is monitored by the PowerStream Reliability Committee. The Committee comprises members from various business units across the organization, and has the mandate to manage and improve reliability. Both outage duration and outage frequency are taken into consideration. In addition momentary outages (outages that are less than 1 minute in duration) are also taken into consideration.

Reliability driven projects are proposed to maintain current levels of service to customers compared to the previous three year moving averages of SAIDI, SAIFI and CAIDI. Feeders with deteriorating reliability statistics are targeted for review, and remedial action plans are developed to improve reliability.

Each year PowerStream identifies a group of Worst Performing Feeders ("WPF") to focus on improving the reliability performance of those feeders.

Safety, Environment Driven Projects at Lines

This category covers the capital work that PowerStream must complete to comply with Health, Safety and Environmental regulations, standards and guidelines.

Compliance to External Directives / Standards at Lines

This category covers the capital work that PowerStream must complete to comply with external directives/standards such as:

- Ontario Energy Board ("OEB") (e.g. Long Term Load Transfer, Distribution System Code)
- Ontario Power Authority ("OPA")
- Electric Safety Authority ("ESA") (e.g. ungrounded Delta Transformers, Clearance)
- Independent Electricity System Operator ("IESO")
- Other Regulatory Standards (eg. Canadian Standards Association ("CSA"))

1d. Transformer / Municipal Station Projects (not capacity driven)

This category covers stations projects that are not capacity driven. It includes the following:

- Station Projects at TS (not capacity driven)
- Station Projects at MS (not capacity driven)

Station Projects at TS (not capacity driven)

This category includes the following:

- Station Projects at TS (not capacity driven)
- Safety, Environment Driven Projects at TS
- Compliance to External Directives / Standards at TS
- Distribution Automation at TS

These projects are described below:

Station Projects at TS (not capacity driven)

This category is for TS projects that are not capacity driven, but are required to sustain PowerStream's fleet of eleven TS's. Sustainment activities include projects to: replace worn out equipment, maintain reliability, enhance operability & maintainability, and to improve & maintain safety.

- Replace worn out equipment: These projects include the replacement of Station Plant Assets not included in the ACA Process. All station equipment except for station circuit breakers, transformers, primary switches, capacitors and reactors are included.
- Maintain reliability: The reliability of all system components, including the reliability of Transformer Stations is monitored by PowerStream's Reliability Committee. The Reliability Committee initiates projects to maintain service to customers. Reliability is measured using the previous three year moving averages of SAIDI, SAIFI and CAIDI.
- Enhance operability: Operability enhancement projects include projects to improve transformer station Supervisory Control and Data Acquisition ("SCADA") functionality.
- Enhance Maintainability: Maintainability enhancement projects include projects to improve the ability of the Stations Sustainment and Protection & Control departments to carry out transformer station maintenance activities. Examples of enhance maintainability projects include the addition of monitoring equipment, network management systems, spare components and on-site storage.

Safety, Environment Driven Projects at TS

This category covers the capital work that PowerStream must complete at TS's to comply with Health, Safety and Environmental regulations, standards and guidelines.

Compliance to External Directives / Standards at TS

This category covers the capital work that PowerStream must complete at TS's to comply with external directives/standards such as:

- OEB (e.g. Distribution System Code)
- OPA

- ESA (e.g. Clearance)
- IESO
- Other Regulatory Standards (CSA)

Distribution Automation at TS

This category covers the capital projects that PowerStream must complete at TS's to prepare and operate the distribution system to meet PowerStream initiatives on Distribution Automation.

<u>Station Projects at MS (not capacity driven)</u>

This category includes the following:

- Station Projects at MS (not capacity driven)
- Safety, Environment Driven Projects at MS
- Compliance to External Directives / Standards at MS
- Distribution Automation at MS

These projects are described below:

Station Projects at MS (not capacity driven)

This category is for those MS's projects that are not capacity driven, but are required to sustain PowerStream's fleet of fifty-four MS's. Sustainment activities include projects to: replace worn out equipment, improve reliability, and enhance operability & maintainability. Please see, *Transformer Station Projects (not capacity driven)* above for descriptions of replace worn out equipment, improve reliability, and enhance operability & maintainability activities.

Safety, Environment Driven Projects at MS

This category covers the capital work that PowerStream must complete at MS's to comply with Health, Safety and Environmental regulations, standards and guidelines.

Compliance to External Directives / Standards at MS

This category covers the capital work that PowerStream must complete at MS's to comply with external directives/standards such as:

- OEB (e.g. Distribution System Code)
- OPA
- ESA (e.g. Clearance)
- IESO
- Other Regulatory Standards (CSA)

Distribution Automation at MS

This category covers the capital projects that PowerStream must complete at MS's to prepare and operate the distribution system to meet PowerStream initiatives on Distribution Automation.

2c. Growth Driven Transformer / Municipal Stations – Additional Capacity

This category covers the following:

- Growth Driven Station Projects at TS
- Growth Driven Station Projects at MS

Growth Driven Station Projects at TS

This category covers the TS capital projects that PowerStream must complete at TS's to provide sufficient capacity to supply new customers and load growth from existing customers, including purchase of land and easements.

Every year System Planning conducts a load forecast studies to identify capacity short falls and recommends projects to ensure sufficient capacity for customer load growth demands.

Growth Driven Station Projects at MS

This category covers the MS capital projects that PowerStream must complete at MS's to provide sufficient capacity to supply new customers and load growth from existing customers, including purchase of land and easements.

Every year System Planning conducts load forecast studies to identify capacity short falls and recommends projects to ensure sufficient capacity for customer load growth demands.

2d. Growth Driven Lines Projects

This category covers the following:

- Growth Driven Lines Projects

Growth Driven Lines Projects

This category covers the Lines capital projects that PowerStream must complete at lines to provide sufficient feeder and component capacity to supply new customers and load growth from existing customers, including purchase of land and easements.

Every year System Planning conducts a load forecast studies to identify capacity short falls and recommends projects to ensure sufficient capacity for customer load growth demands.

PowerStream continues to experience a high level of growth. Growth is one of the major drivers for the short term capital augmentation expenditures. Capacity adequacy issues are addressed through feeder upgrades and the completion of new stations and associated feeders.

4.0 METHODOLOGY & PROCESS TO DETERMINE THE SPEND LEVELS

This section describes the existing PowerStream methodology and process to identify future capital projects.

- Distribution Planning Process
- Planning Guidelines, Standards, and Practices
- Asset Condition Assessment (“ACA”)
- Stations Design and Construction Process

4.1 Distribution Planning Process

PowerStream follows the established planning cycle consisting of seven steps:

1. Review of System Performance
2. Determination of Augmentation Needs
3. Development of Alternative Options to support Augmentation Needs
4. Selection of Preferred/Optimal Options
5. Option Approval and Incorporation into the Budgeting Process
6. Implementation of Options
7. Evaluation of Resultant Performance

The planning process at PowerStream is summarized in Figure 1.

PowerStream also conducts system studies and uses the results of the following studies to formulate proposal for capital projects:

- Load Balancing & System Reconfiguration Plan for PowerStream South (27.6 kV system)
- Load Balancing & System Reconfiguration Plan for PowerStream North (44 kV and 13.8 kV systems)
- Studies for anomalies in the distribution system, such as radial supplies or poorly

performing segments of the system

- Worst Performing Feeders (“WPF”)
- Distribution Automation
- Load Forecast
- Equipment Failure Database and Forensic Analysis
- Asset Condition Assessment (“ACA”)

PowerStream has developed a Planning Philosophy which covers activities relating to:

- Distribution Design
- Distribution Capacity Planning
- Distribution Risk Assessment
- Distribution Reliability Planning

These activities are described below.

Distribution Design

Nearly all loads, within PowerStream service area, are supplied from Dual Element Spot Network (“DESN”) transformer stations either owned by PowerStream or Hydro One Networks Inc.

With the exception of some radial feeders, the vast majority of the distribution feeders are in an “open grid design” arrangement, whereby multiple feeders traverse a distribution area with multiple interconnections between the feeders at various normal open points. In the event of a fault on a feeder or loss of supply to a particular feeder, adjacent feeders have the ability to pickup supply to customers after operator intervention.

Distribution Capacity Planning and Risk Assessment

There are two alternative approaches to distribution planning - *deterministic* and *probabilistic,* PowerStream has adopted the deterministic approach to planning.

For overall planning objectives, at the transmission line and station transformer level,

PowerStream aims to achieve a distribution system that is capable of satisfactorily withstanding any single contingency event. This will be achieved by applying a deterministic approach (N-1) to planning the distribution system. This (N-1) standard provides for the planned or unplanned removal from service any one 230 kV transmission line or station transformer without a sustained interruption to customer loads.

For overall planning objectives, at the distribution feeder level (<50 kV supply) PowerStream has adopted an (N-0) standard. Most events at the distribution level will result in a sustained interruption to customer loads until alternative supply sources are accessed. With increased distribution automation devices and Smart Grid investment, sustained interruptions to customers are expected to decrease in frequency and duration.

Reliability Planning

Power Stream measures distribution system reliability in terms of industry and regulator accepted reliability indices. These indices are customer oriented and have units of "frequency of outage per year" and "outage duration in hours".

SAIDI = System Average Interruption Duration Index
= Customer Hours/System Customers
(i.e. the average length of interruption per customer on the system)

SAIFI = System Average Interruption Frequency Index
= Customers Affected/System Customers
(i.e. the average number of times an interruption occurred per customer on the system)

CAIDI = Customer Average Interruption Duration Index
= Customer Hours/Customers Affected = SAIDI/SAIFI
(i.e. the average length of interruption per customer interrupted)

MAIFI = Momentary Average Interruption Frequency Index
= Number of Momentary Interruptions/System Customers
(i.e. the average number of times a momentary interruption occurred per customer on the system)

In addition to the above four reliability indices, a fifth index, Index of Reliability (“IOR”), is also being used by the industry:

IOR = Index of Reliability (also called RI = Reliability Index; also called ASAI = (Average System Availability Index) = (8760 – SAIDI) / 8760

Reliability performance data is further categorized as:

- All Events
- Excluding Loss of Supply (“LOS”)
- Excluding Major Event Days (“MED”)
- Excluding Loss of Supply & Major Event Days

Reliability performance is being monitored by the PowerStream Reliability Committee. Significant deviations from target reliability would trigger appropriate planning responses to restore service reliability to target levels.

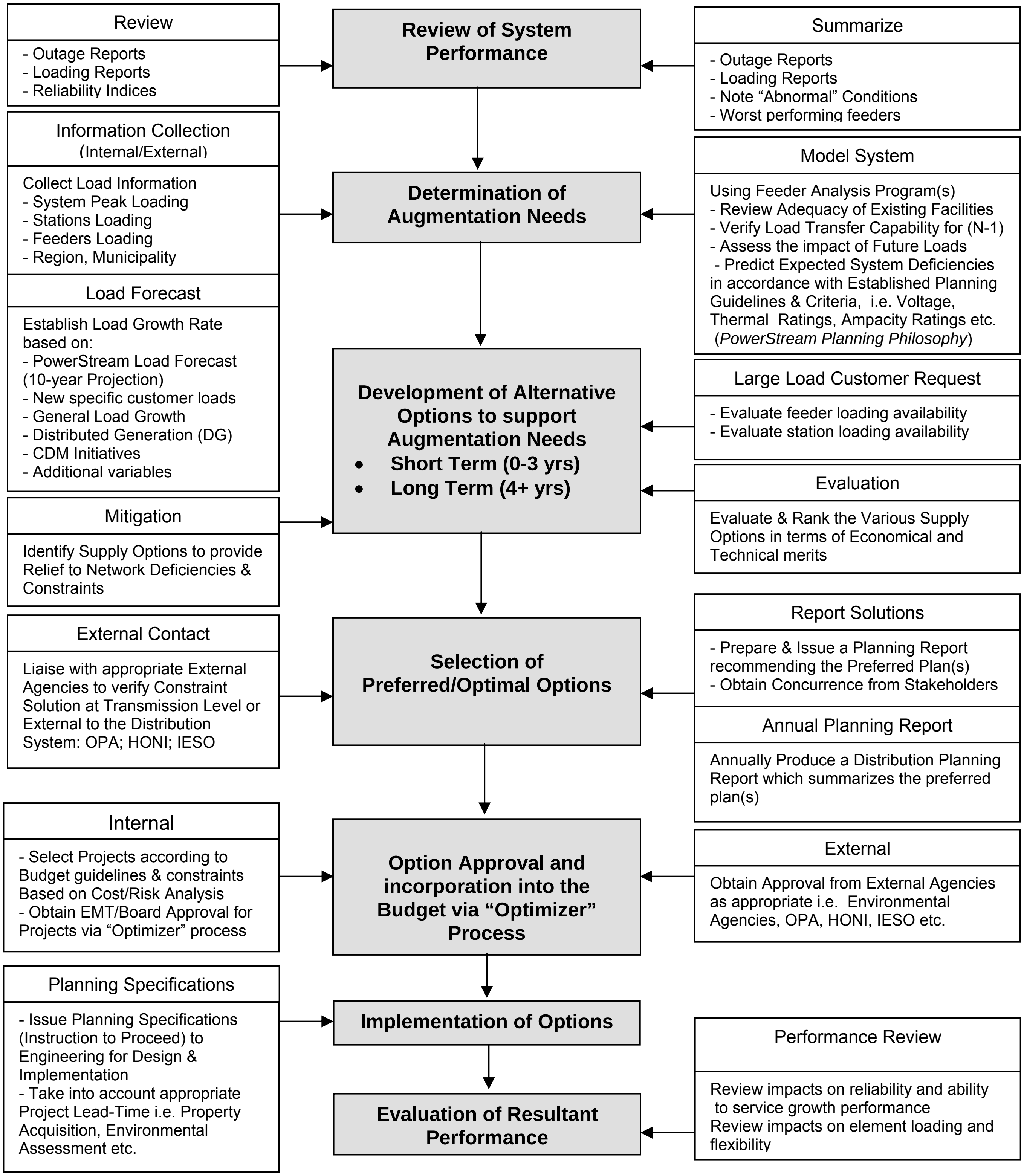


Figure 1 – Distribution System Planning Process

4.2 Planning Standards, Guidelines, and Practices

Below is a summary of PowerStream's Distribution Planning Standards, which consist of Criteria, Practices and Guidelines.

<u>System Voltages</u>

- The primary supply voltages for PowerStream shall be 4.16 kV, 8.32 kV, 13.8 kV, 27.6 kV and 44 kV. Selection is governed by the Conditions of Service.

<u>Load Forecast (Practice)</u>

- An annual summer/winter peak demand load forecast is prepared by System Planning for each transformer station and associated feeders (usually over a ten year window) forming the basis of all planning assessments in the current year. Distribution facilities are planned and designed to meet the expected peak demand as outlined in the official corporate forecast.

<u>Feeder Loading (Guideline)</u>

- All 27.6 kV and 44 kV feeders shall be designed for full backup capability over peak loading conditions through the switching of load to an adjacent feeder or multiple adjacent feeders. In order to facilitate this restoration capability, three phase 27.6 kV and 44 kV feeder loading will be planned to a maximum of 400 amps and 600 amps under normal and emergency operation respectively.
- A planned load guide of 300 amps shall be used for 13.8 kV, 8.32 kV, and 4.16 kV feeders.
- In certain industrial/commercial areas a normal operating limit greater than 400 amps is acceptable provided remotely controlled switching is available for load transfer to adjacent feeder(s) during emergency condition.
- All feeders should not be loaded over their thermal limits of the most limiting component.

<u>Station Transformer Loading (Guideline)</u>

- Station Transformers maximum allowable loading, under contingency conditions, is the ten-day limited time rating ("LTR"). This loading is 1.4 and 1.6 of the transformer-cooled rating for summer and winter respectively. Transformation capacity will be added when a station reaches 100% of its 10 day LTR.

Number of Feeders at Transformer Stations (Practice)

- For the purpose of determining the number of feeders from a transformer station, an average loading of 15 MVA per feeder will be used; (e.g. 27.6 kV nominal voltage, transformer capacity 75/100/125 MVA, Summer ten-day LTR of 170 MVA, the number of feeders is twelve with an average load per feeder of 14.2 MVA). Additional feeders should be planned and placed into service when the average summer peak load per feeder exceeds 15 MVA.

Municipal Station (MS) Loading (Guideline)

- Municipal Stations are supplied from 44 kV or 27.6 kV circuits, and step down the voltage to one of the three distribution voltage levels: 13.8 kV, 8.32 kV, and 4.16 kV. Each MS typically has two to four feeders, supplying a combination of three phase and single phase loads.
- MS load back-up is required under contingency conditions (e.g. station equipment failure) and non-contingency purposes (e.g. planned outage for maintenance or capital work). Under these situations, the MS load is transferred to adjacent MS or MS's via feeder ties between stations.

Feeder Egress Cable & Overhead Conductor Size (Practice)

- For 27.6 kV feeder egress, 1000 kcmil Cu, XLPE (in a concrete encased duct bank where required) will be used from the TS feeder breaker to the cable riser switch or to a suitable point (a switch) where the feeder separates and takes an overhead route. The concentric neutral shall be single-point bonded, grounded at the station end. The riser end shall be terminated with a 3 kV arrestor, without an isolator and a 2/0 copper ground lead. A separate neutral conductor shall be used consisting of no more than two sizes smaller than the phase conductor.
- For 13.8 kV, 8.32 kV, and 4.16 kV feeder egress, 500 kcmil Cu, XLPE will be used.

- For the overhead part of the feeder main conductor, 556 kcmil Al will be used. Overhead laterals of more than 200 amps that could be tied to another feeder or feeder lateral will also have 556 kcmil Al conductors. The neutral conductor will also be 556 kcmil Al within a distance of 1.0 km from the transformer station. Beyond a distance of 1.0 km, from the transformer station, 336 kcmil or 3/0 ACSR will be used as the system neutral.

Planning Horizon (Practice)

- Short-Term Planning Horizon = 0 - 3 years
- Long-Term Planning Horizon = 4+ years

Economic Analysis (Practice)

- Lowest life cycle cost using discounted cash flow analysis. The economic analysis should include capital and maintenance.

First Contingency

- First contingency (N-1) must be covered. Sufficient backup facilities should be planned so that primary supply can be restored from an alternate source at peak demand in contingency of a “major network component” failure.

Distribution Automation

- Distribution automation through remote switching is to be provided when cost justified ensuring that any load lost during single contingencies can be restored in a minimum amount of time.

Industry Standards

- Industry distribution system planning standards that are an integral part of “good utility practice” and are common to all distribution utilities are used as guidelines at PowerStream.

Protection Philosophy

- PowerStream's distribution system is primarily an overhead system. Feeder protection shall incorporate appropriate auto-reclose settings to mitigate the impact of transient faults. In certain circumstances the auto-reclose setting will be disabled where all faults on the circuit are expected to be permanent in nature. In general, "trip saving" protection will be enabled to allow fuses and reclosers to isolate faults where they provide the first line of protection. There are, however, cases in PowerStream North, where "fuse saving" protection may be used.

Transformer Stations (TS)

- All new transformation facilities will be built as Dual Element Spot Network ("DESN") Stations.
- Currently, two types of DESN stations exist within the PowerStream service territory, Bermondsey type and Jones type. New stations will be Bermondsey type (75/125 MVA) stations. The smaller (50/83 MVA) Jones type stations will be considered in areas of low growth and areas of limited growth due to service boundary constraints.

Municipal Stations (MS)

- Municipal Stations will continue to be constructed as required in areas of 44 kV primary supply. The MS secondary supply voltage shall be 27.6 kV or 13.8 kV as determined by the nature and configuration of the load.
- Municipal Stations will not be constructed in areas of 27.6 kV primary supply. New load will not be added to existing Municipal Stations unless a 27.6 kV supply is not available or not financially justified. Existing MS load shall be converted to 27.6 kV when cost/reliability justified.

4.3 Asset Condition Assessment ("ACA")

On an on-going basis, PowerStream continues to fine-tune the ACA models and update the parameters to reflect PowerStream situations. Examples of the parameters include: asset physical condition, testing data, customer interruption cost, replacement cost, failure probability curve, and consequence of asset failure, etc.

The typical Asset Management process gathers engineering and other technical information from numerous sources and ties them to the annual budgeting process. The typical Asset Management process has 4 steps:

1. Data capture
2. Asset evaluations, which translate condition and criticality information into repeatable, quantitative measures
3. Program development, which is a risk-based economic analysis to justify and prioritize spending programs. For the ACA project, the spending programs we are most interested in are risk-management replacement and rehabilitation programs
4. Program execution through the Budgeting process

PowerStream has adopted an Asset Management Framework created by Kinectrics Inc. as illustrated in Figure 2.

Each year, ACA data is collected and ACA models are run to generate asset health index, benefit/cost ratios and recommended timing of intervention actions.

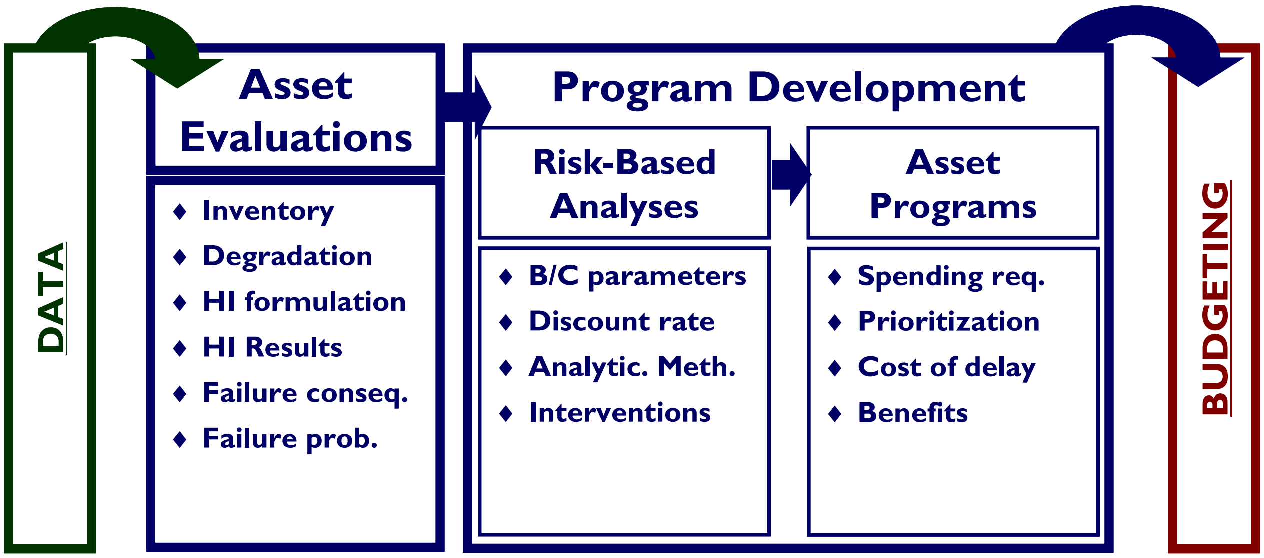
One of the goals of the ACA program is to address the population of assets that are “very poor” or “poor” condition in the next ten years. This will be done on a prioritized basis, taking into consideration the risk cost of asset failure and the benefit of proactive replacement.

Currently, PowerStream has ACA models for the following assets:

- TS Transformer
- MS Transformer
- Station Breakers and Recloser
- MS Primary Switch
- 230 kV TS Switch
- Station Capacitor
- Station Reactor
- Distribution Transformer
- Distribution Switchgear

- Underground Primary Cable
- Wood Poles

Figure 2 – Asset Management Framework



As the first step in adopting optimal asset management, an objective yardstick needs to be developed for accurate and quantitative measurement of the health and condition of major assets, which would provide repeatable results.

By taking into consideration asset health degradation processes and historic failure modes, appropriate algorithms are developed, relating the results of visual inspections, laboratory tests and other relevant demographic and operating parameters to a normalized health indicator, referred to as "Health Index".

Health indices determined in this manner, allow sifting and ranking of the entire population of a specific asset class into five categories: "very poor", "poor", "fair", "good", and "very good". They will also permit quantitative determination of asset failure risk for each category, using probabilistic techniques.

All consequences of failure for each asset class are identified, and the overall impact of failure risk of an asset is quantified using probabilistic techniques. Practical risk mitigation options for each asset category are identified and cost estimates for each mitigation option are prepared. With this model, optimal investment decisions are made by balancing the value of risk against the risk mitigation costs.

PowerStream Overall Asset Condition Assessment Process is illustrated in Figure 3.

Every year asset conditions and test data are collected and ACA asset models are run to generate results.

Meetings among stakeholders are held to ensure the following three-step process is followed before a project is recommended for annual budget approval:

Step 1: Results of the ACA Model: results indicating that asset replacement is required;

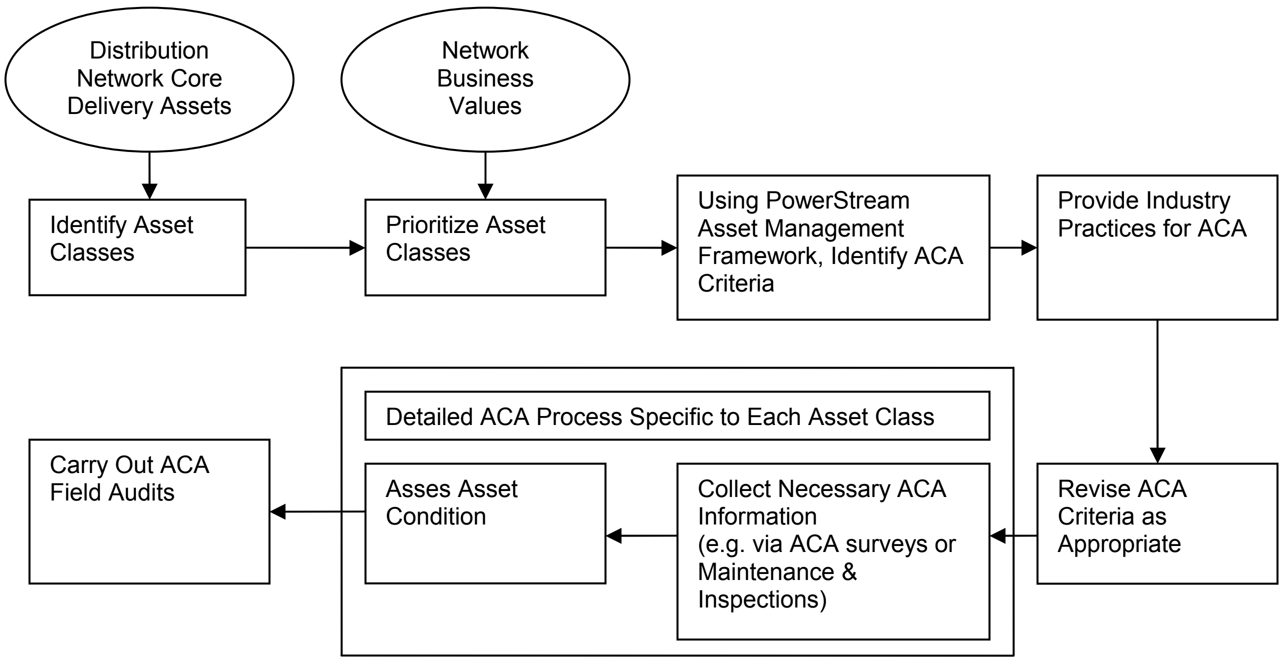
Step 2: Operational Requests: requests are based on experience from System Control on those assets that limit the efficient operations of the distribution system; and

Step 3: Lines and Operations Feedback: these feedbacks are from field staff on those assets that have visually or functionally deteriorated worse than the assessment results from the ACA model. In addition, any safety related issues will be taken into consideration.

Although in theory, the number of replacement units recommended by the ACA models is considered “optimal” or “ideal” under economic viewpoint; in reality, however, PowerStream uses engineering judgment and operations input to spread out the replacement programs over a longer period of time. The intent of spreading the replacement over a number of years is to manage additional risk of asset failure, and smooth out the budget and resource impact.

As a result of this approach, the annual numbers of replacement units proposed in the annual budget may be different from those recommended by the ACA models.

Figure 3 - PowerStream Overall Asset Condition Assessment Process



4.4 Stations Design and Construction Process

The process to determine spending levels for Stations Design and Construction is described below and shown in Figure 4.

Identify Needs

The Identify Needs step determines the need for a station project. The need for a sustainment (not capacity driven) station project can be identified by Station Design & Construction ("SD&C"), Stations Sustainment ("SS"), Operations ("OPS"), Protection & Control ("P&C"), and System Planning ("SP"). The System Planning group identifies station plant asset replacement and capacity driven projects. Sustainment activities include projects to: replace worn out equipment, maintain reliability, enhance operability & maintainability and to improve and maintain safety.

Management of Stations Change Committee Meeting

Management of Station Change ("MOSC") committee reviews recommended changes & improvements to stations to insure the quality and cost effectiveness of proposals.

Concept Design

High level concept design is developed by the assigned Project Engineer. The objective of the concept design step is to validate the program, explore the most promising alternative design solutions, and provide a reasonable basis for analyzing the project cost. The concept design may include:

- Overview of the project
- Background and history of the project
- A space profile and specialized facility needs
- Major equipment lists
- Program issues and objectives

In some instances, sketches could be developed as part of concept design activity.

Develop Cost Estimate

In order to estimate the cost the following steps are taken:

- Request budgetary quotes: the preliminary budget quotes for the potential equipment required for the station are needed. The Project Engineer generates a request to potential external suppliers for budgetary quotes.
- Request Work Hours: the work hours that are estimated to be spent by other departments and stakeholders are needed. The Project Engineer generates a request to SS and P&C for work hour estimates.
- Cost Estimation: performed by the Project Engineer based on the project specifications and the inputs received from Stations Sustainment work hour estimates, P&C work hour estimates, and external supplier budgetary quotes.

Develop Business Case

A business case is developed for the budget approval of the new transformer station project. The Business Case typically consists of the high level concept design, cost estimates and timelines.

<u>Corporate Capital Budget Development</u>

The Capital Budget coordinator puts together the Capital Budget after consolidating all the business cases that have a preliminary approval to be prioritized by the *Optimizer*® tool.

<u>Run Optimizer and prioritize projects</u>

The information from all the approved business cases are entered into the *Optimizer*® tool enabling prioritization of the projects. The *Optimizer*® results are then forwarded to the senior management for approval.

<u>Resubmit to Next Planning Cycle</u>

The business case is resubmitted in the Next Planning Cycle if senior management decides not to pursue the project this year and chooses to defer the project to future years.

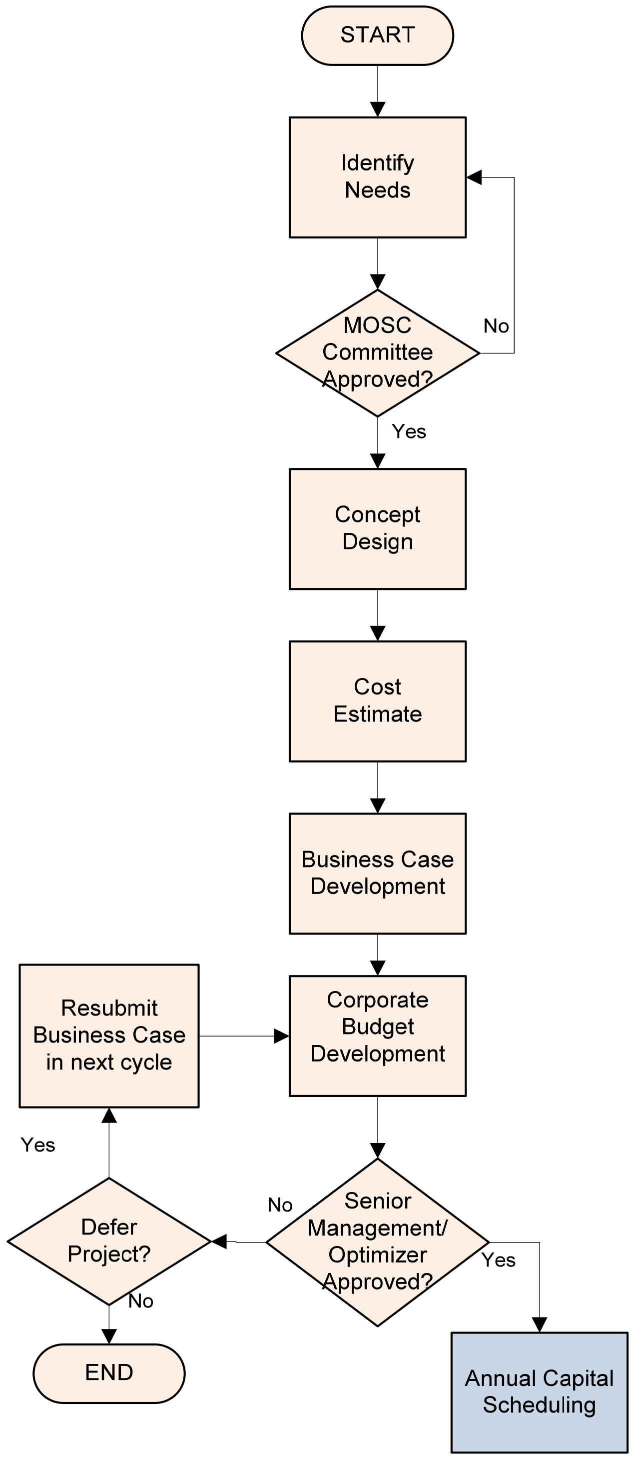
<u>Cancel Project Proposal</u>

Senior management and/or the Stations Group determines that the project is no longer worth pursuing in its present form for future budget cycles. The project is cancelled and withdrawn from future planning cycles.

<u>Project Scheduled</u>

The approved project is scheduled for implementation.

Figure 4 – Process to Determine Spend Levels



5.0 CAPITAL PROJECT JUSTIFICATION & BUDGET APPROVAL PROCESS

PowerStream follows a process to ensure capital projects are well justified and prioritized, and capital funds approval is prudent.

The procedure governing the justification and approval of the annual capital projects is described in PowerStream Procedure No. FCS-F-01 “Justification of Capital Projects & Related Expenditures”.

Each proposed project must be substantiated by a budget form (“mini business case”) in PowerStream Capital Budget Management System (CBMS). In addition, for those proposed projects that meet the following criteria, a “full business case” must also be completed and approved prior to budget submission.

- Non-program projects, greater than $500,000.
- Projects not funded within the current year’s approved capital budget or are funded from emerging funds, greater than $250,000, net of contributed capital.
- New or current capital programs of an on-going, recurring nature included in the annual, planned capital budget and not listed in the listing of program type projects under the mini business case.

For each proposed project, an Optimizer Scoring Form must be completed, in which a number of questions must be answered. Each proposed project is scored based on PowerStream “Strategic Objectives and Success Criteria Weightings”, which include the following criteria in 2011 Budget year:

Criteria	Weighting Factor
Business Excellence	26.2%
Customer Satisfaction	31.9%
Financial	20.1%
Health & Safety	15.1%
Environmental Sustainability	6.7%

6.0 FIVE YEAR CAPITAL PLAN

The capital projects proposed by Engineering Planning for the five years 2012, 2013, 2014, 2015, and 2016 are listed in Appendix A, and are described below.

6.1 Replacement Program

This category mainly covers the replacement of distribution and station assets. It includes the following:

- Overhead Plant Asset Replacement
- Underground Plant Asset Replacement
- Station Plant Asset Replacement

6.1.1 Overhead Plant Asset Replacement

This category mainly covers the replacement of Overhead Plant Assets using the ACA Process. It includes the following:

- Wood Pole Replacement
- Other Overhead Plant Asset Replacement

6.1.1.1 Wood Pole Replacement

PowerStream has 46,414 wood poles in service.

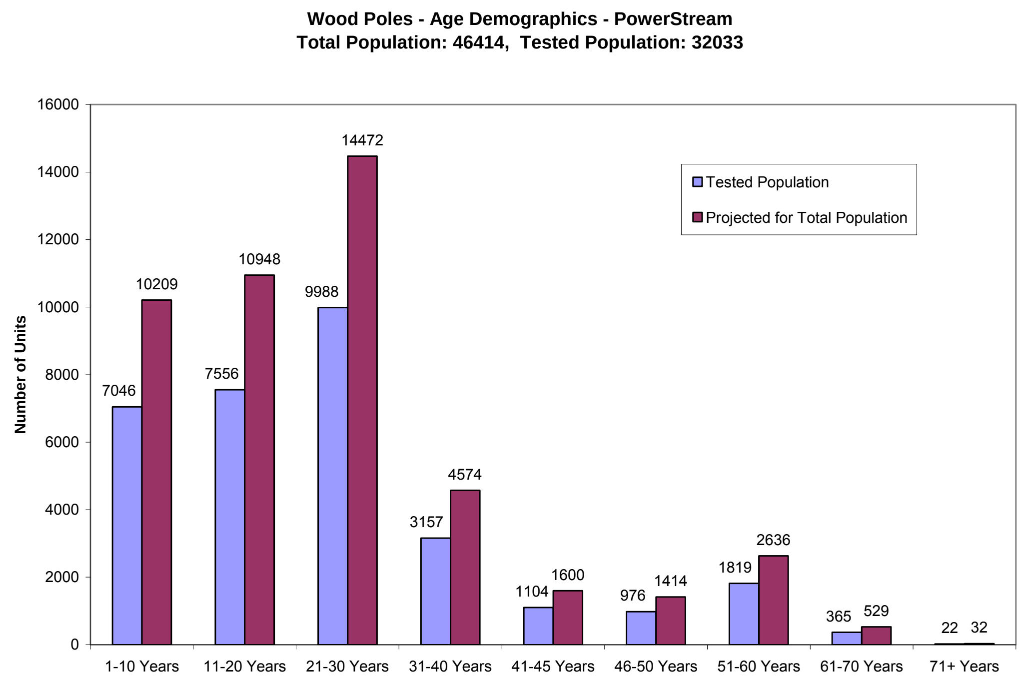
According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

- Useful life of **Wood Poles** is 35-75 years with typical useful life of 45 years.

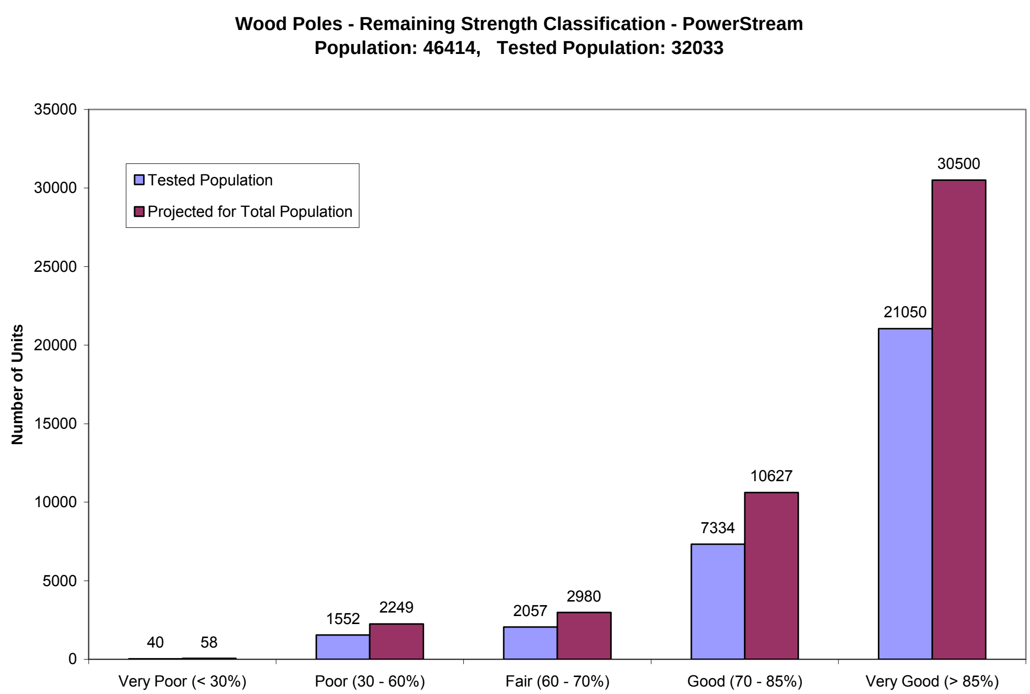
At PowerStream, for IFRS purposes, a useful life of 45 years is used for wood poles.

There are some data gaps with respect to pole age and pole condition. The "Projected" numbers show the estimated result, assuming that the portion of poles with missing data will have similar characteristics as those with data.

The Age demographics for Wood Poles in PowerStream are shown in the following chart.



The Condition demographics for Wood Poles in PowerStream are shown in the following chart.



Poles are critical component of the distribution system as many types of equipment are attached to them (conductors, transformers, switches, street lights, telecommunication attachments, etc.). As a pole's physical condition and structural strength deteriorate, the pole may become inadequate for its intended function, and should be replaced to maintain the integrity of the distribution system.

The PowerStream pole testing program has revealed that a number of poles need to be replaced. One of the criteria used for replacement is "percent remaining strength" as per CSA Standard C22.3 No. 1-06.

Clause 8.3.1.3 of CSA Standard C22.3 No. 1-10 states that "when the strength of a structure has deteriorated to 60% of the required capacity, the structure shall be reinforced or replaced".

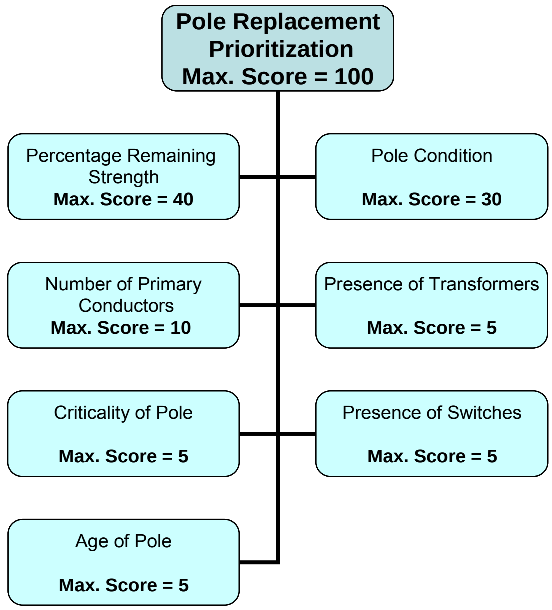
Poles that have been identified by the pole testing contractor as "need to be replaced" or poles that have a remaining strength of less than 60% present a safety risk to the public and staff if they fail when people are in the proximity of the poles. In addition if they fail, reliability and customer service will be negatively impacted.

Every year, on a prioritized basis, a number of poles are proposed for replacement due to the pole conditions and remaining strength. The replacement will have positive impact on PowerStream's goals to maintain public & staff safety, system reliability, and to meet OEB & CSA requirements.

The following criteria will be taken into consideration to prioritize the pole replacement program.

- Remaining Strength
- Pole Condition
- Number of Primaries
- Number of Transformers
- Switch on the pole
- Criticality of the pole (how important it is to the system)
- Age

The following chart shows the weight of each criterion in the prioritization model.



It is estimated that there are approximately 2,307 poles in the “very poor” and “poor” condition. It is recommended that this population of poles be replaced over the next six years.

To address the pole condition concern, it is recommended to replace 300 poles in 2012, then 400 poles per year from 2013 to 2016. At this spend level; all of the approx. 2,307 poles will have been replaced by 2017.

It is expected that as the existing poles are aging and deteriorating, new testing results will show that at the end of the six years, and on a rolling basis, a similar number of poles requiring replacement will be generated (400 poles per year). As a result, it is expected that the pole replacement program will be an on-going program to maintain the integrity of the distribution system.

Cost of Pole Replacement

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
1.1	Pole Replacement	$2,577,561	$3,503,990	$3,571,374	$3,638,759	$3,706,143	**$16,997,827**

6.1.1.2 Other Overhead Plant Asset Replacement

Under this category the following capital work will be discussed:

- Overhead Transformers
- Overhead Hubbell AB Chance Switch Replacement

Overhead Transformer Replacement

PowerStream has 7249 Overhead Transformers in service.

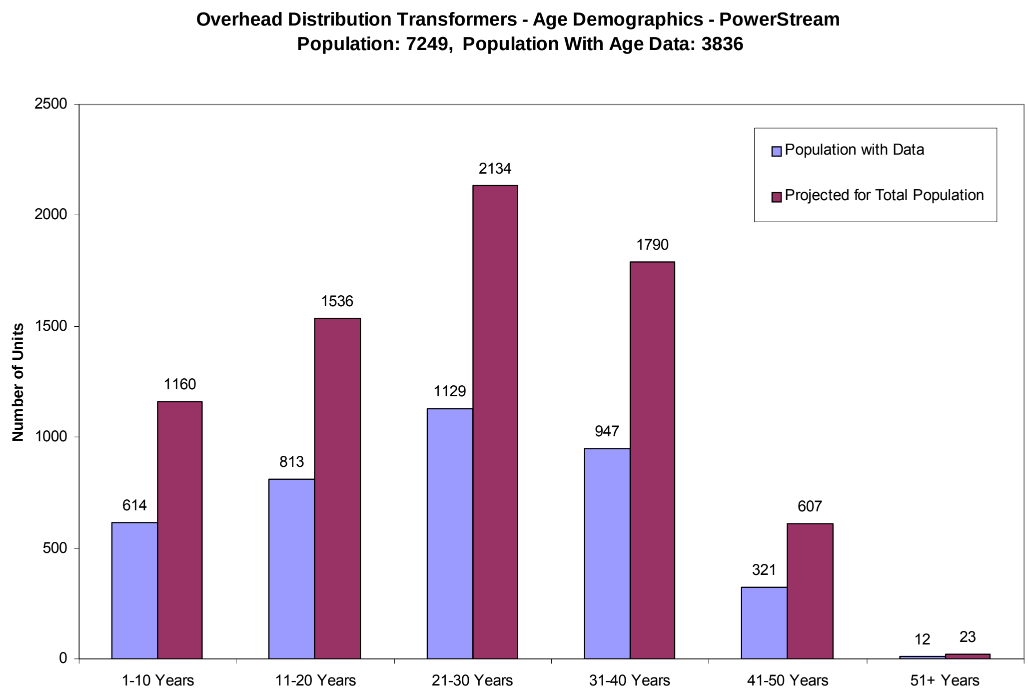
According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

- Useful life of **Overhead Transformers** is 30-60 years with typical useful life of 40 years.

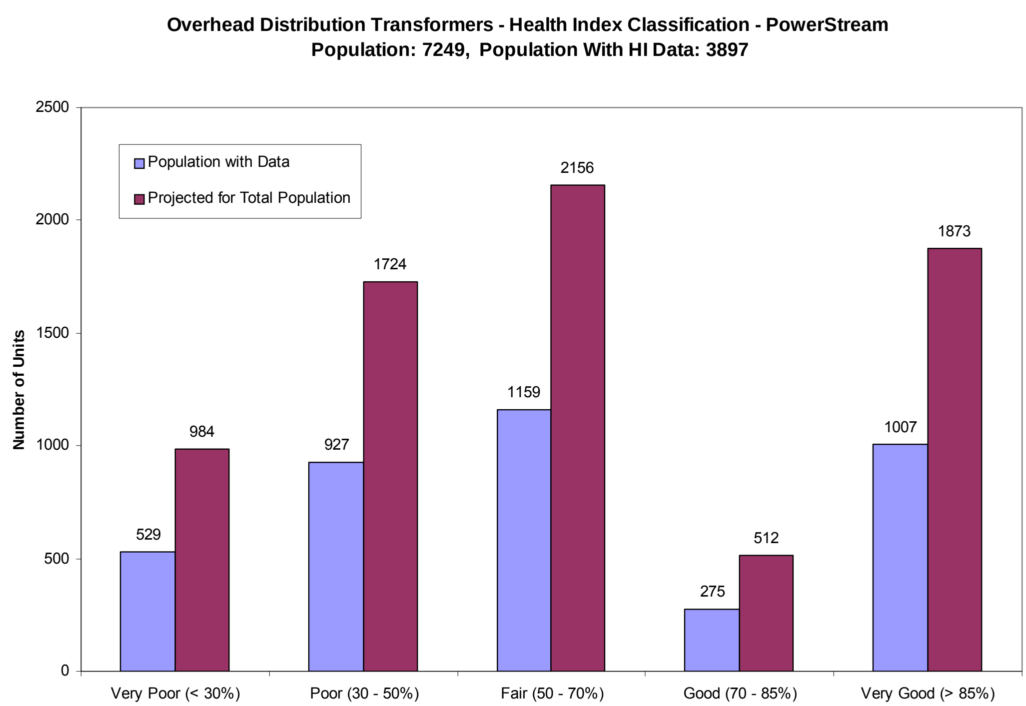
At PowerStream, for IFRS purposes, a useful life of 40 years is used for Overhead Transformers.

There are some data gaps with respect to Overhead Transformers age and condition. The "Projected" numbers show the estimated result, assuming that the portion of Transformers with missing data will have similar characteristics as those with data.

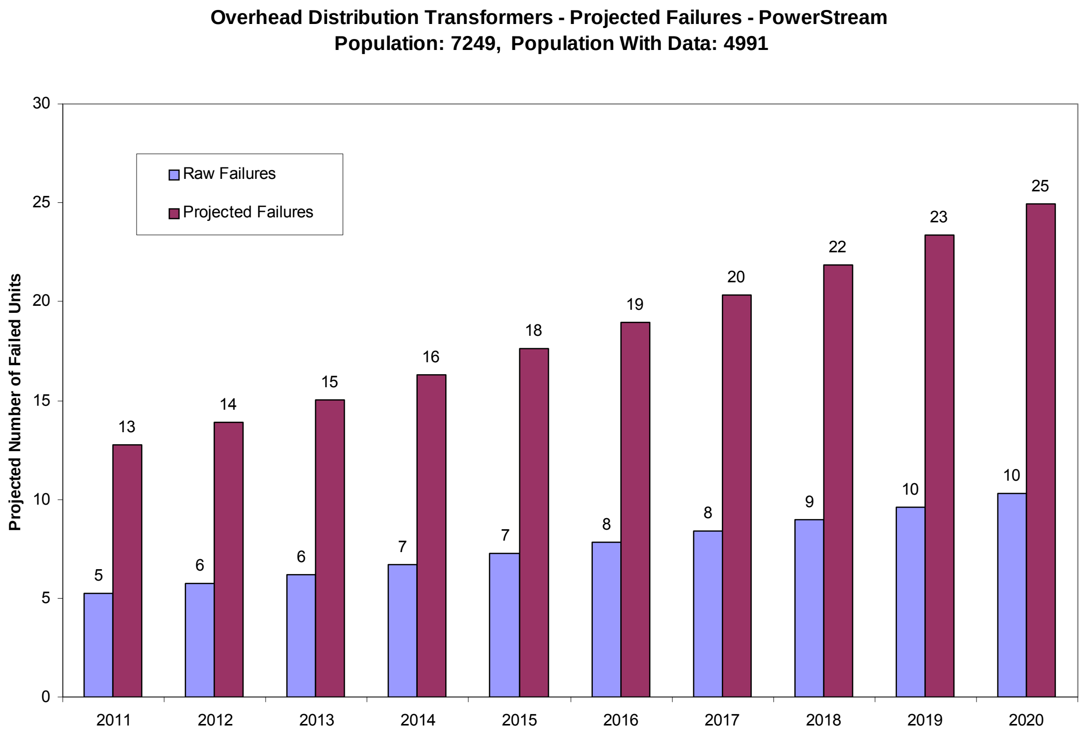
The age demographics for Overhead Transformers are shown in the following chart.



The Condition demographics for Overhead Transformers are shown in the following chart.



The ACA Model projection of future Overhead Transformer failures is shown in the following chart.



With regards to Overhead Transformers, PowerStream will operate based on a run-to-failure approach. It was determined that proactive replacement of Overhead Transformer is not cost effective based on the following reasons:

- The risk and consequence of failure is low. PowerStream had twelve, fourteen, and seventeen Overhead Transformer failures in 2008, 2009, and 2010 respectively (average fourteen units per year).
- PowerStream presently has sufficient capability and effective process and procedures to manage these asset failures at the current failure rate.
- The cost of proactive replacement is higher than the potential benefit.

As a result of this approach, this Five Year Capital Plan does not propose any planned replacement of Overhead Transformers. Therefore, no cost is included in this Five Year Capital Plan.

<u>Overhead Hubbell AB Chance Switch Replacement</u>

Lines Department has raised a safety concern about the performance of the existing overhead Chance switches in PowerStream North (mostly in the south end of Barrie and also in Penetanguishene). The concern is summarized below:

- The failures are associated with mid to late 1990's installations.
- Lines staff is able to visually detect hairline cracks.
- The switches are obsolete and are no longer being purchased.
- The switches with cracking porcelain insulator may develop flashover which will result in power outage, damage to adjacent equipment, and present a safety risk to Lines staff when they are required to operate these switches.
- There was a safety incident where a Chance switch failure occurred, resulting in switch parts falling down in contact with a vehicle located below. Although there was no personal injury in that case, these types of incidents present safety risk to the public.
- It is believed that the cause is associated with the adhesion between the pin (stud) and porcelain connection. Moisture may be getting in and freezing which leads to small hairline cracks in the porcelain and/or complete separation.

The safety concern has been discussed in the PowerStream’s Joint Health & Safety Committee. The Safety Committee issued a Safety Alert Bulletin in August 2010.

The issue was also discussed in the PowerStream Reliability Committee meeting of July 7, 2010. The Reliability Committee agreed that the Chance switches should be replaced and requested System Planning to include the replacement work in the upcoming budget submission.

It is proposed to replace all 380 AB Chance Switches over two years as follows:

- 2011: replace 190 units
- 2012: replace 190 units

Cost of AB Chance Switch Replacement

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
	Switch Replacement (AB Chance Porcelain switch)	$394,494	$0	$0	$0	$0	**$394,494**

6.1.1.3 Cost of Overhead Plant Asset Replacement

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
1	**Overhead Plant Asset Replacement Programs**	**$2,972,056**	**$3,503,990**	**$3,571,374**	**$3,638,759**	**$3,706,143**	**$17,392,321**

6.1.2 Underground Plant Asset Replacement

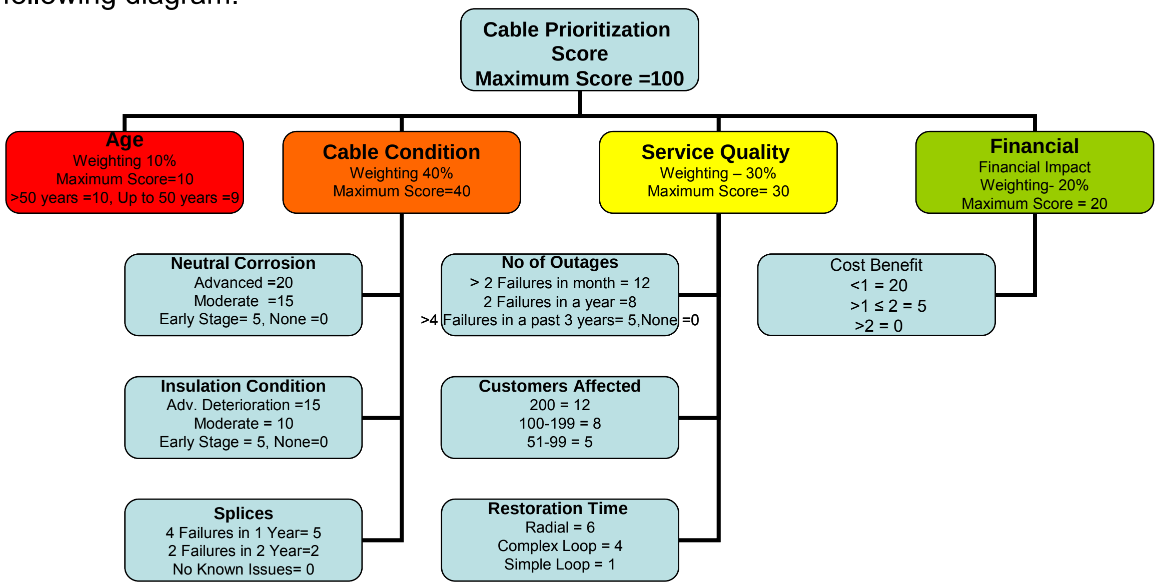
This category mainly covers the replacement of Underground Plant Asset using the ACA Process. It includes the following:

- Underground Cable Replacement
- Underground Cable Injection
- Underground Transformer Replacement
- Underground Switchgear Replacement
- Other Underground Plant Asset Replacement (Splice, Vault, Duct Bank)

Prioritization Methodology for Underground Cable Replacement and Cable Injection

- PowerStream will address the cable aging issue by a combination of cable injection and cable replacement on a prioritized basis
- PowerStream will conduct testing to determine the condition of the cable
- PowerStream has developed a cable prioritization system to select cable replacement and cable injection candidates
- The cable replacement program will last for twenty years initially and continue at the similar rate afterward
- The cable injection program will last for ten years then terminate

The Prioritization Methodology for Cable Replacement and Cable Injection is shown on the following diagram.



The details of the underground cable replacement and injection programs are described below.

6.1.2.1 Underground Cable Replacement

PowerStream has approximately 7,836 km of underground primary cable length, the vast majority of which is direct buried and the rest is in duct.

According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**, the useful lives of various types of underground cable are listed below.

Cable Type	Minimum Useful Life (MIN UL)	Typical Useful Life (T UL)	Maximum Useful Life (MAX UL)
Primary Non-Tree Retardant XLPE - Direct Buried	20 Years	25 Years	30 Years
Primary Non-Tree Retardant XLPE - In Duct	20 Years	25 Years	30 Years
Primary Tree Retardant XLPE - Direct Buried	25 Years	30 Years	35 Years
Primary Tree Retardant XLPE - In Duct	35 Years	40 Years	55 Years

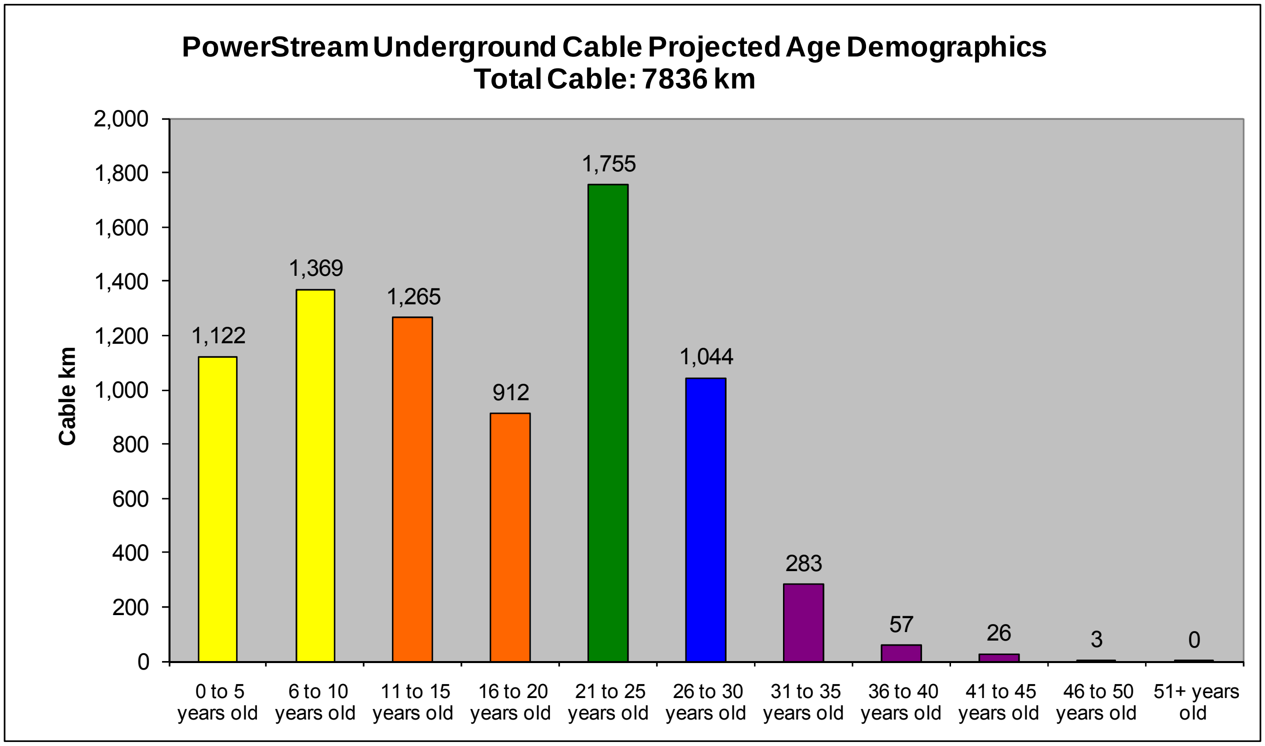
At PowerStream, for IFRS purposes, a useful life of thirty-five years is used for pre-1987 cable and a useful life of forty-five years is used for post-1987 cable.

The Kinectrics Report indicates that the useful life is dependent on a number of Utilization Factors listed below.

- Mechanical Stress
- Electrical Stress
- Operating Practices
- Environment Conditions
- Maintenance Practices
- External Factors

There are some data gaps with respect to cable age. The “Projected” numbers show the estimated result, assuming that the portion of cable with missing data will have similar characteristics as those with data.

Age Demographics for Underground cable is shown in the following chart.



As the cable gets older and the condition deteriorates, it will fail. Initially PowerStream can repair or replace the faulted cable segment under reactive emergency response. But if the cable fails too often, it will result in unacceptable service to the customer, and unacceptable repair costs to PowerStream.

There are two methods of intervention to address the cable aging issue:

- Cable Replacement – replace existing cable
- Cable Injection – extend existing cable service life

The Cable Replacement option is more expensive than the Cable Injection option with respect to initial capital cost. But it has the advantage of new cable that will be utilized for a longer time. In comparing the two options: the extra life expected from injected cable is fifteen - twenty years; the life of new cable is expected to be fifty to fifty-five years; the cost/benefit ratio is 15% better for cable injection compared to new cable. Cable injection is viable for only a certain population of cable.

Currently, PowerStream is experimenting with Cable Injection technology to gain more experience. This plan is developed based on the assumption that Cable Injection is a viable option for a certain quantity of cable. If it is determined that Cable Injection is no longer a viable option, then Cable Replacement will become the only alternative. In that case, the quantity that is proposed for Injection will be proposed for Replacement.

PowerStream will address its Underground Cable assets by using a combination of Cable Replacement and Cable Injection as means of intervention.

The Cable Replacement plan (discussed later in this Section) will be ongoing as we will continually need to replace cable as it gets older. This report will cover the first twenty years of the plan. It is expected that the Cable Replacement plan will continue at a similar spending level after the first twenty years.

The Cable Injection plan (discussed in the next Section - Cable Injection) will take place over a period of ten years. After ten years all suitable candidates for injection will be exhausted, therefore this plan will not be ongoing.

To develop a general plan to address the cable issue (a twenty year plan for cable replacement, and a ten year plan for cable injection) the cable population is divided into the following five groups:

- Group 1: 31 years and older
- Group 2: Between 26 – 30 years
- Group 3: Between 21 – 25 years
- Group 4: Between 11 – 20 years
- Group 5: Between 1 – 10 years

Group 1: 31 years and older:

It is estimated that PowerStream has approximately 370 km of cable older than thirty years.

This population is the older generation of cable that was manufactured with old technologies and processes, using inferior insulation material (non tree-retardant XLPE). In addition, due to age, and installation method (direct buried) the neutral wires are likely corroded. Samples of recent cable failures show that the neutral wires have corroded beyond repair. Cables in this population may be at or close to end-of-life stage and are candidates for cable replacement. As a result Group 1 is excluded from Cable Injection.

Group 2: Between 26 – 30 years:

It is estimated that PowerStream has approximately 1,044 km of cable between twenty-six and thirty years.

This population is also the older generation of cable as described in Group 1 above. It is assumed that the cable components have not deteriorated significantly yet. Cables within this population could be candidates for cable injection. However, it should be noted that a significant portion of this group may not be viable candidates for cable injection, depending on forthcoming tests. For our purposes we assume that 50% (i.e. 522 km) of this population is not suitable for injection and must be replaced, this quantity will be managed under the Cable Replacement Program. The remaining quantity 50% (i.e. 522 km) of this population is suitable candidates for injection, this quantity will be managed under the Cable Injection Program. This issue is covered in detail in the next Section – Cable Injection.

Group 3: Between 21 – 25 years:

It is estimated that PowerStream has approximately 1,755 km of cable between twenty-one and twenty-five years.

This population is a newer generation of cable that was manufactured with new technologies and processes (similar to Group 4 and Group 5), for example, the use of tree-retardant XLPE for insulation and triple extrusion process. Because water trees are not a concern for this group of cable, and Injection’s main purpose is to repair water trees, Injection is not effective for this group of cable. In addition, this population has likely been manufactured using strand-filled material, which does not allow the injection fluid to flow through and therefore injection is not possible. This population of cable will need to be addressed at the end of the twenty-year period once the first two groups of cable have been dealt with.

Group 4: Between 11 – 20 years:

It is estimated that PowerStream has approximately. 2,177 km of cable between eleven – twenty years.

At the end of the twenty-year proposed plan, this population should still maintain a low failure rate and it is estimated a portion of this group will still operate better than Group 3.

Group 5: Between 1 – 10 years:

It is estimated that PowerStream has approximately 2,501 km of cable between one and ten years.

Because this cable is new, it is not an immediate concern. It is assumed it will last well beyond the end of the twenty-year plan.

<u>20-Year Cable Replacement Plan:</u>

The intent of this program is to start to address the aging cable population in a timely manner so that the future spending level (after twenty years) will be manageable.

To address the Group 1 population of 370 km of cable older than thirty years, and 50% of the Group 2 population of 522 km of cable between twenty-six and thirty years (total = 370 km + 522 km = 892 km), it is recommended to:

- Replace 8.5 km in 2012 (same level as 2011)
- Replace 47 km per year for the subsequent 19 years from 2013 – 2031

At this rate, all of the 892 km will have been replaced by 2032.

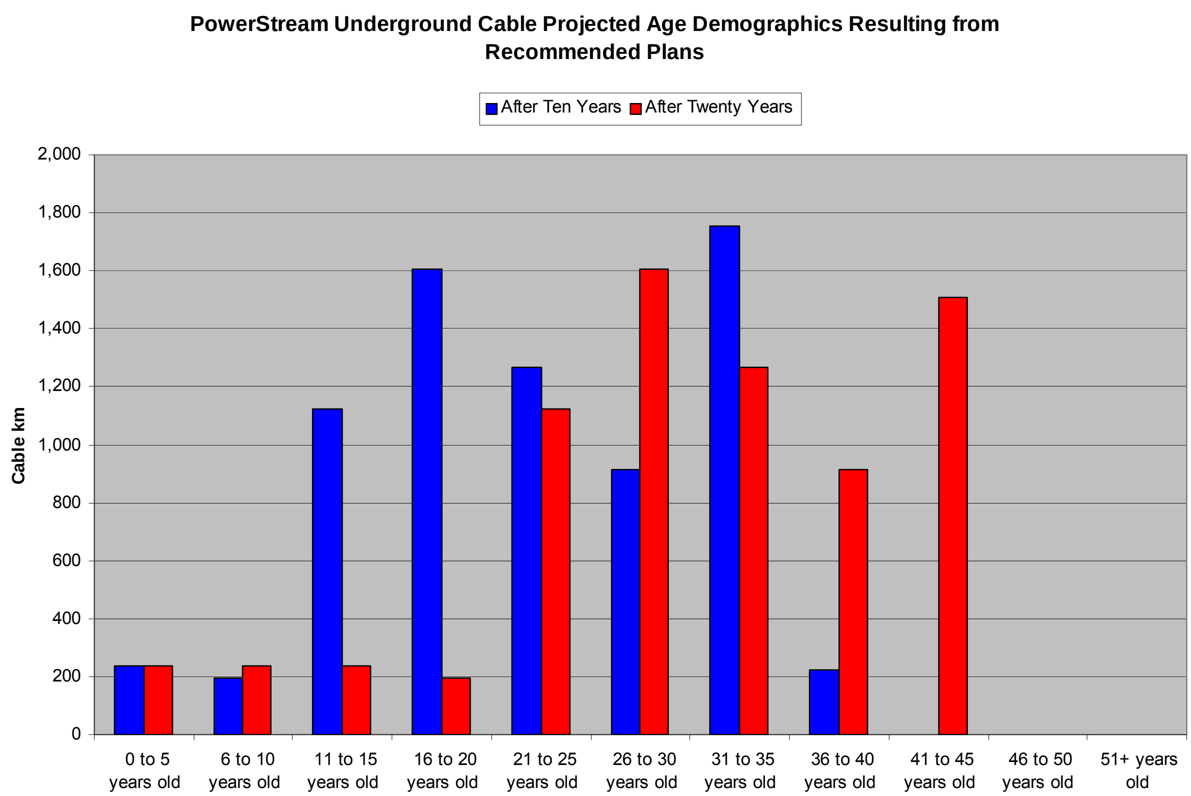
Currently, PowerStream does not have sufficient physical condition and test data to determine the degree of deterioration and to estimate the remaining life of the cable population.

PowerStream, beginning in 2012, will conduct cable testing (e.g. Tan Delta tests, Partial Discharge tests) to further assess the condition of cable to:

- Determine which intervention method (replacement vs. injection) is more suitable to a specific location.
- Determine the appropriate quantity and timing of cable intervention (replacement / injection).
- Validate and prioritize the cable replacement/injection projects.

The following chart shows the cable age profile projections resulting from the proposed plan. The quantities are shown ten years and twenty years into the program.

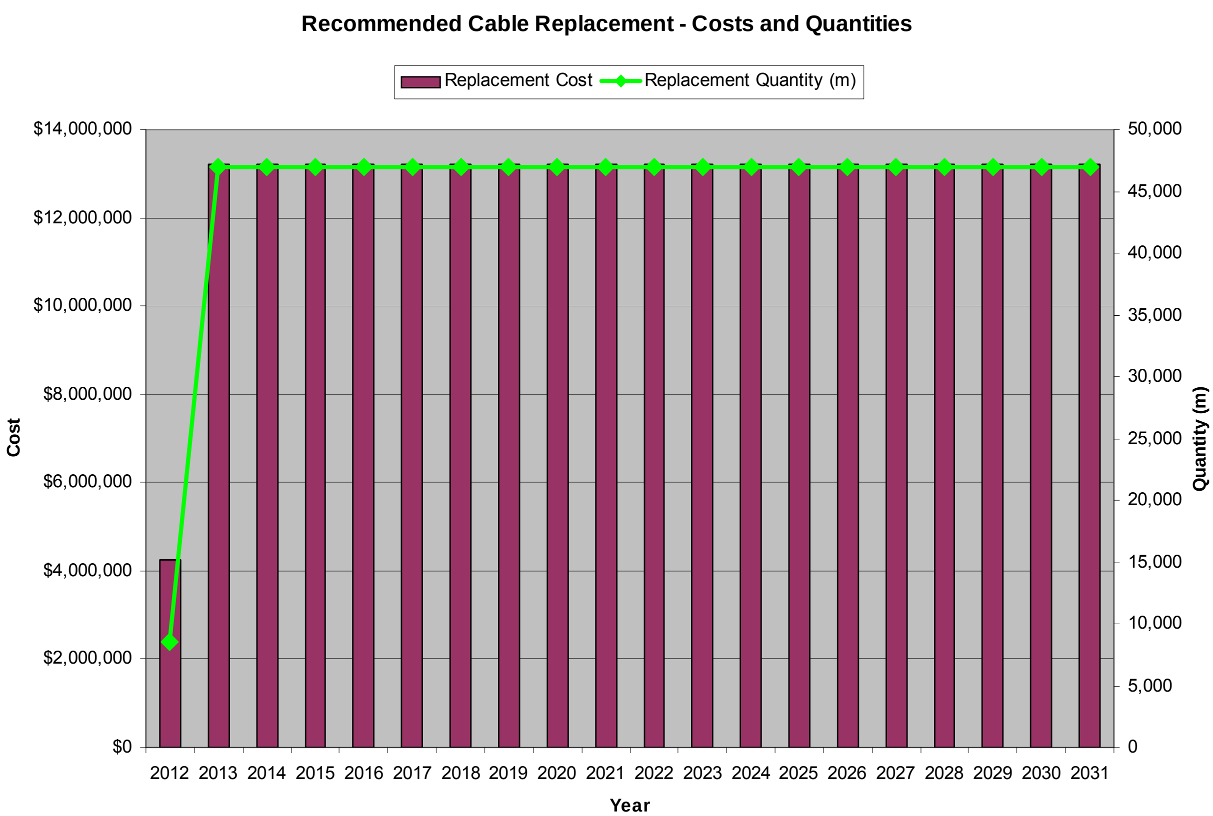
- The blue bars indicate the resulting age profiles ten years into the program.
- The red bars indicate the resulting age profiles twenty years into the program.



Based on the above chart, after twenty years PowerStream will have 1,746 km of cable that is forty-one to forty-five years old. While this is a higher quantity of cable in the age range as compared to the quantity at the start of the program, these cables will be second and third generation cable with improved production quality and corresponding longer expected service life as compared to the cable being addressed in the first twenty year replacement program. At that time this group of cable will be in or entering end-of-life conditions, therefore the replacement program will likely continue at a suitable replacement level to address this population of cable.

The above demonstrates that the proposed twenty year Cable Replacement plan during the first twenty years will result in cable demographics that are reasonably well distributed after twenty years (similar to the first twenty years), supporting the premise that this is the correct level of cable replacement for this asset class.

The recommended cable replacement quantities and costs are shown in the chart below. 2012 costs include the costs of planned projects. For 2013 and onward, the average cost of $281 per meter is used.



Cost of Cable Replacement

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
2.1	Cable Replacement	$4,383,650	$13,735,280	$13,999,420	$14,263,560	$14,527,700	**$60,909,610**

6.1.2.2 Underground Cable Injection

As the cable gets older, the cable insulation may develop a premature aging process caused by a phenomenon known as "water treeing". Water trees will reduce the breakdown strength of the insulation and eventually lead to cable failure. The Cable Injection process will inject silicone chemicals down the strands of the cable. The silicone fluid will diffuse out of the strands through the strand shield and into the insulation. The fluid then polymerizes with water (or moisture) and the silicone molecule grows and fills all water trees and voids. This increases the dielectric strength of the cable and thus extends the life of the cable.

It should be noted that cable dielectric failure may result from causes other than “water treeing” alone. Some examples include impurity, presence of by-products, contaminants, gas, electric trees, etc. As a result, there are many cases where the cable injection process is not effective.

A pilot project on Cable Injection was started in 2009 and completed in 2010. The final report recommended that PowerStream continue with cable injection to polyethylene cable of earlier vintage (pre-to-mid 1980's).

The criteria for selecting Cable Injection candidates are listed below.

- Pre to mid 1980’s (approximately twenty-six years old in 2011)
- Not solid core
- Non strand-filled
- Concentric neutral not corroded significantly
- No electrical trees present (Cable Injection only can repair water trees and not electrical trees).
- Not having too many splices within a cable segment.

Group 1 cables (thirty-one years and older) are assumed to be close to end-of-life. Samples of recent cable failures show that the neutral wires have corroded beyond repair. As a result Group 1 is excluded from Cable Injection.

Group 2 cables (twenty-six to thirty years) could be candidates for Cable Injection provided that the above conditions are met. It should be noted that a significant portion of this group may not be viable candidates for cable injection, depending on forthcoming tests. We assume that 50% (i.e. 522 km) of this population is suitable for injection.

Groups 3, 4 and 5 cables (twenty-five years or younger in 2011) are assumed to have been manufactured with new technologies and processes using tree-retardant XLPE and triple extrusion process and strand-filled material. In general, water trees are not a concern and therefore injection is not effective. As a result Groups 3, 4, and 5 are excluded from cable injection.

Because the Cable Injection option has a number of limitations, a portion the Group 2 population may not be candidates for Cable Injection. For example, it may be more economical to replace cables if there are multiple phases in a trench, or multiple splices in a segment. Another example is during cable failure repair, operations staff adds two new splices to the segment, and one piece of new cable between the splices. As the new piece of cable is strand-filled, injection is not possible for this cable segment. Furthermore, depending on the design and condition of the cable at a specific location (e.g. strand-filled, neutral corrosion, electrical trees) the Cable Injection process may not be feasible at all.

To determine feasibility of cable injection, cable will be tested using cable diagnostic testing such as Tan Delta and Partial Discharge (“PD”) tests.

PowerStream will, beginning in 2012, conduct cable testing (e.g. Tan Delta tests, Partial Discharge tests) to further assess the condition of cable to:

- Determine which intervention method (replacement vs. injection) is more suitable to a specific location
- Determine the appropriate quantity and timing of cable intervention (replacement/injection)
- Validate and prioritize the cable replacement/injection projects

As PowerStream is still experimenting with cable injection technologies and processes, we will proceed with injection projects prudently. This plan is developed based on the assumption that Cable Injection is a viable option for a certain quantity of cable. If it is determined that Cable

Injection is no longer a viable option, then Cable Replacement will become the only alternative. In that case, the quantity that is proposed for Injection will be proposed for Replacement.

Ten-Year Cable Injection Plan:

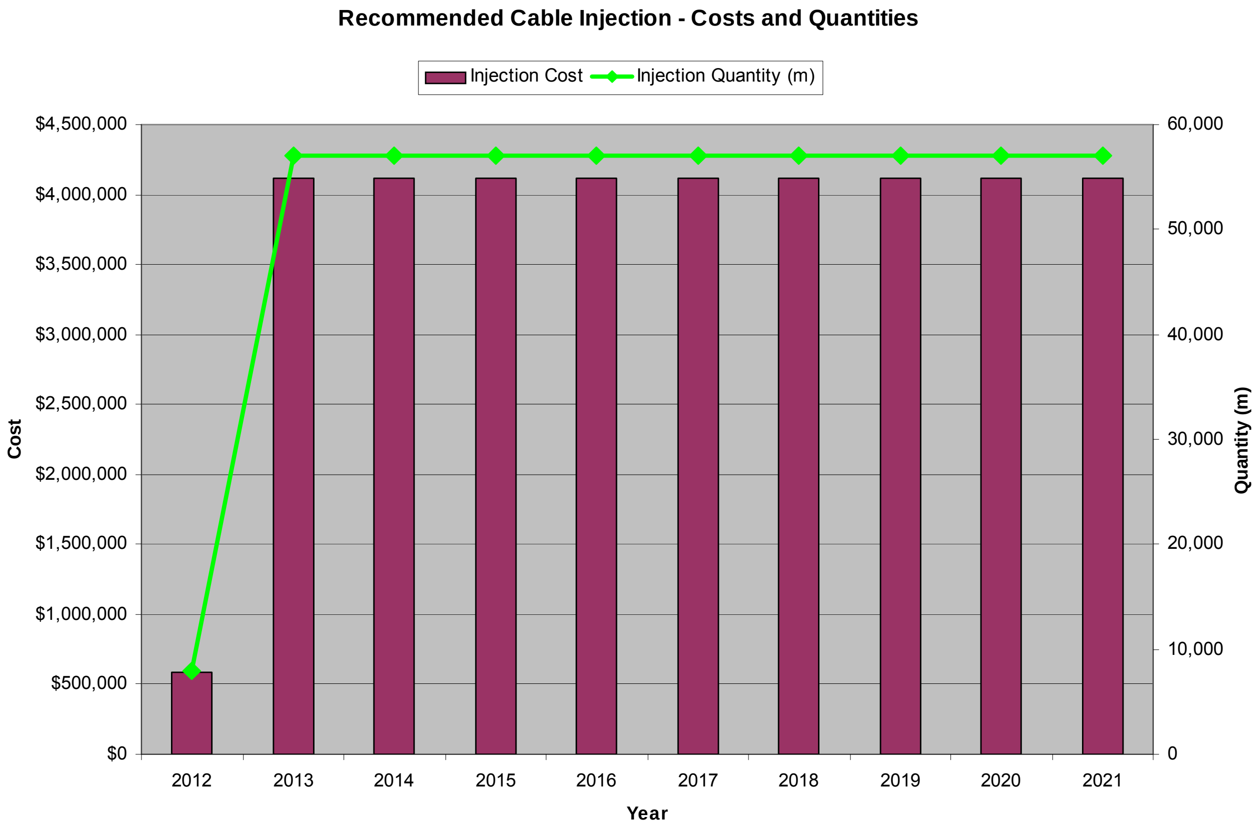
To address the 50% of the Group 2 population of 522 km of cable aging between twenty-six and thirty years, it is recommended to:

- Inject 8 km in 2012 (same level as 2011)
- Inject 57 km per year for the subsequent nine years from 2013 – 2022

Ten years is the optimal time period to get the benefit of the injection program for Group 2. If we extend the period beyond the ten years, the remaining population of Group 2 may become too old to remain suitable candidates for injection.

At this rate all of the 522 km cable between twenty-six and thirty years will have been rehabilitated by 2022.

The recommended cable injection quantities and costs are shown in the chart below using the average cost of $72 per meter.



Cost of Cable Injection

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
2.2	Cable Injection	$589,009	$4,268,160	$4,350,240	$4,432,320	$4,514,400	**$18,154,129**

6.1.2.3 Underground Transformer Replacement

PowerStream has 35,075 Underground Transformers in service.

In this section, there are two types of Underground Transformers being discussed:

- Padmount Transformers
- Submersible Transformers

According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

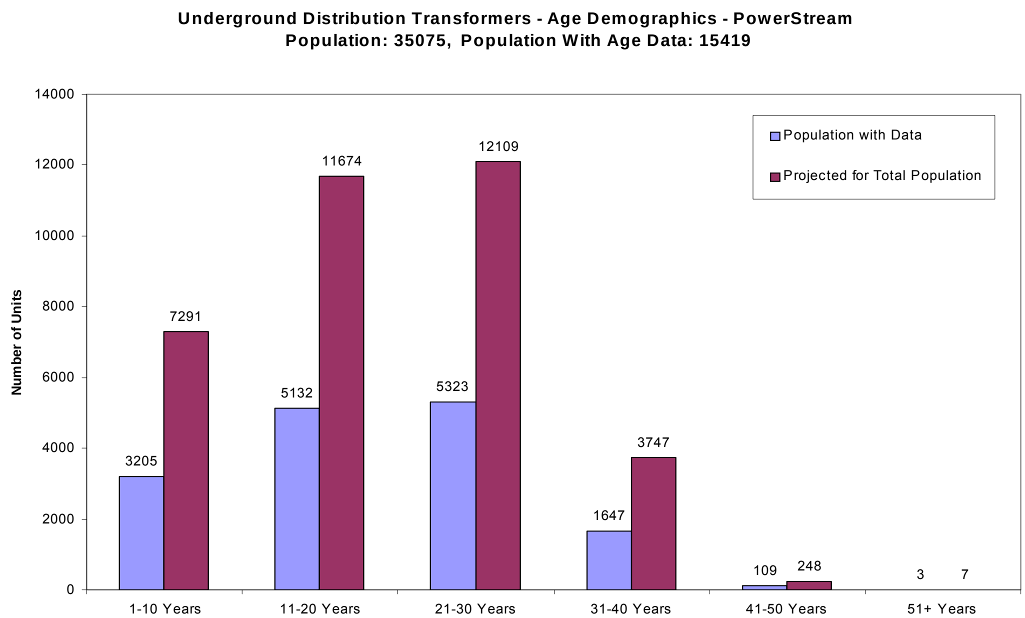
- Useful life of a **Padmount Transformer** is 25-45 years with typical useful life of 40 years.

- Useful life of a **Submersible Transformer** is 25-45 years with typical useful life of 35 years.

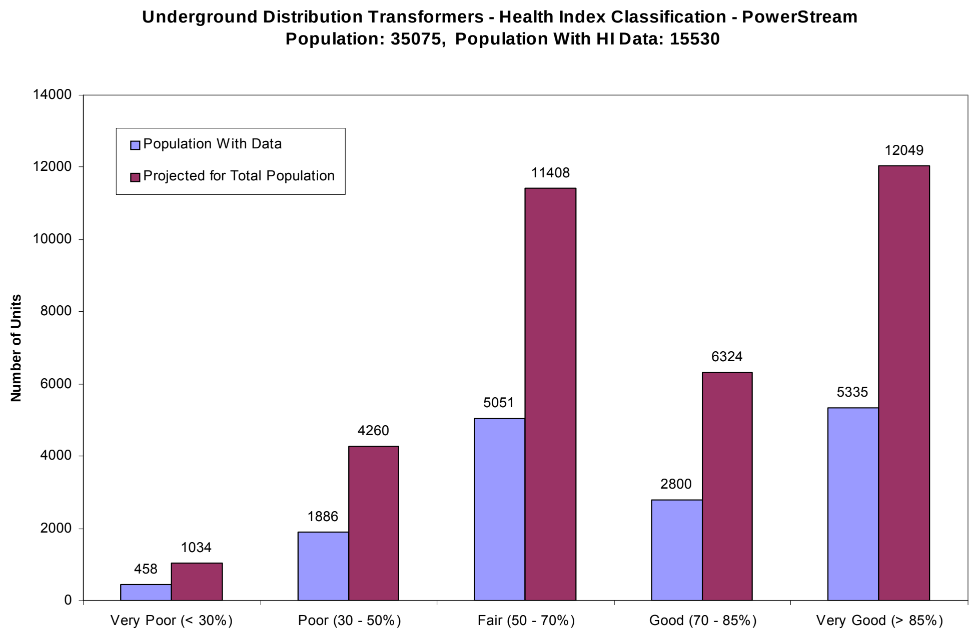
At PowerStream, for IFRS purposes, a useful life of thirty years is used for both Padmount and Submersible type transformers.

There are some data gaps with respect to Underground Transformers age and condition. The "Projected" numbers show the estimated result, assuming that the portion of Transformers with missing data will have similar characteristics as those with data.

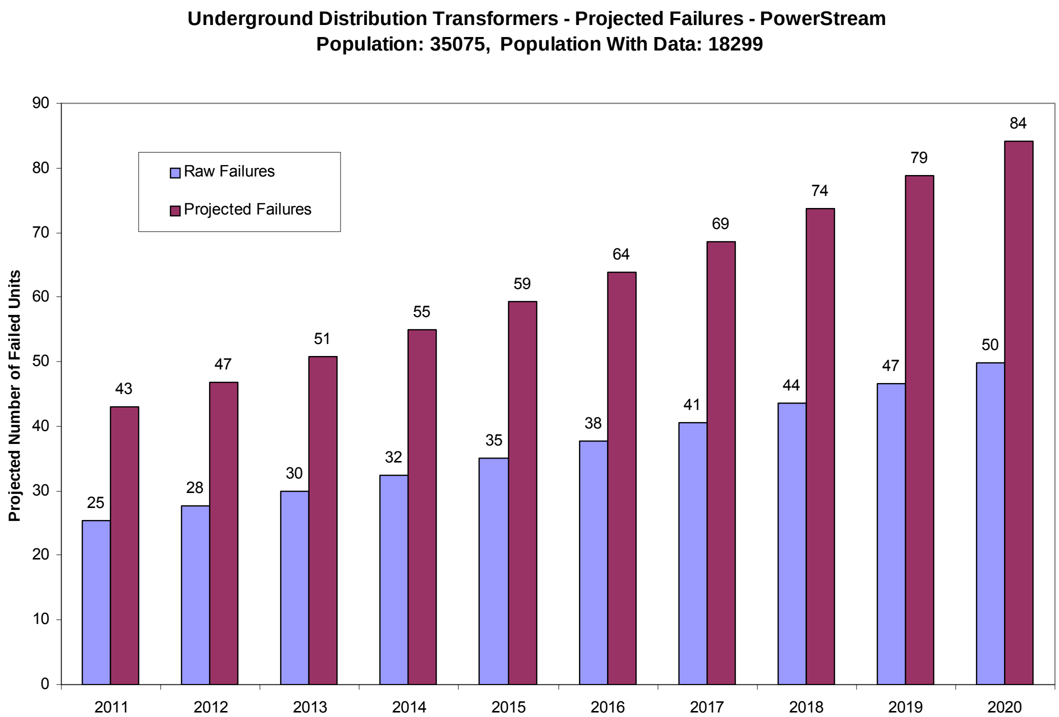
The Age demographics for Underground Transformers are shown in the following chart.



The Condition demographics for Underground Transformers are shown in the following chart.



The ACA Model projection of future Underground Transformer failures is shown in the following chart.



Padmount Transformer Replacement

With regards to Padmount Transformers, PowerStream will operate based on a run-to-failure approach. It was determined that proactive replacement of Padmount Transformer is not cost effective based on the following reasons:

- The risk and consequence of failure is low. PowerStream had fifty-seven, forty-six, and forty-two Underground Transformer failures (including Padmount Transformer and Submersible Transformer) in 2008, 2009, and 2010 respectively (average forty-eight units per year).
- PowerStream presently has sufficient capability and effective process and procedure to manage these asset failures at the current failure rate.
- The cost of proactive replacement is higher than the potential benefit.

As a result of this approach, this Five Year Capital Plan does not propose any planned replacement of Padmount Transformers. Therefore, no cost is included in this Five Year

Capital Plan.

Submersible Transformer Replacement in PowerStream South

In 2008 System Control identified ninety-one equipment locations to be retro-fitted to meet a new operations switching procedure.

The existing submersible unit design and installation do not provide sufficient access to allow field staff to perform switching operations under normal and emergency situations, thus reducing customer service and reliability level to the affected customers. The retro-fitting work, including installation of switches, splice out, replace submersible transformer with Padmount transformer, change to switchable transformer, will make the design and installation similar with the majority of other existing locations in the system, facilitating normal work procedures for the field staff.

The project received approval and started in 2009 and continues in 2010 and 2011. The intent was to complete the project over a period of four to five years.

Of the ninety-one locations, twenty-three locations are in Richmond Hill and sixty-eight in Markham.

In 2011 budget approval has been obtained for the replacement/retrofitting/splice out of fifteen locations. To address the safety and operational concerns, it is recommended to replace/retrofit/splice out at the remaining locations in 2012. At this rate all of the identified submersible transformers will have been replaced by 2012.

Submersible Transformer Replacement in PowerStream North – "Rocketship"

In 2010 Lines Department identified fifty-seven submersible transformer locations to be retrofitted to meet a new operations switching procedure. These transformers are referred to as "Rocketship" by operations staff and are located at various locations in the Barrie area. The existing "Rocketship" transformers do not provide sufficient access to allow field staff to perform switching and maintenance operations under normal and emergency situations, thus reducing customer service and reliability level to the affected customers.

The transformers are obsolete and no longer purchased by PowerStream. These units are of very old vintage, dating back to 1967 and are at end-of-life. They are no longer manufactured, and spare parts are non-existent.

Operations staff has raised many concerns with continued operation of this supply system which are summarized under the following nine items:

1. The transformer units are connected using non-load break equipment which means they cannot be connected or disconnected while energized. As a result, portions of the circuit must be isolated when work is required on any part of the primary system, resulting in approximately eighteen hours of interruption when an unplanned event occurs.
2. The isolation can affect several transformers pending the circuit configuration and may disrupt up to 100 customers at a time.
3. Trouble response work becomes very complicated because of the fusing design. The fuse is connected to a non-conductive fiberglass support system held in place with metal bolts to a metal structure. Faults have occurred passing through the bolts to the grounded equipment. This path cannot be seen from any opening, and is impossible to confirm without dismantling the unit.
4. Failures such as described in Item three above have resulted in the fuse housing being by-passed and the terminations being bolted together in order to restore the circuit.
5. Replacement parts are not available.
6. The physical size of the units restricts any use of live line techniques and requires a "hands on" approach which requires isolation. This would typically involve disconnection, potential testing and grounding.
7. The vault that contains the transformer is undersized. There is only 8 cm (3 inch) between the vault wall and the transformer. As a result, cable movement is next to impossible and work on connections is very limited. The lack of clearance within the unit also prevents access to the potential test points and approved grounding equipment is not available.

8. The primary cable installed between these units is non-jacketed cable. At many locations, the concentric neutral wires have corroded significantly or are non-existent. This is a concern for line staff who rely on system neutral to be able to effectively ground their work zone.

9. Secondary cable is comprised of many tee taps which several services may be connected to. As a result, in the event of a "burn-off", several services can be out of power.

For the above reasons, the submersible transformers should be replaced.

The issues were discussed in the PowerStream Reliability Committee meeting of July 7, 2010. The Reliability Committee has agreed that the units should be replaced.

In 2011 budget approval has been obtained for the replacement of five units. To address the safety and operational concerns, it is recommended to replace five units in 2012, then sixteen units per year from 2013 to 2016. At this rate all Rocketship transformers will have been replaced by 2016.

Cost of Underground Transformer Replacement

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
2.3	UG Transformer Replacement	$845,946	$1,380,454	$1,407,002	$1,433,549	$0	**$5,066,951**

6.1.2.4 Underground Switchgear Replacement

PowerStream has approximately 1,825 distribution switchgear units in service.

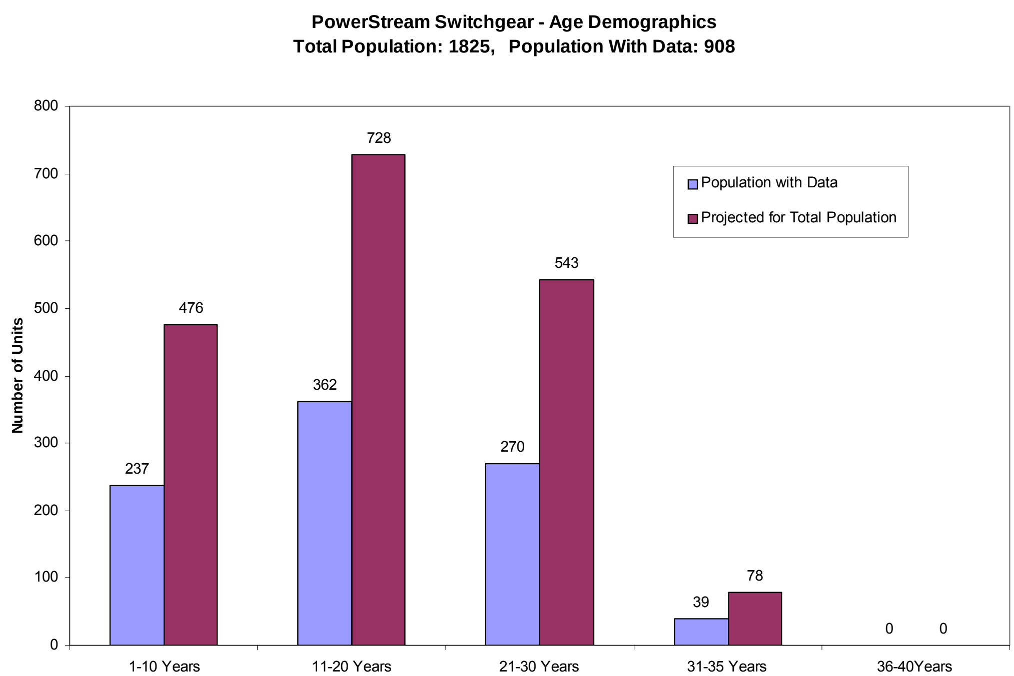
According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

- Useful life of **Pad-Mounted Switchgear** is 20-45 years with typical useful life of 30 years.

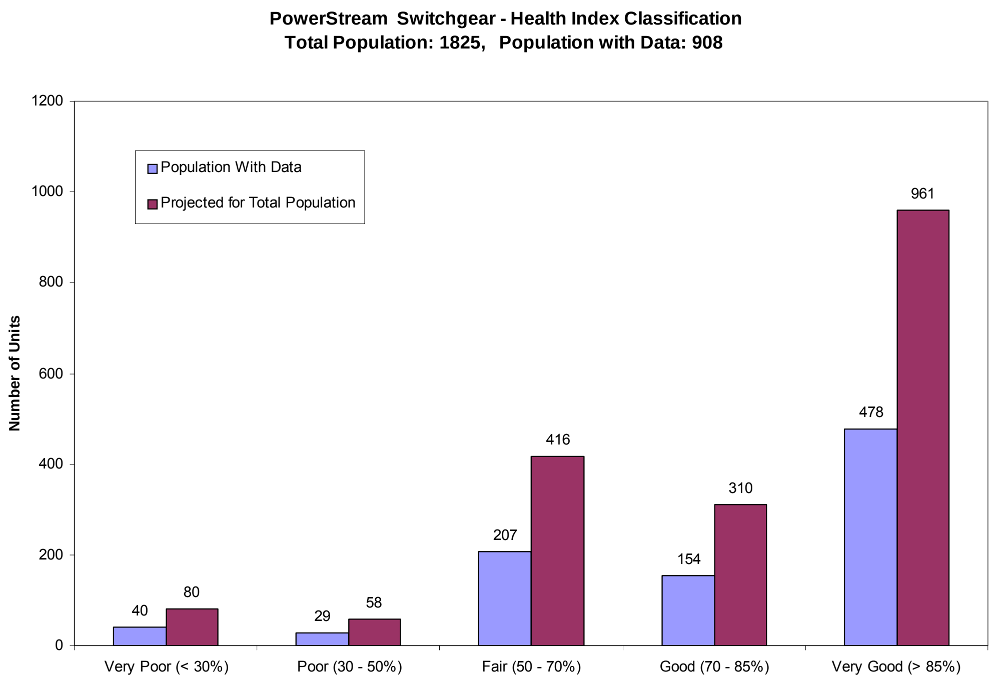
At PowerStream, for IFRS purposes, a useful life of 35 years is used for switchgear.

There are some data gaps with respect to distribution switchgear. The "Projected" numbers show the estimated result, assuming that the portion of Switchgear units with missing data will have similar characteristics as those with data.

The Age demographics for Underground Switchgears are shown in the following chart.

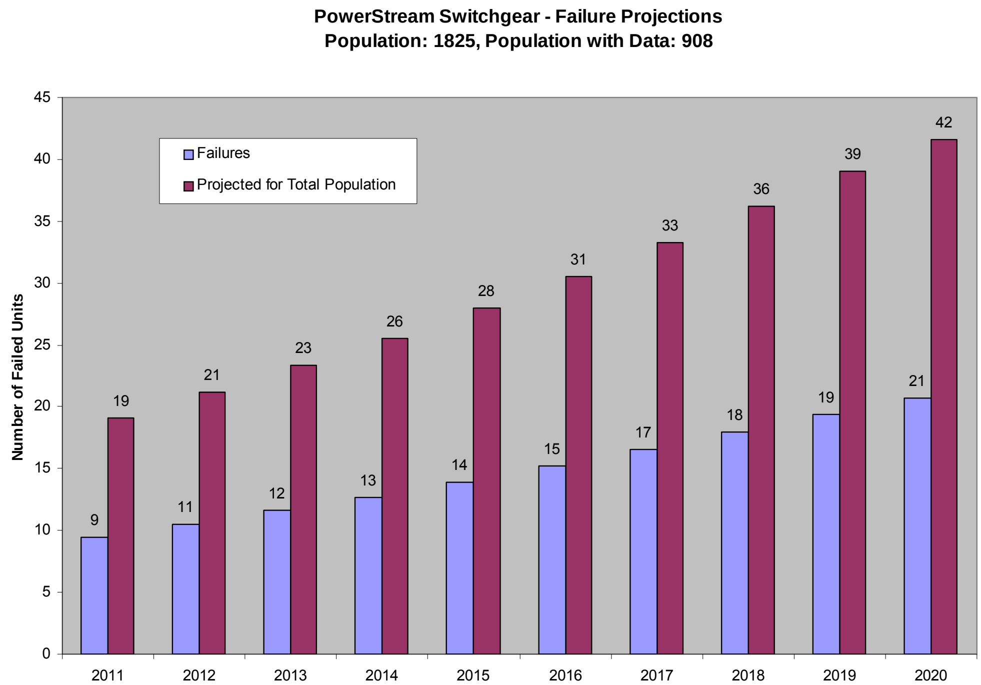


The Condition demographics for Underground Switchgears are shown in the following chart. Budget requirement for emergency replacement of switchgear will be prepared and submitted by Lines Department.



PowerStream had thirty-one, twenty-two, and eighteen Switchgear failures in 2008, 2009, and 2010 respectively (average twenty-three units per year).

The ACA Model projection of future switchgear failures is shown in the following chart.



It is estimated that PowerStream has 138 Switchgear units in very poor and poor condition. To maintain system reliability and customer service, a number of switchgear units will be identified and recommended each year for proactive replacement.

In 2011 budget approval has been obtained for the planned replacement of twelve switchgear units. It is recommended to replace twelve units in 2012, then twenty units per year from 2013 to 2016. At this rate all 138 units will have been replaced by 2018.

It is expected that as the existing distribution switchgear are aging and deteriorating, new inspection and analysis results will show that at the end of the five years, and on a rolling basis, a similar number of switchgear requiring replacement will be generated (ten to twenty units per year). As a result, it is expected that the switchgear replacement program will be an on-going program to maintain the integrity of the distribution system.

Cost of Underground Switchgear Replacement

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
2.4	UG Switchgear Replacement	$720,202	$1,223,872	$1,247,408	$1,270,944	$1,294,480	**$5,756,906**

6.1.2.5 Other Underground Plant Asset Replacement

No other underground plant asset specific replacement is recommended at this time.

6.1.2.6 Cost of Underground Plant Asset Replacement

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
2	**Underground Plant Asset Replacement Programs**	**$6,538,807**	**$20,607,766**	**$21,004,070**	**$21,400,373**	**$20,336,580**	**$89,887,596**

6.1.3 Station Plant Asset Replacement

This category mainly covers the replacement of Station Plant Assets using the ACA Process. It includes the following.

- Station Circuit Breaker Replacement
- Other Station Plant Asset Replacement (Transformer, Primary Switch, Capacitor, Reactor)

6.1.3.1 Station Circuit Breaker Replacement

PowerStream has 388 station circuit breakers in service.

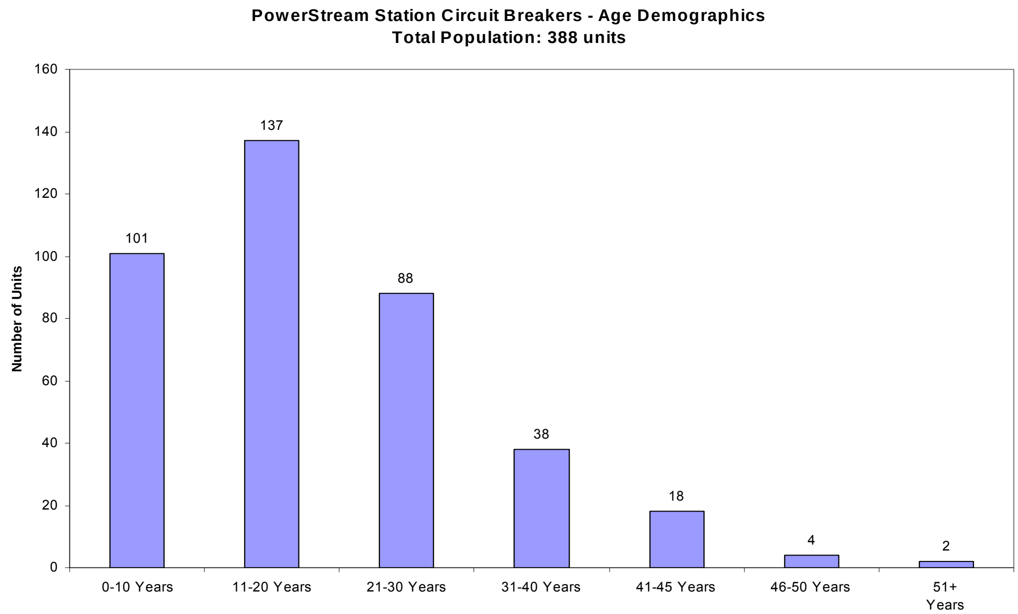
According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

- Useful life of **Station Independent Circuit Breakers** is 35-65 years with typical useful life of 45 years.

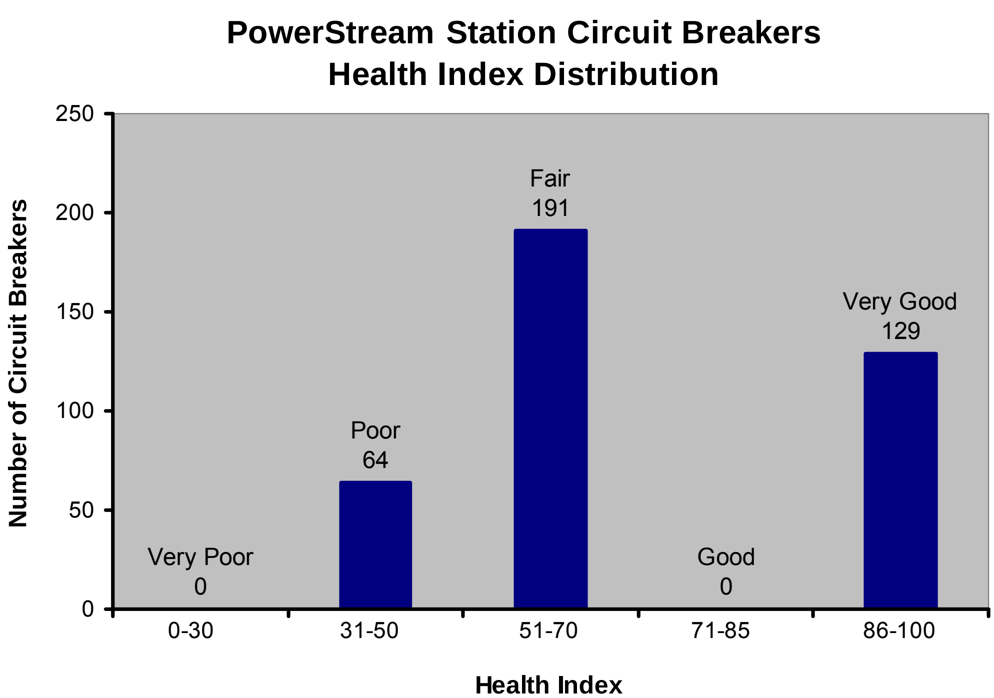
At PowerStream, for IFRS purposes, a useful life of 30 years is used for station circuit breakers.

Of the 388 station circuit breakers PowerStream has in service; six are older than forty-five years.

The Age demographics for station circuit breakers are shown in the following chart.

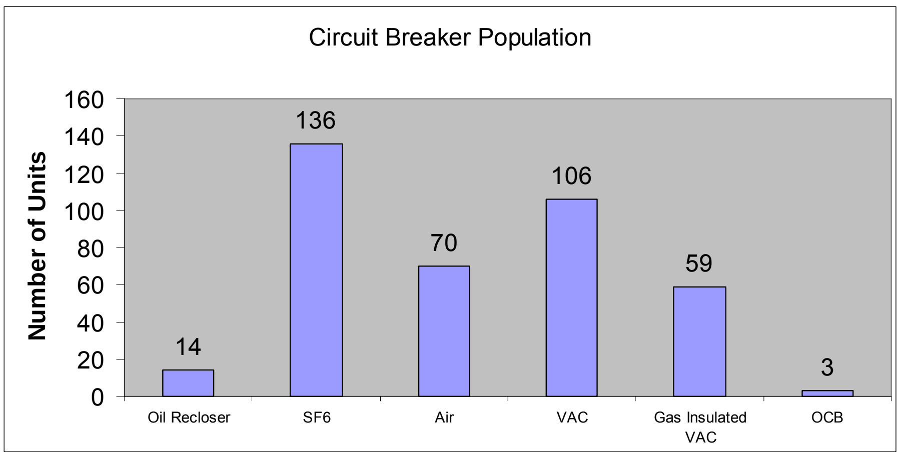


The Condition demographics for station circuit breakers are shown in the following chart.



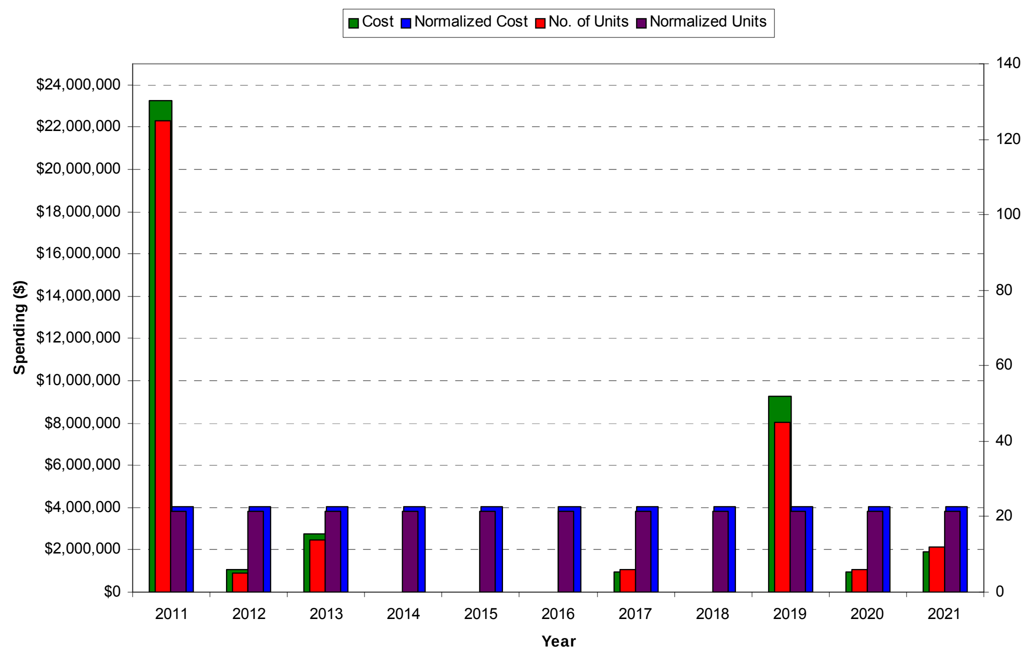
There are six Circuit Breaker types in PowerStream:

- Gas Insulated Vacuum Circuit Breaker
- Oil Circuit Breaker
- Oil Recloser
- Air Circuit Breaker
- Vacuum Circuit Breaker
- SF6 Circuit Breaker



The ACA model recommendations for Circuit Breaker replacement are shown in the following chart.

ACA Spending and Normalized Spending Station Circuit Breakers (TS&MS)



A number of station circuit breaker units (mostly ABB Type HKSA and Outdoor GEC Type OX36) have been identified by the ACA Model as needing replacement, mostly due to age, condition, obsolescence, and historical failures.

There are a total of sixty-four units in the poor condition.

In 2011 budget approval has been obtained for the replacement of ten Circuit Breaker units (first half of Vaughan TS#2 – B Bus, Transformer, and Spare).

To smooth out the budget requirement, it is recommended to replace fewer units per year than indicated by the above chart, but continue to monitor the condition of the Circuit Breakers. Therefore we will replace nine units in 2012, then ten units in 2013, ten units in 2014,eight units in 2015 and eleven units in 2016, on a prioritized basis, according to the following schedule. At this spending level the sixty-four Circuit Breaker units will have been replaced by 2020.

Station Name	No. of Units to Replace	Date to Replace
Vaughan TS#2 (6 on A Bus, 2 Tx CB, 1 BusTie CB)	9	2012
Richmond Hill TS#1 (6 on A Bus, 2 Tx CB, 1 BusTie CB, 1 Spare CB)	10	2013
Richmond Hill TS#1 (6 on B Bus, 2 Tx CB, 2 Spare CB)	10	2014
Markham TS#1 (4 on Y Bus)	4	2015
Markham TS#3 (4 on E Bus)	4	
Markham TS#3 (4 on Z Bus)	4	2016
Markham TS#2 (3 on J Bus and 4 on Q Bus)	7	

<u>Cost of Station Circuit Breaker Replacement</u>

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
3.1	Station Circuit Breaker Replacement	$1,414,072	$1,543,603	$1,403,028	$1,666,820	$1,475,759	**$7,503,282**

6.1.3.2 Other Station Plant Asset Replacement

Under this category the following capital work will be discussed:

- 230 kV Switches
- Primary Switches
- Station Reactors
- Station Capacitors
- MS Transformers
- TS Transformers

<u>230 kV Switches</u>

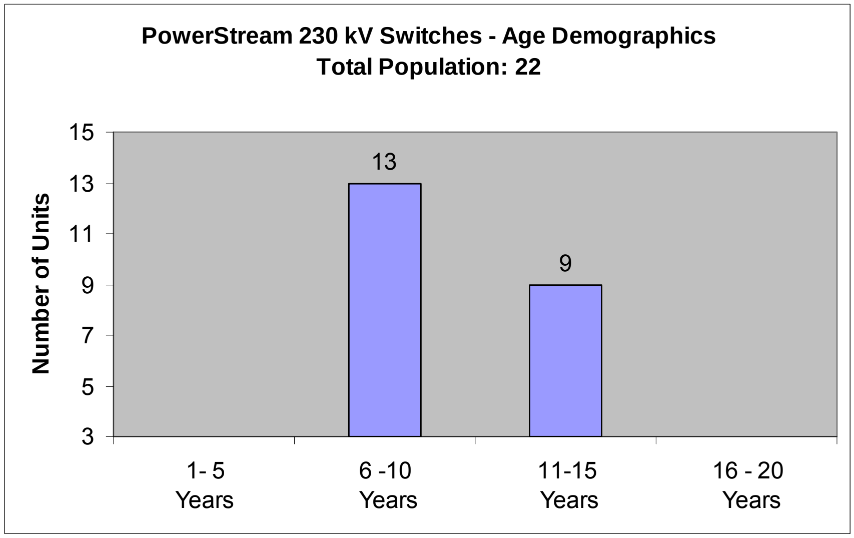
PowerStream has twenty-two 230 kV Switches in service.

According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

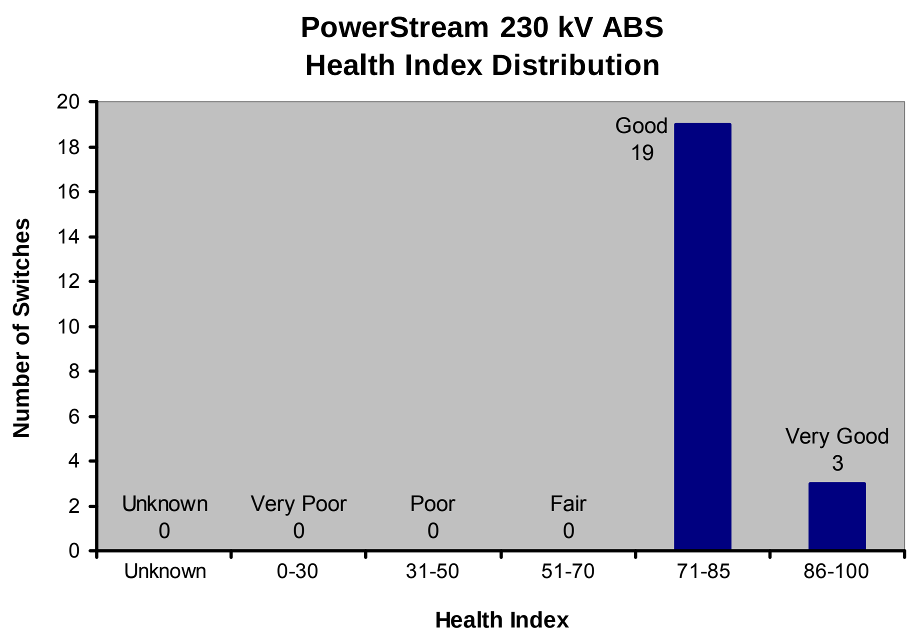
- Useful life of **Station Switches** is 30-60 years with typical useful life of 50 years.

At PowerStream, for IFRS purposes, a useful life of 40 years is used for 230 kV Switches.

The Age demographics for 230 kV ABS are shown in the following chart.



The Condition demographics for 230 kV ABS are shown in the following chart.



There were two Pursley Switches at Richmond Hill TS#1. We replaced one switch in 2011 (RHTS1_T1SW1) due to obsolescence and mechanical failure (failed to open). It is recommended to replace the remaining switch at Richmond Hill TS#1 (RHTS1_T2SW2) in 2012.

<u>Cost of 230 kV Switch Replacement</u>

PowerStream - Capital Work Plan from Planning and Stations						
Category	2012	2013	2014	2015	2016	5 Yr. Total
230 kV Switch Replacement	$71,995	$0	$0	$0	$0	**$71,995**

Primary Switches

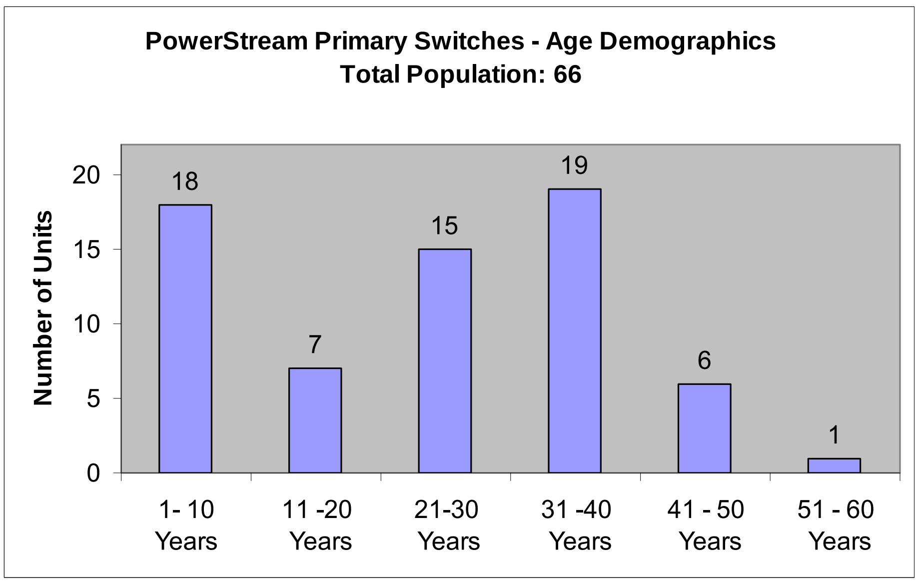
PowerStream has sixty-six Primary Switches in service.

According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

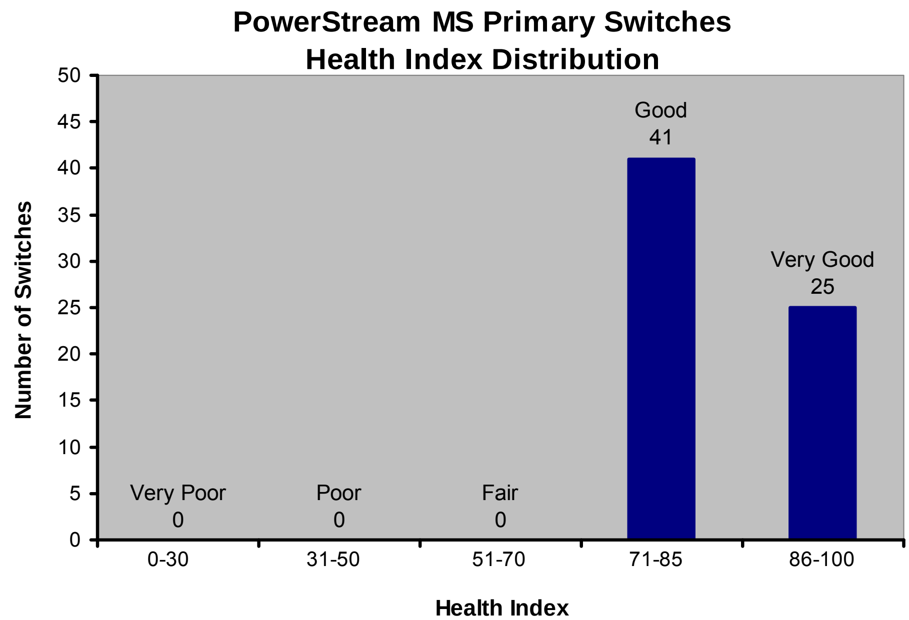
- Useful life of **Station Switches** is 30-60 years with typical useful life of 50 years.

At PowerStream, for IFRS purposes, a useful life of 40 years is used for Primary Switches.

The Age demographics for MS Primary Switches are shown in the following chart.



The Condition demographics for MS Primary Switches are shown in the following chart.



No replacement is recommended at this time.

Station Reactors

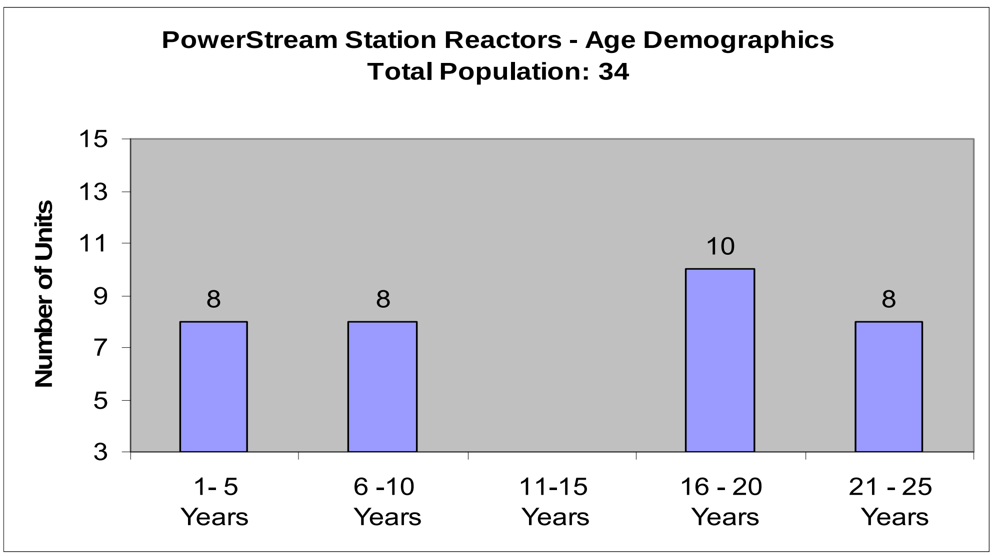
PowerStream has thirty-four Station Reactors in service.

According to **Kinectrics Inc. Report "Asset Amortization Study for PowerStream"**:

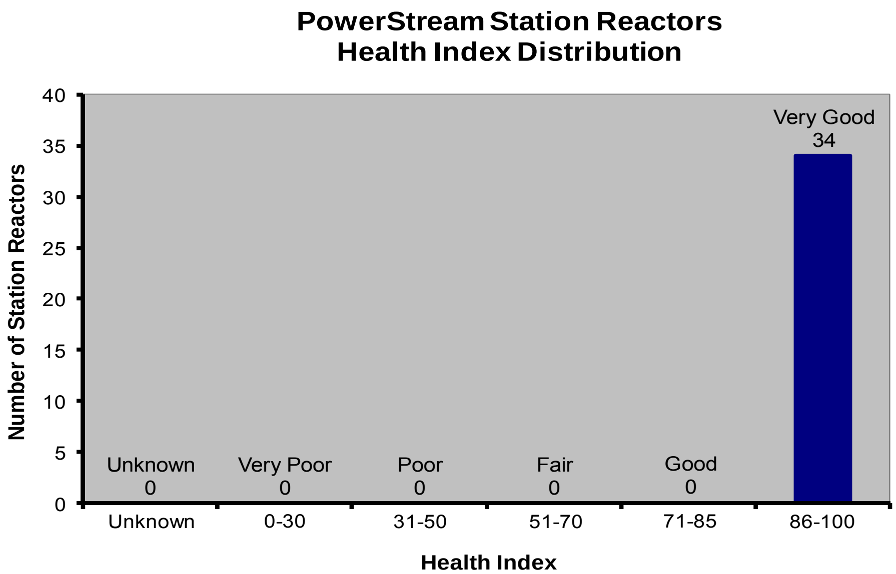
- Useful life of **Inductors** is 25-60 years with typical useful life of 45 years.

At PowerStream, for IFRS purposes, a useful life of 40 years is used for Station Reactors.

The Age demographics for Station Reactors are shown in the following chart.



The Condition demographics for Station Reactors are shown in the following chart.



No replacement is recommended at this time.

Station Capacitors

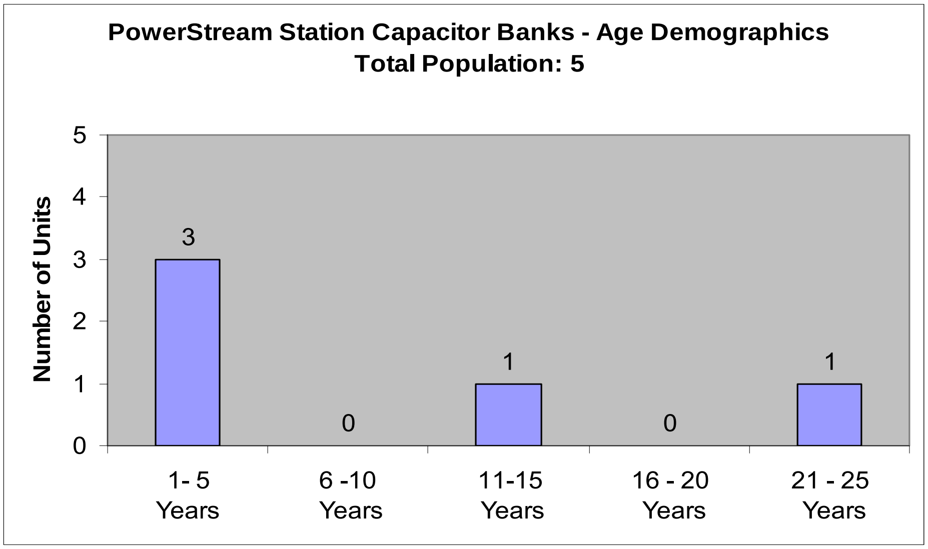
PowerStream has five Capacitor Banks in service.

According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

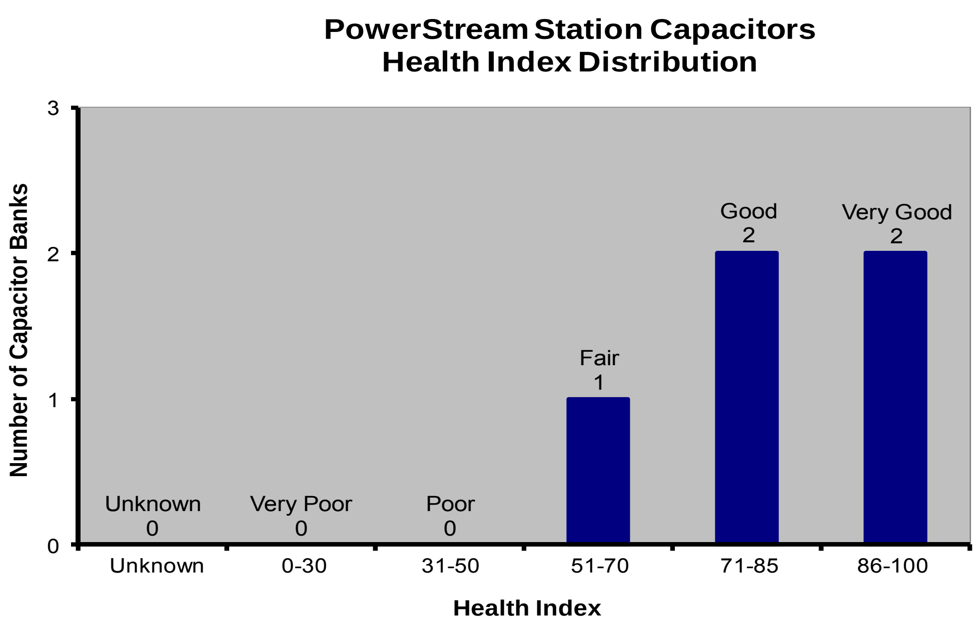
- Useful life of **Capacitor Banks** is 25-40 years with typical useful life of 30 years.

At PowerStream, for IFRS purposes, a useful life of 30 years is used for Capacitor Banks.

The Age demographics for Station Capacitor Banks are shown in the following chart.



The Condition demographics for Station Capacitor Banks are shown in the following chart.



The consequence of failure of the Capacitor bank is very low. Generally, only individual can(s) will fail within the Capacitor bank; in those cases, the individual can(s) will be replaced without causing customer outages. In addition, PowerStream has a Station Maintenance program in place to monitor the Capacitor banks. Therefore no replacement is recommended at this time.

<u>MS Transformers</u>

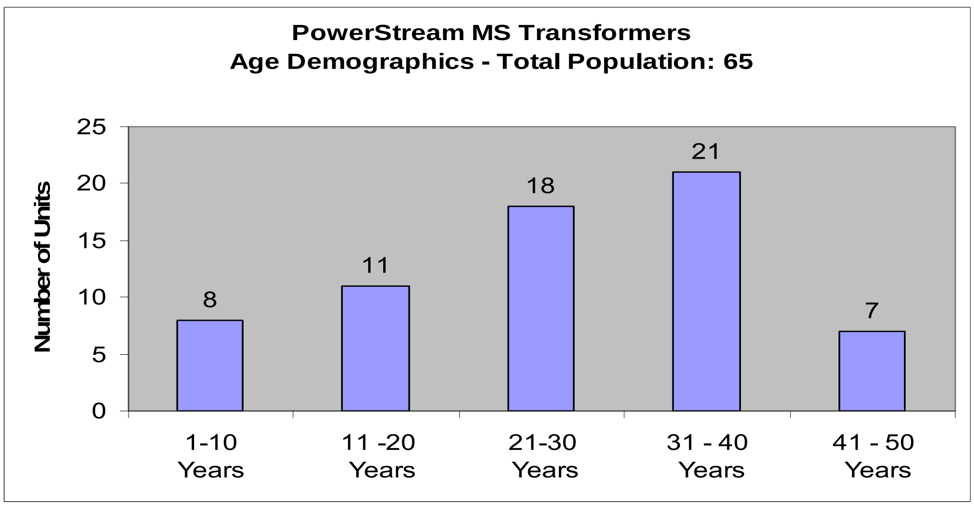
PowerStream has sixty-five MS Transformers in service.

According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

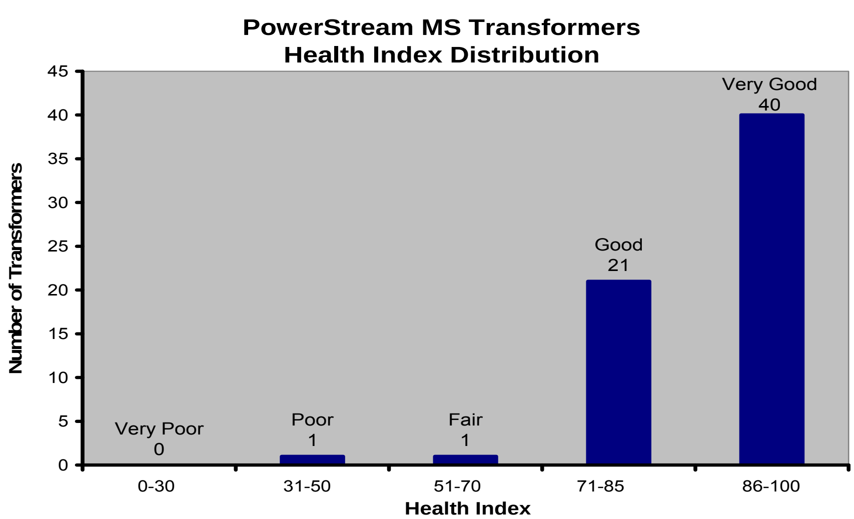
- Useful life of **Power Transformers** is 30-60 years with typical useful life of 45 years.

At PowerStream, for IFRS purposes, a useful life of 40 years is used for MS Transformers.

The Age demographics for MS Transformers are shown in the following chart.



The Condition demographics for MS Transformers are shown in the following chart.



The unit indicated as poor in the above chart is out of service. Therefore no replacement is recommended at this time.

<u>TS Transformers</u>

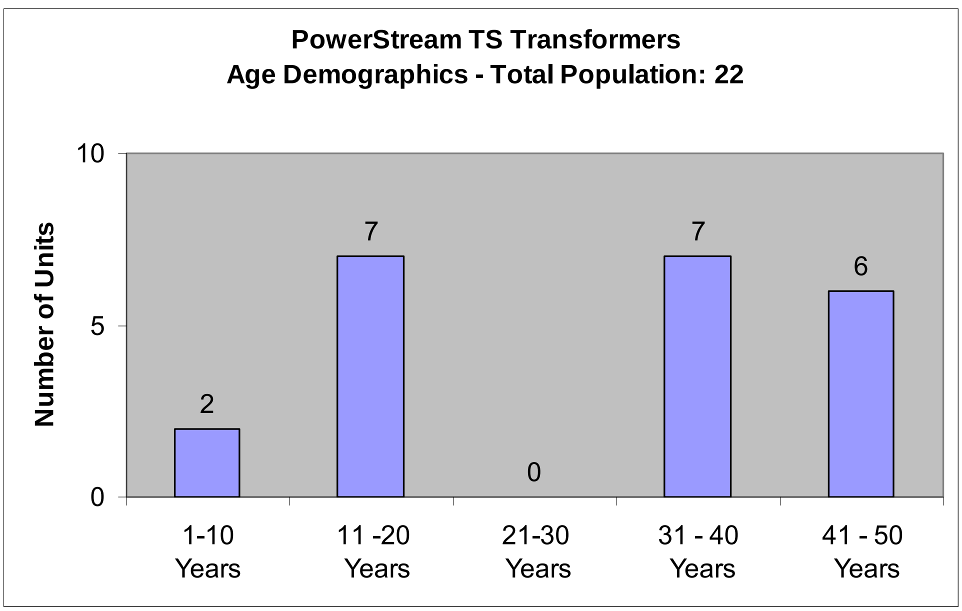
PowerStream has twenty-two TS Transformers in service.

According to **Kinectrics Inc. Report "Asset Amortization Study for the Ontario Energy Board"**:

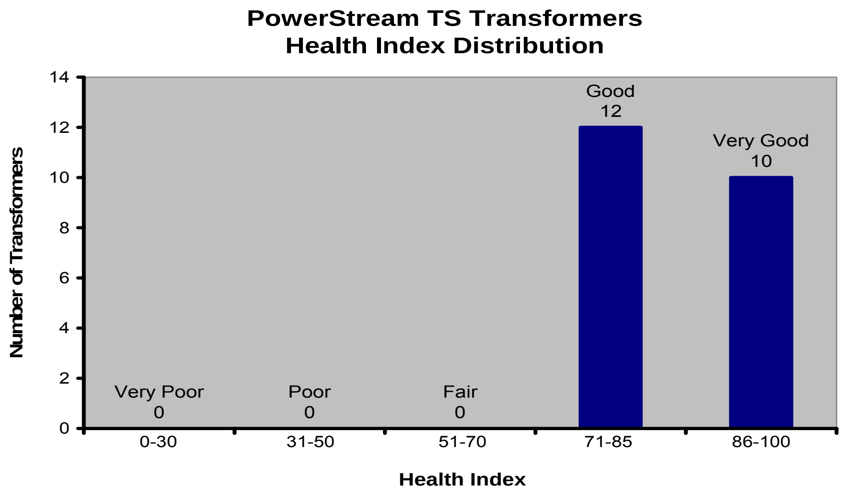
- Useful life of **Power Transformers** is 30-60 years with typical useful life of 45 years.

At PowerStream, for IFRS purposes, a useful life of 40 years is used for TS Transformers.

The Age demographics for TS Transformers are shown in the following chart.



The Condition demographics for TS Transformers are shown in the following chart.



No replacement is recommended at this time.

6.1.3.3 Cost of Station Plant Asset Replacement

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
3	Station Plant Asset Replacement Programs	$1,486,067	$1,543,603	$1,403,028	$1,666,820	$1,475,759	$7,575,277

6.1.4 Cost of Replacement Program

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
1a	Replacement Program	$10,996,930	$25,655,359	$25,978,472	$26,705,952	$25,518,482	$114,855,194

6.2 Sustainment Driven Lines Projects

This category mainly covers the Lines projects that are not capacity driven. It includes the following:

- Lines Projects (not capacity driven)

6.2.1 Lines Projects (not capacity driven)

This category is mainly for those projects that are not capacity driven, but are required to sustain the distribution system. It includes the following:

- Conversion Project
- System Re-configuration Project

- Radial Supply Remediation Project
- Distribution Automation Project
- Reliability Driven Project

6.2.1.1 Conversion Projects

The objective of voltage conversion projects is to improve power supply reliability, and reduce line losses and maintenance.

In Power Stream North (Barrie, Bradford, Alliston, Thornton, Penetanguishene, Beeton & Tottenham) there are three distribution voltages: 4.16 kV, 8.32 kV and 13.8 kV. These voltages are well established within their particular supply area and there are no plans to carry out planned voltage conversion in PowerStream North.

There are three distribution voltages in Power Stream South (Markham, Richmond Hill and Vaughan, and Aurora) network: 27.6 kV, 13.8 kV and 8.32 kV. For the most part, PowerStream uses the 27.6 kV voltage level to distribute electricity. A small amount of load (2%) is supplied at 13.8 kV or 8.3 kV from MS's.

The 13.8 kV and 8.3 kV systems are fed from substations in Vaughan and Markham in the form of isolated islands. There are two 27.6 kV/13.8 kV substations and two 27.6 /8.3 kV substations in Markham. There are three 27.6/8.3 kV substations and one 27.6/13.8 kV substation and in Vaughan. There are no 13.8 kV or 8.3 kV systems in Richmond Hill.

A MS typically comprises one or two step down (27.6/8.3 or 13.8 kV) transformers, and associated switches, circuit breakers that are enclosed within a fenced area.

The MS are very lightly loaded due to voltage conversion efforts made in the past. For example, the transformer capacity in Rainbow MS is 13.3 MVA, but the peak load on the transformers was 0.6 MW in 2010.

The presence of 13.8 kV and 8.3 kV systems causes extra losses on the system due to 27.6 kV/13.8 kV or 27.6 kV/8.3 kV transformation and higher losses in 13.8 kV and 8.3 kV feeders.

The 13.8 kV and 8.3 kV systems are also costly in that additional 13.8 kV & 8.3 kV rated equipment has to be carried in inventory even though the 13.8 kV and 8.3 kV systems supply only 2% of system loads. The MS stations were built between 1958 and 1976. Some units are approaching end-of-life and there is potential for significant expenditure to repair and replace aging units. Amber, Morgan, John and Elder Mills substations have experienced power transformers failures between 1989 and 2010.

Low voltage supply areas are located in isolated areas similar to “islands”. Some of them are supplied by one single transformer or single feeder. Any transformer or feeder failure will cause prolonged outage to the customers.

Net Present Value (“NPV”) method is used to justify voltage conversion projects.

Cost of Conversion Projects

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
4.1	Conversion Projects	$693,563	$1,835,600	$530,000	$1,431,000	$0	$4,490,163

6.2.1.2 System Re-configuration Projects

System Planning, in consultation with System Control and Lines, recommend a number of projects to resolve feeder loading balancing and load transfer capability under normal and emergency situations. Operations and safety issues will be considered.

Cost of System Re-configuration Projects

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
4.2	System Reconfiguration Projects	$1,351,768	$520,000	$0	$0	$0	$1,871,768

6.2.1.3 Radial Supply Remediation Projects

Distribution networks can be designed to distribute power in a number of different ways depending on the nature of the load and the level of reliability needed. There are five types of networks: Radial, Dual Radial, Closed Loop, Open Grid (Open Loop), and Network Supply.

Open Grid is the most common method of supply in urban areas. The primary reason is that it is less costly than other systems, and provides a reasonable level of reliability. It is also much simpler to analyze, plan, design and operate. In the Open Grid network, multiple feeders traverse a distribution area with multiple interconnections between the feeders at various points, i.e. normal open points. In the event of a fault on a feeder or loss of supply to a particular feeder, adjacent feeders could pickup supply to customers, except for those customers in the faulted area. The ability of adjacent feeders to pickup load is limited by the preloaded state and spare capacity available.

PowerStream's distribution network has been designed as an Open Grid network. "PowerStream Planning Philosophy" recommended to continue with the current open grid feeder design and to provide for full backup capability over peak loading periods through switching of load to adjacent feeders.

Radial supply situations do exist in PowerStream South. A report titled "PowerStream Radial Supply Review" was completed in 2007 to review radial supplies in PowerStream South and recommend necessary remediation to minimize the impact of radial supplies at reasonable cost.

PowerStream North also has areas that are supplied radially; however, no study has been carried out to identify the specific areas. A study to identify areas that are radially supplied will be carried out in 2012.

Cost of Radial Supply Remediation Projects

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
4.3	Radial Supply Remediation Projects	$306,000	$312,000	$1,393,900	$351,000	$2,032,800	$4,395,700

6.2.1.4 Distribution Automation Projects - Lines

Distribution automation switches/reclosers are proposed to be installed at strategic locations to achieve the following two objectives:

1. To reduce feeder down time in case of outages
2. To reduce number of customers affected by outages

It is estimated that there is an incremental outage time saving of thirty minutes between manual switching versus remote automatic switching which is estimated to save 6000 CMI/year on one automatic switch installation.

Every year PowerStream planning department ranks Feeders based on the FAIDI, FAIFI and SAIFI contributions to the systems and determines Worst Performing Feeders. Planning also reviews the outage causes, the load on the feeders and location of existing automatic switches and calculates the benefits (CMI reduction) of installing additional switches and re-closers. Typically radial feeders divided into half are expected to improve the reliability by 25%, and radial feeders divided into thirds improve the reliability to 33%.

In addition, we have approximately forty existing overhead RTU controlled switches that are at or close to end-of-life (fail to close/open remotely). It is recommended that these units be replaced with automatic switches over the next five years at a rate of eight units per year.

In 2011 budget approval has been obtained for the installation of fifteen Automated Switches. It is recommended to install and replace twenty-three units in 2012, then twenty-eight units in 2013 through 2016.

Cost of Distribution Automation Projects - Lines

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
4.4	Distribution Automation Projects	$2,415,961	$2,407,576	$2,453,876	$2,500,175	$2,546,475	**$12,324,062**

6.2.1.5 Reliability Driven Projects

PowerStream system reliability performance over the last three years (2008, 2009, and 2010), are shown in Table below.

CATEGORY	SAIDI (hr)	SAIFI	CAIDI (hr)	IOR
LOS & MEDS Included	1.399	1.206	1.149	0.999840
LOS Excluded	1.078	1.006	1.04	0.999877
LOS and MED Excluded	0.875	0.941	0.918	0.999900

PowerStream has a target of achieving 99.999% Reliability ("Five 9's", IOR = 0.99999) by the end of 2015. PowerStream Reliability Committee has a five year work plan, subject to budget approval, to achieve the corporate target.

This reliability work plan examines all the factors that have impacts on reliability, discusses the initiatives that have positive impact on reliability, and recommends projects and associated cost to improve reliability over the next five years.

Work programs include analyzing the outages causes; determining ways to improve service restoration time; Worst Performing Feeders designation and maintenance; distribution automation; and inspection and training of contractors/personnel, and transformer bushing/elbow replacement.

Improving Service Restoration Times:

The initiatives under this program are geared to improve the trouble crew coverage and response time in an event of a fault and are funded through Lines Maintenance programs.

Worst Performing Feeder

Each year PowerStream planning looks at average three year FAIDI, FAIFI and SAIDI contribution of the feeder to the overall indices to identify the Worst Performing Feeders (“WPF”)so that remediation work can be prioritized on a feeder-by-feeder basis.

This feeder specific work plan is funded through Lines Maintenance programs, and includes the following:

- Feeder Patrol
- Tree Trimming
- Wildlife Guard
- Infrared Inspection
- Insulator Washing
- Lightning Arrestor
- Fault Indicator
- Feeder Re-configuration
- Feeder Protection Review

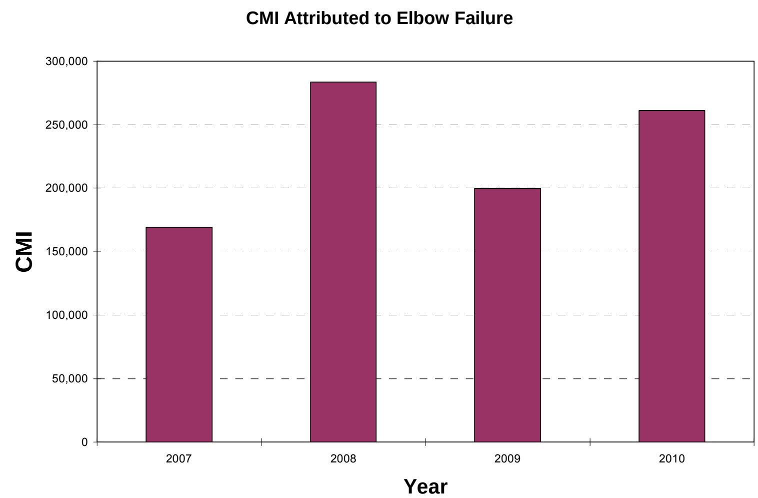
Inspection and Training

Effective inspection and maintenance programs help identify potential reliability problems, and initiate remedial actions to prevent or reduce the extent of future outages.

It is recognized that work on distribution assets require a trained workforce and it is also essential to ensure that the contractors working on PowerStream’s system are trained. This program includes work specific training (e.g. splicing) to PowerStream staff and contractors, and are funded through Lines Maintenance programs.

Bushing/Elbow Replacement Program on Pad Mounted Transformer

One of the identified initiatives at PowerStream is to look at equipment failures and determine programs that can address the component failures. The following chart indicates Customer Minutes Interrupted ("CMI")'s attributed to Elbow/Bushing failures.



Literature review and manufacturer's data suggest that there should be active maintenance program. Often the failure of the elbow/bushing leads to the failure of the transformers due to arcing. Cost/benefit analysis suggests that we develop an active monitoring and maintenance program for separable insulated connectors (SICs). By testing in one specific area it was determined that 2% of the elbow/bushing needed replacement. PowerStream has about 35,000 padmount transformers. We propose to replace 500 bushing/elbows per year through a program. This is done on a prioritized basis based on inspection and infrared results.

By conservative estimates a targeted elbow bushing replacement in two services area (Markham/Richmond Hill) can lead to a 75,000 CMI savings/year based on the data for the last four years.

Cost of elbow/bushing replacement: $200/unit

Number of elbow/bushing to be replaced: 500 units/year

Total Cost of program: $100,000/year - to be prepared and submitted by Engineering Planning.

<u>Cost of Reliability Driven Projects</u>

The table below is based on the elbow/bushing replacement cost.

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
4.5	Reliability Driven Projects	$102,000	$104,000	$106,000	$108,000	$110,000	**$530,000**

6.2.1.6 Safety, Environment Driven Projects at Lines

This category covers the capital work that PowerStream must complete to comply with Health, Safety and Environmental regulations, standards and guidelines. There is no specific Safety, Environmental driven project or program recommended by system planning at this time.

6.2.1.7 Compliance to External Directives / Standards at Lines

This category covers the capital work that PowerStream must complete to comply with external directives/standards such as:

- OEB (e.g. Long Term Load Transfer, Distribution System Code)
- OPA
- ESA (e.g. Ungrounded Delta Transformers, Clearance)
- IESO
- Other Regulatory Standards (CSA)

<u>Long Term Load Transfers</u>

Section 6.5 of the Distribution System Code covers Long Term Load Transfers ("LTLT"). LDC's have until June 30, 2014 to complete the Long Term Load Transfers. Also, starting November 2011, the OEB will require an updated Implementation Plan from the LDC's.

A total of 108 LTLT customers exist in proximity to service area boundaries between Hydro One Networks and PowerStream North. There are seventy-two Hydro One Networks' LTLT customers to be transferred from Hydro One Networks to PowerStream. There are seventeen LTLT customers to be transferred from PowerStream to Hydro One Networks. There are nineteen LTLT customers to remain as Hydro One Networks customers.

PowerStream is in the process of formulating a Plan to eliminate all LTLT by late 2013.

<u>Ungrounded Delta Transformers</u>

Majority of 600 V customers use four wire grounded wye system; however, some customers are supplied by delta ungrounded system. As per metering department, 2700 self contained and 1000 transformer rated delta smart meter units have been deployed. ESA does not have preference on Delta or Wye supply transformers, as long as the Code requirements for each installation are satisfied.

Most of the delta ungrounded transformers are supplied from the low voltage system (13.8 kV and 8.32 kV) in PowerStream. PowerStream has been in the process to convert these voltages to 27.6 kV supply. PowerStream has converted a few transformers under emergency condition or as temporary solution from a delta ungrounded supply (3 phase, 3 wire) to a Wye grounded supply (3 phase, 4 wire) in the system, and the neutral is not connected and left floating.

ESA stated that:

> "Floating the neutral when replacing the delta with a Wye is not code compliant as per the Ontario Safety Code ("OESC"). Recognizing that it is done under emergency condition, but sometimes this temporary solution remains as the permanent installation, in that case code requirements needs to be satisfied."

Electric Safe Code Rule 10-204 requires that the new 3 phase, 4 wire system be connected to a grounding conductor at each individual service. In most cases, there will be no system grounded conductor (neutral) run to each consumer's service and no neutral conductor installed as part of the existing delta connected consumer's service.

PowerStream will be responsible for the cost of the 3 wire to 4 wire conversion including all modifications required at the customer premises since these conversion were initiated by PowerStream. ESA Bulletin 10-22-0 has to be followed in the 3 wire to 4 wire conversion.

To meet ESA requirement, PowerStream will gradually eliminate the floating neutral in the system. The estimated average cost for converting 600 V Delta to 600 V Wye system is estimated to be $2,500 per customer if the supply is overhead and $10,000 per customer if the supply is underground.

ESA Clearance Issues

The proposed work program from 2011 to 2016 will mitigate clearance issues in the PowerStream North service territory at various locations in Alliston and Tottenham to comply with ESA and CSA

Rules. Ontario Electrical Safety Code Rule 75-312 & CSA 22.3 No.1-06 both state that the minimum horizontal & vertical clearance to a building, structure, etc. is 3m (10ft.) & 4.8m (16ft), respectively. PowerStream has adopted the above “Rule” and has issued Construction Standard 03-4 to comply with CSA and the Electrical Safety Code.

<u>Cost of Compliance to External Directive / Standards Projects</u>

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
4.7	Compliance to External Directives / Standards Lines	$918,000	$936,000	$848,000	$864,000	$880,000	$4,446,000

6.2.2 Cost of Sustainment Driven Lines Projects

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
1b	Sustainment Driven Lines Projects	$5,787,292	$6,115,176	$5,331,776	$5,254,175	$5,569,275	$28,057,694

6.3 Transformer / Municipal Station Projects (not capacity driven)

This category covers stations projects that are not capacity driven. It includes the following:

- Station Projects at TS (not capacity driven)
- Station Projects at MS (not capacity driven)

6.3.1 Station Projects at TS (not capacity driven)

This category covers TS stations projects that are not capacity driven. It includes the following:

- Transformer Station Projects (not capacity driven)
- Safety, Environment Driven Projects at TS
- Compliance to External Directives / Standards at TS
- Distribution Automation at TS

6.3.1.1 Transformer Station Projects (not capacity driven)

This category is for those TS projects that are not capacity driven, but are required to sustain PowerStream’s fleet of eleven TS’s. Sustainment activities include projects to: replace worn out equipment, improve reliability, enhance operability & maintainability, and to improve & maintain safety.

PowerStream's fleet of eleven transformer stations can be divided into two groups:

- Jones – A Jones station consists of two 50/83 MVA two winding transformers, two main breakers, a bus tie breaker and eight feeders. There are five Jones stations, of which two are equipped with single 20 MVar capacitor banks and breakers.
- Bermondsey - A Bermondsey station consists of two 75/125 MVA three winding transformers, four main breakers, a bus tie breaker and twelve feeders. There are six Bermondsey stations, of which three are equipped with dual 20 MVar capacitor banks and breakers.

The graph below shows the number of each type of transformer station as well as an indication of the ages of the stations.

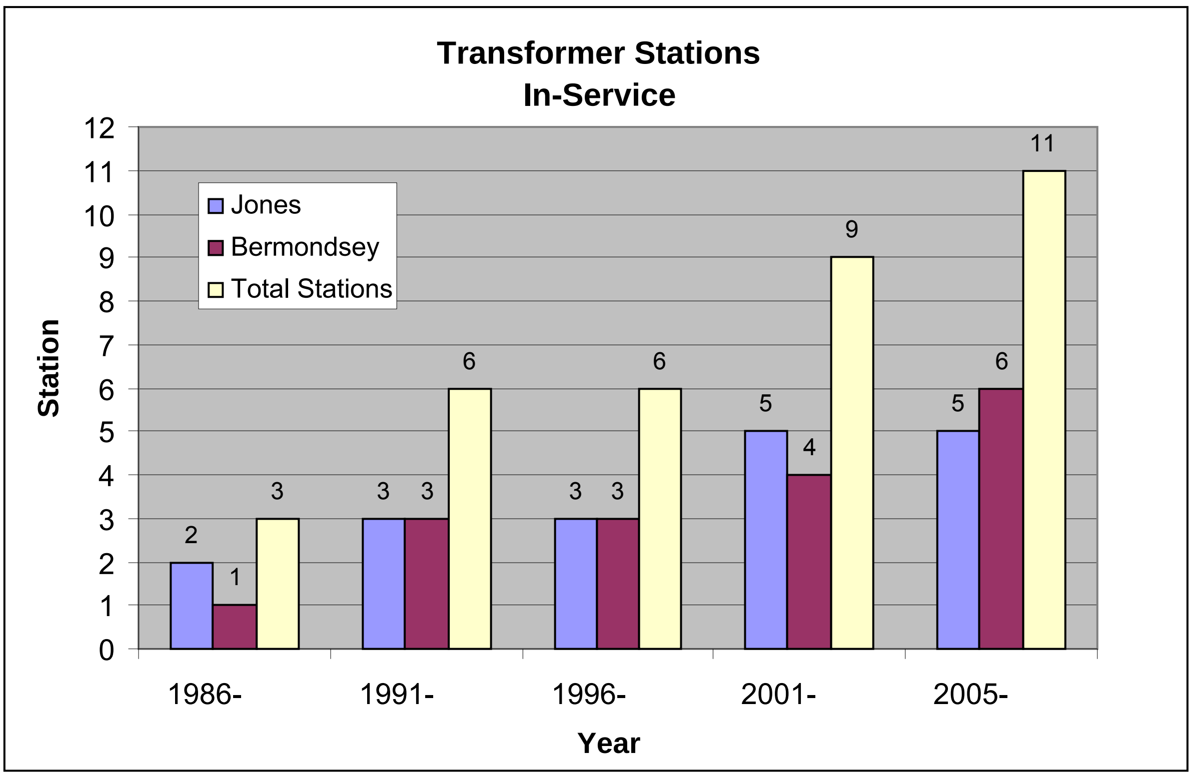


Figure 6.1 - Transformer Stations In-Service Dates

As can be seen from Figure 6.1; PowerStream's fleet of stations ranges in age from nearly new to over twenty years old. A number of trends and challenges have arisen as time has passed and as the stations have aged, as follows:

- Rising fault levels on the Bulk Electrical System, coupled with the requirement to accommodate renewable generators that further increase the fault levels at our stations and on our 28kV feeders has created a requirement to reduce fault levels on the 28kV busses at two of our TS's by introducing fault level limiting air core reactors.

- PowerStream has adopted a *Trip Saving* feeder protection strategy. As a result, the obsolete feeder protections need to be upgraded at two of our stations in Markham.
- A number of the 28kV transformer bushings have a design flaw that shortens their useful life. This problem became evident on one of the 230/28kV transformers at Markham TS#1 where a bushing failed and started a fire. As a result, we have a multi year program to replace all of this type of bushing and to install on-line bushing monitoring.
- Due to the increasing costs of copper, steel and mineral oil; the replacement cost of our station transformers has increased to about three million dollars each. For this reason we have initiated a program to install on-line monitoring equipment on the station transformers in an effort to detect incipient problems and take proactive steps to correct the causes of problems, instead of waiting for the transformer fail to then repairing or replacing it. The three stations in Markham have been equipped with the on-line monitoring equipment. A multi-year program is in place to equip the remaining station transformers in Richmond Hill and Vaughan.
- Since September 11, 2001 there has been a heightened awareness of the need for physical and cyber security at our stations. Also, as the price of copper has been increasing; there has been a corresponding increase in copper theft from our stations that has increased the need for security. For these reasons we have embarked on a multi year program to install video surveillance and improve outdoor lighting at our stations.
- In response to increased cyber threats and attacks on electrical utilities; the North American Electrical Reliability Corporation ("NERC") has developed a set of Critical Infrastructure Protection ("CIP") standards. The Ontario IESO has adopted these standards and requires *Generators* and *Transmitters* in Ontario to comply with them. PowerStream is a *Distributor* and is not yet required to comply with the NERC CIP standards. However, PowerStream's transformer stations are connected directly to the Bulk Electricity System ("BES"). For this reason and, because the CIP standards

are viewed as good utility practices; PowerStream has voluntarily adopted the CIP standards. A number of station projects are planned to improve our cyber security by implementing the CIP standards.

- The IESO requires that stations connected to the BES have 90% or better power factor. For this reason capacitors have recently been installed at Vaughan TS #2. We expect to be required to add capacitor banks at stations in Richmond Hill and Markham.

Cost of Transformer Station Projects (not capacity driven)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
5.1	Station Projects at TS (not capacity driven)	$1,461,036	$1,367,823	$1,813,806	$414,826	$1,629,297	**$6,686,788**

6.3.1.2 Safety and Environment Driven Projects at TS

There are no specific Safety & Environment driven projects or program at TS recommended by system planning at this time.

6.3.1.3 Compliance to External Directives / Standards at TS

There is no specific Compliance to External Directives / Standards at TS driven project or program recommended by system planning at this time.

6.3.1.4 Distribution Automation at TS

Automatic feeder restoration projects are planned for Vaughan TS#1 and Markham TS#3. These projects are a Station Design initiative, to develop the intelligent fault isolating strategies needed to improve PowerStream's reliability. The VTS#1 project involves the implementation of an Automatic Feeder Restoration proof of concept on four feeders: 20M11, 20M12, 20M21 and 20M22. The MTS#3 project involves the implementation of an Automatic Feeder Restoration proof of concept on three feeders: 26M14, 26M17 and 26M18. The projects are expected to reduce the annual average CMI on these seven feeders by a total of 885,218 minutes.

Cost of Distribution Automation at TS

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
5.4	Distribution Automation at TS	$346,438	$275,311	$0	$0	$0	$621,749

6.3.1.5 Cost of All Station Projects at TS (not capacity driven)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
5	Station Projects at TS (not capacity driven)	$1,807,473	$1,643,134	$1,813,806	$414,826	$1,629,297	$7,308,536

6.3.2 Station Projects at MS (not capacity driven)

This category covers TS stations projects that are not capacity driven. It includes the following:

- Station Projects at MS (not capacity driven)
- Safety, Environment Driven Projects at MS
- Compliance to External Directives / Standards at MS
- Distribution Automation at MS

6.3.2.1 Station Projects at MS (not capacity driven)

This category is for those MS projects that are not capacity driven, but are required to sustain PowerStream's fleet of fifty-four MS's. Sustainment activities include projects to: replace worn out equipment, improve reliability, enhance operability & maintainability, and to improve & maintain safety.

PowerStream's fleet of fifty-four Ms's can be divided into two groups:

- 44 kV Primary Voltage – The 44 kV MS's are supplied from Hydro One TS's in Alliston, Aurora, Barrie, Beeton, Bradford, Penetang, Thornton and Tottenham. These stations typically have one or two transformer with a 44 kV primary winding & a 4 to 13.8 kV secondary winding and two to four feeders.
- 28 kV Primary Voltage – The 28 kV MS's are supplied from PowerStream TS's in Markham and Vaughan. These stations typically have one or two transformers with a 28 kV primary winding, a 13.8 kV secondary winding and four feeders.

The graph below shows the number of each type of MS as well as an indication of the ages of the stations.

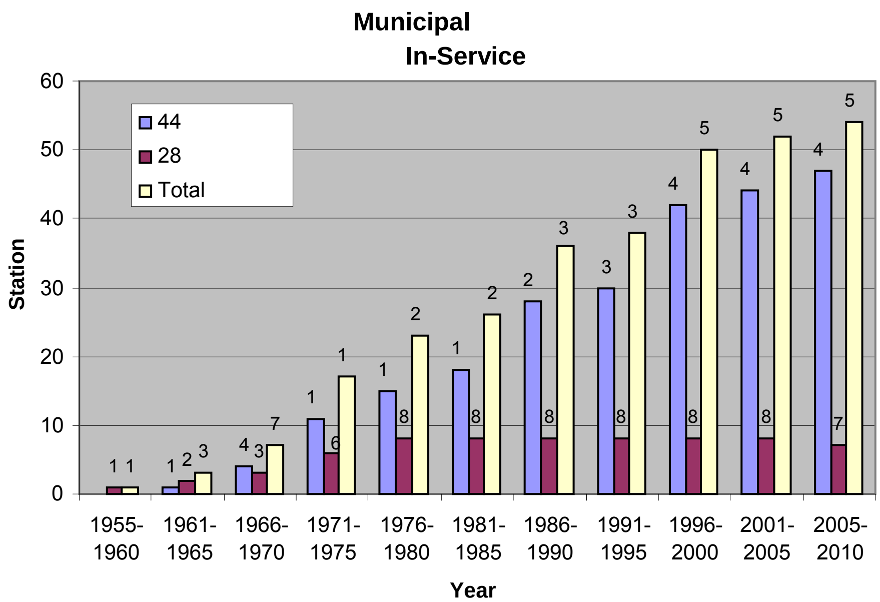


Figure 6.2 - Municipal Stations In-Service Dates

As can be seen from Figure 6.2; PowerStream's fleet of MS's ranges in age from nearly new to over fifty years old. A number of trends and challenges have arisen as time has passed and as the stations have aged, as follows:

- Due to the increasing costs of copper, steel and mineral oil; the replacement cost of our municipal station transformers has increased significantly. For this reason we have initiated a program to install on-line monitoring equipment on the larger, 10 to 20MVA transformers, in an effort to detect incipient problems and take proactive steps to correct the causes of problems, instead of waiting for the transformer fail to then repairing or replacing it. The 20MVA transformers in Barrie have already been equipped with on-line monitoring equipment. A multi-year program is in place to equip the station transformers in Aurora and to add on-line gas-in-oil monitoring to the 20MVA transformers in Barrie.
- Since September 11, 2001 there has been a heightened awareness of the need for physical security at our stations. Also, as the price of copper has been increasing; there has been a corresponding increase in copper theft from our stations that has increased the need for security. For these reasons we have embarked on a multi year program to install video surveillance at our larger municipal stations.

- The MOE has enacted legislation regarding and prohibiting oil spills. PowerStream's 230/28 kV transformers all have oil containment facilities. All MS's built since 2007 and many of the larger municipal station transformers have been equipped with oil containment. A multi year program is in place to equip the remaining MS transformers with oil containment.
- Many of the older MS's are equipped with reclosers and interrupters that are in need of replacement or refurbishment.

Cost of Station Projects at MS (not capacity driven)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
6.1	Station Projects at MS (not capacity driven)	$886,826	$2,280,010	$639,580	$545,791	$555,898	**$4,908,104**

6.3.2.2 Safety, Environment Driven Projects at MS

There are no specific Safety & Environmental driven projects or programs at MS's recommended at this time.

6.3.2.3 Compliance to External Directives / Standards at MS

There is no specific Compliance to External Directives / Standards at MS driven project or program recommended at this time.

6.3.2.4 Distribution Automation at MS

There is no specific Distribution Automation at MS driven project or program recommended at this time.

6.3.2.5 Cost of All Station Projects at MS (not capacity driven)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
6	**Station Projects at MS (not capacity driven)**	**$886,826**	**$2,280,010**	**$639,580**	**$545,791**	**$555,898**	**$4,908,104**

6.3.3 Cost of Transformer / Municipal Station Projects (not capacity driven)

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
1d	**Transformer / Municipal Station Projects**	**$2,694,299**	**$3,923,144**	**$2,453,386**	**$960,617**	**$2,185,195**	**$12,216,641**

6.4 Growth Driven Transformer / Municipal Stations – Additional Capacity

This category covers the following:

- Growth Driven Station Projects at TS
- Growth Driven Station Projects at MS

6.4.1 Growth Driven Station Projects at TS

The goal of these projects is to maintain sufficient system capacity to supply load growth in PowerStream.

PowerStream Planning Philosophy approved in 2007 recommended:

Adopt station transformer loading of 1.4 per unit (pu) and 1.6 per unit (pu) of forced cooled rating, for summer and winter, respectively and accept an annual insulation loss of life of 2%.

This overloading is referred to as the ten day LTR.

There are constraints that must be considered when developing potential options. These are:

- The availability of adequate 230 kV supply;
- The availability of land, preferably close to the area of expected load growth and adjacent or near existing 230 kV lines;
- The suitability of the option based on the Class EA requirements.

PowerStream performs annual load forecast and system capacity adequacy assessment to assess future need for additional transformation and distribution facilities for PowerStream service territory.

The PowerStream Load Forecast 2011-2020 concluded that additional transformation capacity and associated distribution facilities will be required in 2016 to provide service for the growing load.

PowerStream is currently working with the OPA who is leading the York Regional Supply Adequacy Study. The outcome of this study is likely to be that a new TS will be required in Vaughan.

Transformation capacity could be in conjunction with new transmission facilities, could be coupled to existing transformer stations and existing transmission facilities, or could require new land to construct a station on.

During this five-year period, no new TS's are required in PowerStream North, but there is a need for a new Vaughan TS#4 in PowerStream South, expected to be in service in 2015-2016 timeframe.

The station portion cost of Vaughan TS#4 is estimated at $23 million.

The first phase of distribution feeder egress and grid integration is estimated in 2015 at $5.4 million, and the second phase is estimated in 2016 at $5.5 million. The purchase of land for Vaughan TS#4 is estimated in 2013 at $1,040,000.

6.4.1.1 Cost of Growth Driven Station Projects at TS

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
8	Growth Driven Station Projects at TS	$28,050	$1,144,000	$4,462,581	$20,614,899	$1,134,216	$27,383,745

6.4.2 Growth Driven Station Projects at MS

PowerStream performs load forecast and system capacity adequacy assessment annually to assess future need for additional transformation and distribution facilities for PowerStream's service territory.

The primary goal of MS projects is to maintain existing MS's below their computed firm rating. Also, to have sufficient spare capacity such that if there is a loss of one station, the neighbouring two stations can accommodate the lost capacity.

System Planning has identified requirements for three new MS's.

- Sandringham Dr. MS - in service date 2013
- Harvie Rd. MS – in service date 2014
- Aurora MS#9 – in service date 2014

Sandringham Dr. MS (in-service date 2013)

The proposed general location of this station is Big Bay Point Rd. and Sandringham Dr. just east of Yonge St. in the city of Barrie.

This station is required for capacity relief of the existing Big Bay Point Rd. MS (MS304).

The 2010 summer peak loading on this station was 26.1 MVA or 116% of the ONAN rating.

This station has an ONAN rating of 22.5 MVA. The maximum “normal” station load is 25 MVA limited by the 44 kV feeder loading.

This area continues to experience subdivision and industrial/commercial growth and it is expected that the station peak will be 30 MVA by the summer of 2013.

Also, an important issue is backup capability. Loss of the station transformer, the load can not be fully backed up by the neighboring stations. The neighboring stations being Huronia MS (loaded to 100% of ONAN rating), and Saunders MS (loaded to 93% of ONAN rating). Partial capacity relief to Saunders and Huronia MS will be provided by Park Place MS and in turn Huronia MS can provide partial (2 to 3 MVA) relief to Big Bay Point MS. Full capacity relief will be provided by the proposed Sandringham MS with a proposed in-service date of 2013.

Harvie Rd. MS (in-service date 2014)

The proposed general location of this station is Harvie Rd. and Veterans Drive just east of HWY 27 in the city of Barrie.

This station is required for capacity relief of the existing Holly MS (MS305) and Ferndale Dr. MS (MS303).

The 2010 summer peak loading on Holly MS was 21.7 MVA (96.4% of ONAN rating) and Ferndale Dr. MS it was 19.7 MVA (87.6% of ONAN rating).

Both Holly and Ferndale Dr. MS have an ONAN rating of 22.5 MVA. The maximum “normal” station load is 25 MVA limited by the 44 kV feeder loading.

This area continues to experience growth and it is expected that Holly MS station peak will be over 25 MVA by the summer of 2014, while Ferndale Dr. MS peak will be over 23 MVA during the same period.

Also, an important issue is backup capability. Loss of the station transformer at either of these two stations, the load can not be fully backed up by the neighboring stations. The neighboring stations being Saunders MS (loaded to 93% of ONAN rating), and Huronia MS (loaded to 100% of ONAN rating). Partial relief (approx. 1,500 kVA) to Holly and Ferndale Dr stations will be provided by Park Place MS.

Full capacity relief will be provided by the proposed Harvie Rd. MS with a proposed in-service date of 2014.

Aurora MS#9 (in-service date 2014)

The proposed general location of this station is Leslie St. and St. John's Sideroad in Aurora. This station is required to supply the development in the 2C land.

The Town of Aurora has requested an amendment to the York Region Official Plan to expand the Region's "Urban Area" boundary and designate approximately 445 ha (1,100 acres) of land in Leslie and St. John's Sideroad area from "Rural Policy Area" to "Urban Area".

The expansion of the 2C Lands is consistent with the requirements of the Provincial Policy Statement and the Draft Places to Grow Plan to accommodate future growth. This area was identified in the Town's 1996 Growth Management Strategy as the most appropriate location for future urban expansion in Aurora.

Lands in the 2C Secondary Plan Area are intended to accommodate approximately 8,000 residents in 2,800 residential units and between 5,200 and 6,400 employment opportunities over the next 20 years.

The proposed in-service for Aurora MS#9 is 2014.

6.4.2.1 Cost of Growth Driven Station Projects at MS

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
9	Growth Driven Station Projects at MS	$1,806,467	$5,009,692	$4,715,315	$0	$0	$11,531,474

6.4.3 Cost of Growth Driven Transformer / Municipal Stations – Additional Capacity

PowerStream - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
2c	Growth Driven Transformer / Municipal Stations - Additional Capacity	$1,834,517	$6,153,692	$9,177,896	$20,614,899	$1,134,216	$38,915,219

6.5 Growth Driven Lines Projects

This category covers the following:

- Growth Driven Lines Projects

6.5.1 Growth Driven Lines Projects

The primary goal of these projects is to maintain feeder peak loading below 400 amps under normal conditions and to comply with calculated feeder egress ratings during normal and contingency conditions. This is required to maintain reliable supply to customers.

PowerStream Planning Philosophy approved in 2007 recommended:

- Using 400 amps as the maximum planned feeder loading under normal conditions and 600 amps under contingency conditions.

All 27.6 kV and 44 kV feeders shall be designed for full backup capability over peak loading conditions through the switching of load to an adjacent feeder or multiple adjacent feeders. To facilitate this restoration capability, three phase feeder loading will be planned to a maximum of 400 amps under normal operation and 600 amps under contingency conditions.

In certain industrial/commercial areas a normal operating limit greater than 400 amps is acceptable provided remotely controlled switching is available for load transfer to adjacent feeder(s) during emergency condition.

Engineering Planning has prepared various reports to document feeder cable egress information and ampacity for all PowerStream transformer stations and municipal stations using CYME software (CYMCAP) based on duct structures, cables and cable bonding schemes. These feeder loading limits have been retained for use in this system optimization and feeder balancing plan. The 27.6 kV and 44 kV feeder peak loading has to be below 400 amps or the calculated feeder egress rating, whichever is lower.

The majority of capital line project work originates from construction driven by the various municipalities within PowerStream service area for servicing new subdivisions, industrial, commercial and institutional developments.

One significant project is the feeder integration for the future Vaughan TS #4. The first phase of distribution feeder egress and grid integration is estimated in 2015 at $5.4 million, and the second phase is estimated in 2016 at $5.5 million.

6.5.2 Cost of Growth Driven Lines Projects

PowerStream Total - Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
2d	Growth Driven Lines Projects	$6,158,587	$13,018,304	$5,522,600	$9,828,000	$19,630,600	$54,158,091

7.0 SUMMARY OF FIVE YEAR CAPITAL SPEND LEVELS

7.1 Funding based on Major Categories

PowerStream Capital Work Plan from Planning and Stations							
Category		2012	2013	2014	2015	2016	5 Yr. Total
1	Sustainment	$19,478,521	$35,693,679	$33,763,634	$32,920,744	$33,272,952	**$155,129,529**
2	Development	$7,993,104	$19,171,996	$14,700,496	$30,442,899	$20,764,816	**$93,073,310**
3	Operations	$0	$0	$0	$0	$0	**$0**
Total:		**$27,471,625**	**$54,865,675**	**$48,464,129**	**$63,363,642**	**$54,037,767**	**$248,202,838**

7.2 Funding based on Sub-Categories

PowerStream - Capital Work Plan from Planning and Stations							
1. Sustainment Capital							
Category		**2012**	**2013**	**2014**	**2015**	**2016**	**5 Yr. Total**
1a	Replacement Program	$10,996,930	$25,655,359	$25,978,472	$26,705,952	$25,518,482	**$114,855,194**
1b	Sustainment Driven Lines Projects	$5,787,292	$6,115,176	$5,331,776	$5,254,175	$5,569,275	**$28,057,694**
1d	Transformer / Municipal Station Projects (not capacity-driven)	$2,694,299	$3,923,144	$2,453,386	$960,617	$2,185,195	**$12,216,641**
	Total Sustainment:	**$19,478,521**	**$35,693,679**	**$33,763,634**	**$32,920,744**	**$33,272,952**	**$155,129,529**
2. Development Capital							
Category		**2012**	**2013**	**2014**	**2015**	**2016**	**5 Yr. Total**
2c	Growth Driven Transformer / Municipal Stations - Additional Capacity	$1,834,517	$6,153,692	$9,177,896	$20,614,899	$1,134,216	**$38,915,219**
2d	Growth Driven Lines Projects	$6,158,587	$13,018,304	$5,522,600	$9,828,000	$19,630,600	**$54,158,091**
	Total Development:	**$7,993,104**	**$19,171,996**	**$14,700,496**	**$30,442,899**	**$20,764,816**	**$93,073,310**
3. Operations Capital							
Category		**2012**	**2013**	**2014**	**2015**	**2016**	**5 Yr. Total**
	Total Operations:	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grand Total							
		2012	**2013**	**2014**	**2015**	**2016**	**5 Yr. Total**
	Grand Total:	**$27,471,625**	**$54,865,675**	**$48,464,129**	**$63,363,642**	**$54,037,767**	**$248,202,838**

7.3 Funding based on Minor Categories and Sub-Minor Categories

PowerStream - Capital Work Plan from Planning and Stations							
1. Sustainment Capital							
	Category	2012	2013	2014	2015	2016	5 Yr.
1a	**Replacement Program**	**$10,996,930**	**$25,655,359**	**$25,978,472**	**$26,705,952**	**$25,518,482**	**$114,855,194**
1	**Overhead Plant Asset Replacement Programs**	**$2,972,056**	**$3,503,990**	**$3,571,374**	**$3,638,759**	**$3,706,143**	**$17,392,321**
	1.1 Pole Replacement	$2,577,561	$3,503,990	$3,571,374	$3,638,759	$3,706,143	**$16,997,827**
	1.2 Other OH Plant Asset Replacement (Switch, OH Transformer, Insulator)	$394,494	$0	$0	$0	$0	**$394,494**
2	**Underground Plant Asset Replacement Programs**	**$6,538,807**	**$20,607,766**	**$21,004,070**	**$21,400,373**	**$20,336,580**	**$89,887,596**
	2.1 Cable Replacement	$4,383,650	$13,735,280	$13,999,420	$14,263,560	$14,527,700	**$60,909,610**
	2.2 Cable Injection	$589,009	$4,268,160	$4,350,240	$4,432,320	$4,514,400	**$18,154,129**
	2.3 UG Transformer Replacement	$845,946	$1,380,454	$1,407,002	$1,433,549	$0	**$5,066,951**
	2.4 UG Switchgear Replacement	$720,202	$1,223,872	$1,247,408	$1,270,944	$1,294,480	**$5,756,906**
3	**Station Plant Asset Replacement Programs**	**$1,486,067**	**$1,543,603**	**$1,403,028**	**$1,666,820**	**$1,475,759**	**$7,575,277**
	3.1 Station Circuit Breaker Replacement	$1,414,072	$1,543,603	$1,403,028	$1,666,820	$1,475,759	**$7,503,282**
	3.2 Other Station Plant Asset Replacement	$71,995	$0	$0	$0	$0	**$71,995**
1b	**Sustainment Driven Lines Projects**	**$5,787,292**	**$6,115,176**	**$5,331,776**	**$5,254,175**	**$5,569,275**	**$28,057,694**
4	**Lines Projects (not capacity driven)**	**$5,787,292**	**$6,115,176**	**$5,331,776**	**$5,254,175**	**$5,569,275**	**$28,057,694**
	4.1 Conversion Projects	$693,563	$1,835,600	$530,000	$1,431,000	$0	**$4,490,163**
	4.2 System Reconfiguration Projects	$1,351,768	$520,000	$0	$0	$0	**$1,871,768**
	4.3 Radial Supply Remediation Projects	$306,000	$312,000	$1,393,900	$351,000	$2,032,800	**$4,395,700**
	4.4 Distribution Automation Projects	$2,415,961	$2,407,576	$2,453,876	$2,500,175	$2,546,475	**$12,324,062**
	4.5 Reliability Driven Projects	$102,000	$104,000	$106,000	$108,000	$110,000	**$530,000**
	4.7 Compliance to External Directives / Standards Lines	$918,000	$936,000	$848,000	$864,000	$880,000	**$4,446,000**
1d	**Transformer / Municipal Station Projects**	**$2,694,299**	**$3,923,144**	**$2,453,386**	**$960,617**	**$2,185,195**	**$12,216,641**
5	**Station Projects at TS (not capacity driven)**	**$1,807,473**	**$1,643,134**	**$1,813,806**	**$414,826**	**$1,629,297**	**$7,308,536**
	5.1 Station Projects at TS (not capacity driven)	$1,461,036	$1,367,823	$1,813,806	$414,826	$1,629,297	**$6,686,788**
	5.4 Distribution Automation at TS	$346,438	$275,311	$0	$0	$0	**$621,749**
6	**Station Projects at MS (not capacity driven)**	**$886,826**	**$2,280,010**	**$639,580**	**$545,791**	**$555,898**	**$4,908,104**
	6.1 Station Projects at MS (not capacity driven)	$886,826	$2,280,010	$639,580	$545,791	$555,898	**$4,908,104**
	Sustainment:	**$19,478,521**	**$35,693,679**	**$33,763,634**	**$32,920,744**	**$33,272,952**	**$155,129,529**
2. Development Capital							
	Category	2012	2013	2014	2015	2016	5 Yr. Total
2c	**Growth Driven Transformer / Municipal Stations - Additional Capacity**	**$1,834,517**	**$6,153,692**	**$9,177,896**	**$20,614,899**	**$1,134,216**	**$38,915,219**
8	**8.1 Growth Driven Station Projects at TS**	**$28,050**	**$1,144,000**	**$4,462,581**	**$20,614,899**	**$1,134,216**	**$27,383,745**
9	**9.1 Growth Driven Station Projects at MS**	**$1,806,467**	**$5,009,692**	**$4,715,315**	**$0**	**$0**	**$11,531,474**
2d	**Growth Driven Lines Projects**	**$6,158,587**	**$13,018,304**	**$5,522,600**	**$9,828,000**	**$19,630,600**	**$54,158,091**
10	**10.1 Growth Driven Line Projects**	**$6,158,587**	**$13,018,304**	**$5,522,600**	**$9,828,000**	**$19,630,600**	**$54,158,091**
	Development:	**$7,993,104**	**$19,171,996**	**$14,700,496**	**$30,442,899**	**$20,764,816**	**$93,073,310**
3. Operations Capital							
	Category	2012	2013	2014	2015	2016	5 Yr. Total
	Operations:	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Grand Total							
	Grand Total:	**$27,471,625**	**$54,865,675**	**$48,464,129**	**$63,363,642**	**$54,037,767**	**$248,202,838**

8.0 Appendix A – Listing of Individual Capital Projects

PowerStream 5-Year (2012 - 2016) Capital Plan

Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2012	2013	2014	2015	2016
PSS#1	13.8 kV Feeder Tie Switch outside MS4, Aurora	Sustainment	Richard Wang	4.2 System Reconfiguration Projects	Planning	$41,685				
PSS#2	13.8 kV Pole Line - Mackenzie Pioneer Rd. Alliston	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning		$208,000			
PSS#3	230 kV Replacement (ACA) Richmond Hill TS1 - South	Sustainment	Quan Tran	3.2 Other Station Plant Asset Replacement	Planning	$71,995				
PSS#4	27.6 kV Additional Cct on 16th Ave	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning					$1,150,600
PSS#5	27.6 kV Additional Cct on Dufferin St	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning			$364,640		
PSS#6	27.6 kV Additional Cct on Leslie St. Phase 2	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning		$364,000			
PSS#7	27.6 kV Additional Cct on Steeles Ave	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning					$880,000
PSS#8	27.6 kV Additional Cct's (2) on Bathhurst St	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning		$400,400			
PSS#9	27.6 kV Additional Cct's (2) on Hwy 7	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning	$350,443				
PSS#10	27.6 kV Additional Cct's (2) on Warden Ave	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning		$416,000			
PSS#11	27.6 kV Pole Line on 14th Ave., Markham	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning	$1,058,423	$2,066,064			
PSS#12	27.6 kV Pole Line on 16th Ave.	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning		$1,087,840			
PSS#13	27.6 kV Pole Line on Dufferin St.	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning	$1,534,357				
PSS#14	27.6 kV Pole Line on Reesor Rd	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning	$31,416		$2,544,000		
PSS#15	44 kV Additional Cct on Bloomington Rd.	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning	$152,357				
PSS#16	44 kV Feeder Integration (Holland TS), Bradford	Sustainment	Joe Bonadie	4.2 System Reconfiguration Projects	Planning	$158,382				
PSS#17	44 kV Feeder Tie between 98M3 & 98M7, Penetanguishene	Sustainment	Joe Bonadie	4.2 System Reconfiguration Projects	Planning	$641,701				
PSS#18	44 kV Load Interrupter Switches (LIS) required at various locations for Feeder Load Balancing (quantity of 4)	Sustainment	Joe Bonadie	4.2 System Reconfiguration Projects	Planning	$255,000	$260,000			
PSS#19	44 kV Midhurst TS2 - Egress	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning		$780,000			

PowerStream 5-Year (2012 - 2016) Capital Plan

Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2012	2013	2014	2015	2016
PSS#20	44 kV Midhurst TS2 - Feeder route Design	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning	$25,500				
PSS#21	44 kV Midhurst TS2 - Pole Line	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning		$1,560,000			
PSS#22	44 kV Pole Line - Commodore TD Data Centre, Barrie	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning	$0	$0			
PSS#23	44 kV Pole Line - Data Centre (24 MVA), Barrie	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning	$0				
PSS#24	44/13.8 kV Pole Line - Middletown Rd., Bradford	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning	$387,572				
PSS#25	Add 2nd 27.6 kV Cct on Elgin Mills Rd.	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning			$26,500		
PSS#26	Add 2nd cct on 19th Ave	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning			$424,000		
PSS#27	Add one 27.6 kV cct on Kennedy Rd	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning			$265,000		
PSS#28	Add one 27.6 kV Cct on Woodbine Ave	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning			$520,460		
PSS#29	Add one cct on Hwy 50	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning	$122,400				
PSS#30	Amber F3 - Conversion	Sustainment	Richard Wang	4.1 Conversion Projects	Planning	$408,000	$416,000			
PSS#31	Aurora MS #9 Year 1 of 2	Development	Gerry Reesor	9.1 Growth Driven Station Projects at MS	Stations		$415,130			
PSS#32	Aurora MS #9 Year 2 of 2	Development	Gerry Reesor	9.1 Growth Driven Station Projects at MS	Stations			$1,470,680		
PSS#33	Aurora MS#9 Purchase Site for new MS	Development	Richard Wang	9.1 Growth Driven Station Projects at MS	Planning			$530,000		
PSS#34	Automatic Feeder Restoration - MTS3	Sustainment	Dave Burns	5.4 Distribution Automation at TS	Stations		$275,311			
PSS#35	Automatic Feeder Restoration - VTS1	Sustainment	Dave Burns	5.4 Distribution Automation at TS	Stations	$346,438				
PSS#36	Baythorne MS Arc Flash Mitigation	Sustainment	Dave Burns	6.1 Station Projects at MS (not capacity driven)	Stations			$43,855		
PSS#37	Cable Rehab, Barrie Design - Ph 2	Sustainment	Quan Tran	2.1 Cable Replacement	Planning	$26,389				
PSS#38	Cable Rehab, Flowervale, Markham (Pri Cable & Tx's) - Phase 3	Sustainment	Quan Tran	2.1 Cable Replacement	Planning	$1,531,691				

PowerStream 5-Year (2012 - 2016) Capital Plan

Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2012	2013	2014	2015	2016
PSS#39	Cable Rehab, Romfield, Markham (Pri Cable & Tx's) - Phase 2	Sustainment	Quan Tran	2.1 Cable Replacement	Planning	$1,972,917				
PSS#40	Cable Rehab, Romfield, Markham Design (Pri Cable & Tx's) - Phase 3	Sustainment	Quan Tran	2.1 Cable Replacement	Planning	$31,416				
PSS#41	Cable Rehab, Varden (Pri Cable & Tx's), Barrie	Sustainment	Quan Tran	2.1 Cable Replacement	Planning	$821,237				
PSS#42	Cable Rejuvenation - TBD (North)	Sustainment	Quan Tran	2.2 Cable Injection	Planning	$294,505	$838,656	$854,784	$870,912	$887,040
PSS#43	Cable Rejuvenation - TBD (South)	Sustainment	Quan Tran	2.2 Cable Injection	Planning	$294,505	$3,429,504	$3,495,456	$3,561,408	$3,627,360
PSS#44	Communications Tower AMS #4	Sustainment	Dave Burns	6.1 Station Projects at MS (not capacity driven)	Stations	$102,165				
PSS#45	Connect TS's to Town Water & Sewage	Sustainment	Bob Braletic	5.1 Station Projects at TS (not capacity driven)	Stations		$212,581			
PSS#46	Construct Back-up supply to IBM . Extent the 13M7 Feeder from Little Ave. along Fairview to Big Bay Pt. and down Bayview to IBM	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning	$0				
PSS#47	Conversion, Concord MS to 27.6 kV - Ph1	Sustainment	Richard Wang	4.1 Conversion Projects	Planning	$51,000				
PSS#48	Conversion, Concord MS to 27.6 kV - Ph2	Sustainment	Richard Wang	4.1 Conversion Projects	Planning		$1,352,000			
PSS#49	Conversion, Concord MS to 27.6 kV - Ph2 (Design)	Sustainment	Richard Wang	4.1 Conversion Projects	Planning		$26,000			
PSS#50	Conversion, Concord MS to 27.6 kV - Ph3	Sustainment	Richard Wang	4.1 Conversion Projects	Planning			$530,000		
PSS#51	Conversion, Concord MS to 27.6 kV - Ph4	Sustainment	Richard Wang	4.1 Conversion Projects	Planning				$1,404,000	
PSS#52	Conversion, Elders MS Decommission	Sustainment	Richard Wang	4.1 Conversion Projects	Planning		$20,800			
PSS#53	Conversion, Morgan MS to 27.6 kV (Design)	Sustainment	Richard Wang	4.1 Conversion Projects	Planning				$27,000	
PSS#54	Conversion, MS #4 T2, Aurora from 27.6 kV to 44 kV	Sustainment	Richard Wang	4.1 Conversion Projects	Planning	$15,282				
PSS#55	Conversion, MS #6 T2, Aurora from 27.6 kV to 44 kV	Sustainment	Richard Wang	4.1 Conversion Projects	Planning	$15,282				
PSS#56	Conversion, Rainbow MS Decommission	Sustainment	Richard Wang	4.1 Conversion Projects	Planning		$20,800			
PSS#57	Cyber Security - Network Management System	Sustainment	Dave Burns	5.1 Station Projects at TS (not capacity driven)	Stations	$16,023				

PowerStream 5-Year (2012 - 2016) Capital Plan										
Pro.#	**Project/Program Title**	**OEB Cat.**	**Project Lead**	**PS Sub-Minor Cat.**	**Dept.**	**2012**	**2013**	**2014**	**2015**	**2016**
PSS#58	Cyber Security Enhancements - PS North	Sustainment	Dave Burns	6.1 Station Projects at MS (not capacity driven)	Stations		$88,421			
PSS#59	Distribution (13.8; 4.16 & 8.32 kV) Load Interrupter Switches (LIS) required at various locations for Feeder Load Balancing (quantity of 6)	Sustainment	Joe Bonadie	4.2 System Reconfiguration Projects	Planning	$255,000	$260,000			
PSS#60	Distribution Automation Switches/Recloser - South	Sustainment	Quan Tran	4.4 Distribution Automation Projects	Planning	$1,391,596	$1,655,363	$1,687,197	$1,719,031	$1,750,865
PSS#61	Distribution Automation Switches/Recloser -North	Sustainment	Quan Tran	4.4 Distribution Automation Projects	Planning	$528,710	$752,213	$766,679	$781,145	$795,610
PSS#62	Distribution Switchgear Replacement Program (ACA) - North	Sustainment	Quan Tran	2.4 UG Switchgear Replacement	Planning	$120,034	$305,968	$311,852	$317,736	$323,620
PSS#63	Distribution Switchgear Replacement Program (ACA) - South	Sustainment	Quan Tran	2.4 UG Switchgear Replacement	Planning	$600,168	$917,904	$935,556	$953,208	$970,860
PSS#64	Double ccts on Hwy 50	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning	$510,000				
PSS#65	Double ccts on Major Mack	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning				$1,080,000	$1,100,000
PSS#66	Double circuit 23M25 from AB-B11 to LC406 (Burton MS tap), 1.2 km	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning	$510,000				
PSS#67	Double circuit pole line from Midhurst TS to Barie South area approximately 16 km	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning				$540,000	
PSS#68	Elbow/Bushing Replacement	Sustainment	Riaz Shaikh	4.5 Reliability Driven Projects	Planning	$102,000	$104,000	$106,000	$108,000	$110,000
PSS#69	Elder Mill MS Conversion	Sustainment	Richard Wang	4.1 Conversion Projects	Planning	$204,000				
PSS#70	ESA/CSA Clearance Issues in Tottenham & Alliston	Sustainment	Joe Bonadie	4.7 Compliance to External Directives / Standards Lines	Planning	$408,000	$416,000	$424,000	$432,000	$440,000
PSS#71	Extend 16kV single phase on Kipling Ave south toTeston Rd	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning	$102,000				
PSS#72	Harvie Rd MS 44 kV Supply to new MS	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning			$424,000		
PSS#73	Harvie Rd. MS, 13.8 kV Feeder Integration	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning			$530,000		
PSS#74	Harvie Rd.MS Purchase Site for new MS	Development	Joe Bonadie	9.1 Growth Driven Station Projects at MS	Planning		$520,000			
PSS#75	Harvie Road MS; New 44-13.8 kV, 20 MVA, 4 Feeder MS	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning			$0		
PSS#76	High Set Instantaneous Feeder Protection - Markham TS #2	Sustainment	Dave Burns	5.1 Station Projects at TS (not capacity driven)	Stations	$330,635				

PowerStream 5-Year (2012 - 2016) Capital Plan										
Pro.#	**Project/Program Title**	**OEB Cat.**	**Project Lead**	**PS Sub-Minor Cat.**	**Dept.**	**2012**	**2013**	**2014**	**2015**	**2016**
PSS#77	High Set Instantaneous Feeder Protection - Markham TS #3	Sustainment	Dave Burns	5.1 Station Projects at TS (not capacity driven)	Stations		$345,547			
PSS#78	Hydro One Asset Purchase, Alliston	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning	$183,648				
PSS#79	Hydro One Asset Purchase, Barrie	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning	$272,469				
PSS#80	Install Capacitor Banks at Lazenby TS	Sustainment	Bob Braletic	5.1 Station Projects at TS (not capacity driven)	Stations					$1,303,928
PSS#81	Install Capacitor Banks at Markham TS#2	Sustainment	Bob Braletic	5.1 Station Projects at TS (not capacity driven)	Stations			$1,195,065		
PSS#82	Letitia MS (MS413), Increase Capacity from 5 MVA to 10 MVA and add one 4.16 kV Feeder	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning			$424,000		
PSS#83	Long Term Load Transfers (LTLT's)	Sustainment	Joe Bonadie	4.7 Compliance to External Directives / Standards Lines	Planning	$102,000	$104,000			
PSS#84	Low Voltage Bushing Replacement - Markham TS#2 T1 & T2	Sustainment	Gerry Reesor	5.1 Station Projects at TS (not capacity driven)	Stations	$213,556				
PSS#85	Low Voltage Bushing Replacement - Transformer Station	Sustainment	Bob Braletic	5.1 Station Projects at TS (not capacity driven)	Stations		$370,494	$395,455	$414,826	
PSS#86	Markham TS#3 Capacitor Bank Harmonic Study	Sustainment	Gerry Reesor	5.1 Station Projects at TS (not capacity driven)	Stations	$34,670				
PSS#87	Melbourne MS (MS322), Increase Capacity from 10 MVA to 20 MVA and add one 13.8 kV Feeder.	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning				$648,000	
PSS#88	Mitigate harmonics from MTS#3 Capacitor Bank	Sustainment	Gerry Reesor	5.1 Station Projects at TS (not capacity driven)	Stations		$188,036			
PSS#89	Monitor MS Transformer Temperature - Aurora MS #1, 2, 3	Sustainment	Bob Braletic	6.1 Station Projects at MS (not capacity driven)	Stations	$49,236				
PSS#90	Monitor MS Transformer Temperature - Aurora MS #4, 5, 6	Sustainment	Bob Braletic	6.1 Station Projects at MS (not capacity driven)	Stations		$55,058			
PSS#91	New 44 kV Feeder from Midhurst TS; (T3/T4) to Bayfield and Livingstone St., approximately 3 km. (Poleline to be framed for double circuit including underbuild of Hydro One existing distribution feeder) Phase 1	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning	$918,000				
PSS#92	New 44 kV Feeder from Midhurst TS; Double circuit the existing 23M5 feeder from Sunnidale Rd. and Ferndale Dr. to Ferndale & Hwy 27. Continue the double circuit down Veterans to Caplan and pick-up the BMO tap, approximately 9 km.. Phase 2	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning		$3,120,000			
PSS#93	New 44 kV Feeder, approx. 6 km from Barrie TS (using M4 Breaker) to Mapleview Dr.	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning					$3,300,000
PSS#94	New 44 kV Feeder, approx. 8 km from Barrie TS (using M1 Breaker) to Mapleview Dr.	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning					$4,400,000
PSS#95	New Harvie MS in Barrie - 20MVA Year 1 of 2	Development	Bob Braletic	9.1 Growth Driven Station Projects at MS	Stations		$1,437,962			

PowerStream 5-Year (2012 - 2016) Capital Plan										
Pro.#	**Project/Program Title**	**OEB Cat.**	**Project Lead**	**PS Sub-Minor Cat.**	**Dept.**	**2012**	**2013**	**2014**	**2015**	**2016**
PSS#96	New Harvie MS in Barrie - 20MVA Year 2 of 2	Development	Bob Braletic	9.1 Growth Driven Station Projects at MS	Stations			$2,714,635		
PSS#97	New Sandringham MS in Barrie - 20MVA Year 1 of 2	Development	Bob Braletic	9.1 Growth Driven Station Projects at MS	Stations	$1,296,467				
PSS#98	New Sandringham MS in Barrie - 20MVA Year 2 of 2	Development	Gerry Reesor	9.1 Growth Driven Station Projects at MS	Stations		$2,636,601			
PSS#99	New Scada Controlled LIS, just west of Cundles Rd. East MS tap.	Sustainment	Joe Bonadie	4.4 Distribution Automation Projects	Planning	$91,800				
PSS#100	New Transformer Station - Vaughan	Development	Gerry Reesor	8.1 Growth Driven Station Projects at TS	Stations			$4,462,581	$20,614,899	$1,134,216
PSS#101	Oil Containment Systems - PS North Stations	Sustainment	Gerry Reesor	6.1 Station Projects at MS (not capacity driven)	Stations	$227,275	$248,877	$260,657	$272,895	$277,949
PSS#102	Oil Containment Systems - PS South Stations	Sustainment	Gerry Reesor	6.1 Station Projects at MS (not capacity driven)	Stations	$192,153	$248,877	$260,657	$272,895	$277,949
PSS#103	On-Line Oil Monitor MS-301 Transformer Barrie	Sustainment	Bob Braletic	6.1 Station Projects at MS (not capacity driven)	Stations	$51,436				
PSS#104	On-Line Oil Monitor MS-302 Transformer Barrie	Sustainment	Gerry Reesor	6.1 Station Projects at MS (not capacity driven)	Stations		$43,128			
PSS#105	On-Line Oil Monitor MS303 Transformer - Barrie	Sustainment	Bob Braletic	6.1 Station Projects at MS (not capacity driven)	Stations			$52,982		
PSS#106	Pole Replacement Program (ACA) - North	Sustainment	Quan Tran	1.1 Pole Replacement	Planning	$429,951	$438,382	$446,812	$455,243	$463,673
PSS#107	Pole Replacement Program (ACA) - South	Sustainment	Quan Tran	1.1 Pole Replacement	Planning	$2,147,610	$3,065,608	$3,124,562	$3,183,516	$3,242,470
PSS#108	Purchase replacement Hollow Columns for MS303 - Ferndale South MS	Sustainment	Dave Burns	6.1 Station Projects at MS (not capacity driven)	Stations	$27,358				
PSS#109	Radial Supply Remediation - 27.6 kV Cct on 19th Ave (Design)	Sustainment	Richard Wang	4.3 Radial Supply Remediation Projects	Planning				$27,000	
PSS#110	Radial Supply Remediation - 27.6 kV Cct on Woodbine Ave	Sustainment	Richard Wang	4.3 Radial Supply Remediation Projects	Planning					$540,100
PSS#111	Radial Supply Remediation - 27.6 kV Cct to Doney Cres.	Sustainment	Richard Wang	4.3 Radial Supply Remediation Projects	Planning					$78,100
PSS#112	Radial Supply Remediation - 27.6 kV Cct's (2) on Major Mackenzie Dr	Sustainment	Richard Wang	4.3 Radial Supply Remediation Projects	Planning					$1,084,600
PSS#113	Radial Supply Remediation - North	Sustainment	Joe Bonadie	4.3 Radial Supply Remediation Projects	Planning		$312,000	$318,000	$324,000	$330,000
PSS#114	Radial Supply Remediation - North	Sustainment	Joe Bonadie	4.3 Radial Supply Remediation Projects	Planning	$306,000				

PowerStream 5-Year (2012 - 2016) Capital Plan										
Pro.#	**Project/Program Title**	**OEB Cat.**	**Project Lead**	**PS Sub-Minor Cat.**	**Dept.**	**2012**	**2013**	**2014**	**2015**	**2016**
PSS#115	Radial Supply Remediation/Conversion - 13.8 kV to 27.6 kV on Miller Ave	Sustainment	Richard Wang	4.3 Radial Supply Remediation Projects	Planning			$1,075,900		
PSS#116	Rebuild 27.6 kV pole for 2 additional Ccts on Warden Ave	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning		$2,080,000			
PSS#117	Rebuild 27.6 kV pole for 4 Ccts on Warden Ave	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning				$2,160,000	
PSS#118	Rebuild pole line on 16th Ave to 4 ccts	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning					$3,300,000
PSS#119	Refurbish Aurora MS-1	Sustainment	Gerry Reesor	6.1 Station Projects at MS (not capacity driven)	Stations		$1,461,533			
PSS#120	Remote Cooling Control T3 & T4 at RHTS #2	Sustainment	Dave Burns	5.1 Station Projects at TS (not capacity driven)	Stations		$5,692			
PSS#121	Replace 125V Battery Bank - Torstar TS	Sustainment	Dave Burns	5.1 Station Projects at TS (not capacity driven)	Stations		$29,355			
PSS#122	Replace Battery Banks - PowerStream North MS's	Sustainment	Gerry Reesor	6.1 Station Projects at MS (not capacity driven)	Stations	$15,548	$20,923	$10,976		
PSS#123	Replace Battery Banks - PowerStream South MS	Sustainment	Dave Burns	6.1 Station Projects at MS (not capacity driven)	Stations	$10,548				
PSS#124	Replacement of Legacy RTU and Recloser Controllers at Morgan MS	Sustainment	Bob Braletic	6.1 Station Projects at MS (not capacity driven)	Stations	$82,651				
PSS#125	Replacement of RHTS#1 Basement Switch Operators	Sustainment	Bob Braletic	5.1 Station Projects at TS (not capacity driven)	Stations	$155,115				
PSS#126	Sandringham MS 44 kV Supply to new MS	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning		$416,000			
PSS#127	Sandringham MS Purchase Site for new MS	Development	Joe Bonadie	9.1 Growth Driven Station Projects at MS	Planning	$510,000				
PSS#128	Sandringham MS, 13.8 kV Feeder Integration	Development	Joe Bonadie	10.1 Growth Driven Lines Projects	Planning		$520,000			
PSS#129	Sandringham MS; New 44-13.8 kV, 10 MVA, 3 Feeder MS	Development	Joe Bonadie	9.1 Growth Driven Station Projects at MS	Planning		$0			
PSS#130	Separate SCADA Alarms	Sustainment	Dave Burns	5.1 Station Projects at TS (not capacity driven)	Stations					$91,741
PSS#131	Spare HD4 Circuit Breakers and GTD's	Sustainment	Bob Braletic	5.1 Station Projects at TS (not capacity driven)	Stations	$161,953				
PSS#132	Spare TS Capacitor Cans	Sustainment	Gerry Reesor	5.1 Station Projects at TS (not capacity driven)	Stations	$9,613	$10,096			
PSS#133	Station Circuit Breaker Replacement Program (ACA) Anne MS-301	Sustainment	Quan Tran	3.1 Station Circuit Breaker Replacement	Planning				$613,056	

PowerStream 5-Year (2012 - 2016) Capital Plan

Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2012	2013	2014	2015	2016
PSS#134	Station Circuit Breaker Replacement Program (ACA) Markham TS1 Final Phase	Sustainment	Quan Tran	3.1 Station Circuit Breaker Replacement	Planning				$526,882	
PSS#135	Station Circuit Breaker Replacement Program (ACA) Markham TS2	Sustainment	Quan Tran	3.1 Station Circuit Breaker Replacement	Planning					$939,120
PSS#136	Station Circuit Breaker Replacement Program (ACA) Markham TS3 Ph 2	Sustainment	Quan Tran	3.1 Station Circuit Breaker Replacement	Planning					$536,639
PSS#137	Station Circuit Breaker Replacement Program (ACA) Markham TS3 Ph1	Sustainment	Quan Tran	3.1 Station Circuit Breaker Replacement	Planning				$526,882	
PSS#138	Station Circuit Breaker Replacement Program (ACA) Richmond Hill TS1 Ph. 1	Sustainment	Quan Tran	3.1 Station Circuit Breaker Replacement	Planning		$1,543,603			
PSS#139	Station Circuit Breaker Replacement Program (ACA) Richmond Hill TS1 Ph. 2	Sustainment	Quan Tran	3.1 Station Circuit Breaker Replacement	Planning			$1,403,028		
PSS#140	Station Circuit Breaker Replacement Program (ACA) Vaughan TS2 Ph.2	Sustainment	Quan Tran	3.1 Station Circuit Breaker Replacement	Planning	$1,414,072				
PSS#141	Station Perimeter Door Security Monitoring via SCADA Expansion	Sustainment	Bob Braletic	5.1 Station Projects at TS (not capacity driven)	Stations	$43,822				
PSS#142	Station Service Transfer Panels	Sustainment	Gerry Reesor	6.1 Station Projects at MS (not capacity driven)	Stations	$69,076	$25,375	$10,452		
PSS#143	Submersible Transformer & Vault Replacement - South	Sustainment	Quan Tran	2.3 UG Transformer Replacement	Planning	$422,852				
PSS#144	Submersible Transformer Vault Replacement - North	Sustainment	Quan Tran	2.3 UG Transformer Replacement	Planning	$423,094	$1,380,454	$1,407,002	$1,433,549	
PSS#145	Switch Replacement Program (AB Chance Porcelain Switch) - North	Sustainment	Quan Tran	1.2 Other OH Plant Asset Replacement (Switch, OH Transformer, Insulator)	Planning	$394,494				
PSS#146	TorstarTS Feeder Protections & RTU Replacment - Year 2	Sustainment	Gerry Reesor	5.1 Station Projects at TS (not capacity driven)	Stations	$250,300				
PSS#147	Tottenham Substation Protection Upgrade	Sustainment	Joe Bonadie	4.4 Distribution Automation Projects	Planning	$403,855				
PSS#148	Transformer On-Line Oil Analysis - Richmond Hill TS#2	Sustainment	Bob Braletic	5.1 Station Projects at TS (not capacity driven)	Stations					$233,628
PSS#149	Transformer On-Line Oil Analysis - Vaughan TS #1 - T1 / T2	Sustainment	Bob Braletic	5.1 Station Projects at TS (not capacity driven)	Stations	$195,113				
PSS#150	Transformer On-Line Oil Analysis - Vaughan TS #1 - T3 / T4	Sustainment	Bob Braletic	5.1 Station Projects at TS (not capacity driven)	Stations		$206,022			
PSS#151	Transformer On-Line Oil Analysis - Vaughan TS #2	Sustainment	Bob Braletic	5.1 Station Projects at TS (not capacity driven)	Stations			$223,286		
PSS#152	Underground Primary Cable Replacement (North)	Sustainment	Quan Tran	2.1 Cable Replacement	Planning		$2,747,056	$2,799,884	$2,852,712	$2,905,540

PowerStream 5-Year (2012 - 2016) Capital Plan

Pro.#	Project/Program Title	OEB Cat.	Project Lead	PS Sub-Minor Cat.	Dept.	2012	2013	2014	2015	2016
PSS#153	Underground Primary Cable Replacement (South)	Sustainment	Quan Tran	2.1 Cable Replacement	Planning		$10,988,224	$11,199,536	$11,410,848	$11,622,160
PSS#154	Vaughan TS #4 Planning - Ph2	Development	Richard Wang	8.1 Growth Driven Station Projects at TS	Planning	$28,050				
PSS#155	Vaughan TS #4 Planning - Ph3	Development	Richard Wang	8.1 Growth Driven Station Projects at TS	Planning		$1,040,000			
PSS#156	Vaughan TS #4 Station - Ph1 (Design)	Development	Richard Wang	8.1 Growth Driven Station Projects at TS	Planning		$104,000			
PSS#157	Video Surveillance PS North MS's	Sustainment	Dave Burns	6.1 Station Projects at MS (not capacity driven)	Stations		$87,819			
PSS#158	Video Survellance at Vaughan TS#3	Sustainment	Dave Burns	5.1 Station Projects at TS (not capacity driven)	Stations	$50,235				
PSS#159	Video Survellance PS North Stations	Sustainment	Dave Burns	6.1 Station Projects at MS (not capacity driven)	Stations	$59,379				
PSS#160	VTS#4 Feeder Integration	Development	Richard Wang	10.1 Growth Driven Lines Projects	Planning				$5,400,000	$5,500,000
PSS#161	VTS#4 Phase 1-2 Construct	Development	Richard Wang	8.1 Growth Driven Station Projects at TS	Planning				$0	$0
PSS#162	Worst Performing Feeder Capital Work - North	Sustainment	Riaz Shaikh	4.5 Reliability Driven Projects	Planning		$0	$0		
PSS#163	Worst Performing Feeder Capital Work - South	Sustainment	Riaz Shaikh	4.5 Reliability Driven Projects	Planning		$0	$0		
PSS#164	Wye transformers supply delta service remediation	Sustainment	Richard Wang	4.7 Compliance to External Directives / Standards Lines	Planning	$408,000	$416,000	$424,000	$432,000	$440,000
PSS#165	York-Durham Sewage Tunnel Project	Development	Richard Wang	7.1 Plant Relocation Driven by External Authorities	Planning	$0	$0			

	2012	2013	2014	2015	2016	Totals
Totals	$27,471,625	$54,865,675	$48,464,129	$63,363,642	$54,037,767	$248,202,838
Sustainment	$19,478,521	$35,693,679	$33,763,634	$32,920,744	$33,272,952	$155,129,529
Development	$7,993,104	$19,171,996	$14,700,496	$30,442,899	$20,764,816	$93,073,310
Operations	$0	$0	$0	$0	$0	$0

ASSESSMENT CONDITION ASSESSMENT OVERVIEW

In 2009, PowerStream engaged Kinectrics Inc. and BIS Consulting, LLC to complete an Asset Condition Assessment ("ACA") Technical Report. An ACA is one of the analyses that helps PowerStream make informed decisions for maintenance programs and capital investments.

The ACA Technical Report addresses the status of the following distribution asset classes:

- Transformer Station ("TS") Transformers
- Municipal Station ("MS") Transformers
- Circuit Breakers
- 230kV Switches
- Municipal Station ("MS") Primary Switches
- Station Capacitors
- Station Reactors
- Distribution Transformers
- Distribution Switchgear
- Wood Poles
- Underground Distribution Primary Cable

Each of the above asset classes are discussed under the following headings:

- Summary of Asset Class
- Asset Degradation
- Health Index Formulation and Results
- Failure Probability
- Intervention Mode
- Econometric Replacement Results

- Conclusion

PowerStream Engineering staff completed an update to the ACA Technical Report in 2012. The document is in Exhibit B1, Tab 2, Schedule 4.

In summary, the ACA Technical Report indicates the need to systematically replace or refurbish aging station and distribution assets.

On-going programs at sustained replacement levels are required for:

- Underground Distribution Primary Cable (Injection and Replacement)
- Wood Poles
- Distribution Switchgear

Near term replacements are required for:

- 230kV Switches
- Circuit Breakers

Distribution Transformers will be operated on a “run-to-failure” approach with no planned pro-active replacement program.

In the near term no replacements are required for:

- Station Reactors
- Municipal Station (“MS”) Primary Switches
- Municipal Station (“MS”) Transformers
- Transformer Station (“TS”) Transformers
- Station Capacitors

PowerStream

Asset Condition Assessment

Technical Report

Revision 1 – March 8, 2012

Notes:

- The Original Report, dated April 05, 2009, was prepared by PowerStream Inc., Kinectrics Inc., and BIS Consulting, LLC
- This version of the report, Revision 1 – March 8, 2012, was prepared by PowerStream Inc.

Table of Contents

1. INTRODUCTION

PowerStream is the second largest municipally-owned electricity distribution company in Ontario, delivering power to more than 330,000 customers residing or owning a business in communities located immediately north of Toronto and in Central Ontario. The communities we serve include Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan. PowerStream owns and operates distribution assets valued at approximately $950.6 million, including 11 transformer stations and 54 municipal substations.

PowerStream has implemented an asset management program for its station and distribution assets. The program includes the development of Health Indices, risk-based economic analyses (probability of failure and criticality), and recommended Asset Sustainability Plans (replacements).

A key part of the asset management program is Asset Condition Assessment (ACA), involving collection and interpretation of condition and performance data to enable informed investment decisions. The primary purpose of the ACA is to detect and quantify long-term degradation, which would necessitate major capital expenditure. The result of the ACA is an optimized life-cycle plan based on asset sustainability.

PowerStream uses the ACA methodology developed by Kinectrics Inc. and BIS Consulting, LLC to run the ACA models.

On an on-going basis, PowerStream continues to fine-tune the ACA models and update the parameters to reflect PowerStream's current asset information. Examples of the parameters include: asset physical condition, testing data, customer interruption cost, replacement cost, failure probability curve, consequence of asset failure, etc.

The ACA model results are taken into consideration when PowerStream prioritizes and selects capital projects to be submitted for approval in the annual budgeting process.

In theory, the number and timing of replacement units recommended by the ACA models ("Econometric Replacement Results") is considered "optimal" or "ideal" from a pure economic viewpoint. In practice, however, PowerStream incorporates engineering judgment and operations input with the econometric model results to prudently spread out the replacement programs over a longer period of time. The intent of spreading the replacement requirement over a number of years is to smooth out the budget, resource and rate impacts while managing the incremental risk of asset failure.

As a result of this approach, the annual numbers of replacement units proposed in the annual budget may be different from those recommended by the ACA models.

This report will discuss the Asset Condition Assessment Framework and provide the status of PowerStream ACA programs for the following assets:

- TS Transformer
- MS Transformer
- Circuit Breaker
- 230 kV Switch
- MS Primary Switch
- Station Capacitor
- Station Reactor
- Distribution Transformer
- Distribution Switchgear
- Wood Pole
- Distribution UG Primary Cable

For each of the above asset class the following items will be covered:

- Summary of Asset Class
- Asset Degradation
- Health Index Formulation and Results
- Failure Probability
- Intervention Mode
- Econometric Replacement Results
- Conclusion

2. ASSET CONDITION ASSESSMENT FRAMEWORK

- The general ACA framework is a two-step process:
- Asset Evaluations
- Program Development

Asset Evaluations

The Asset Evaluations step translates condition and criticality information into repeatable, quantitative measures. Asset Evaluations will cover the following:

- Health Index
- Failure Rate
- Criticality
- Risk Matrix
- Projected Failure Quantity and Reactive Capital

Health Index

Asset Evaluations involves a technical condition assessment, wherein condition information is translated into a quantitative Health Index. The Health Index is based on information such as equipment age, historical utilization, maintenance, and visual inspections.

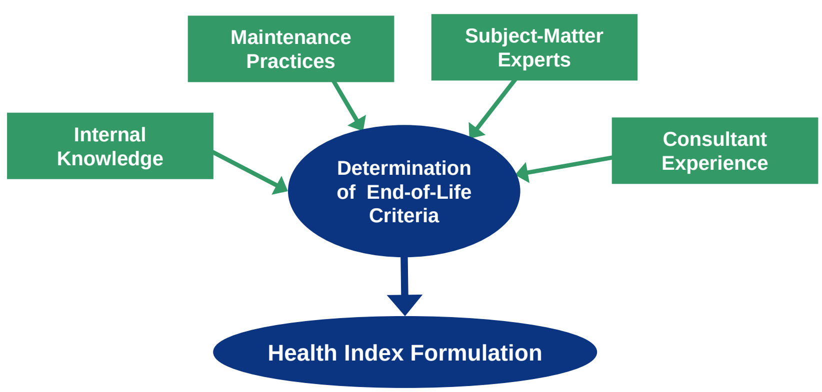


Figure 1. The Health Index establishes the condition of the asset population relative to end of life.

To illustrate the formulation of health index, an example for a 230kV Switch is shown below.

Sample Heath Index for 230kV Switch

Factor	Maximum Score (A)	Actual Score (B)	Weight (C)	Weighted Score (D) = (B x C)	Maximum Possible Weighted Score (E) = (A x C)
Age	4	3	3	9	12
Expert Feedback	4	3	10	30	40
Load	4	2	3	6	12
Switch Contact	4	4	5	20	20
Blade/Arm	4	3	5	15	20
Mechanism	4	3	5	15	20
Arc Break	4	3	5	15	20
Lock/Handle	4	3	1	3	4
		Total Score (F):		**113**	**148**
		Health Index (HI) = (F/E):		**76%**	**100%**

Each factor is given a Maximum Score (A) and a Weight (C). The Actual Score (B) of each factor is determined by its condition. The Weighted Score (D) is determined by multiplying the Actual Score by the Weight. The Total Score (F) is the sum of all Weighted Scores for all factors.

The final Heath Index is calculated by the Total Score divided by the Maximum Possible Score (E).

The Health Index Formulation for each of PowerStream's assets will be described in greater detail in the "Health Index Formulation and Results" portions of this report.

Failure Rate

The model includes failure probability curves, projecting failures as a function of age and type. The failure probability curve, or hazard rate, is a conditional probability; for example, the chance of a transformer failing at age 30 given it is 30 years old. The curves are based on the experience of PowerStream's technical experts and Industry Standards. Over time, failure data will be collected to determine if any changes are warranted to the curves.

Failure probability can vary within an asset class. For example, different types of breakers (e.g., air, SF6, etc.) may have different failure probability curves. Because of this, the failure probability curve, and hence risk cost, for an asset may be different before replacement than after if replacement is not "in-kind".

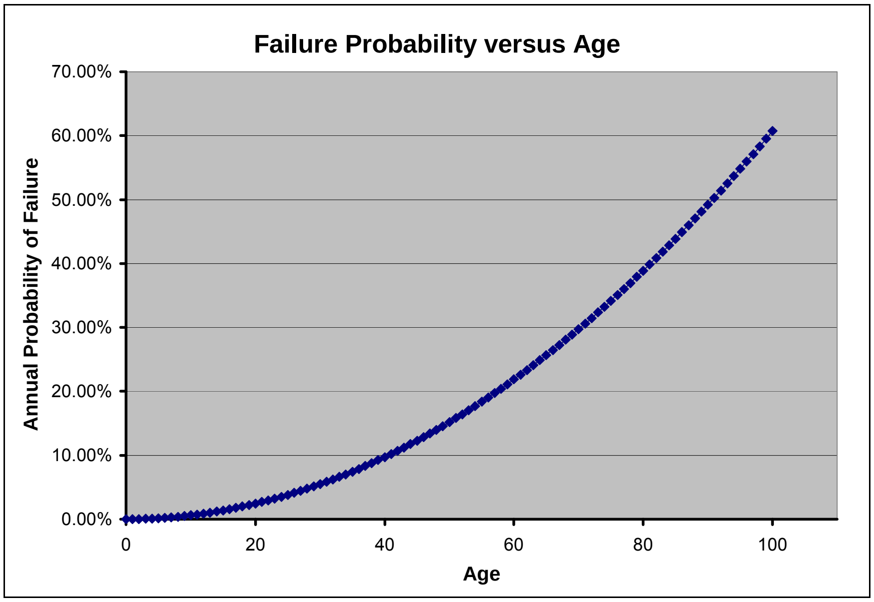


Figure 2. The failure probability curve projects conditional failure probability versus age.

Criticality

The consequences of an asset failure include the replacement cost of the failed asset and customer outage impacts. The expected consequence may be the average of multiple failure scenarios, weighted by their relative probabilities. All costs must be expressed in dollar terms for consistent prioritization.

An asset management-based system of justifying expenditures must consider not only the direct costs to the utility, but also the costs to its customers in lost power and inconvenience. Customer outage costs can be estimated using a willingness to pay or willingness to accept method. The method evaluates outage consequences based on how much customers are willing to pay to avoid them, or what payment they would require to accept them. There have been a number of studies published related to customer interruption cost or value of lost load. The studies were reviewed and results correlated with our own experience with respect to average interruption time, average frequency of loss, average load lost and other factors for residential and commercial/industrial premises. Average costs for \$/kW and \$/kWh could then be estimated. For this study PowerStream has elected to use the following customer interruption costs, which can be updated at a later stage pending the future availability of additional relevant customer impact studies.

Table 1. Customer Interruption Costs

Customer Interruption Cost

	Residential	Mixed Residential, Commercial & Industrial (approx. 30% Res, 70% C & I)	Purely Commercial & Industrial (100% C & I)
$/kW (Frequency Cost)	$2.00	$20.00	$20.00
$/kWh (Duration Cost)	$4.00	$20.00	$30.00

Risk Matrix

The Asset Evaluations step also includes defining the inputs for an asset risk assessment. Risk is calculated by multiplying asset failure probability times the consequence of asset failure. The failure probability is an annual failure rate, based on end of life failures. The consequence of asset failure is related to the criticality of the asset, is defined in dollar terms, and is also intended to reflect customer impact.

The risk matrix summarizes the condition and criticality of an asset. The risk matrix plots the current age failure probability versus the consequence of failure (criticality). The blue diamonds represent the entire asset population, while the red diamonds relate to the assets recommended for immediate intervention. An example for circuit breakers is shown below.

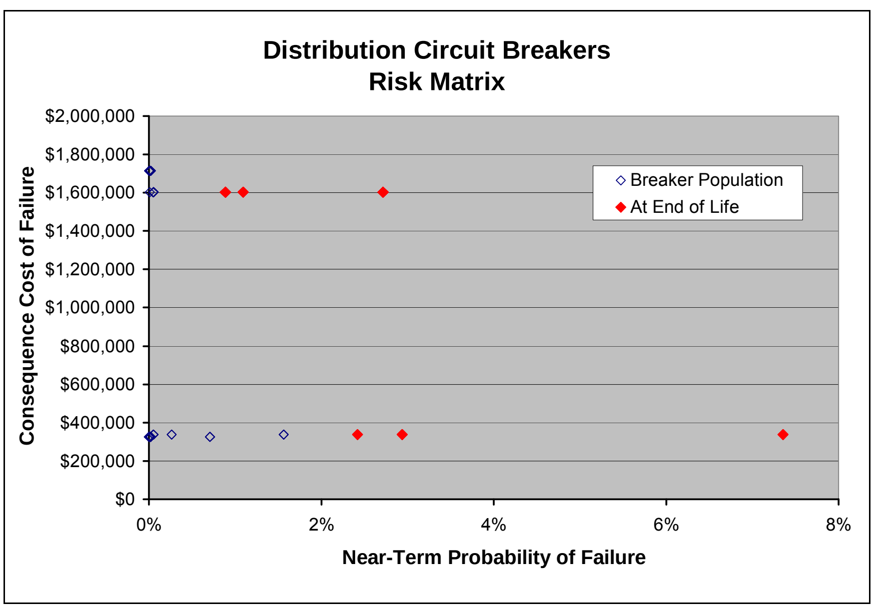


Figure 3. The risk matrix plots consequence cost of failure versus failure probability.

Projected Failure Quantity and Reactive Capital

The projected failures account for system-wide annual failures. The reactive capital is an estimate of the reactive replacement spending associated with the projected failures. An example for distribution transformers is shown below.

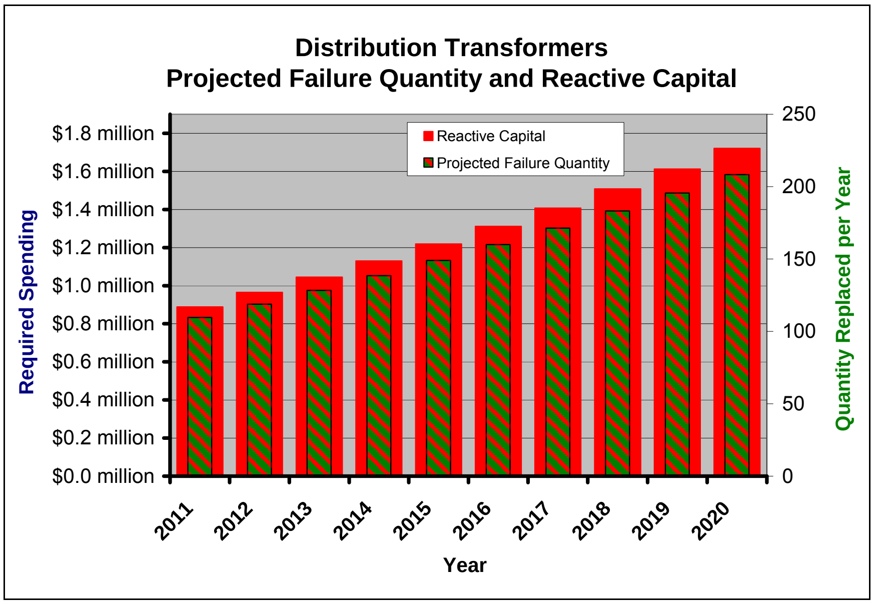


Figure 4. Projected failures and associated reactive replacement spending.

Program Development

The Program Development step involves defining intervention modes to mitigate asset risk, performing analyses to minimize asset life-cycle cost, and recommending long-range spending. Program Development will cover the following:

- Intervention Modes
- Risk-Based Economic Analysis
- Spending Justification and Prioritization
- Econometric Replacement Results

Intervention Modes

Intervention modes are actions that can be done to mitigate asset risk, such as rehabilitation, replacement, monitoring, or purchase of spares. Intervention modes may affect the probability or consequence of failure.

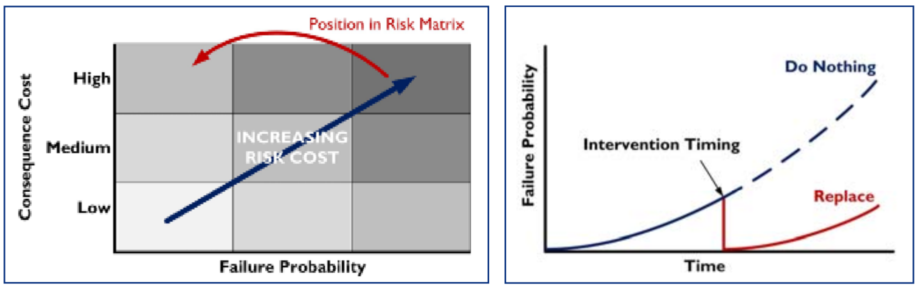


Figure 5. Effect of replacement on risk mitigation.

The simplest example is "in-kind" replacement, whereby an old asset with relatively high failure probability is replaced with a new one with lower failure probability.

Risk-Based Economic Analysis

The risk-based economic analysis determines the asset least life-cycle cost by balancing the risk of failure against the benefit of delaying capital expenditures.

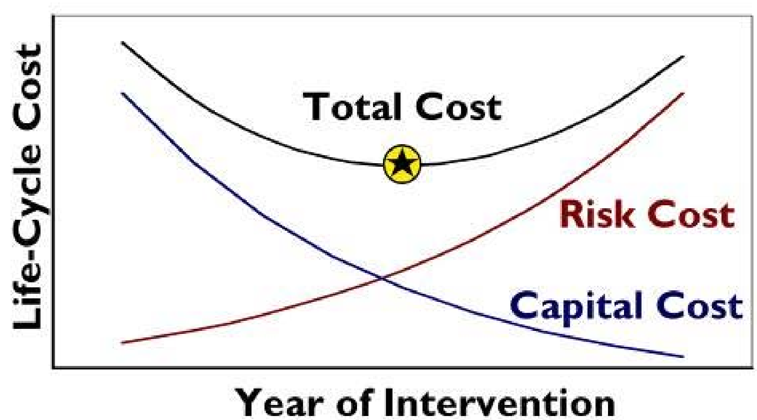


Figure 6. Life-cycle optimization.

The economic analysis methodology compares the available intervention alternatives to determine the lowest cost strategy (e.g., inject cable in 10 years, and then replace cable in 30 years). The methodology projects the performance effects of each strategy (i.e., mitigating failure probability or consequence of failure) to determine the optimal intervention timing.

The risk-based economic analysis methodology justifies spending decisions by determining the economically optimal timing of asset expenditures based on the associated asset risk profiles and related capital costs for interventions. Applying the same methodology to all the assets in an asset class produces a consistent spending program. The associated benefits and costs of delaying from the optimal timing provide the basis for a benefit/cost ratio for prioritization of limited resources.

Existing assets may be replaced with shorter-life assets. This means that the life-cycle cost of the new asset is different than the existing asset. The methodology in this case requires two steps, as shown below.

1. Calculate the annualized life-cycle cost of the new asset.
2. Identify the year in which the risk cost of the existing asset reaches this value. In that year, it is less expensive to replace the assets than to continue operating the existing asset.

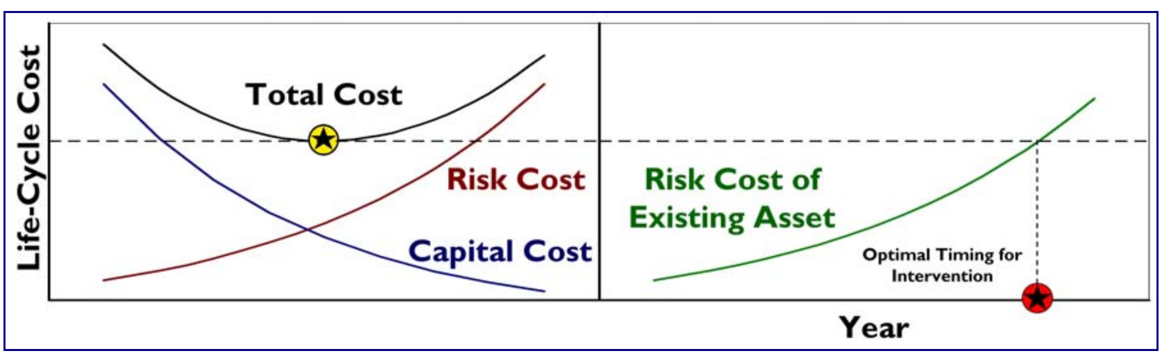


Figure 7. Optimizing replacement timing of assets.

Spending Justification and Prioritization

Limited resources should be directed toward programs with higher benefit/cost ratios. A benefit/cost ratio is calculated for all assets recommended for an intervention in the current or next year. In the case of asset replacements, benefit is the avoided cost of delaying replacement for one year. If an asset should be replaced this year, but replacement is delayed for one year, the incremental cost is the difference between the asset's risk cost and the annualized cost of the new asset. The graph below indicates the additional risk cost resulting from delaying intervention.

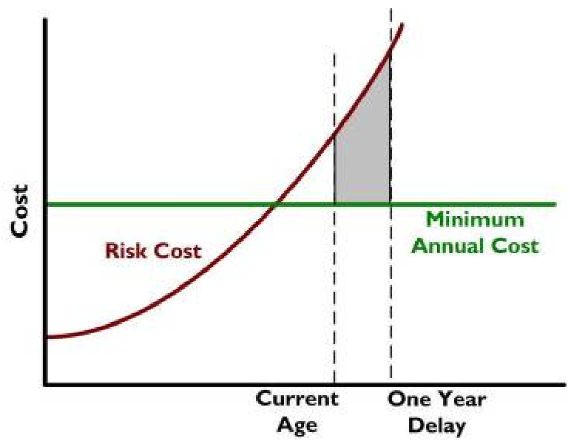
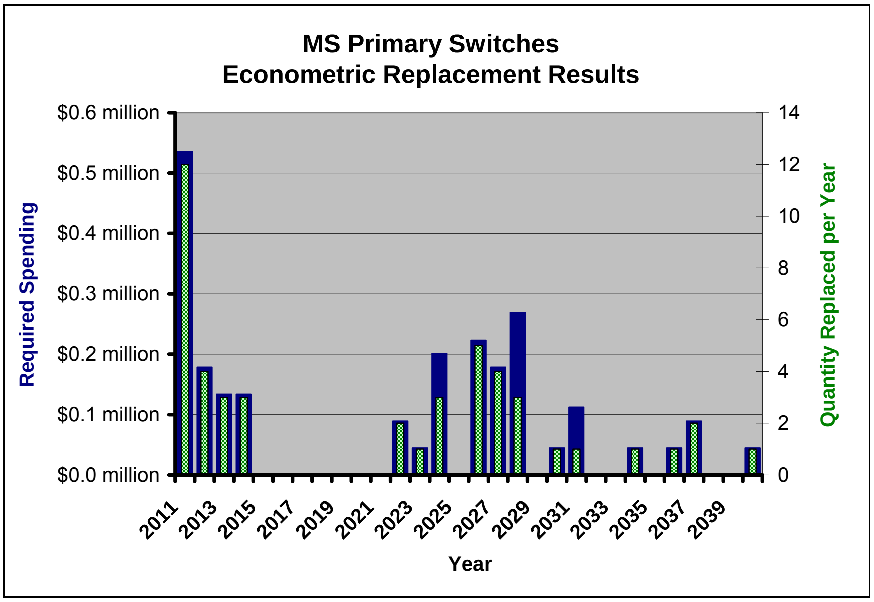


Figure 8. Incremental Benefit of Replacement this Year instead of Next Year.

The shaded area represents the net incremental benefit of replacement. This quantity is compared to the cost of the replacement to calculate benefit/cost ratio, which is used for prioritization.

Econometric Replacement Results

The economic model projects the optimal intervention timing for each asset analyzed. The econometric replacement results are generated by combining the optimal intervention timings and the associated capital costs. An example for MS Primary Switches is shown below.

1


2 **Figure 9. Econometric replacement results and associated capital costs.**

3. ASSET CLASS DETAILS AND RESULTS

3.1 TS Transformers

Summary of Asset Class

Transformer Station (TS) Transformers are highly complex assets with a very high price per unit. A number of methods are available to assess condition and status. PowerStream employs most of them, which enabled detailed analysis of asset condition to be completed efficiently. Risk analysis was more complex as redundancy needed to be addressed and different intervention options evaluated (most importantly levels of spares).

Data Sources Available

Comprehensive demographic and condition data is available. Test data is available, which includes DGA tests, standard oil tests, and Doble power factor tests. Comprehensive load data is also available, which was useful both for condition and criticality assessments.

Demographics

Number of units: 22

Typical life expectancy (years): 30-60 (as per Kinectrics Inc. Report No: K-418099-RA-001-R000 "Asset Amortization Study for the Ontario Energy Board")

Estimated replacement cost: $1.5 to 3.5 million

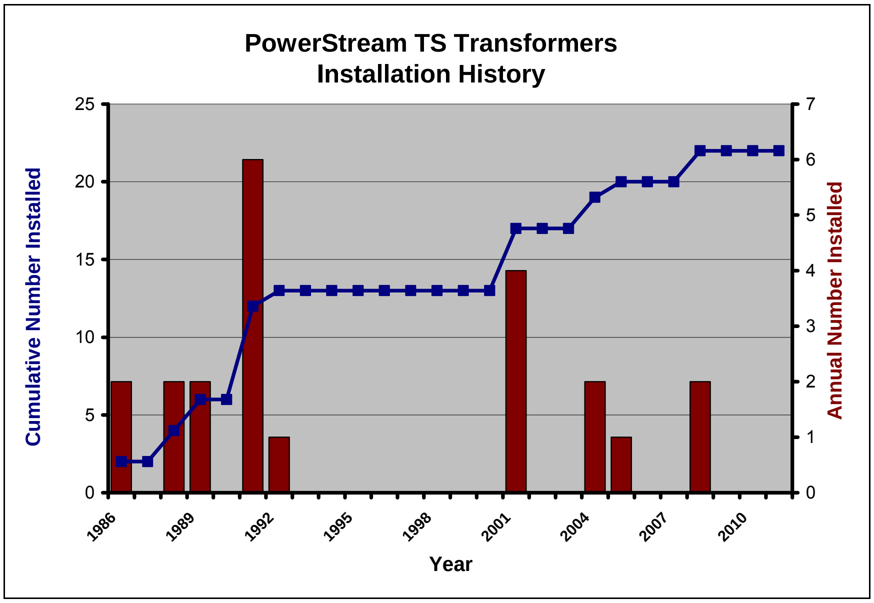


Figure 10. TS transformers installation history.

Asset Degradation

TS transformers are employed to step-down the transmission voltage to distribution voltage levels. TS transformers vary in capacity and ratings over a broad range.

For a majority of transformers, end of life (EOL) is expected to be defined by the failure of an insulation system and, more specifically, the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in service in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are presence of oxygen, high temperature and moisture.

The paper insulation consists of long cellulose chains. As the paper ages through oxidization, these chains are broken. The tensile strength and ductility of insulting paper are determined by the average length of the cellulose chains. Therefore, as the paper oxidizes the tensile strength and ductility are significantly reduced and the insulating paper becomes brittle. The average length of the cellulose chains can be determined by measurement of the degree of polymerization (DP). As the paper ages the DP value gradually decreases. The lack of mechanical strength of paper insulation can result in failure if the transformer is subjected to mechanical shocks that may be experienced during normal operational situations.

In addition to the general oxidation of the paper, degradation and failure can also result from partial discharges which can be initiated if the level of moisture is allowed to rise in the paper or if there are other minor defects within active areas of the transformer.

The relative levels of carbon dioxide and carbon monoxide dissolved in oil can provide an indication of paper degradation. Detection and measurement of furans in the oil provides a more direct measure of the paper degradation. Furans are a group of chemicals that are created as a bi-product of the oxidation process of the cellulose chains. The occurrence of partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units at high risk of failure.

Other condition assessment techniques for TS transformers include Doble (power factor) testing, infrared surveys, partial discharge detection and location using ultrasonic's and/or electro Load tap changers (LTCs) are prone to failure resulting from either mechanical or electrical degradation. Active maintenance is required for tap changers in order to manage these issues. It is normal practice to maintain tap changers either at a fixed time interval or after a number of operations. During operation wear of contacts and build up of oil degradation products, resulting from arcing activity during make and break of contacts, are the primary degradation processes. Maintenance, cleaning and replacement of contacts and any defective components in the mechanism, and changing or reprocessing of oil are the primary maintenance activities that deal with these issues. Oil analysis for tap changers is considered more difficult than oil analysis for transformers due to the generation of gases and general degradation of the oil during arcing under normal LTC operation.

The health indicator parameters for TS transformers usually include:

- Condition of the bushings
- Condition of transformer tank
- Condition of gaskets and oil leaks
- Condition of transformer foundations
- Oil test results
- Transformer age and winding temperature profiles

The anticipated life of transformers is often quoted as being 30 to 60 years. Many transformers in service are now approaching this age but failure rates remain low and there is little evidence that many are at, or near, end-of-life (EOL). There are a number of contributory factors to the long life of transformers such as regular and effective maintenance practices. In addition, the loading of many of these transformers has been relatively light during their working life.

Health Index Formulation and Results

The following charts provide the main condition parameters that are used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Transformer Inspections:

Transformer Visual Inspection Criteria	Weight
Bushing Condition	3
Main Tank/ Controls	0.5
Conservator	0.5
Oil Leaks	1
Foundation/Grounding	0.5
Radiator/Cooling	0.5
Overall Physical	2

Trans-former Health Index

Transformer Testing:

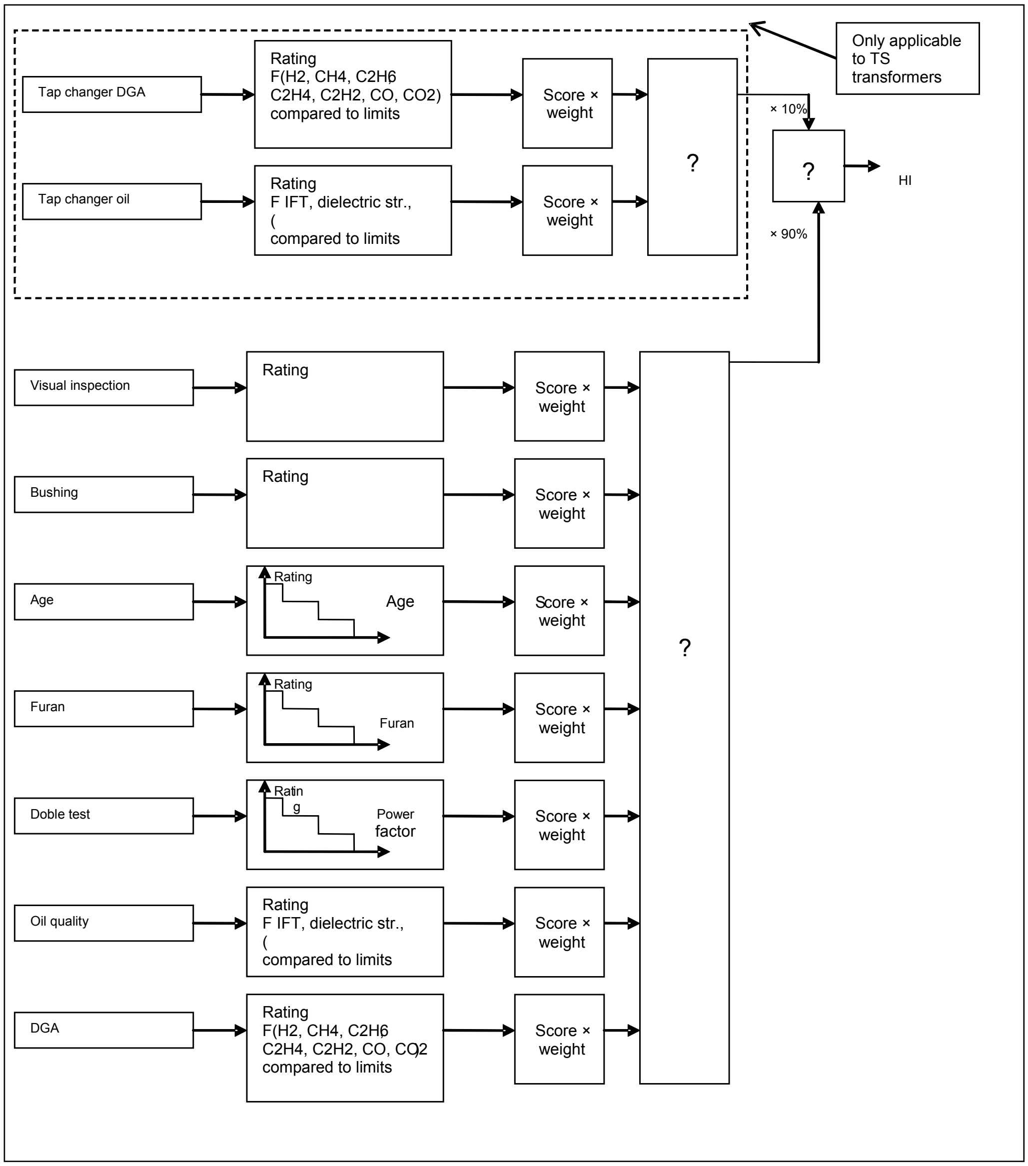
Weight	Transformer Testing Analysis Criteria
4	DGA Analysis
4	Furan Analysis
4	Winding Doble Test
2	Thermograph
3	Oil Quality Test

Tap Changer Criteria:

Tap Changer Criteria	Weight
Tank Condition	0.5
Gaskets/Seals	0.5
Control & Mechanism	1
Tank Leaks	1
Overall Physical	2

Figure 11. TS transformers Health Index flowchart.

TS Transformers

1 

2 **Figure 4. TS transformers Health Index formulation flowchart.**

Table 2. TS transformers Health Index parameters and weights

#	Transformers Condition Parameters	Weight
1	Bushing Condition	3
2	Oil Leaks	1
3	Main Tank/Cabinets and Controls	0.5
4	Conservator/Oil Preservation System (Airbag Integrity)	0.5
5	Radiators/Cooling System	0.5
6	Foundation/Support Steel/Ground	0.5
7	Overall Power Transformer	2
8	DGA Oil Analysis*	4
9	Furan Oil Analysis*	4
10	Age	2
11	Winding Doble Test	4
12	Oil Quality Test	3

*In the case of a score of E, overall Health Index is divided by 2

Tap changers are responsible for a high percentage of transformer failures. Therefore, in developing a relevant health index for transformers, it is appropriate to include information specific to tap changers. The Table below shows the Health Index formulation for tap changers.

Table 3. TS transformers tap changers Health Index condition parameters and weights

#	Tap Changers Condition Parameters	Weight
1	Tank Condition	0.5
2	Tank Leaks	1
3	Gaskets, Seals and Pressure Relief	0.5
4	LTC Control and Mechanism Cabinet	0.5
5	Control and Mechanisms Cabinet Component and operation	0.5
6	Overall Tap Changer Condition	2

7	DGA, Moisture, Metal Content	4
8	Oil Quality Tests	3

Table 4. TS transformer parameter #1: bushing condition

Condition Factor	Factor	Condition Criteria Description
A	4	Bushings are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	3	Bushings are not broken, however minor chips and cracks are visible. Cementing and fasteners are secure.
C	2	Bushings are not broken, however major chips, and some flashover burns and copper splash are visible. Cementing and fasteners are secure.
D	1	Bushings are broken/damaged or cementing and fasteners are not secure.
E	0	Bushings, cementing or fasteners are broken/damaged beyond repair.

Table 5. TS transformer parameter #2: oil leaks

Condition Factor	Factor	Condition Criteria Description
A	4	No oil leakage or water ingress at any of the bushing-metal interfaces or at gaskets, weld seals, flanges, valve fittings, gauges, monitors.
B	3	Minor oil leaks evident, no moisture ingress likely.
C	2	Clear evidence of oil leaks but rate of loss is not likely to cause any operational or environmental impacts
D	1	Major oil leakage and probable moisture ingress. If left uncorrected it could cause operational and/or environmental problems.
E	0	Oil leaks or moisture ingress have resulted in complete failure or damage/degradation beyond repair.

Table 6. TS transformer parameter #3: transformer main tank /cabinets and control condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on main tank. No external or internal rust in cabinets – no evidence of condensation, moisture or insect ingress. No rust or corrosion on weld seals, flanges, valve fittings, gauges, monitors. All wiring, terminal blocks, switches, relays, monitoring and control devices are in good condition.
B	3	No rust or corrosion on main tank, some evidence of slight moisture ingress or condensation in cabinets
C	2	Some rust and corrosion on both tank and on cabinets.
D	1	Significant corrosion on main tank and on cabinets. Defective sealing leading to water ingress and insects/rodent damage.
E	0	Corrosion, water ingress or insect/rodent damage or degradation is beyond repair.

Table 7. TS transformer parameter #4: transformer conservator /oil preservation system condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on body conservator tank. No rust, corrosion on weld seals, flanges, valve fittings, gauges, monitors.
B	3	No rust or corrosion on conservator.
C	2	Some rust and corrosion on conservator.
D	1	Significant rust and corrosion on conservator. Could lead to major oil leakage or water ingress.
E	0	Major oil leakage or water ingress has resulted in damage/degradation beyond repair. Any seal failure on a sealed tank transformer. <u>Note:</u> For transformers employing sealed tanks or air bags, a failure of the seal would be indicated

		by the presence of air in the tank, which can be detected by measuring oxygen or nitrogen content while conducting gas in oil analysis.

Table 8. TS transformer parameter #5: transformer radiators/cooling system condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on body of radiators. Fan and pump enclosures are free of rust and corrosion and securely mounted in position, pump bearings are in good condition and fan controls are operating per design.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	Fan and pump enclosures damaged/degraded beyond repair.

Table 9. TS transformer parameter #6: transformer foundation/support steel /grounding condition

Condition Factor	Factor	Condition Criteria Description
A	4	Concrete foundation is level and free from cracks and spalling. Support steel and/or anchor bolts are tight and free from corrosion. Ground connections are tight, free of corrosion and made directly to tanks, radiators, cabinets and supports, without any intervening paint or corrosion.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	Foundation, supports, or grounding damaged/degraded beyond repair.

Table 10. TS transformer parameter #7: overall power transformer condition

Condition Factor	Factor	Condition Criteria Description
A	4	Power transformer externally is clean, and corrosion free. All primary and secondary connections are in good condition. All monitoring, protection and control, pressure relief, gas accumulation and silica gel devices, and auxiliary systems, mounted on the power transformer, are in good condition. No external evidence of overheating or internal overpressure. Appears to be well maintained with service records readily available.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	More than two of the above characteristics are unacceptable and cannot be brought into acceptable condition.

Table 11. TS transformer parameter #8: DGA oil analysis

Condition Factor	Factor	Condition Criteria Description
A	4	DGA overall factor is less than 1.2
B	3	DGA overall factor between 1.2 and 1.5
C	2	DGA overall factor is between 1.5 and 2.0
D	1	DGA overall factor is between 2.0 and 3.0
E	0	DGA overall factor is greater than 3.0

Where the DGA overall factor is the weighted average of the following gas scores:

	Scores						
	1	**2**	**3**	**4**	**5**	**6**	**Weight**
H2	<=100	<=200	<=300	<=500	<=700	>700	2
CH4	<=120	<=150	<=200	<=400	<=600	>600	3
C2H6	<=50	<=100	<=150	<=250	<=500	>500	3
C2H4	<=65	<=100	<=150	<=250	<=500	>500	3
C2H2	<=3	<=10	<=50	<=100	<=200	>200	5
CO	<=700	<=800	<=900	<=1100	<=1300	>1300	1
CO2	<=3000	<=3500	<=4000	<=4500	<=5000	>5000	1

Table 12. TS transformer parameter #9: transformer furan analysis

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 100 PPB of 2-furaldehyde and no significant change from last test
B	3	Between 100 and 250 PPB of 2-furaldehyde and no significant change from last test
C	2	Between 250 and 500 PPB of 2-furaldehyde or significant change from last test
D	1	Between 500 and 1000 of 2-furaldehyde and significant change from last test
E	0	Greater than 1000 PPB of 2-furaldehyde

Table 13. TS transformer parameter #10: age

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	20-40 years old
C	2	40-60 years old
D	1	Greater than 60 years old
E	0	Not Applicable

Table 14. TS transformer parameter #11: winding Doble test

Condition Factor	Factor	Condition Criteria Description
G	4	Values well within acceptable ranges; power factor less than 0.5 %
D	2	Values considerably exceed acceptable levels; power factor between 0.5 - 1%
I	1	Values exceed acceptable ranges; power factor between 1 – 2%.
B	0	Values are not acceptable> 2%, immediate attention required; power factor greater than 2%

G = Good

D = De-graded

I = Investigate

B = Bad

Table 15. TS transformer parameter #12: oil quality test

Condition Factor	Factor	Condition Criteria Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

	Scores				
	1	**2**	**3**	**4**	**Weight**
*** Moisture PPM (T °C Corrected)** U ≤ 69 kV	<=20	<=30	<=40	>40	4
*** Moisture PPM (T °C Corrected)** 230 kV ≤ U	<=15	<=20	<=25	>25	
*** Dielectric Str. kV 1mm D1816** 230 kV ≤ U	>30	>28	>=25	Less than 25	3
*** Dielectric Str. kV 1mm D1816** U ≤ 69 kV	>23	>20	>=18	Less than 18	
*** Dielectric Str. kV D877**	>40	>30	>20	Less than 20	
*** IFT dynes/cm** U ≤ 69 kV	>20	16-20	13.5-16	Less than 13.5	2
*** IFT dynes/cm** 230 kV ≤ U	> 32	25-32	20-25	Less than 20	

Table 16. TS transformer tap changer parameter #1: tank condition

Condition Factor	Factor	Condition Criteria Description
A	4	No external corrosion or rust on the LTC tank, conservator or switch compartments. No rust or corrosion on tank, cover plates, weld seals, flanges, valve fittings, pressure relief diaphragms, qualitrol or other relays and fittings associated with the LTC.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	More than two unacceptable characteristics that cannot be made acceptable

Table 17. TS transformer tap changer parameter #2: tank leaks

Condition Factor	Factor	Condition Criteria Description
A	4	No external corrosion or rust on the LTC tank, conservator or switch compartments. No rust or corrosion on tank, cover plates, weld seals, flanges, valve fittings, pressure relief diaphragms, qualitrol or other relays and fittings associated with the LTC.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	More than two unacceptable characteristics that cannot be made acceptable

Table 18. TS transformer tap changer parameter #3: gaskets, seals and pressure relief condition

Condition Factor	Factor	Condition Criteria Description
A	4	No external sign of deterioration of tank gaskets, weld seams or gaskets on valve fittings, pressure relief diaphragms, qualitrol or other relays and fittings associated with the LTC. Weather seal of LTC mechanism cabinet is in good condition. Dynamic seals of drive shaft are in good condition.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	More than two unacceptable characteristics that cannot be brought into acceptable condition.

Table 19. TS transformer tap changer parameter #4: LTC control and mechanism cabinet

Condition Factor	Factor	Condition Criteria Description
A	4	No external or internal rust in cabinets. No rust, corrosion or paint peeling on cabinets, sealing very effective – no evidence of moisture or insect ingress or condensation. All control devices are in good condition.
B	3	No rust or corrosion, some evidence of slight moisture ingress or condensation in mechanism cabinet or control circuitry.
C	2	Some rust and corrosion on mechanism cabinet or some deterioration of control circuitry, requires corrective maintenance within the next several months.
D	1	Significant corrosion on mechanism cabinet or significant deterioration of control circuitry. Defective sealing leading to water ingress and insects/rodent damage. Requires immediate

		corrective action.
E	0	Corrosion, water ingress, or insect/rodent damage/degradation that is beyond repair.

Table 20. TS transformer tap changer parameter #5: control and mechanism cabinet component condition

Condition Factor	Factor	Condition Criteria Description
A	4	Wiring, terminal blocks, relays, heaters, motors, contactors and switches all in good condition. LTC operating mechanism, shafts, brakes, gears, bearings, indicators are free from corrosion, abrasion or obstruction and are lubricated. No sign of overheating or deterioration on any electrical or mechanical components.
B	3	A small percentage of the wiring, terminal blocks, relays and switches are in a degraded condition. LTC operating mechanism is in good condition
C	2	About 20% of the wiring, terminal blocks, relays and switches are in a degraded condition. LTC operating mechanism is in fair condition.
D	1	Significant amount of wiring, terminal blocks, relays and switches are in very poor condition. Fuses blow periodically. One or more of the LTC operating mechanism components is in imminent danger of failure. Requires immediate corrective action.
E	0	Components have failed or are damaged/degraded beyond repair.

Table 21. TS transformer tap changer parameter #6: overall tap changer condition

Condition Factor	Factor	Condition Criteria Description
A	4	Tap changer external components, including the mechanism cabinet components, are all in good operating condition, and free from corrosion, deformation, cracks and obstruction. No external evidence of overheating or switch contact failure. Operation counter readings are below the critical range for this type of LTC. Appears to be well

		maintained with service records readily available.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	More than two characteristics that are unacceptable and cannot be brought into acceptable condition.

Table 22. TS transformer tap changer parameter #7: oil analysis (DGA metal content)

Condition Factor	Factor	Condition Criteria Description
A	4	Oil tests passed; DGA overall factor<3 or limited metal content
E	0	Any failed oil test; DGA overall factor>3 or serious metal content

Table 23. TS transformer tap changer parameter #8: oil quality test

Condition Factor	Factor	Condition Criteria Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

	Scores				
	1	**2**	**3**	**4**	**Weight**
*** Moisture PPM (T °C Corrected)** U ≤ 69 kV	<=20	<=30	<=40	>40	4
*** Moisture PPM (T °C Corrected)** 230 kV ≤ U	<=15	<=20	<=25	>25	
*** Dielectric Str. kV 1mm D1816** 230 kV ≤ U	>30	>28	>=25	Less than 25	3
*** Dielectric Str. kV 1mm D1816** U ≤ 69 kV	>23	>20	>=18	Less than 18	
*** Dielectric Str. kV D877**	>40	>30	>20	Less than 20	
*** IFT dynes/cm** U ≤ 69 kV	>20	16-20	13.5-16	Less than 13.5	2
*** IFT dynes/cm** 230 kV ≤ U	> 32	25-32	20-25	Less than 20	

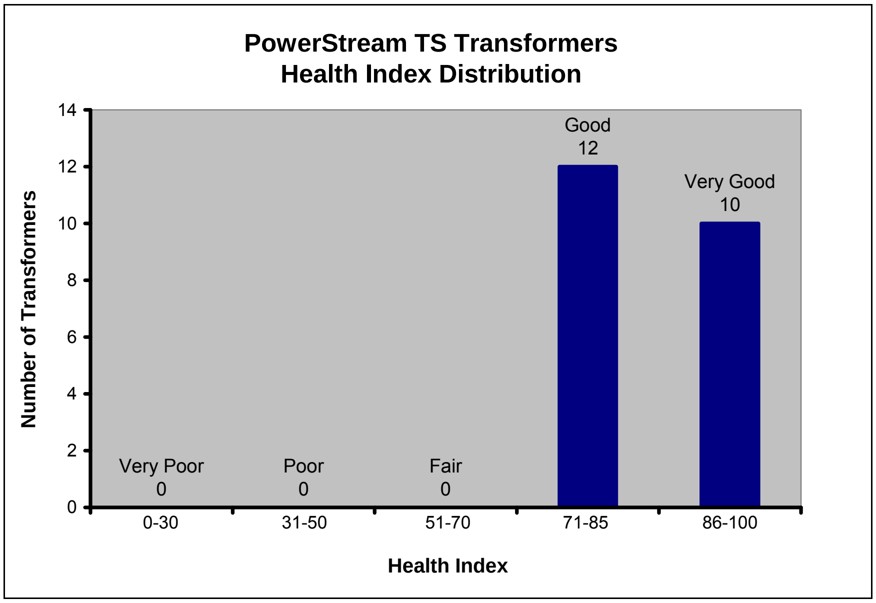


Figure 5. TS transformers Health Index histogram.

Location	Position	Manufacturer	Model	MVA Nameplate	Age	Health Index
Greenwood -Vaughan MTS #1	T1	TTI	ABB	125	22	74
Greenwood -Vaughan MTS #1	T2	TTI	ABB	125	22	77
Greenwood -Vaughan MTS #1 Expansion	T3	ABB	ABB	125	19	86
Greenwood -Vaughan MTS #1 Expansion	T4	ABB	MR	125	6	86
Torstar - Vaughan MTS #2	T1	ABB	ABB	125	20	84
Torstar - Vaughan MTS #2	T2	ABB	ABB	125	20	84
Lorna Jackson - Vaughan MTS #3	T1	ABB	MR	125	10	86
Lorna Jackson - Vaughan MTS #3	T2	ABB	MR	125	10	86
Lazenby MTS1 - Richmond Hill MTS#1	T1	Hyundai	MR	125	20	87
Lazenby MTS1 - Richmond Hill MTS#1	T2	Hyundai	MR	125	20	87
Lazenby MTS1 - Richmond Hill MTS#2	T1	Pauwels	MR	83	10	86
Lazenby MTS1 - Richmond Hill MTS#2	T2	Pauwels	MR	83	10	95
J.V. Fry - Markham MTS#1	T1	Ferranti Packard	FP	83	25	78
J.V. Fry - Markham MTS#1	T2	Ferranti Packard	FP	83	25	78
A.M. Walker - Markham MTS#2	T1	TTI	ASEA	83	23	80
A.M. Walker - Markham MTS#2	T2	TTI	ASEA	83	23	80
D.H. Cockburn - Markham MTS#3	T1	ABB	ABB	83	20	77
D.H. Cockburn - Markham MTS#3	T2	ABB	ABB	83	20	82
D.H. Cockburn - Markham MTS#3 Expansion	T3	Pauwels	MR	83	7	83
D.H. Cockburn - Markham MTS#3 Expansion	T4	Pauwels	MR	83	7	83
Fabro TS -Markham TS#4	T1	ABB	MR	125	3	94
Fabro TS -Markham TS#4	T2	ABB	MR	125	3	94

Figure 6. TS transformers Health Index results.

As can be seen the lowest Health Index is 74 which is classified as Good (71-85), again showing that the overall transformer fleet is in satisfactory condition.

Failure Probability

The TS transformer failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry standards. The Weibull curve parameters are:

- Shape = 3.00, Scale = 50.5

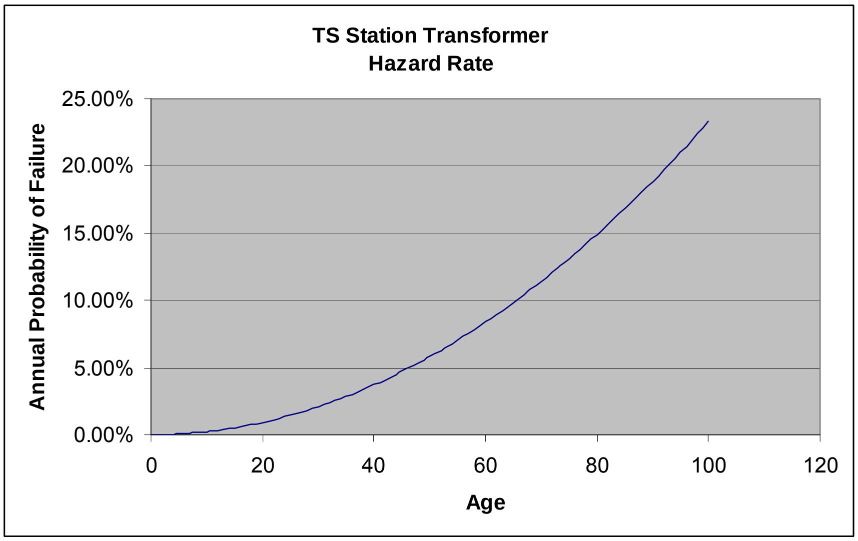


Figure 7. TS transformer hazard rate curve.

The curve fits the failure experience of other utilities with larger populations.

Failure Effects

At PowerStream, all TS's have Dual Element Spot Network (DESN) arrangement, which allows a second transformer to carry all load in the case of a single TS transformer failure. As a result, failure of a single TS transformer will not cause a customer outage. Failure of the second transformer in the station is assumed to cause a 360-hour outage for all customers. Outage costs are based on peak loading.

Risk Matrix

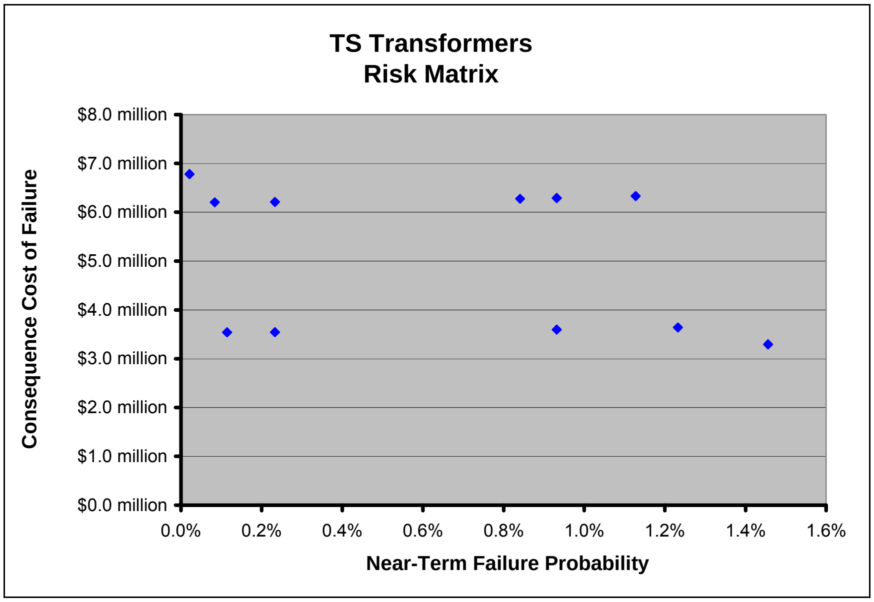


Figure 8. Risk matrix plotting consequence of failure versus failure probability.

Intervention Mode

The intervention mode modeled for TS transformers is replacement in-kind.

Econometric Replacement Results

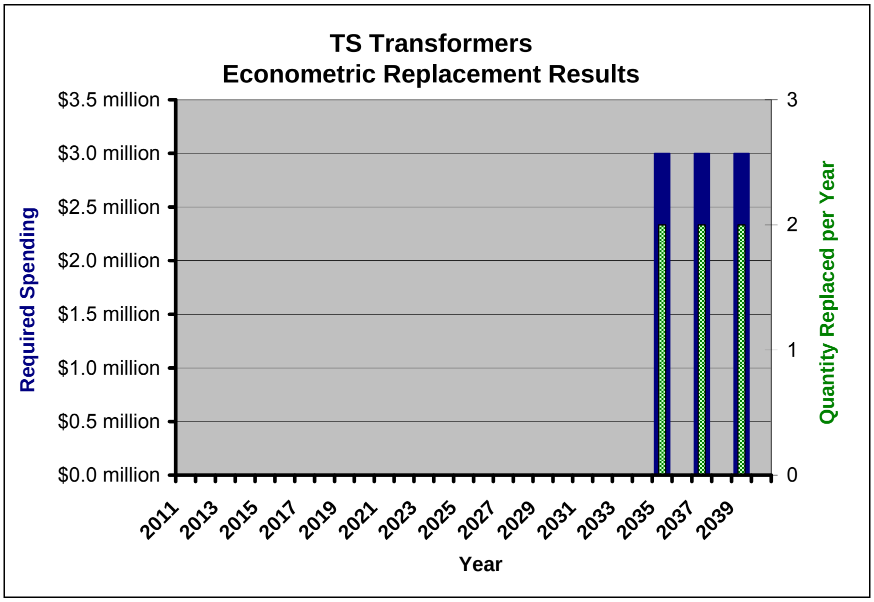


Figure 9. TS transformer econometric replacement results.

Conclusions

- Recommendations:
  - No replacement is proposed in the next five years.
- Gaps:
  - None identified.

3.2 MS Transformers

Summary of Asset Class

Municipal Station (MS) transformers are highly complex assets with a high price per unit.

Many methods are available to assess condition and status; PowerStream employs most of them, which enabled detailed analysis of asset condition to be completed efficiently.

Data Sources Available

Comprehensive demographic and condition data is available. Test data is available, which includes DGA tests, standard oil tests, and limited visual condition.

Demographics

Number of units: 65 (2 of which are not in-service)

Typical life expectancy (years): 30-60 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 "Asset Amortization Study for the Ontario Energy Board"

Estimated replacement cost: $300,000 - $700,000

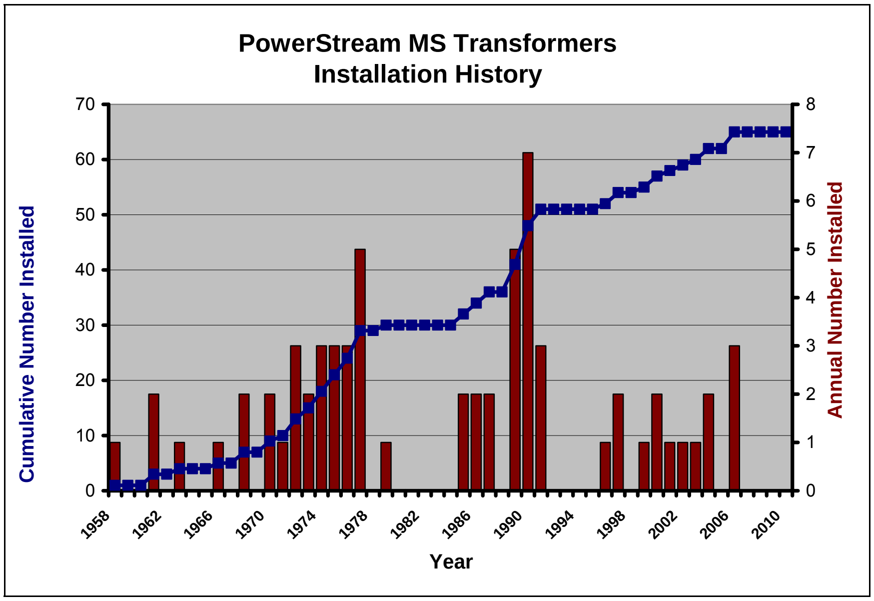


Figure 18. MS transformers installation history.

Asset Degradation

MS transformers are employed to step down the sub-transmission voltage or higher distribution voltage to lower distribution voltage levels.

For a majority of transformers, end of life (EOL) is expected to be defined by the failure of an insulation system and more specifically the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in service in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are presence of oxygen, high temperature and moisture.

The paper insulation consists of long cellulose chains. As the paper ages through oxidization, these chains are broken. The tensile strength and ductility of insulting paper are determined by the average length of the cellulose chains. Therefore, as the paper oxidizes the tensile strength and ductility are significantly reduced and the insulating paper becomes brittle. The average length of the cellulose chains can be determined by measurement of the degree of polymerization (DP). As the paper ages the DP value gradually decreases. The lack of mechanical strength of paper insulation can result in failure if the transformer is subjected to mechanical shocks that may be experienced during normal operational situations.

In addition to the general oxidation of the paper, degradation and failure can also result from partial discharges which can be initiated if the level of moisture is allowed to rise in the paper or if there are other minor defects within active areas of the transformer.

The relative levels of carbon dioxide and carbon monoxide dissolved in oil can provide an indication of paper degradation. Detection and measurement of furans in the oil provides a more direct measure of the paper degradation. Furans are a group of chemicals that are created as a bi-product of the oxidation process of the cellulose chains. The occurrence of partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units at high risk of failure.

Other condition assessment techniques for MS transformers include Doble (power factor) testing, infrared surveys, partial discharge detection and location using ultrasonics and/or electromagnetic detection and frequency response analysis.

The health indicator parameters for MS transformers usually include:

- Condition of the bushings
- Condition of transformer tank
- Condition of gaskets and oil leaks
- Condition of transformer foundations
- Oil test results
- Transformer age and winding temperature profiles

The anticipated life of transformers is often quoted as being 30 to 60 years. Many transformers in service are now approaching this age but failure rates remain low with few units at, or near, EOL. There are a number of contributory factors to the long life of transformers. In the 1950s and 1960s transformers were designed and manufactured conservatively such that the thermal and electrical stresses, even at high load, were relatively low compared to modern designs. In addition, the loading of many of these transformers has been relatively light during their working life.

Health Index Formulation and Results

The following figure and charts provide the main condition parameters that are used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

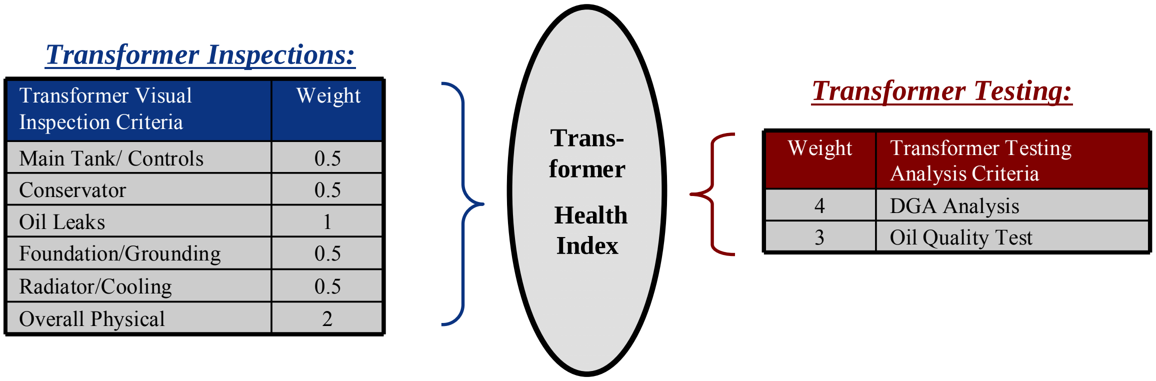


Figure 19. MS transformers Health Index flowchart.

Table 24. Circuit breakers Health Index parameters and weights

#	MS Transformer Condition Parameters	Weight
1	Oil Leaks	1
2	Transformer Main Tank/Cabinets and Control Condition	0.5
3	Transformer Conservator/Oil Preservation System Condition	0.5
4	Transformer Radiators/Cooling System Condition	0.5
5	Transformer Foundation/Support Steel/Grounding Condition	0.5
6	Overall Power Transformer Condition	2
7	DGA Oil Analysis	4
8	Furan Oil Analysis*	4
9	Winding Doble Test	4
10	Bushing Condition	3
11	Oil Quality Test	3
12	Age	2

Table 25. MS transformer parameter #1: oil leaks

Condition Factor	Factor	Condition Criteria Description
A	4	No oil leakage or water ingress at any of the bushing-metal interfaces or at gaskets, weld seals, flanges, valve fittings, gauges, monitors.
B	3	Minor oil leaks evident, no moisture ingress likely.
C	2	Clear evidence of oil leaks but rate of loss is not likely to cause any operational or environmental impacts
D	1	Major oil leakage and probable moisture ingress. If left uncorrected it could cause operational and/or environmental problems.
E	0	Oil leaks or moisture ingress have resulted in complete failure or damage/degradation beyond repair.

Table 26. MS transformer parameter #2: transformer main tank /cabinets and control condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on main tank. No external or internal rust in cabinets – no evidence of condensation, moisture or insect ingress. No rust or corrosion on weld seals, flanges, valve fittings, gauges, monitors. All wiring, terminal blocks, switches, relays, monitoring and control devices are in good condition.
B	3	No rust or corrosion on main tank, some evidence of slight moisture ingress or condensation in cabinets
C	2	Some rust and corrosion on both tank and on cabinets.
D	1	Significant corrosion on main tank and on cabinets. Defective sealing leading to water ingress and insects/rodent damage.
E	0	Corrosion, water ingress or insect/rodent damage or degradation is beyond repair.

Table 27. MS transformer parameter #3: transformer conservator /oil preservation system condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on body conservator tank. No rust, corrosion on weld seals, flanges, valve fittings, gauges, monitors.
B	3	No rust or corrosion on conservator.
C	2	Some rust and corrosion on conservator.
D	1	Significant rust and corrosion on conservator. Could lead to major oil leakage or water ingress.
E	0	Major oil leakage or water ingress has resulted in damage/degradation beyond repair. Note: For transformers employing sealed tanks or air bags, a failure of the seal would be indicated by the presence of air in the tank, which can be detected by measuring oxygen or nitrogen content while conducting gas in oil analysis.

Table 28. MS transformer parameter #4: transformer radiators /cooling system condition

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on body of radiators. Fan and pump enclosures are free of rust and corrosion and securely mounted in position, pump bearings are in good condition and fan controls are operating per design.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	Fan and pump enclosures damaged/degraded

		beyond repair.

Table 29. MS transformer parameter #5: transformer foundation/ support steel /grounding condition

Condition Factor	Factor	Condition Criteria Description
A	4	Concrete foundation is level and free from cracks and spalling. Support steel and/or anchor bolts are tight and free from corrosion. Ground connections are tight, free of corrosion and made directly to tanks, radiators, cabinets and supports, without any intervening paint or corrosion.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	Foundation, supports, or grounding damaged/degraded beyond repair.

Table 30. MS transformer parameter #6: overall power transformer condition

Condition Factor	Factor	Condition Criteria Description
A	4	Power transformer externally is clean, and corrosion free. All primary and secondary connections are in good condition. All monitoring, protection and control, pressure relief, gas accumulation and silica gel devices, and auxiliary systems, mounted on the power transformer, are in good condition. No external evidence of overheating or internal overpressure. Appears to be well maintained with service records readily available.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are

		unacceptable.
E	0	More than two of the above characteristics are unacceptable and cannot be brought into acceptable condition.

1 **Table 31. MS transformer parameter #7: DGA oil analysis**

Condition Factor	Factor	Condition Criteria Description
A	4	DGA overall factor is less than 1.2
B	3	DGA overall factor between 1.2 and 1.5
C	2	DGA overall factor is between 1.5 and 2.0
D	1	DGA overall factor is between 2.0 and 3.0
E	0	DGA overall factor is greater than 3.0

2 Where the DGA overall factor is the weighted average of the following gas scores:

	Scores						
	1	2	3	4	5	6	Weight
H2	<=100	<=200	<=300	<=500	<=700	>700	2
CH4	<=120	<=150	<=200	<=400	<=600	>600	3
C2H6	<=50	<=100	<=150	<=250	<=500	>500	3
C2H4	<=65	<=100	<=150	<=250	<=500	>500	3
C2H2	<=3	<=10	<=50	<=100	<=200	>200	5
CO	<=700	<=800	<=900	<=1100	<=1300	>1300	1
CO2	<=3000	<=3500	<=4000	<=4500	<=5000	>5000	1

3 **Table 32. MS transformer parameter #8: transformer furan analysis**

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 100 PPB of 2-furaldehyde and no significant change from last test
B	3	Between 100 and 250 PPB of 2-furaldehyde and no significant change from last test

C	2	Between 250 and 500 PPB of 2-furaldehyde or significant change from last test
D	1	Between 500 and 1000 of 2-furaldehyde and significant change from last test
E	0	Greater than 1000 PPB of 2-furaldehyde

Table 33. MS transformer parameter #9: winding Doble test

Condition Factor	Factor	Condition Criteria Description
G	4	Values well within acceptable ranges; power factor less than 0.5 %
D	2	Values considerably exceed acceptable levels; power factor between 0.5 - 1%
I	1	Values exceed acceptable ranges; power factor between 1 – 2%.
B	0	Values are not acceptable> 2%, immediate attention required; power factor greater than 2%

G = Good

D = De-Graded

I = Investigate

B = Bad

Table 34. MS transformer parameter #10: bushing condition

Condition Factor	Factor	Condition Criteria Description
A	4	Bushings are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	3	Bushings are not broken, however minor chips and cracks are visible. Cementing and fasteners are secure.

C	2	Bushings are not broken, however major chips, and some flashover burns and copper splash are visible. Cementing and fasteners are secure.
D	1	Bushings are broken/damaged or cementing and fasteners are not secure.
E	0	Bushings, cementing or fasteners are broken/damaged beyond repair.

Table 35. MS transformer parameter #11: oil quality test

Condition Factor	Factor	Condition Criteria Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

<table>
<tr><th></th><th colspan="5">Scores</th></tr>
<tr><th></th><th>1</th><th>2</th><th>3</th><th>4</th><th>Weight</th></tr>
<tr><td>* Moisture PPM
(T °C Corrected)
U ≤ 69 kV</td><td><=20</td><td><=30</td><td><=40</td><td>>40</td><td rowspan="2">4</td></tr>
<tr><td>* Moisture PPM
(T °C Corrected)
230 kV ≤ U</td><td><=15</td><td><=20</td><td><=25</td><td>>25</td></tr>
<tr><td>* Dielectric Str. kV 1mm
D1816 230 kV ≤ U</td><td>>30</td><td>>28</td><td>>=25</td><td>Less than 25</td><td rowspan="3">3</td></tr>
<tr><td>* Dielectric Str. kV 1mm
D1816 U ≤ 69 kV</td><td>>23</td><td>>20</td><td>>=18</td><td>Less than 18</td></tr>
<tr><td>* Dielectric Str. kV</td><td>>40</td><td>>30</td><td>>20</td><td>Less than 20</td></tr>
</table>

D877					
*** IFT** **dynes/cm** U ≤ 69 kV	>20	16-20	13.5-16	Less than 13.5	2
*** IFT** **dynes/cm** 230 kV ≤U	> 32	25-32	20-25	Less than 20	

Table 36. MS transformer parameter #12: age

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	20-40 years old
C	2	40-60 years old
D	1	Greater than 60 years old
E	0	Not Applicable

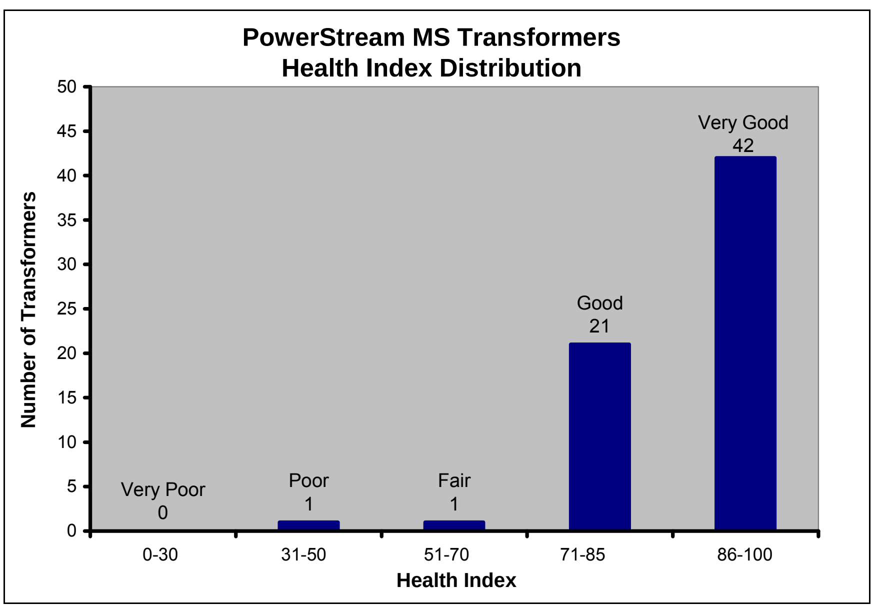


Figure 20. MS transformers Health Index histogram.

The Health of the transformer population is generally satisfactory. Only 1 transformer is in Fair condition. The unit indicated as Poor in Figure 20 is currently out of service.

MS Transformers

Location	Position	Manufacturer	MVA Nameplate	Age	Health Index
Amber MS-T1	T1	West	10	39	90
Amber MS-T2	T2	Moloney	10	39	33
Baythorn MS-T1	T1	FPE	7.5	35	92
Baythorn MS-T2	T2	Northern Transformer	7.5	35	92
Morgan MS-T1	T1	Moloney	5	34	95
Morgan MS-T2	T2	Moloney	5	34	87
John Street MS-T1	T1	Ferranti Packard	10	37	91
John Street MS-T2	T2	Moloney	10	37	84
Elder Mills MS-T1	T1	Ferranti Packard	5	15	75
Rainbow MS-T1	T1		10	41	75
Concord MS-T1	T1	West	15	41	73
King MS-T1	T1	West	5	50	89
Aurora MS#1-T1	T1	ABB	10	10	97
Aurora MS#1-T2	T2	Ferranti Packard	10	27	88
Aurora MS#2-T1	T1	Ferranti Packard	10	32	86
Aurora MS#3-T1	T1	Federal Pioneer	10	22	86
Aurora MS#3-T2	T2	Federal Pioneer	10	21	89
Aurora MS#4-T1	T1	Northern Transformer	10	5	94
Aurora MS#4-T2	T2	West	10	38	88
Aurora MS#5-T1	T1	Northern Transformer	10	15	97
Aurora MS#5-T2	T2	Northern Transformer	10	9	97
Aurora MS#6-T1	T1	Northern Transformer	10	14	93
Aurora MS#6-T2	T2	West	10	38	94
Aurora MS#7-T1	T1	Northern Transformer	10	5	97
Aurora MS#8-T1	T1	Northern Transformer	10	5	97
ANNE NORTH-301-T1	301-T1	Federal Pioneer	20	22	91
SAUNDERS-302-T1	302-T1	Federal Pioneer	20	22	91
FERNDALE SOUTH-303-T1	303-T1	Federal Pioneer	20	22	88
BIG BAY POINT-304-T1	304-T1	Federal Pioneer	20	21	86
HOLLY-305-T1	305-T1	Ferranti	20	11	93
LITTLE LAKE-306-T1	306-T1	Federal Pioneer	20	21	79
HURONIA-307-T1	307-T1	Northern	10	8	75
Park Place-308-T1	308-T1	Ferranti	20	11	86
John-321-T1	321-T1	Moloney	10	34	78
Melborne-322-T1	322-T1	Federal Pioneer	10	35	75
8th Line-323-T2	323-T2	Northern	10	21	81
Reagans-324-T1	324-T1	Northern	10	12	73
8th Ave-330-T1	330-T1	Northern	10	20	94
14th Line-331-T1	331-T1	Northern	10	7	100
14th Line-331-T2	331-T2	Northern	10	7	100
Patterson-336-T1	336-T1	B.G. High Voltage	7.5	21	93
ANNE TEMP-402-T1	402-T1	C.G.E.	5	45	73
BLAKE-404-T1	404-T1	TTI	10	22	92
BROCK-405-T1	405-T1	TTI	10	21	92
BURTON-406-T1	406-T1	Moloney	5	37	81
CUNDLES EAST-407-T1	407-T1	General Electric	5	48	84
CUNDLES WEST-408-T1	408-T1	Federal Pioneer	5	36	86
DUCKWORTH-409-T1	409-T1	Westinghouse	5	43	60
FERNDALE-410-T1	410-T1	Westinghouse	5	26	85
INNISFIL-411-T1	411-T1	Federal Pioneer	5	34	87
JOHNSON-412-T1	412-T1	Federal Pioneer	10	24	91
LETITIA-413-T1	413-T1	Federal Pioneer	5	34	84
LITTLE-414-T1	414-T1	C.G.E.	5	39	90
MARY-415-T1	415-T1	TTI	10	21	90
ST. VINCENT-417-T1	417-T1	TTI	10	24	75
WELLINGTON-418-T1	418-T1	TTI	10	20	75
PERRY -419-T1	419-T1	Federal Pioneer	10	20	77
Fox-421-T1	421-T1	ABB	5	14	89
Robert-422-T1	422-T1	Federal Pioneer	5	25	87
Bellisle-423-T1	423-T1	Porter	5	36	76
Centennial-424-T1	424-T1	Markham Electric	6	18	87
Dufferin-431-T1	431-T1	Westinghouse	5	50	78
Fletcher-432-T1	432-T1	C.G.E.	5	40	94
Nolan-834-T1	834-T1	Westinghouse	10	26	90
Mill St.-835-T1	835-T1	Markham Electric	6	36	84

Figure 21. MS transformers Health Index results.

Failure Probability

The MS Transformer failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry standards. The Weibull curve parameters are:

- Shape = 3.00, Scale = 74.77

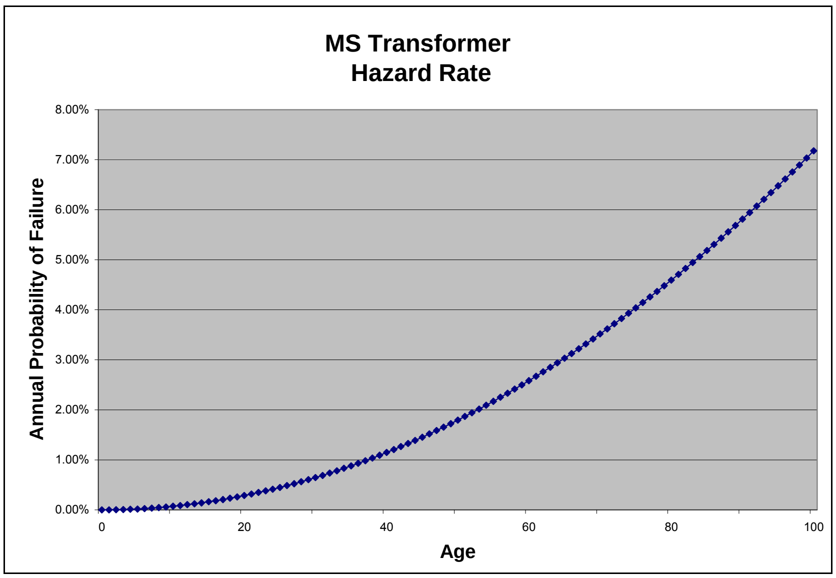


Figure 22. MS transformer hazard rate curve.

The curve fits the failure experience of other utilities with larger populations.

Failure Effects

MS transformer failures are assumed to cause a 5-hour outage, mitigated, in most cases, through switching to other MS transformers. Outage costs are based on peak loading.

Risk Matrix

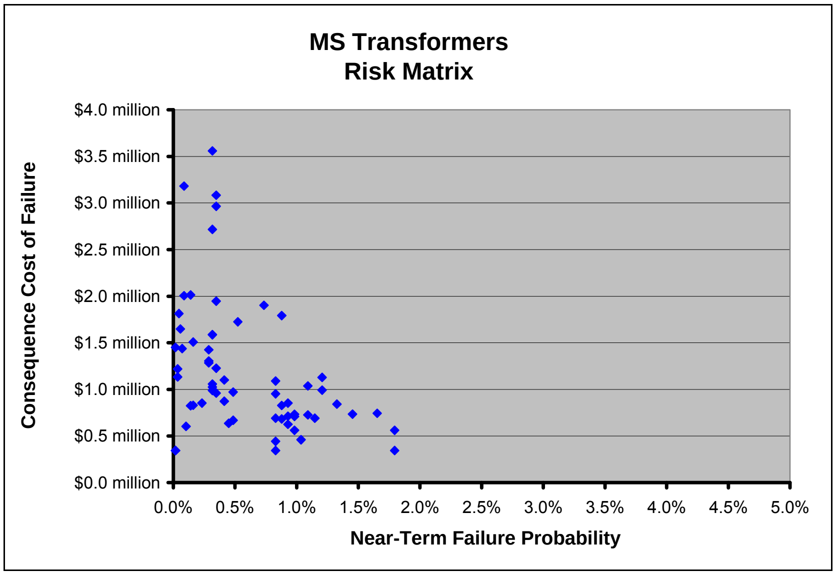


Figure 23. Risk matrix plotting consequence of failure versus failure probability.

Intervention Mode

The intervention mode modeled for MS transformers is replacement in-kind.

Econometric Replacement Results

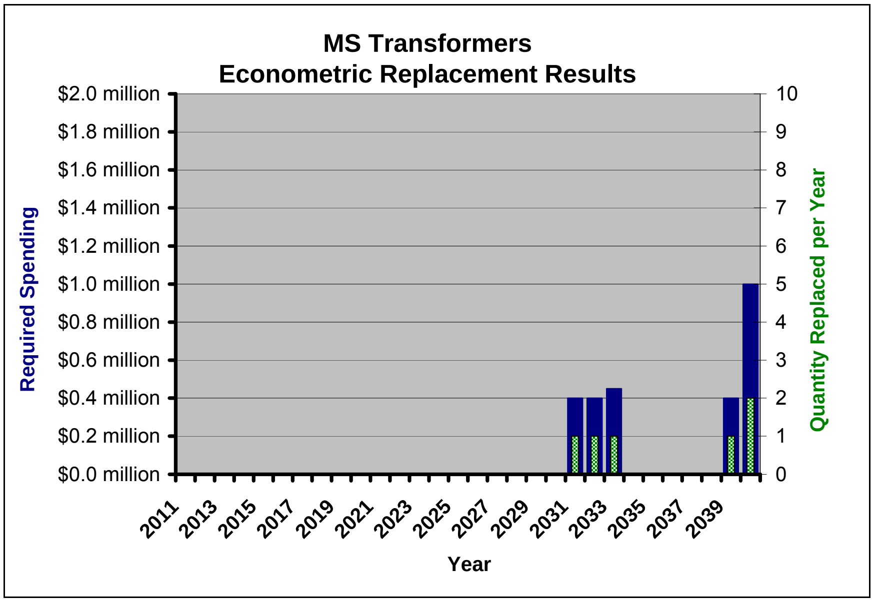


Figure 24. MS transformers econometric replacement results.

Conclusions

- Recommendations:
  - No replacement is proposed in the next five years.
- Gaps:
  - None identified.

3.3 Circuit Breakers

Summary of Asset Class

Circuit breakers are highly complex assets with a moderate price per unit. Types include vacuum, oil, air, and SF6 breakers.

There is limited end-of-life condition data available; health index formulation is based on industry best-practice with an emphasis on mechanical degradation indicators. Mechanical and electrical condition data is collected on an ongoing basis.

Data Sources Available

The data sources available for circuit breakers include assumed loading, nameplate, and general demographic information.

Demographics

Number of units: 399 (386 with HI assessments)

Typical life expectancy (years): 35-65 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 "Asset Amortization Study for the Ontario Energy Board"

Estimated replacement cost: $160,000 - $212,000

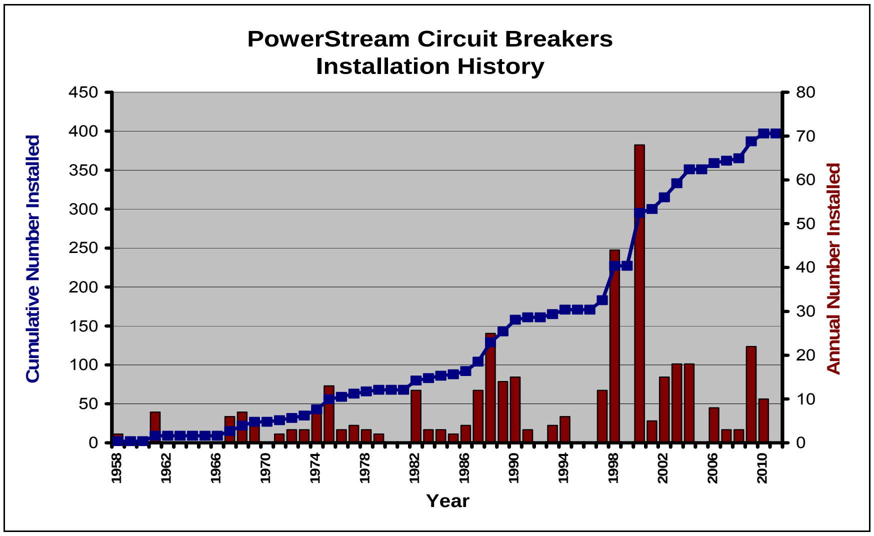


Figure 25. Circuit breaker installation history.

Asset Degradation

The station circuit breakers are automated switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions. Circuit breakers are required to operate infrequently, however, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage. Circuit breakers designs have evolved over the years and many different types are currently in use. Commonly used circuit breaker types include oil circuit breakers, vacuum breakers, magnetic air circuit breakers and SF6 circuit breakers.

Station circuit breakers have many moving parts that are subject to wear and stress. They frequently "make" and "break" high currents and experience the arcing accompanying these operations. All circuit breakers undergo some contact degradation every time they open to interrupt an arc. Also, arcing produces heat and decomposition products that degrade surrounding insulation materials, nozzles, and interrupter chambers. The mechanical energy needed for the high contact velocities of these assets adds mechanical deterioration to their degradation processes.

The rate and severity of degradation depends on many factors, including insulating and conducting materials, operating environments, and a breaker's specific duties. The International Council on Large Electric Systems' (CIGRE) has identified the following factors that lead to end-of-life for this asset class:

- Decreasing reliability, availability and maintainability
- High maintenance and operating costs
- Changes in operating conditions, rendering the existing asset obsolete
- Maintenance overhaul requirements
- Circuit breaker age

Outdoor circuit breakers may experience adverse environmental conditions that influence their rate and severity of degradation. For outdoor mounted circuit breakers, the following represent additional degradation factors:

- Corrosion
- Effects of moisture
- Bushing/insulator deterioration
- Mechanical

Corrosion and moisture commonly cause degradation of internal insulation, breaker performance mechanisms, and major components like bushings, structural components, and oil seals. Corrosion presents problems for almost all circuit breakers, irrespective of their location or housing material. Rates of corrosion degradation, however, vary depending on exposure to environmental elements. Underside tank corrosion causes problems in many types of breakers, particularly those with steel tanks. Another widespread problem involves corrosion of operating mechanism linkages that result in eventual link seizures. Corrosion also causes damage to metal flanges, bushing hardware and support insulators.

Moisture causes degradation of the insulating system. Outdoor circuit breakers experience moisture ingress through defective seals, gaskets, pressure relief and venting devices. Moisture in the interrupter tank can lead to general degradation of internal components. Also, sometimes free water collects in tank bottoms, creating potential catastrophic failure conditions.

For circuit breakers, mechanical degradation presents greater end-of-life concerns than electrical degradation. Generally, operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Oil and gas leakage also occurs. Contacts, nozzles, and highly stressed components can also experience electrical-related degradation and deterioration. Other defects that arise with aging include:

- Loose primary and grounding connections
- Oil contamination and/or leakage
- Deterioration of concrete foundation affecting stability of breakers

The diagnostic tests to assess the condition of circuit breakers include:

- Visual inspections
- Travel time tests
- Contact resistance measurements
- Bushing - Doble (Power Factor) Test
- Stored energy tests (Air/Hydraulic/Spring Recharge Time)
- Insulating medium tests

As indicated above, the useful life of circuit breakers can vary significantly depending on the duty cycle and typically lies within a broad range of 35 to 65 years.

Consequences of circuit breaker failure may be significant as they can directly lead to catastrophic failure of the protected equipment, leading to customer interruptions, health and safety consequences and adverse environmental impacts.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

The following figure illustrates the HI formulation for circuit breakers.

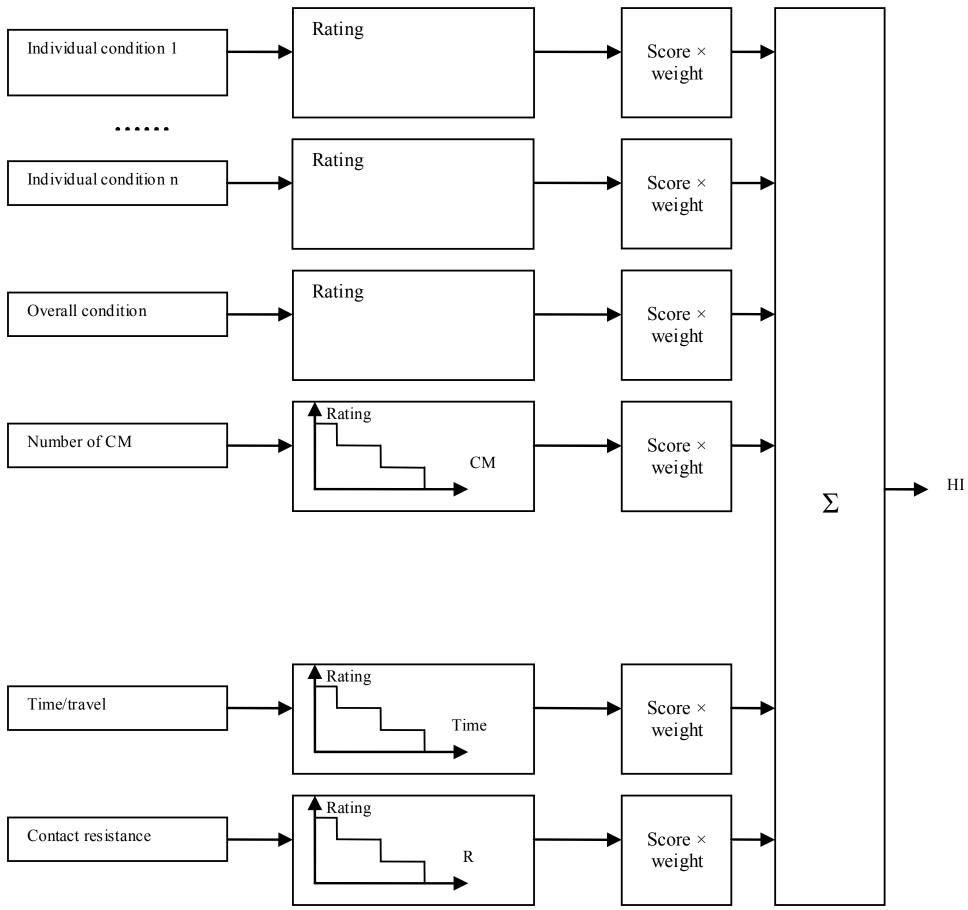


Figure 26. Circuit breaker Health Index formulation flowchart.

Table 37. Circuit breakers Health Index parameters and weights

#	CB Condition Parameters	Weight
1	Bushing/Insulator Condition	3
2	Leaks (OCB only)	3
3	Tank and Control/Mechanism Box	2
4	Control and Mechanism Box Components	2
5	Foundation and Support Steel Grounding	2

6	Overall Condition	4
7	Time/Travel	3
8	Contact Resistance	4

1 **Table 38. Circuit breaker parameter #1: bushing/insulator condition**

Condition Factor	Factor	Condition Criteria Description
A	4	Bushings/Support Insulators are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure.
B	3	Bushings/Support Insulators are not broken, however there are some minor chips and cracks. No flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
C	2	Bushings/Support Insulators are not broken, however there are some major chips and cracks. Some evidence of flashover burns or copper splash or copper wash. Cementing and fasteners are secure.
D	1	Bushings/Support Insulators are broken/damaged, or cementing or fasteners are not secure.
E	0	Bushings/Support Insulators, cementing or fasteners are broken/damaged beyond repair.

Table 39. Circuit breaker parameter #2: leaks

Condition Factor	Factor	Condition Criteria Description
A	4	No oil leakage or water ingress at any of the bushing-metal interfaces. No oil leakage or water ingress at any of the flanges, manholes, covers, breathers, pipes or gauges. Oil levels are acceptable.
B	3	Minor oil leaks evident, no moisture ingress likely.
C	2	Clear evidence of oil leaks but rate of loss is not likely to cause any operational or environmental impacts
D	1	Major oil leakage and probable moisture ingress at the bushings, or at one other location indicate the immediate need for a major reconditioning or replacement.
E	0	Significant oil leakage and moisture ingress resulting in damage/degradation beyond repair.

Table 40. Circuit breaker parameter #3: tank and control/mechanism box

Condition Factor	Factor	Condition Criteria Description
A	4	No rust or corrosion on main tank. No external or internal rust in cabinets. No rust, corrosion or paint peeling on tanks or cabinets, sealing very effective – no evidence of moisture or insect ingress or condensation.
B	3	No rust or corrosion on main tank, some evidence of slight moisture ingress or condensation in mechanism box.
C	2	Some rust and corrosion on both tank and on mechanism box, requires corrective maintenance within the next several months.
D	1	Significant corrosion on main tank and on mechanism box. Defective sealing leading to water ingress and insects/rodent damage. Requires immediate corrective action.
E	0	Corrosion, water, insect or rodent damage or

		degradation beyond repair.

1 **Table 41. Circuit breaker parameter #4: control and mechanism components**

Condition Factor	Factor	Condition Criteria Description
A	4	Wiring, terminal blocks, relays, contactors and switches all in good condition. Operating mechanism, trip and close coils, relays, auxiliary switches, motors, compressors, springs are all in good condition. No sign of overheating or deterioration. Linkages, drive rods, trip latches are clean, lubricated, free from cracks, distortion, abrasion or obstruction. Mechanical integrity of dampers/dashpots, and oil levels, is acceptable. No visible evidence of poor mechanism settings, looseness, loss of adjustment, excess bearing wear or other out of tolerance operation.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	Control and mechanism components are damaged/degraded beyond repair.

2 **Table 42. Circuit breaker parameter #5: foundation and support steel grounding**

Condition Factor	Factor	Condition Criteria Description
A	4	Support steel and/or anchor bolts are tight and free from corrosion. Ground connections are direct to tank, cabinets, supports without any intervening paint or corrosion.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.

E	0	Supports or grounding are damaged/degraded beyond repair.

1 **Table 43. Circuit breaker parameter #6: overall condition**

Condition Factor	Factor	Condition Criteria Description
A	4	Breaker externally is clean, corrosion free. All primary and secondary connections are in good condition. No external evidence of overheating. Number of breaker operations on counter, and run timer readings on auxiliary motors, are below average range for age of breaker. Appears to be well maintained with service records readily available.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One or two of the above characteristics are unacceptable.
D	1	More than two of the above characteristics are unacceptable.
E	0	The circuit breaker is damaged/degraded beyond repair.

2 **Table 44. Circuit breaker parameter #7: time/travel**

Condition Factor	Factor	Condition Criteria Description
A	4	Close travel, wipe, overtravel, rebound and time are all within specified limits. Trip time and velocity are within specified limits. Trip free time is within specified limits. Interpole close and trip contact time spread is within specified limits for the specific application.
B	3	Normal signs of wear with respect to the above characteristics.
C	2	One of the above characteristics is unacceptable.
D	1	Two or more of the above characteristics are unacceptable.
E	0	Two or more of the above characteristics are

		unacceptable and cannot be brought into acceptable condition.

Table 45. Circuit breaker parameter #8: contact resistance

Condition Factor	Factor	Condition Criteria Description
A	4	Values well within specifications with high margins
B	3	Values close to specification (little or no margin)
C	2	Values do not meet specification (by a small amount)
D	1	Values do not meet specification (by a significant margin)
E	0	Values do not meet specification and cannot be brought into specification condition.

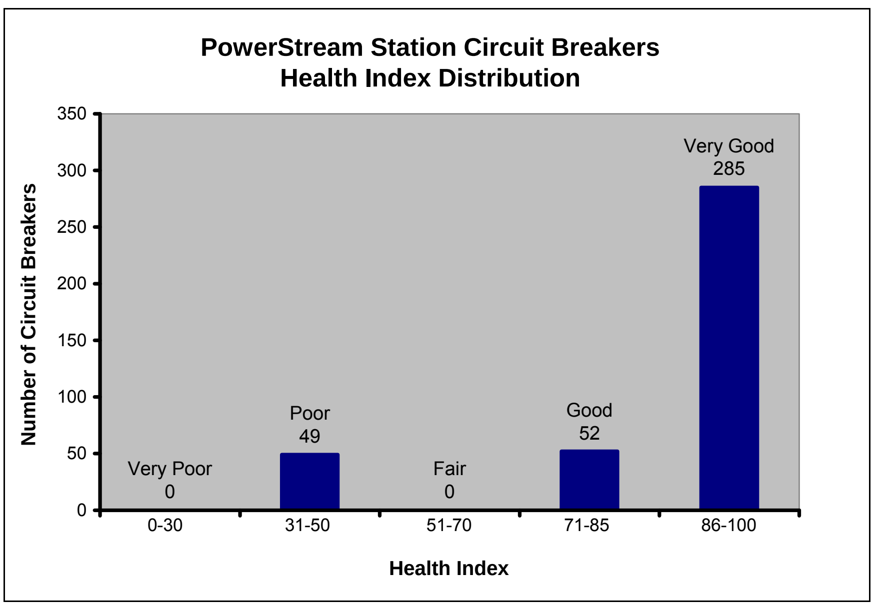


Figure 27. Station Circuit Breakers Index histogram.

Failure Probability

The circuit breaker failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry standards. The Weibull curve parameters are:

- **Gas insulated VAC / Air-** Shape = 3.00, Scale = 74.77
- **OCB -** Shape = 3.00, Scale = 59.8
- **SF6 -** Shape = 3.00, Scale = 52.4

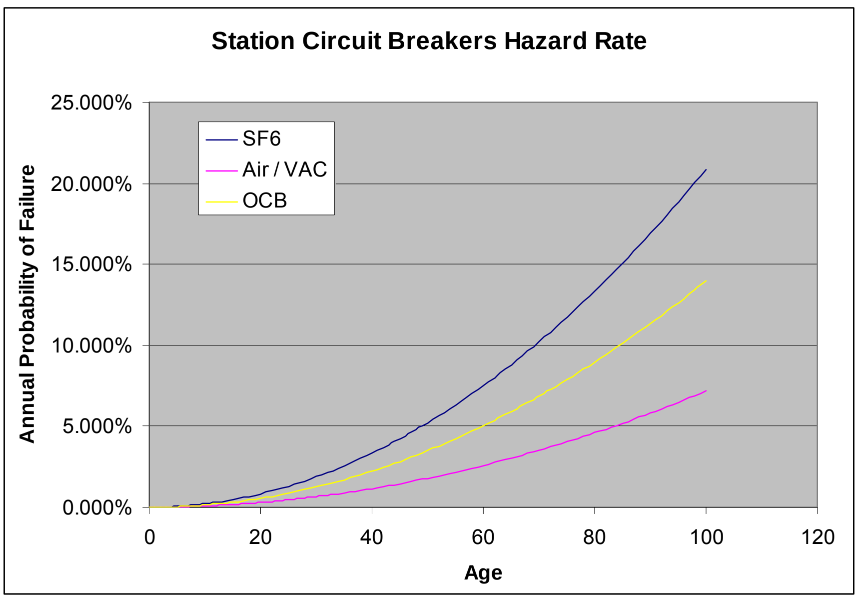


Figure 28. Circuit breaker hazard rate curves.

The curves fit the failure experience of other utilities with larger populations.

Failure Effects

Circuit breakers are assumed to fail with two dominant failure modes: operational failure and catastrophic failure. The relative probability and costs of each failure mode occurring differs for obsolete versus non-obsolete breakers. The failure effects are summarized in the following figures:

Effects of Distribution Circuit Breaker Failure
Non-Obsolete Breaker

Failure Mode 1		
Relative Probability	50%	
Description	Operational failure	
Effect	Repair required; non-destructive	
Cost		
Direct cost	15%	Percent of replacement cost
Outage cost	2	Hours that breaker is out
Occurrence factor	3	Occurrences over life of breaker

Failure Mode 2		
Relative Probability	50%	
Description	Failure to open; catastrophic	
Effect		
Cost		
Direct cost	115%	Percent of replacement cost
Outage cost	2	Full station is out

Figure 29. Non-obsolete circuit breaker failure effects.

Effects of Distribution Circuit Breaker Failure
Obsolete Breaker

Failure Mode 1		
Relative Probability	40%	
Description	Operational failure	
Effect	Repair required; non-destructive	
Cost		
Direct cost	30%	Percent of replacement cost
Outage cost	2	Hours that breaker is out
Occurrence factor	3	Occurrences over life of breaker

Failure Mode 2		
Relative Probability	60%	
Description	Failure to open; catastrophic	
Effect		
Cost		
Direct cost	130%	Percent of replacement cost
Outage cost	2	Full station is out

Figure 30. Obsolete circuit breaker failure effects.

Risk Matrix

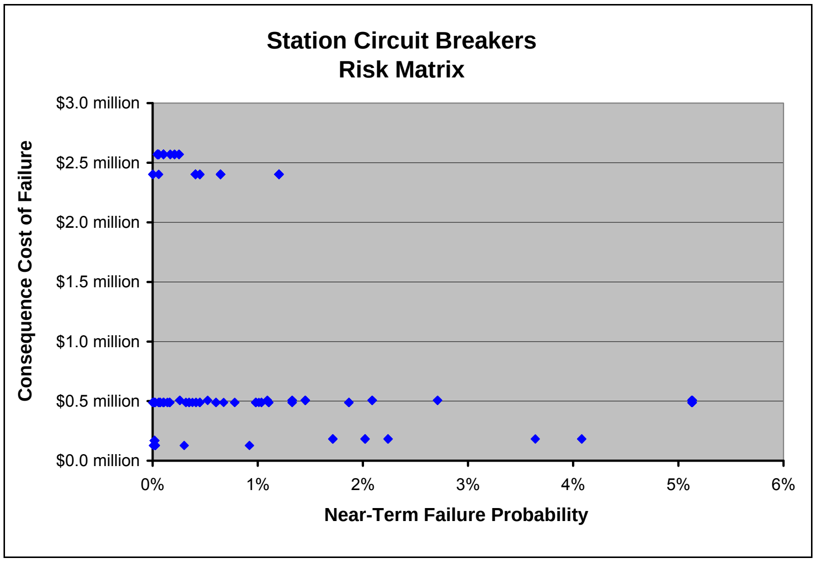


Figure 31. Risk matrix plotting consequence of failure versus failure probability.

Intervention Mode

The intervention mode modeled for circuit breakers is replacement in-kind. The replacement costs vary by circuit breaker type and size.

Econometric Replacement Results

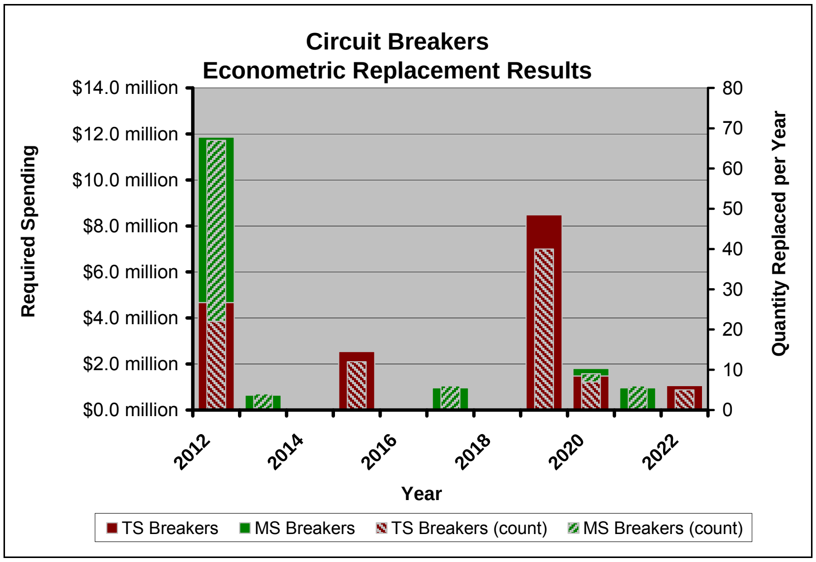


Figure 32. Circuit beaker econometric replacement results.

Conclusions

- Recommendations:
  - Near-term circuit breaker replacements are warranted.
- Gaps:
  - Some breakers missing contact resistance data.

3.4 230kV Switches

Summary of Asset Class

230kV switches are moderately complex assets with a moderate price per unit.

A 230 kV switch failure is assumed to have no consequence cost. No load will be lost as the remaining transformer will be able to carry the load of the companion transformer (there may be a momentary outage).

Health index formulation is based on industry best-practice.

Data Sources Available

Comprehensive demographic and condition data was made available.

Demographics

Number of units: 22

Typical life expectancy (years): 30-60 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 “Asset Amortization Study for the Ontario Energy Board”

Estimated replacement cost: $46,280

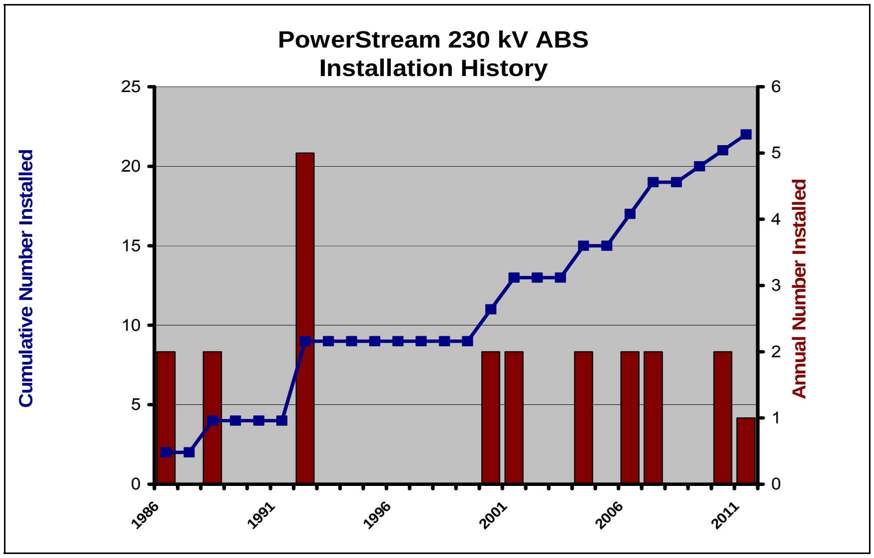


Figure 33. 230kV switches installation history.

Asset Degradation

This asset group consists of transmission air break switches. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of switches are rated for load interruption, others are designed to be operated only under no load conditions. These switches can be operated only when the current through the switch is zero or near zero (e.g. line charging current). Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in the open position.

In general, line switches consist of mechanically movable copper blades supported on insulators and mounted on metal bases. Their operating or control mechanism can be either a simple hook stick or a manual gang. Since they do not typically need to interrupt short circuit currents, disconnect switches are relatively simple in design compared to circuit breakers.

Air break switches isolate equipment or sections of line. Air serves as the insulating medium between contacts when these switches are in the open position. Air break switches must have the capability of providing visual confirmation of the open/close position.

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation
- Loose connections
- Insulator damage
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out the switch operating mechanism may seize making the disconnect switch inoperable. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road de-icing salt is used.

The condition assessment of switches involves visual inspections which can reveal the extent of corrosion on main contacts, condition of stand-off insulators and operating mechanism. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots on switches.

The following parameters can be considered in establishing the asset health index formulation:

- Condition of switch blades (contacts)
- Operating arm and switch mounting
- Condition of arcing horns or arc suppressors
- Condition of operating handle padlocks
- Condition of operating mechanism
- Age of disconnect switch

- Expert feedback

The average life expectancy of switches is approximately 40 years. Consequences of switch failure may include customer interruption and health and safety consequences for operators.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 46. 230kV switches Health Index parameters and weights

#	230kV Switch Condition Parameters	Weight
1	Age	3
2	Expert Feedback	10
3	Load	3
4	Switch Contact	5
5	Blade/Arm	5
6	Mechanism	5
7	Arc Break	5
8	Lock/Handle	1

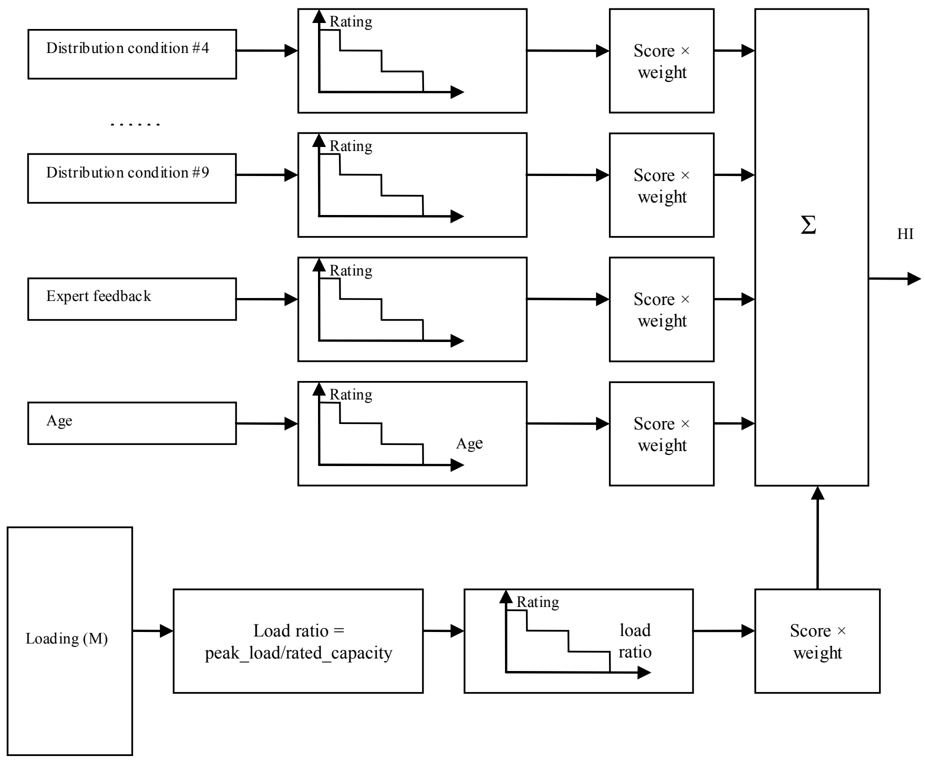


Figure 34. 230kV switches Health Index flowchart.

Table 47. 230kV switches parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	<10 years old
B	3	10-19 years old
C	2	20-29 years old
D	1	30-39 years old
E	0	>=40 years old

Table 48. 230kV switches parameter #2: expert feedback

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent

B	3	Very Good
C	2	Good
	N/A	Unknown

Table 49. 230kV switches parameter #3: loading condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	N < 1
B	3	1 <= N < 1.1
C	2	1.1 <= N < 1.2
D	1	1.2 <= N < 1.4
E	0	N >= 1.4

Where N = peak load / rated capacity

Table 50. 230kV switches parameter #4: switch contact resistance criteria

Condition Factor	Factor	Condition Criteria Description
A	4	[0,200) uΩ
B	3	[200, 250) uΩ
D	1	[250, 300) uΩ
E	0	[300, ∞) uΩ

Table 51. 230kV switches parameters #5-8: inspection asset condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

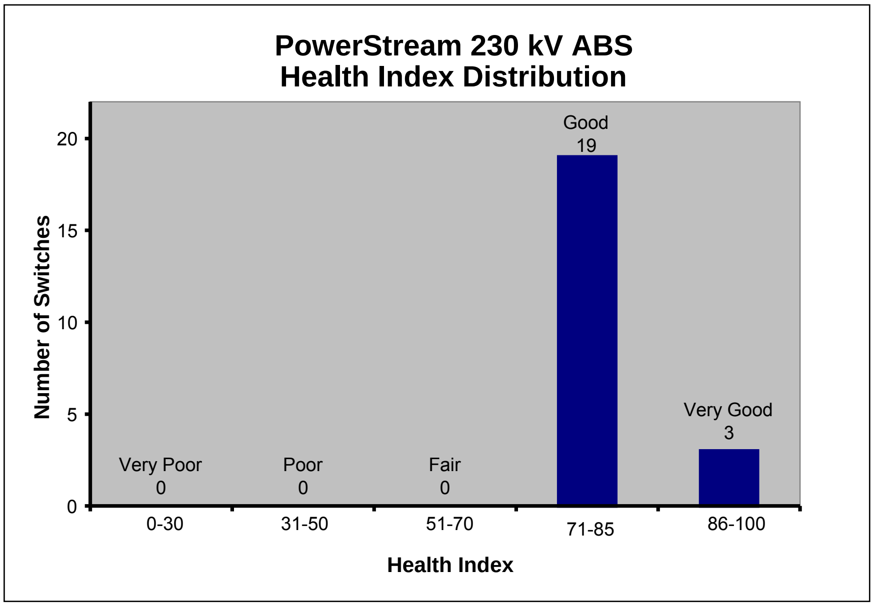


Figure 35. 230kV switches Health Index histogram.

Failure Probability

The 230kV switch failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry best practice. The Weibull curve parameters are:

- Shape = 3.00, Scale = 66.9

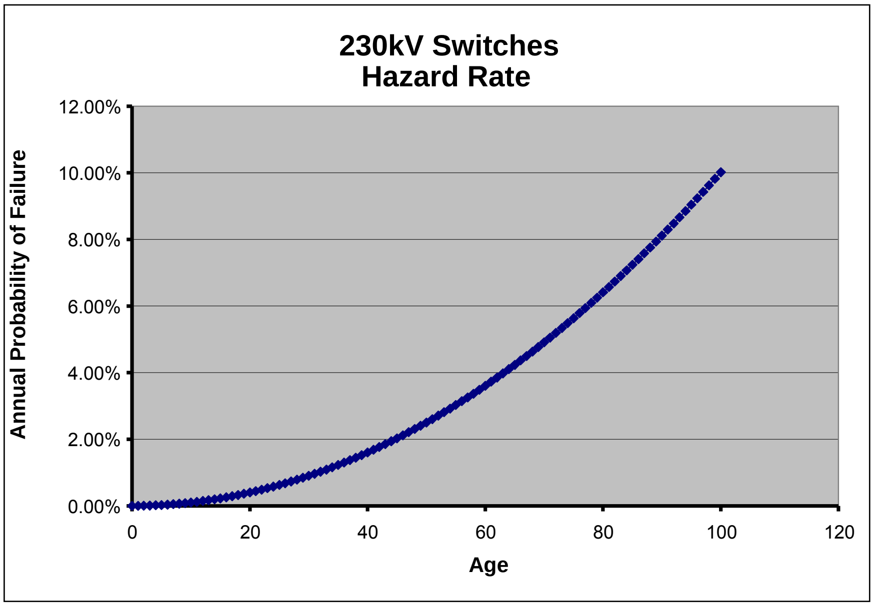


Figure 36. 230kV switches hazard rate curve.

Failure Effects

The dominant failure mode assessed for a 230kV switch is catastrophic failure requiring replacement.

The failure effects are based on the following assumptions:

- In the event of a loss of a 230 kV switch, no load will be lost as the remaining transformer will be able to carry the load of the companion transformer. There may be a momentary outage. The transmission circuit may need to be isolated for a few hours to allow the defective switch to be isolated and replaced. During this period, stations on same transmission circuit would be at single contingency status.

Risk Matrix

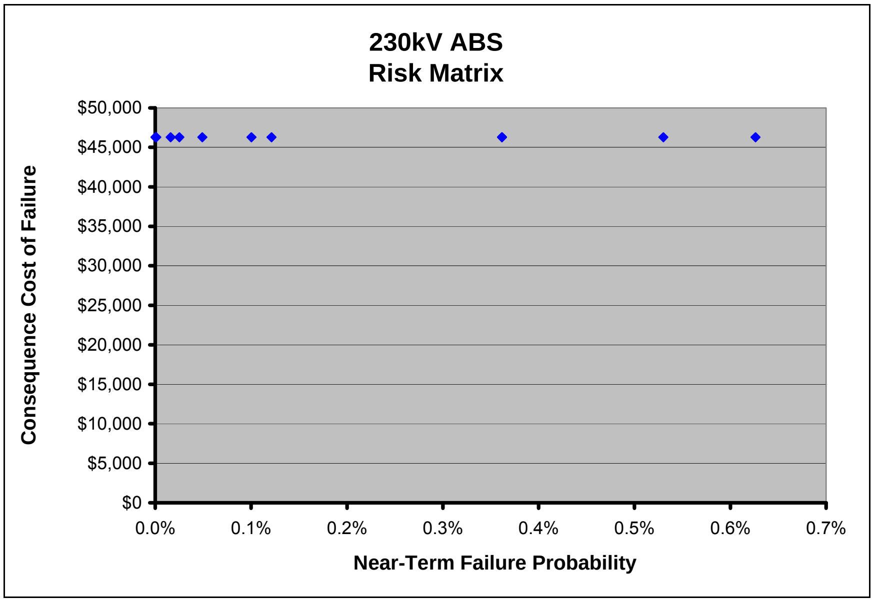


Figure 37. Risk matrix plotting consequence of failure versus failure probability.

Projected Failure Quantity and Reactive Capital

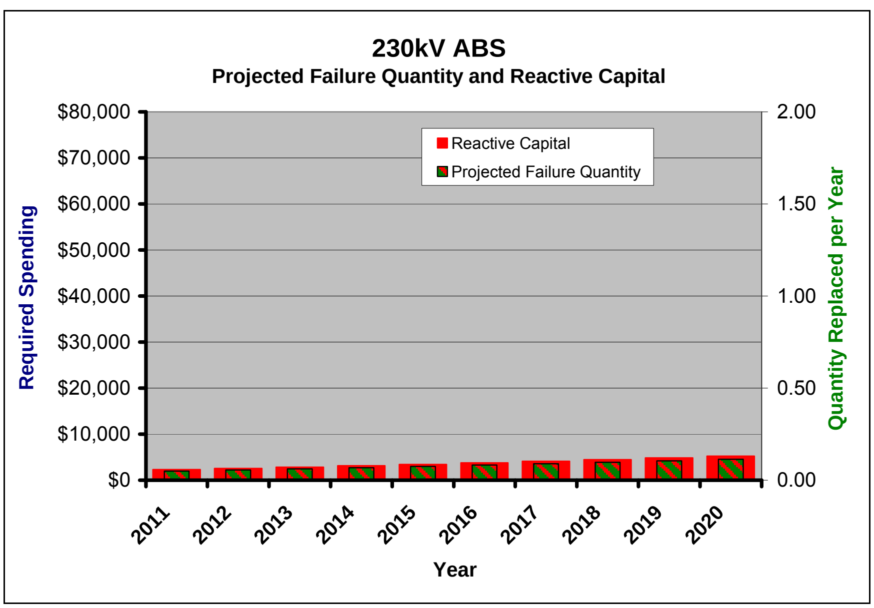


Figure 38. 230kV switches projected failure quantity and reactive capital.

Intervention Mode

The intervention mode modeled for 230kV switches is replacement in-kind. The replacement costs vary by type and size.

Econometric Replacement Results

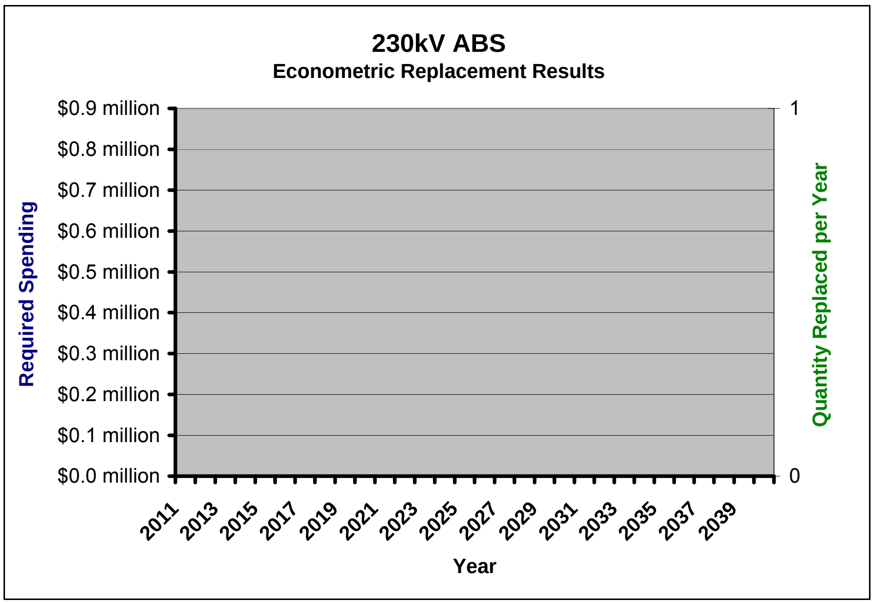


Figure 39. 230kV switches econometric replacement results.

Conclusions

- Recommendations:
  - One unit is proposed for replacement for the next five years due to obsolescence and no replacement stock (Richmond Hill RHTS1_T2SW2). PowerStream will replace this switch in 2012 at a cost of $70,584.
- Gaps:
  - None identified.

3.5 MS Primary Switches

Summary of Asset Class

MS primary switches are moderately complex assets with a moderate price per unit.

Health index formulation is based on industry best-practice and condition data is collected.

Data Sources Available

Assumed loading, nameplate, and general demographic data.

Demographics

Number of units: 66

Typical life expectancy (years): 30-60 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 "Asset Amortization Study for the Ontario Energy Board"

Estimated replacement cost: $45,000 - $113,000

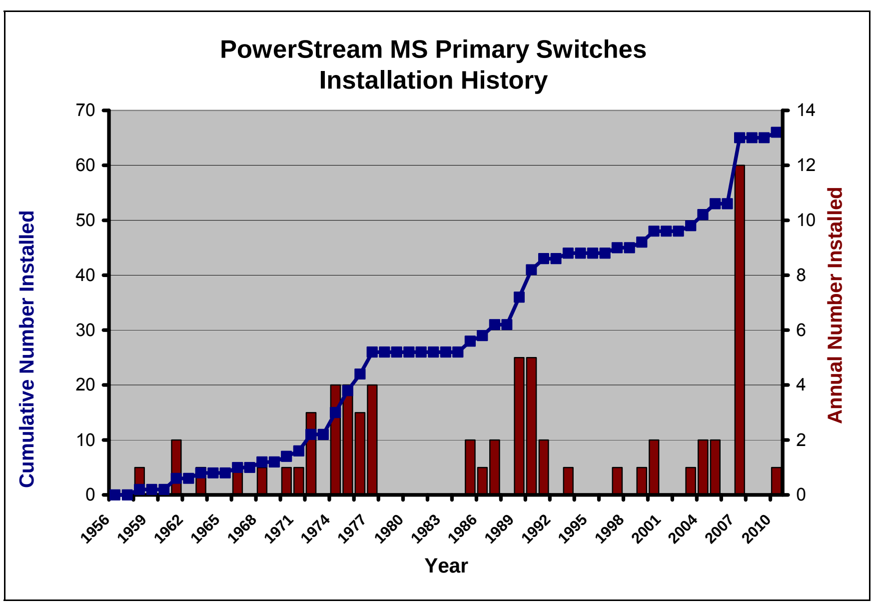


Figure 40. MS primary switches installation history.

Asset Degradation

This asset group consists of municipal station air break and fused switches. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of switches are rated for load interruption, others are designed to be operated only under no load conditions. These switches can be operated only when the current through the switch is zero or near zero (e.g. line charging current). Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in the open position.

In general, line switches consist of mechanically movable copper blades supported on insulators and mounted on metal bases. Their operating or control mechanism can be either a simple hook stick or a manual gang. Since they do not typically need to interrupt short circuit currents, disconnect switches are relatively simple in design compared to circuit breakers.

Air break switches isolate equipment or sections of line. Air serves as the insulating medium between contacts when these switches are in the open position. Air break switches must have the capability of providing visual confirmation of the open/close position.

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation
- Loose connections
- Insulator damage
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out the switch operating mechanism may seize making the disconnect switch inoperable. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road de-icing salt is used.

The condition assessment of switches involves visual inspections which can reveal the extent of corrosion on main contacts, condition of stand-off insulators and operating mechanism. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots on switches.

The following parameters can be considered in establishing the asset health index formulation:

- Condition of switch blades (contacts)
- Operating arm and switch mounting
- Condition of arcing horns or arc suppressors
- Condition of operating handle padlocks
- Condition of operating mechanism
- Age of disconnect switch
- Expert feedback

The average life expectancy of switches is approximately 40 years. Consequences of switch failure may include customer interruption and health and safety consequences for operators.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 52. MS primary switches Health Index parameters and weights

#	MS Primary Switch Condition Parameters	Weight
1	Age	3
2	Expert Feedback	10
3	Load	3
4	Switch Contact	5
5	Blade/Arm	5
6	Mechanism	5
7	Fuse	3
8	Arc Break	5
9	Lock/Handle	1

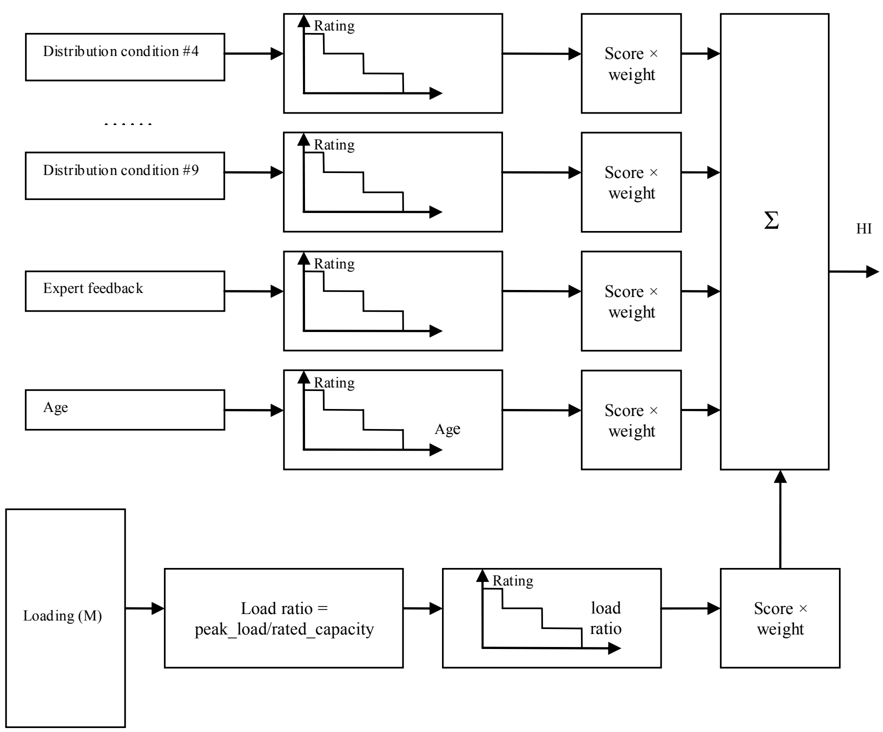


Figure 41. MS primary switches Health Index flowchart.

Table 53. MS primary switches parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	< 20 years old
B	3	20-39 years old
C	2	40-49 years old
D	1	50-59 years old
E	0	>=60 years old

Table 54. MS primary switches parameter #2: expert feedback

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 55. MS primary switches parameter #3: loading condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	N < 1
B	3	1 <= N < 1.1
C	2	1.1 <= N < 1.2
D	1	1.2 <= N < 1.4
E	0	N >= 1.4

Where N = peak_load / rated_capacity

Table 56. MS primary switches parameter #4: switch contact condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	[0,200) uΩ

B	3	[200, 250) uΩ
D	1	[250, 300) uΩ
E	0	[300, ∞) uΩ

Table 57. MS primary switches parameters #5-9: inspection asset condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

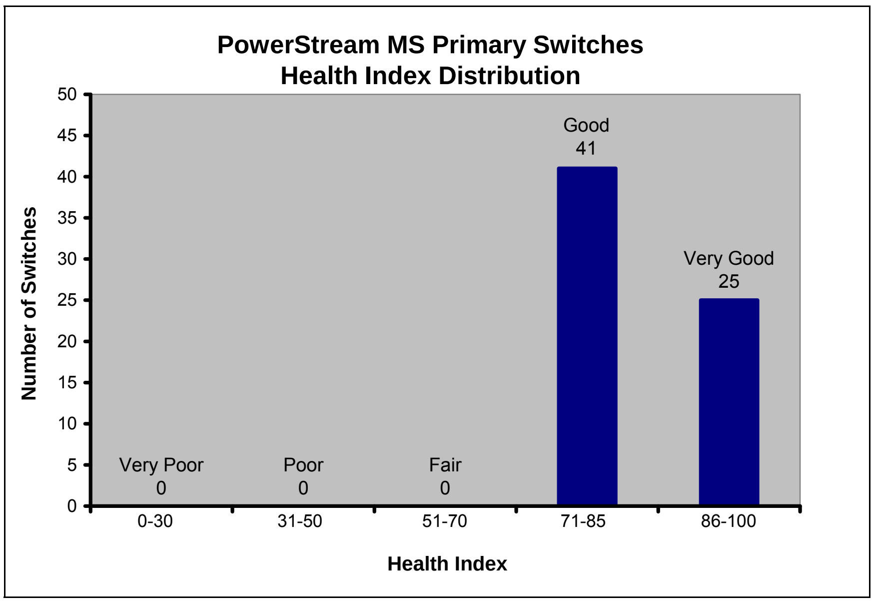


Figure 42. MS primary switches Health Index histogram.

Failure Probability

The MS primary switch failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry best practice. The Weibull curve parameters are:

- Shape = 3.00, Scale = 74.77

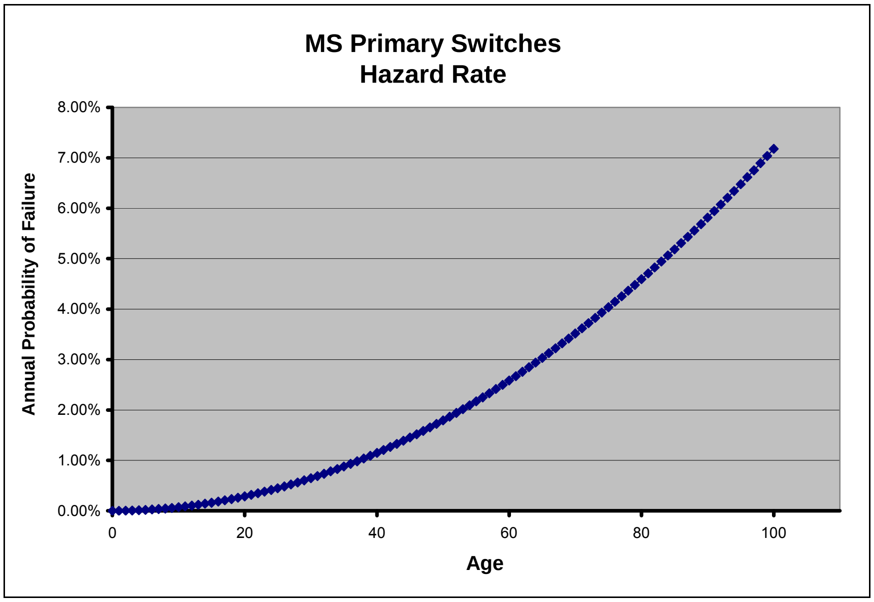


Figure 43. MS primary switches hazard rate curve.

Failure Effects

The dominant failure mode assessed for MS primary switches is catastrophic failure requiring replacement. The failure effects by type and size are summarized below.

Description	Type	Loss of Peak Load (kW)	Outage Duration (hours)
Pole Mounted Load Interrupter Switch & Fuse	Pole	5,167	3
Load Interrupter Switch & Fuse In Metal Clad Enclosure	Enclosure	5,167	3

Figure 44. MS primary switches failure effects.

The failure effects are based on the following assumptions:

Total peak load for all transformers = 341,000 kW

Total number of transformers = 65

Average Loss of Peak Load (kW) =341,000 kW/65 =5167 kW

Risk Matrix

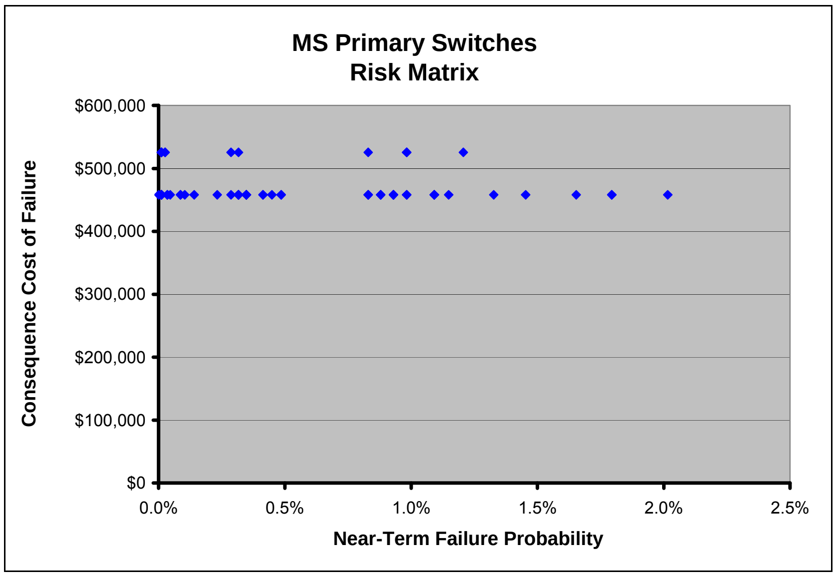


Figure 45. Risk matrix plotting consequence of failure versus failure probability.

Projected Failure Quantity and Reactive Capital

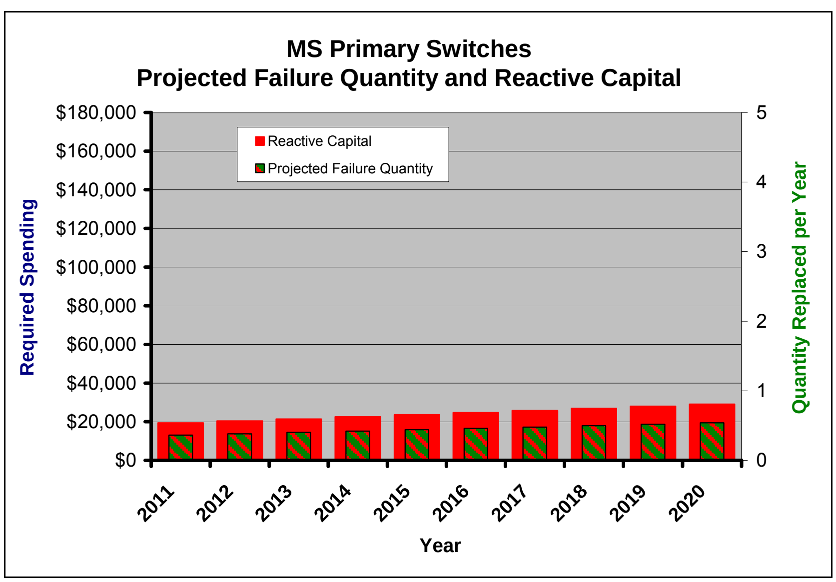


Figure 46. MS primary switches projected failure quantity and reactive capital.

Intervention Mode

The intervention mode modeled for MS primary switches is replacement in-kind. The replacement costs vary by type and size. The replacement costs are summarized below.

Material Cost	Material Cost plus Overhead and Burden	Replacement Labour Hours	Replacement Labour Cost Plus Overhead and Burden	Truck Hours	Truck Cost plus Overhead and Burden	Type	Total
$30,000	$39,600	60	$3,420	30	$1,590	Pole	$44,610
$80,000	$105,600	80	$4,560	40	$2,120	Enclosure	$112,280

Figure 47. MS primary switches replacement costs.

Econometric Replacement Results

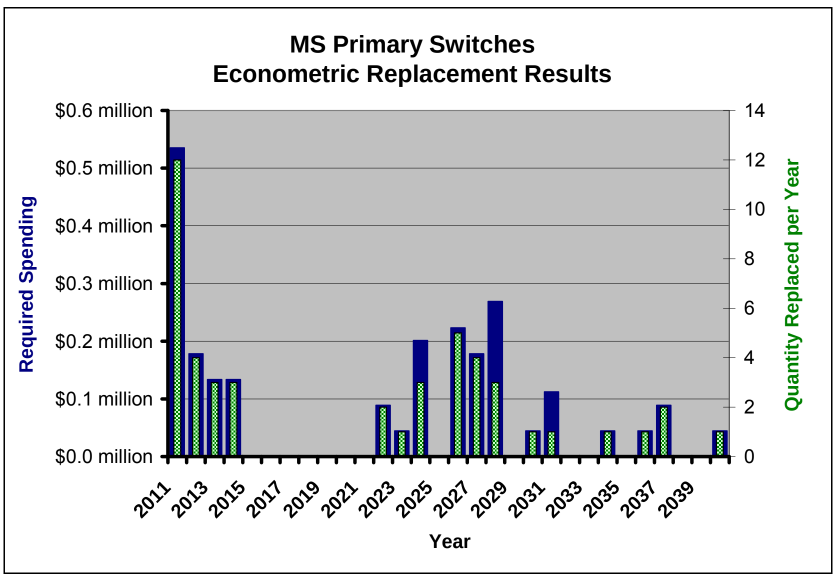


Figure 48. MS primary switches econometric replacement results.

Conclusions

- Recommendations:
  - The model recommends replacement based on econometric risk-assessment. When we incorporate engineering judgment and operations input with the econometric model results, we have concluded that the MS primary switches are still in satisfactory working condition and that the incremental risk of asset failure, by deferring replacement, can be

managed. Therefore, no replacement is recommended at this time. PowerStream will continue to monitor condition of primary switches.

- Gaps:
    - None identified

3.6 Station Capacitors

Summary of Asset Class

Station capacitors are moderately complex assets with a moderate price per unit.

The dominant failure mode assessed for station capacitors is a can failure. Loss of a single unit or the entire capacitor bank will not affect station load. Capacitor bank replacements are justified based on increasing risk of can failures and associated annual costs.

Health index formulation is based on industry best-practice, and condition data is collected.

Data Sources Available

Nameplate and general demographic data.

Demographics

Number of units: 5 banks

Typical life expectancy (years): 25-40 years per can as per Kinectrics Inc. Report No: K-418099-RA-001-R000 “Asset Amortization Study for the Ontario Energy Board”

Estimated replacement cost: $110,000 for a bank

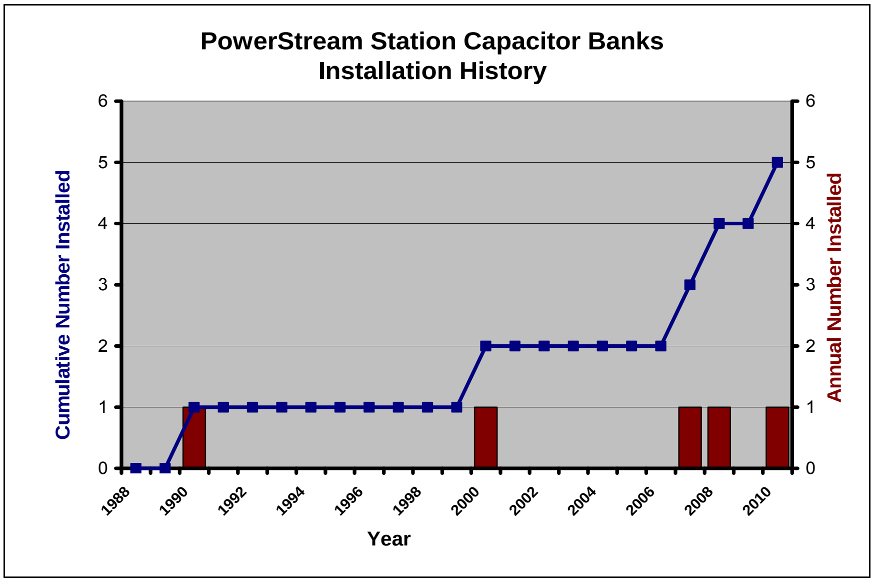


Figure 49. Station capacitors installation history.

Asset Degradation

The primary function of capacitors is to improve the quality of the electrical supply and the efficient operation of the power system. The major applications include power factor improvement and voltage regulation.

In practical implementation, such asset functions in the form of capacitor bank, i.e., a combination of various capacitor units. The operation of capacitors requires much fewer switching-on/switching-off operations. The main degradation processes associated with capacitors include:

- Imbalance due to fuse (either internally or externally) failure
- Capacitor unit fluid leaking
- Insulator problem

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. The rate of deterioration depends heavily on environmental conditions in which the equipment operates.

In externally fused, fuseless or unfused capacitor banks, the failed element within the can is short-circuited by the weld that naturally occurs at the point of failure (the element fails short-circuited). This short circuit puts the whole group of elements out of service, increasing the voltage on the remaining groups. Several capacitor elements breakdowns may occur before the external fuse (if exists) removes the entire unit. The external fuse will operate when a capacitor unit becomes essentially short circuited, isolating the faulted unit. Internally fused capacitors have individual fused capacitor elements that are disconnected when an element breakdown occurs (the element fails opened). The risk of successive faults is minimized because the fuse will isolate the faulty element within a few cycles. The degree of imbalance introduced by an element failure is less than that which occurs with externally fused units (since the amount of capacitance removed by blown fuse is less) and hence a more sensitive imbalance protection scheme is required when internally fused units are used.

Capacitor unit fluid leaking is mainly due to mechanical damage to the capacitor case. Insulator problems can be either insulator crack, or pollution on insulators.

The condition assessment of capacitors involves visual inspections which can reveal the extent of problems, as well as utility experts' feedback that tells the general status. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots on capacitors.

The following parameters can be considered in establishing the asset health index formulation:

- Visual inspection on capacitors
- Visual inspection on insulators
- Age of capacitors
- Expert feedback

The average life expectancy of capacitors is approximately 30 years. This can, however, be prolonged by individually replacing the faulty units. Consequences of capacitors failure may include local under-voltage and lack of reactive power for operators.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 58. Station capacitors Health Index parameters and weights

#	Station Capacitor Condition Parameters	Weight
1	Age	10
2	Expert feedback	15
3	Visual inspection	5
4	Insulators	1

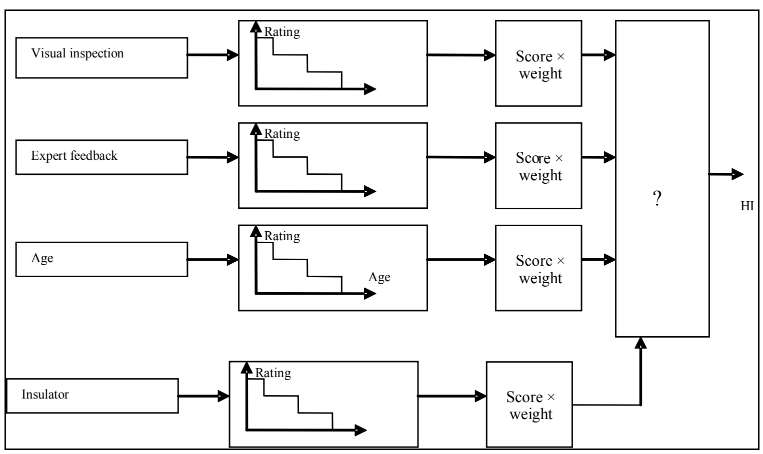


Figure 50. Station capacitors Health Index flowchart.

Table 59. Station capacitors parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	<20 years old
B	3	20-29 years old
C	2	30-39 years old
D	1	40-49 years old
E	0	>=50 years old

Table 60. Station capacitors parameter #2: expert feedback condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 61 Station capacitors parameter #3: visual inspection condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 62 Station capacitors parameter #4: insulator condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

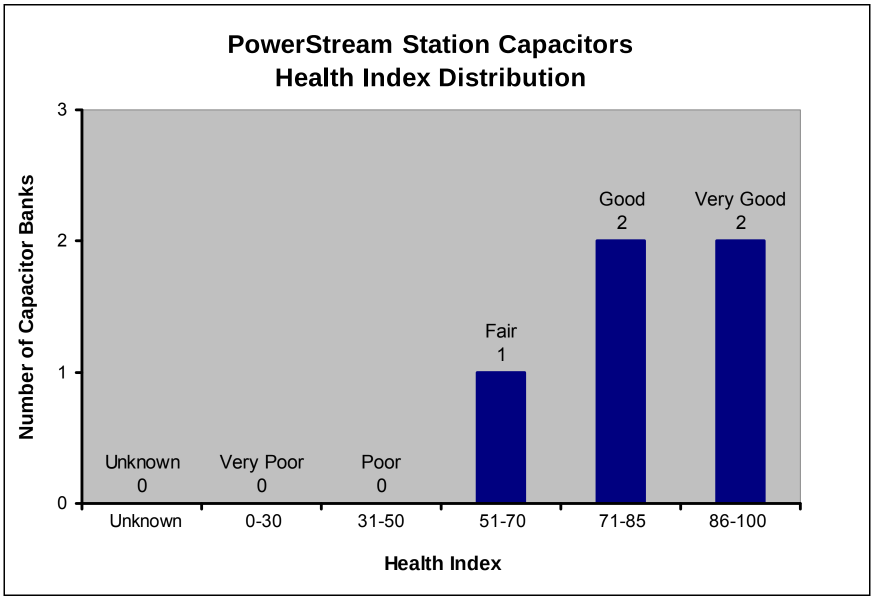


Figure 51. Station capacitors Health Index histogram.

Failure Probability

The station capacitor cans failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry standards. The Weibull curve parameters are:

- Shape = 3.00, Scale = 37.41

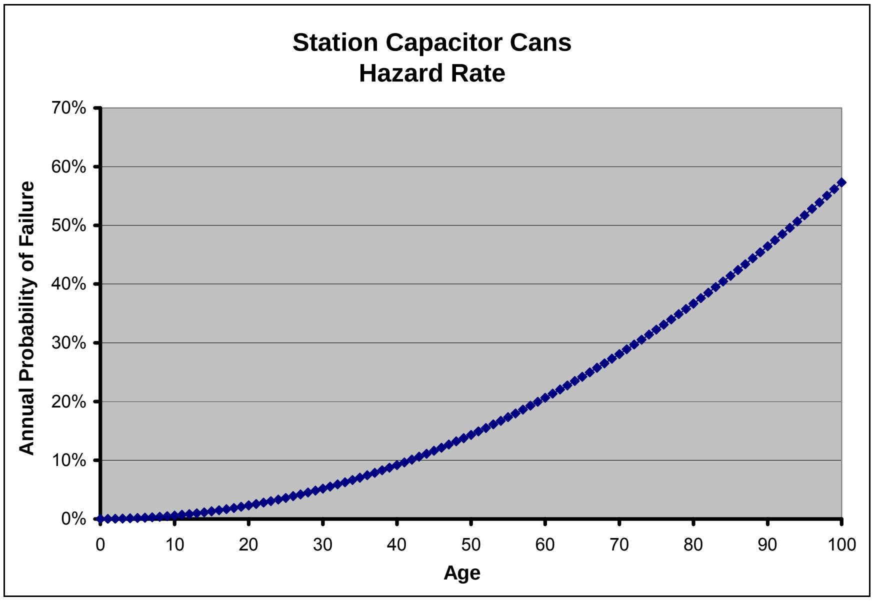


Figure 52. Station capacitors hazard rate curve.

Failure Effects

The dominant failure mode assessed for station capacitors is a can failure requiring replacement of the can. The loss of a single unit or the entire capacitor bank will not affect the station load.

Risk Matrix

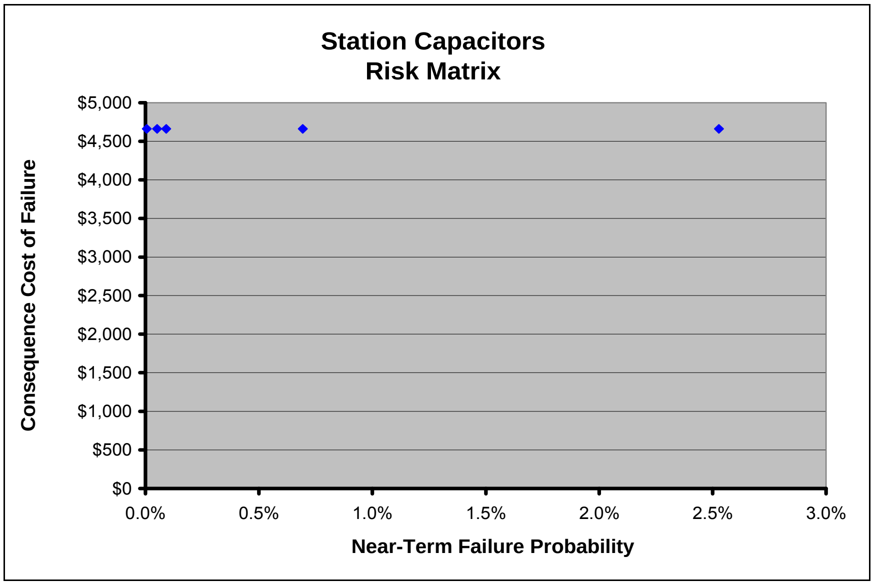


Figure 53. Risk matrix plotting consequence of failure versus failure probability.

Projected Failure Quantity and Reactive Capital

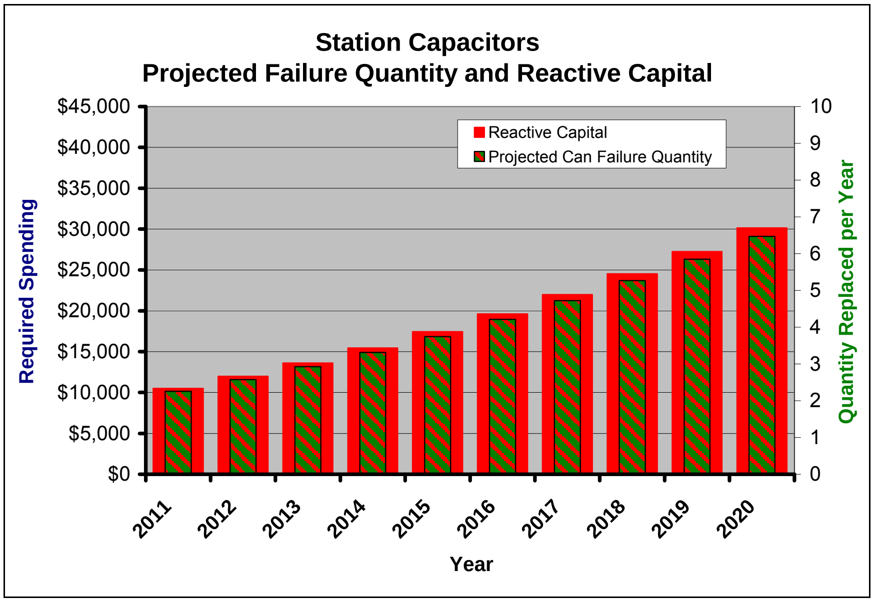


Figure 54. Station capacitors projected failure quantity and reactive capital.

Intervention Mode

The intervention mode modeled for station capacitors is capacitor bank replacement in-kind. The replacement costs vary by type and size.

Econometric Replacement Results

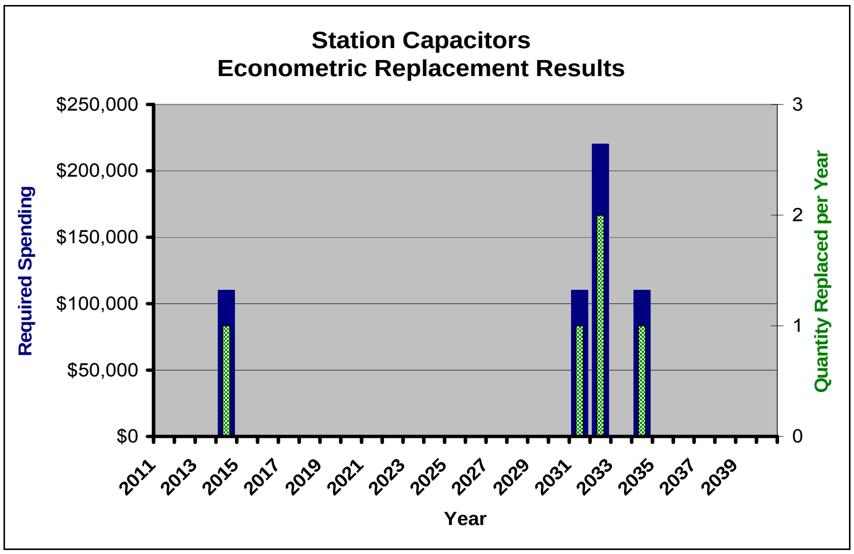


Figure 55. Station capacitors econometric replacement results.

Conclusions

- Recommendations:
  - The model recommends replacement based on econometric risk-assessment. When we incorporate engineering judgment and operations input with the econometric model results, we have concluded that the station capacitors are still in satisfactory working condition and that the incremental risk of asset failure, by deferring replacement, can be managed. Therefore, no replacement is recommended at this time. PowerStream will continue to monitor condition of station capacitors.
  - Continue capturing condition data per health index formulation and update the model.
  - Continue capturing can condition and age at failure to support customized failure probability curves and health index correlations.
- Gaps:

- ○ None identified.

3.7 Station Reactors

Summary of Asset Class

Station reactors are moderately complex assets with a moderate price per unit.

A station reactor failure is assumed to have no consequence cost. Loss of a station reactor, no load will be lost as the remaining transformer will be able to carry the load of the companion transformer, there maybe a momentary outage. No risk-based planned replacement program is recommended.

Health index formulation is based on industry best-practice.

Data Sources Available

Nameplate and general demographic data.

Demographics

Number of units: 34

Typical life expectancy (years): 25-60 as per Kinectrics Inc. Report No:

K-418238-RA-0001-R00 "Useful Life Of Transmission/Distribution System Asset And Their Components"

Estimated replacement cost: $41,270

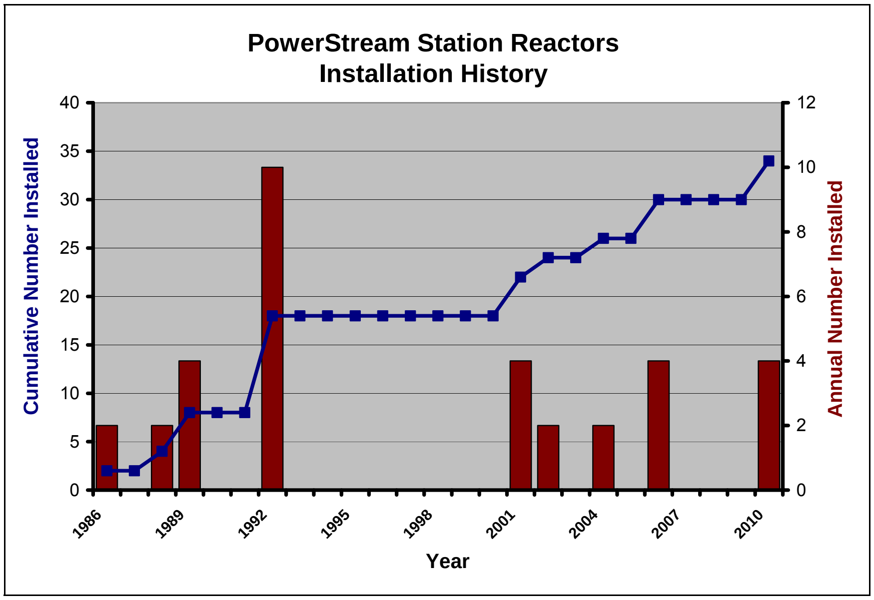


Figure 56. Station reactors installation history.

Asset Degradation

The primary function of reactors is to limit the short circuit current of a line when there is a short circuit. It can also be used to absorb reactive power, or as part of a filtering circuit.

When being used as a current limiting component, a reactor is connected in series with other components in a line. When being used to absorb reactive power, a shunt reactor is adopted. Because of such character, in normal case a reactor does not require switching operation once it is put in service.

Unlike other assets, reactors are almost maintenance free. They can be in operation for decades without any failure reported. The condition assessment of reactors involves mainly visual inspections and expert feedbacks.

The average life expectancy of reactors can be over 70 years.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 63. Station reactors Health Index parameters and weights

#	Distribution Condition Parameters	Weight
1	Age	10
2	Expert feedback	15
3	Visual inspection	5

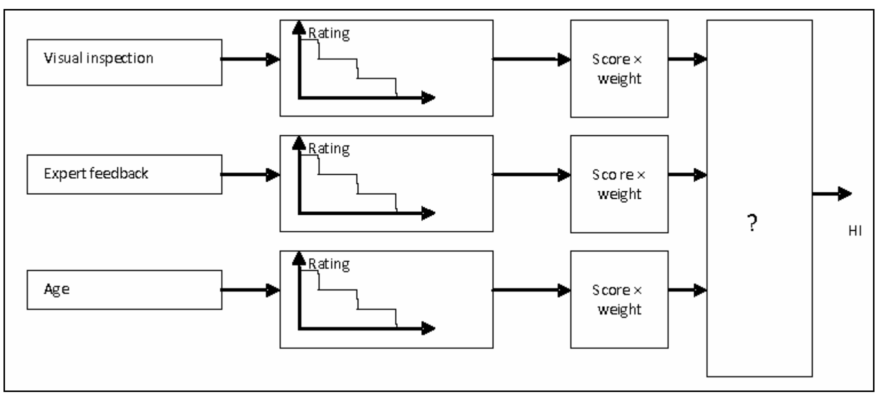


Figure 57. Station reactors Health Index flowchart.

Table 64. Station reactors parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	< 50 years old
B	3	50-74 years old
C	2	75-99 years old
D	1	100-149 years old
E	0	>=150 years old

Table 65. Station reactors parameter #2: expert feedback condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

Table 66. Station reactors parameter #3: visual inspection condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Excellent
B	3	Very Good
C	2	Good
	N/A	Unknown

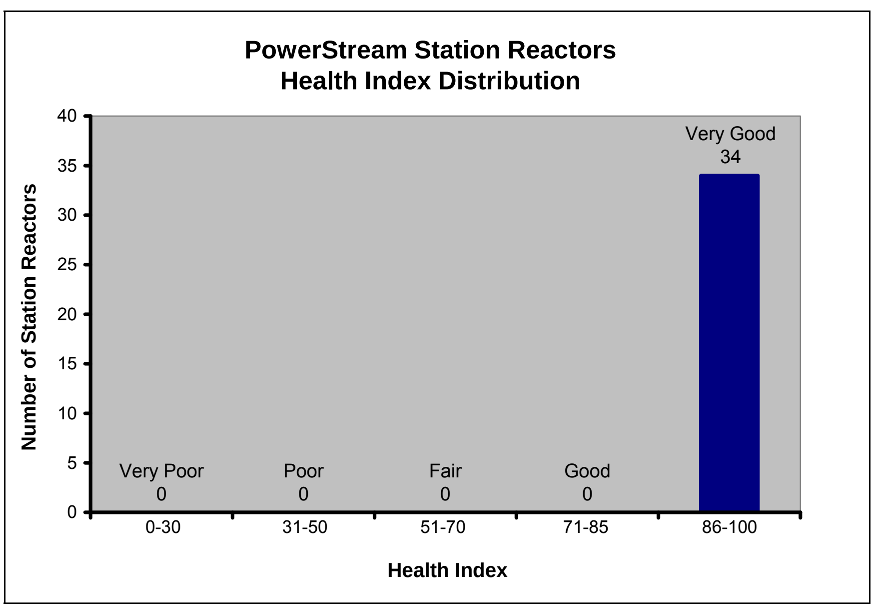


Figure 58. Station reactors Health Index histogram.

Failure Probability

The station reactor cans failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated based on industry standards. The Weibull curve parameters are:

- Shape = 3.00, Scale = 66.9

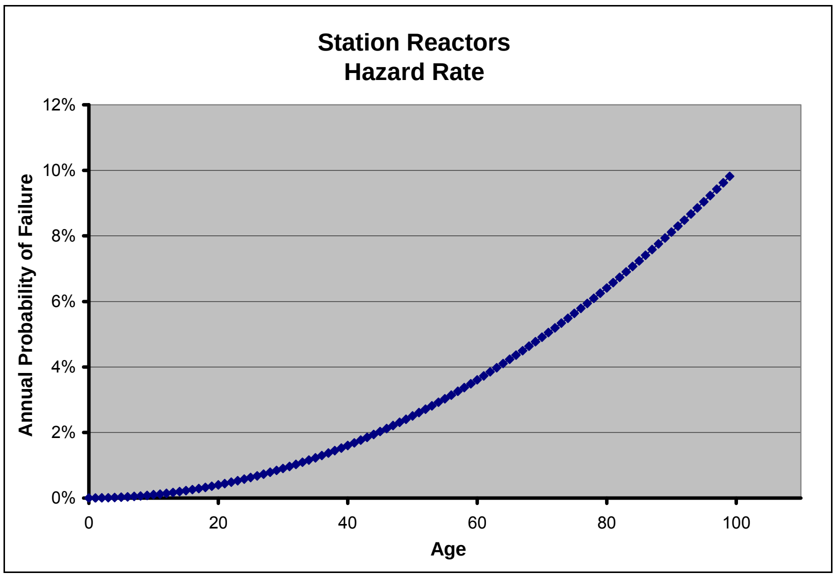


Figure 59. Station reactors hazard rate curve.

Failure Effects

The dominant failure mode assessed for station reactors is catastrophic failure requiring replacement. The loss of a station reactor, no load will be lost as the remaining transformer will be able to carry the load of the companion transformer, there may be a momentary outage.

Risk Matrix

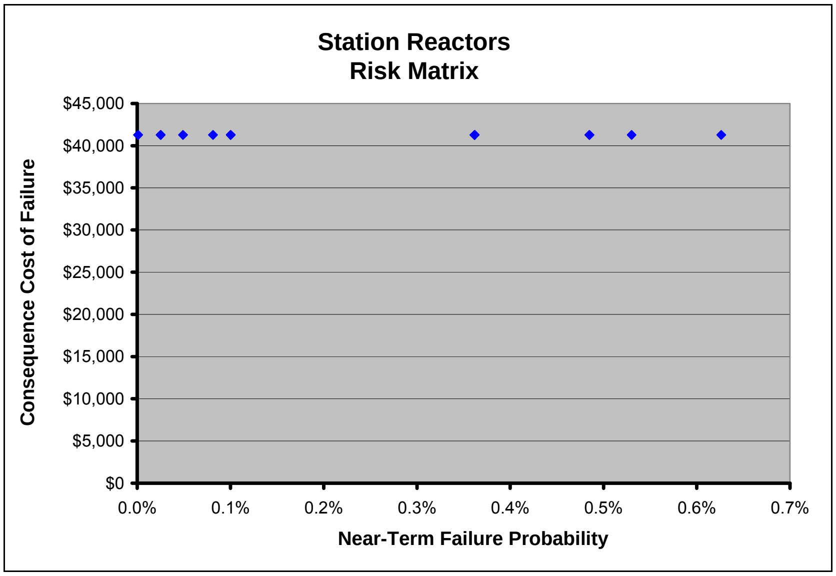


Figure 60. Risk matrix plotting consequence of failure versus failure probability.

Projected Failure Quantity and Reactive Capital

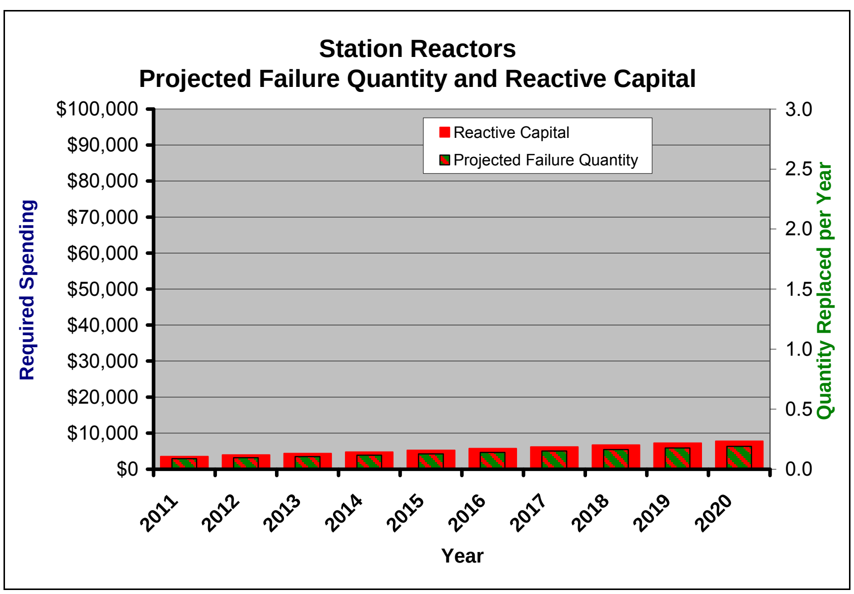


Figure 61. Station reactors projected failure quantity and reactive capital.

Intervention Mode

The intervention mode modeled for station reactors is replacement in-kind.

Econometric Replacement Results

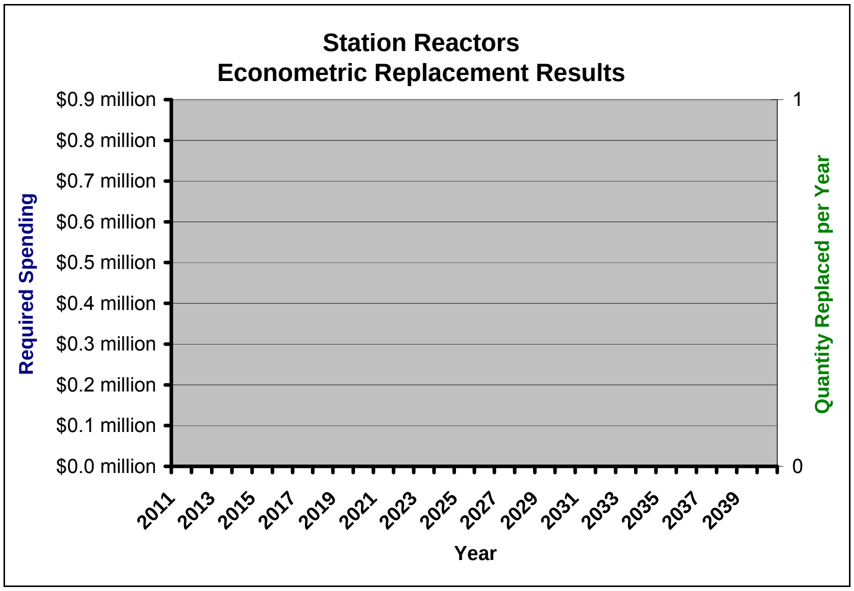


Figure 62. Station reactors econometric replacement results.

Conclusions

- Recommendations:
  - No replacement is proposed in the next five years.
- Gaps:
  - None identified.

3.8 Distribution Transformers

Summary of Asset Class

Distribution Transformers are moderately complex assets with a relatively low price per unit.

Limited end-of-life condition data available; health index formulation is based on industry best-practice and condition data is collected in conjunction with PowerStream's distribution transformer inspection process.

Data Sources Available

Assumed loading, nameplate, and general demographic data.

Demographics

Number of units: 43,535

Typical life expectancy (years): 25-60 as per Kinectrics Inc. Report No: K-418099-RA-001-R000

Estimated replacement cost: $3,000 - $30,000

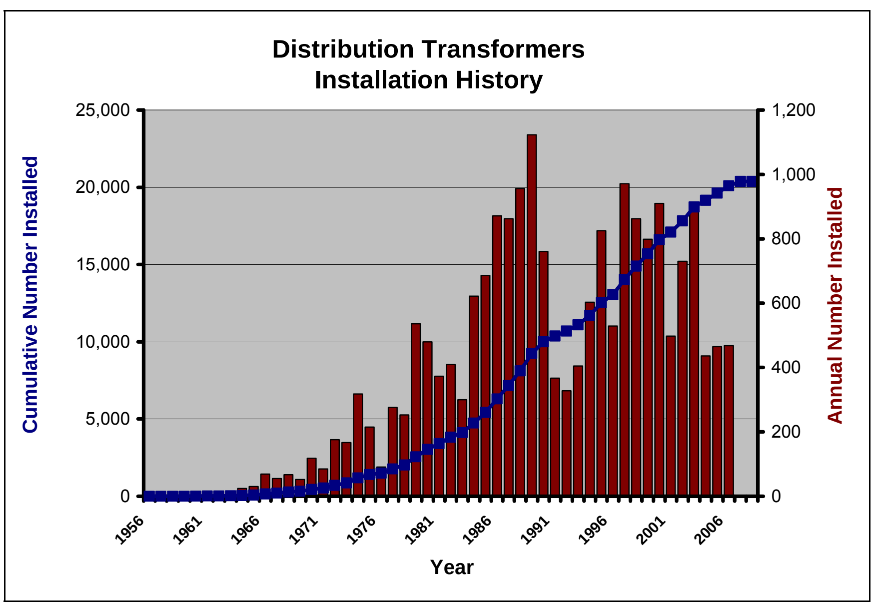


Figure 63. Distribution transformers installation history.

Due to data gaps within our distribution transformer population, the above chart includes only transformers with a known installation date.

Asset Degradation

PowerStream's distribution transformer asset class consists of all transformers used to step down power from medium voltage to utilization voltage. A majority of these transformers are liquid filled, with mineral insulating oil being the predominant liquid, while the rest are of dry submersible type. All of these designs employ sealed tank construction.

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers may, sometimes, need to be removed from service as a result of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of the transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors can be considered in developing the health index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- PCB level
- Transfer operating age and winding temperature profile
- Failure rate

The consequences of distribution transformer failure are mostly reliability impacts and relatively minor. This is why most utilities run their distribution transformers for residential services to failure. However, for larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts may be high, transformers may be replaced as they are near the end of life.

PowerStream has capacity and processes in place to effectively to manage asset failure at the current annual failure rate (3 year average = 14 overhead transformers + 48 underground transformers = 62 transformers total per year). Rate of change of failure in future years expected to be moderate and manageable. Any emerging significant deviations from expected reactive spend would trigger a program review.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 67. Distribution transformer Health Index parameters and weights

#	Distribution Transformer Condition Parameters	Weight
1	Age	4
2	PCB	1
3	Loading history (weighted average)	*
4	Failure rate	*

* A multiplying factor is adopted for HI adjustment: The initial HI is calculated based on condition criteria # 1 and #2. The final HI result is calculated by multiplying the initial HI with the multiplying factors corresponding to condition criteria #3 and #4. Refer to Table for details on the multiplying factors.

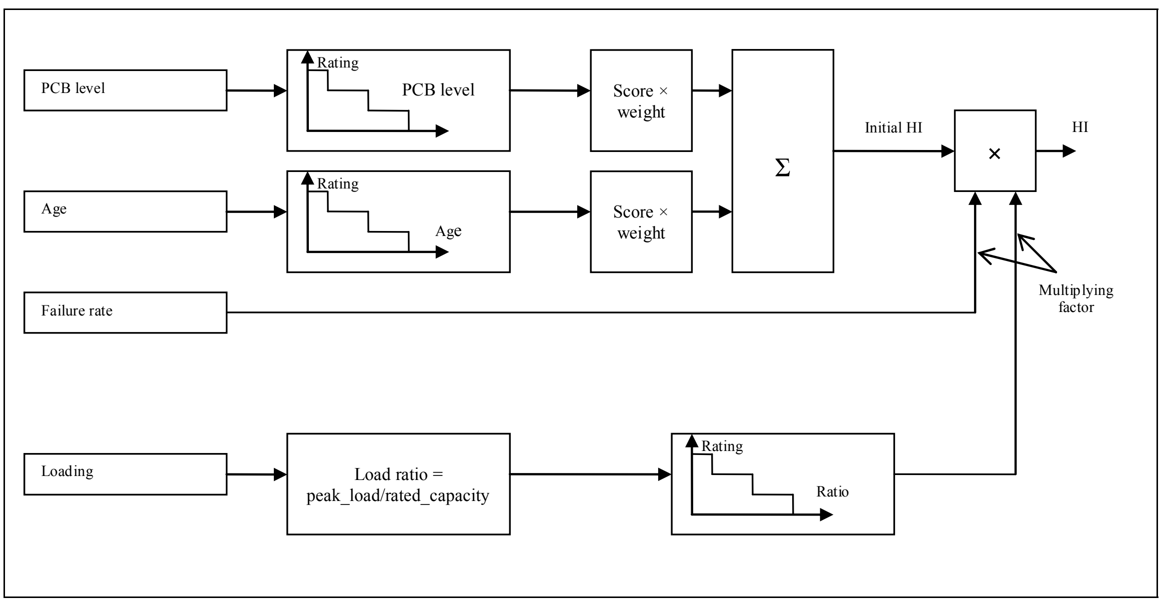


Figure 64. Distribution transformers Health Index flowchart.

Table 68. Distribution transformer parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	21-30 years old
C	2	31-40 years old

D	1	41-50 years old
E	0	>50 years old

Table 69. Distribution transformer parameter #2: PCB level criteria

Condition Factor	Factor	Condition Criteria Description
A	4	PCB < 5 mg/L
B	3	5 <= PCB < 50 mg/L
D	1	50 mg/L <= PCB < 500 mg/L
E	0	PCB >= 500 mg/L

Table 70. Distribution transformer parameter #3: loading criteria

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	N < 1.26
B	0.9	1.26 <= N < 1.5
C	0.7	1.5 <= N < 1.6
D	0.5	1.6 <= N < 1.67
E	0.3	N >= 1.68

Where N = (Peak Load)/(Rated Capacity)

The loading condition is not assigned a weight in the HI formulation. Instead it is used as a multiplying factor for final HI results.

Table 71. Distribution transformer parameter #4: failure rate

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	M < 0.05
B	0.9	0.05 <= M < 0.1
C	0.8	0.1 <= M < 0.2
D	0.7	0.2 <= M < 0.4

E	0.6	M >= 0.4

Where M = Failure Rate x Age

The failure rate condition is not assigned a weight in HI formulation. Instead it is used as a multiplying factor for final HI results.

Transformer Size	Voltage	Failure Rate *
300 – 10,000 kVA	0.16 – 15 kV	0.0052
300 – 10,000 kVA	> 15 kV	0.011
> 10,000 kVA		0.0153

- Failure rate is based on the survey data in IEEE Gold book (IEEE Std 493-1997)

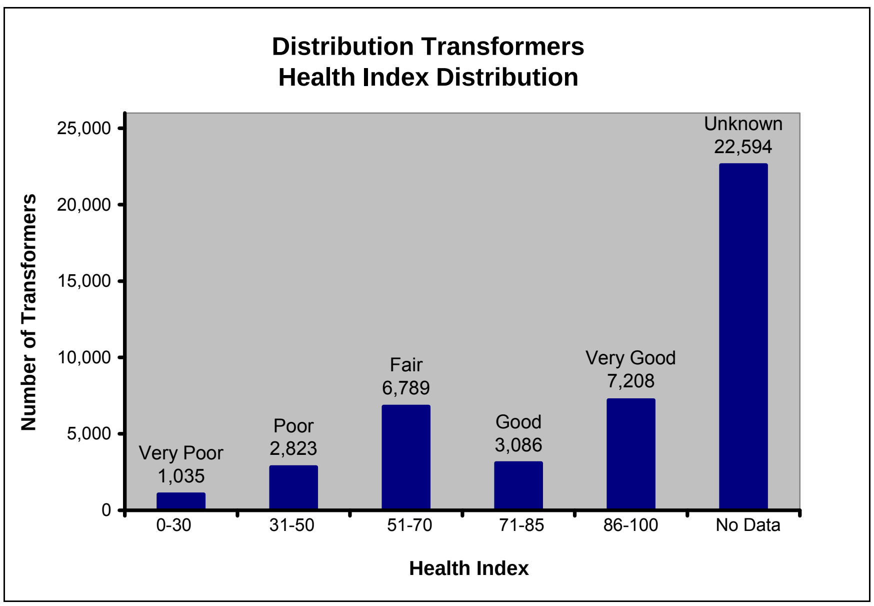


Figure 65. Distribution transformers Health Index histogram.

Failure Probability

The distribution transformer failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated to match the historic failures experienced by PowerStream. The Weibull curve parameters are:

- Shape = 3.00, Scale = 83.24

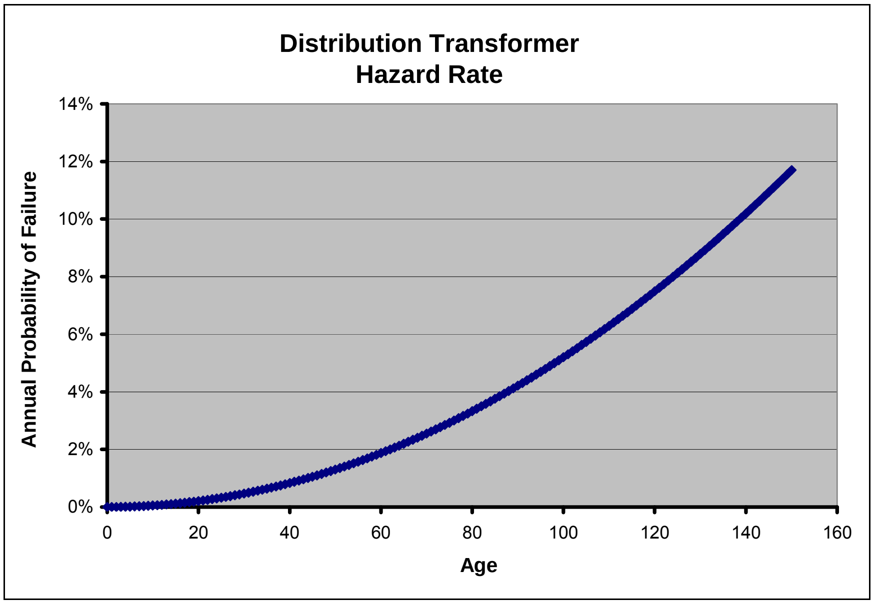


Figure 66. Distribution transformer hazard rate curve.

Failure Effects

The dominant failure mode assessed for distribution transformers is core damage failure requiring replacement. The failure effects by type and size are summarized the figure below:

Description	Type	Phases	Size	LOOKUP	Estimated # of Customers without Supply due to Loss of Equipment	Loss of Peak Load (kW)	Outage Duration (hours)
1-phase 25 kVA	Overhead	1	25	Overhead-1-25	5	20	3
1-phase 50 kVA	Overhead	1	50	Overhead-1-50	8	32	3
1-phase 100 kVA	Overhead	1	100	Overhead-1-100	16	64	3
1-phase 167 kVA	Overhead	1	167	Overhead-1-167	30	120	3
3-Phase 50 kVA	Overhead	3	50	Overhead-3-50	4	100	4
3-Phase 100 kVA	Overhead	3	100	Overhead-3-100	7	170	4
3-Phase 167kVA	Overhead	3	167	Overhead-3-167	10	300	4
3-Phase 250kVA	Overhead	3	250	Overhead-3-250	7	444	4
3-Phase 333kVA	Overhead	3	333	Overhead-3-333	10	575	4
3-Phase 750kVA	Overhead	3	750	Overhead-3-750	11	635	4
3-Phase 50 kVA	Vault	3	50	Vault-3-50	4	100	4
3-Phase 100 kVA	Vault	3	100	Vault-3-100	7	170	4
3-Phase 167kVA	Vault	3	167	Vault-3-167	10	300	4
3-Phase 250 kVA	Vault	3	250	Vault-3-250	7	444	4
3-Phase 333kVA	Vault	3	333	Vault-3-333	10	575	4
3-Phase 750kVA	Vault	3	750	Vault-3-750	11	635	4
1-phase 50 kVA	Padmount	1	50	Padmount-1-50	8	32	3
1-phase 100 kVA	Padmount	1	100	Padmount-1-100	16	64	3
1-phase 167 kVA	Padmount	1	167	Padmount-1-167	30	120	3
3-Phase 150 kVA	Padmount	3	150	Padmount-3-150	4	100	4
3-Phase 300 kVA	Padmount	3	300	Padmount-3-300	7	170	4
3-Phase 500 kVA	Padmount	3	500	Padmount-3-500	10	300	4

Figure 67. Distribution transformer failure effects.

Projected Failure Quantity and Reactive Capital

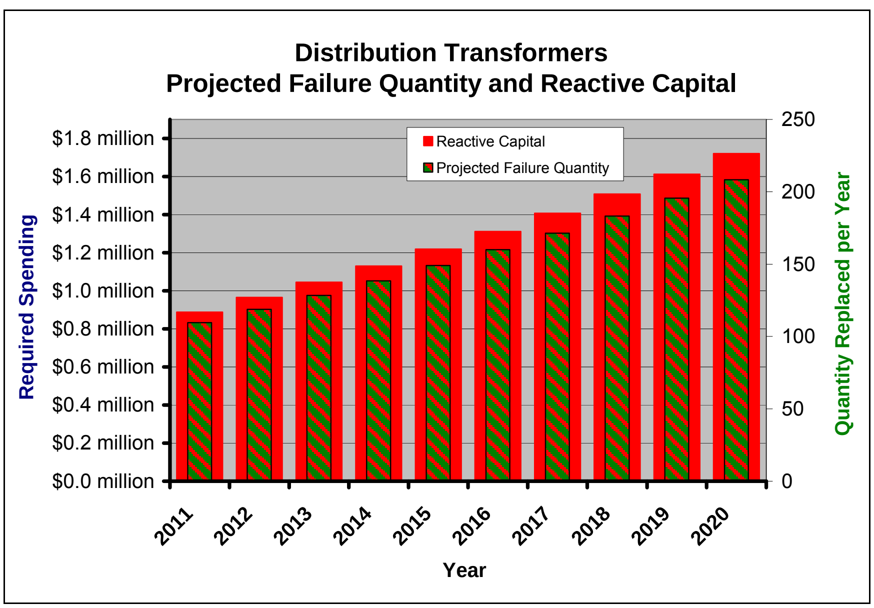


Figure 68. Distribution transformers projected failure quantity and reactive capital.

The "Projected Failure Quantity" shows the estimated result for the total population, which assumes that the portion of Distribution Transformers with missing data will have similar characteristics as those with data.

Intervention Mode

The intervention mode modeled for distribution transformers is replacement in-kind. The replacement costs vary by type and size. The replacement costs are summarized in the figure below:

Description	PowerStream Stock Code	Secondary Voltage	Have Spare	Type	Phases	Size	LOOKUP	Replacement Cost
1-phase 25 kVA	3162025	120/240	Y	Overhead	1	25	Overhead-1-25	$3,426
1-phase 50 kVA	3162050	120/240	Y	Overhead	1	50	Overhead-1-50	$4,226
1-phase 100 kVA	3162100	120/240	Y	Overhead	1	100	Overhead-1-100	$5,526
1-phase 167 kVA	3162167	120/240	Y	Overhead	1	167	Overhead-1-167	$7,126
3-Phase 50 kVA	3163050	600/347	Y	Overhead	3	50	Overhead-3-50	$5,404
3-Phase 100 kVA	3163100	600/347	Y	Overhead	3	100	Overhead-3-100	$6,604
3-Phase 167kVA	3163167	600/347	Y	Overhead	3	167	Overhead-3-167	$8,204
1-Phase 50 kVA	3172050	120/208	Y	Vault	1	50	Vault-1-50	$6,990
1-Phase 100 kVA	3172100	120/208	Y	Vault	1	100	Vault-1-100	$8,716
1-Phase 167kVA	3172167	120/208	Y	Vault	1	167	Vault-1-167	$10,841
3-Phase 100 kVA	3173100	600/347	Y	Vault	3	100	Vault-3-100	$9,115
3-Phase 167kVA	3173167	600/347	Y	Vault	3	167	Vault-3-167	$11,240
3-Phase 250 kVA	3173250	600/347	Y	Vault	3	250	Vault-3-250	$17,614
1-phase 50 kVA	4162050	120/240	Y	Padmount	1	50	Padmount-1-50	$7,298
1-phase 100 kVA	4162100	120/240	Y	Padmount	1	100	Padmount-1-100	$9,278
1-phase 167 kVA	4162167	120/240	Y	Padmount	1	167	Padmount-1-167	$9,542
3-Phase 150 kVA	7302150	120/208	Y	Padmount	3	150	Padmount-3-150	$21,144
3-Phase 300 kVA	7302300	120/208	Y	Padmount	3	300	Padmount-3-300	$25,104
3-Phase 500 kVA	7302500	120/208	Y	Padmount	3	500	Padmount-3-500	$28,536
3-Phase 150 kVA	7306150	600/347	Y	Padmount	3	150	Padmount-3-150	$21,804
3-Phase 300 kVA	7306300	600/347	Y	Padmount	3	300	Padmount-3-300	$25,764
3-Phase 500 kVA	7306500	600/347	Y	Padmount	3	500	Padmount-3-500	$29,724

Figure 69. Distribution transformers replacement costs.

Econometric Replacement Results

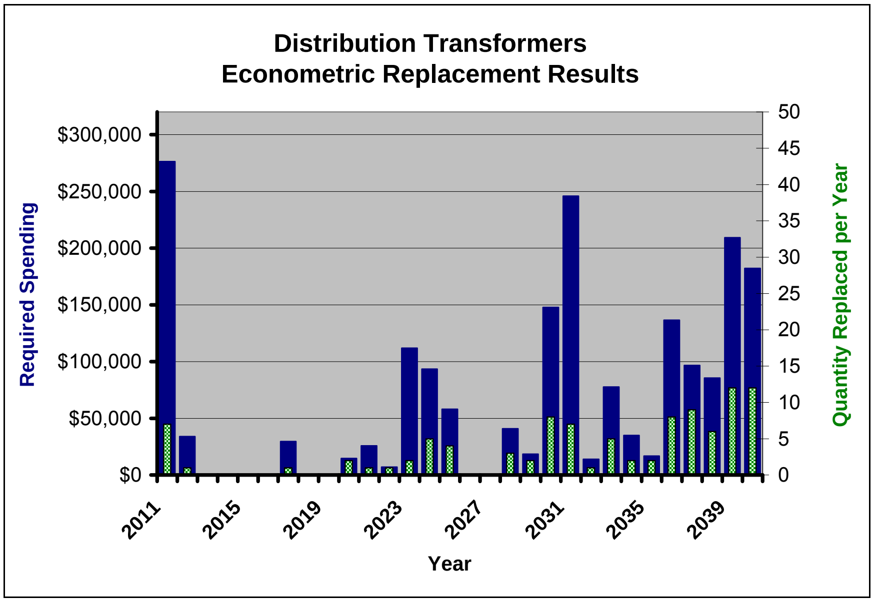


Figure 70. Distribution transformers econometric replacement results.

The econometric and reactive spending results are extrapolated to account for missing demographic data.

Conclusions

- Recommendations:
  - No risk-based planned replacement program is recommended.
  - Operate the distribution transformers program on a run-to-failure basis.
  - Continue to collect field data to update and run the ACA model.
  - Continue to collect nameplate data and update the model.
  - Capture transformer condition and age at failure to support customized failure probability curves and health index correlations.
  - Continue to monitor annual failure rates to identify any emerging deviations from expected reactive spend.
- Gaps:
  - Demographic and condition data not available for entire population. Data collection is in progress.

3.9 Distribution Switchgear

Summary of Asset Class

Distribution switchgear is a moderately complex asset with a moderate price per unit.

Limited demographic and condition data available; health index formulation is based on industry best-practice, and asset data is collected on an ongoing basis as a result of PowerStream's Switchgear inspection process.

Data Sources Available

Assumed loading, nameplate, and general demographic data.

Demographics

Number of units: 1,739

Typical life expectancy (years): 30-85 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 "Asset Amortization Study for the Ontario Energy Board"

Estimated replacement cost: $2,000 - $100,000

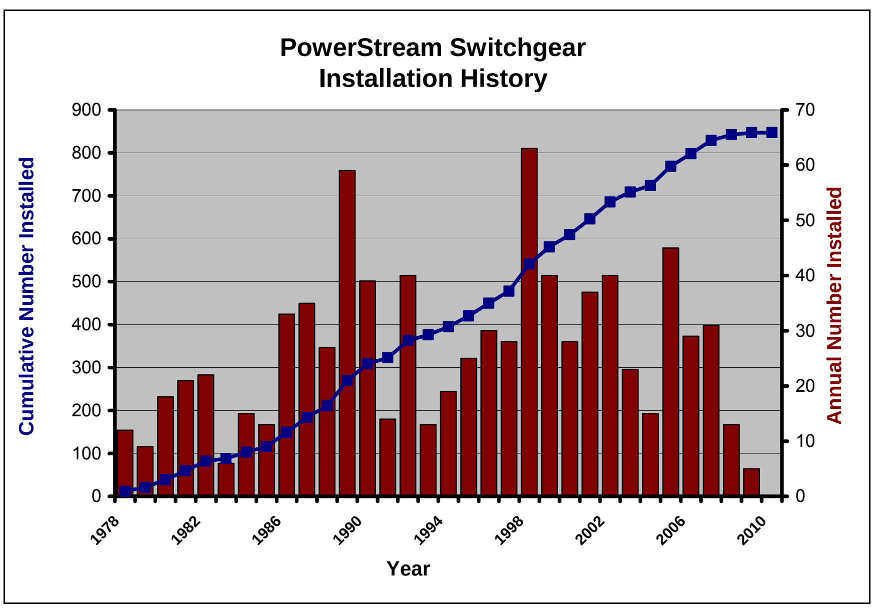


Figure 71. Distribution switchgear installation history.

Due to data gaps within our distribution switchgear population, the above chart includes only switchgear with a known installation date.

Asset Degradation

This asset group covers the switchgear units used in distribution loops supplying residential subdivisions and commercial/industrial customers. The switchgear population comprises of different types of interrupting medium such as air, oil, gas, and solid dielectric. Switchgear units are utilized to isolate/control other equipment, and to reconfigure the loops for maintenance, restoration or other operating requirements.

Switchgear degradation depends on a number of factors, such as condition of mechanical mechanisms, degradation of solid insulation, and corrosion. The important issues tend to be obsolescence or specific/generic defects.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end-of-life, just short of failure. To optimize the life of this asset and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without total replacement of the switchgear.

The switchgear health and condition can be indicated by the following parameters:

- Equipment age
- Presence of hotspots
- Condition mechanical mechanism
- Condition of bus insulation
- Failure rate

The life expectancy for medium voltage distribution switchgear is 25 to 50 years. Failure consequences include customer interruptions and employee safety.

Health Index Formulation and Results

The following charts provide the main condition parameters that were used in the PowerStream asset condition assessment and the weights assigned to each. Details of the Health Index formulation are provided in the tables.

Table 72. Distribution switchgear Health Index parameters and weights

#	Distribution Switchgear Condition Parameters	Air Type Weight	Oil Type Weight
1	Age	2	5
2	IR record	2	2
3	Field inspection	5	5
4	Failure rate	*	*

* A multiplying factor is adopted for HI adjustment: The initial HI is calculated based on condition criteria # 1 to #3. The final HI result is calculated by multiplying the initial HI with the multiplying factors corresponding to condition criterion #4.

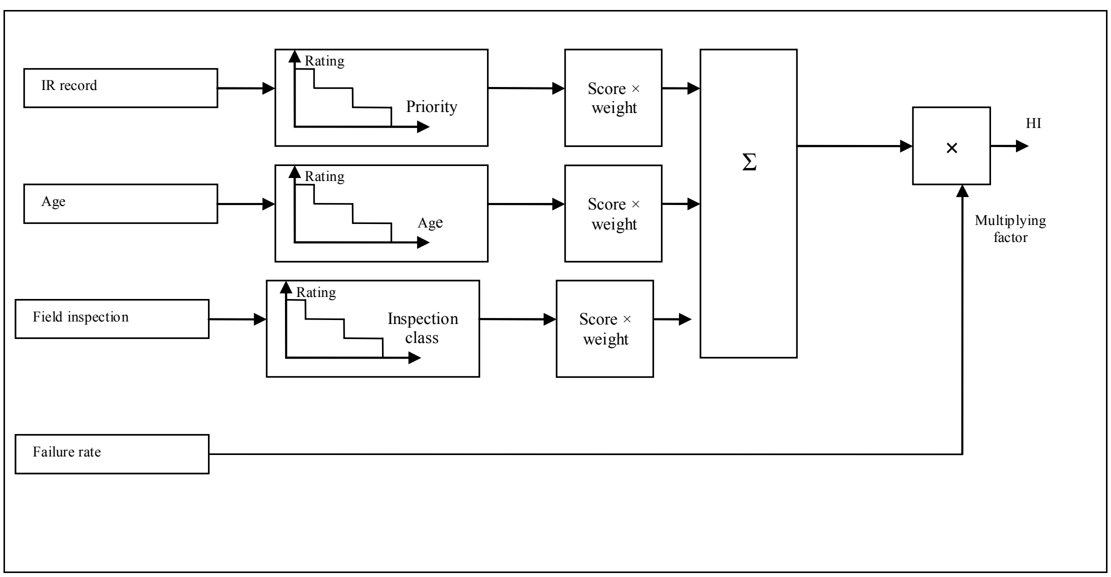


Figure 72. Distribution switchgear Health Index flowchart.

Table 73. Distribution switchgear parameter #1: age/condition criteria

Condition Factor	Factor	Condition Criteria Description
A	4	Less than 20 years old
B	3	20-40 years old
C	2	41-60 years old
D	1	61-70 years old
E	0	> 70 years old

Table 74. Distribution switchgear parameter #2: IR record condition criteria

Condition Factor	Factor	Condition Criteria Description
A	0	Corrective measures are required at the earliest possible time.
B	2	Corrective measures are required at the next available opportunity or shutdown.
C	3	Corrective measures are required as scheduling permits.
D	4	Normal maintenance cycle can be followed.

Table 75. Distribution switchgear parameter #3: field inspection condition criteria

Condition Factor	Factor	Condition Criteria Description
A	0	Corrective measures are required at the earliest possible time.
B	2	Corrective measures are required at the next available opportunity or shutdown.
C	3	Corrective measures are required as scheduling permits.
D	4	Normal maintenance cycle can be followed.

Table 76. Distribution switchgear parameter #4: failure rate criteria

Condition Factor	Multiplying Factor	Condition Criteria Description
A	1	M < 0.05

B	0.9	0.05 <= M < 0.1
C	0.8	0.1 <= M < 0.2
D	0.7	0.2 <= M < 0.4
E	0.6	M >= 0.4

Where M = failure rate x age

Failure rate for distribution switchgear = 0.0048, calculated based on IEEE Gold book (IEEE Std 493-1997).

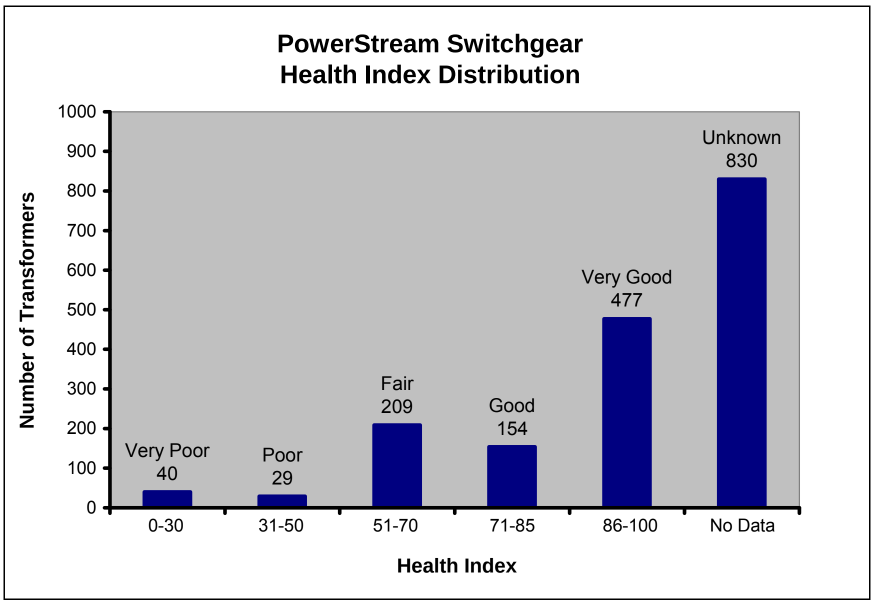


Figure 73. Distribution switchgear Health Index histogram.

Failure Probability

The distribution switchgear failure probability (hazard rate) curve is based on a Weibull curve, which is calibrated to match the historic failures experienced by PowerStream. The Weibull curve parameters are:

- Shape = 3.00, Scale = 40.53

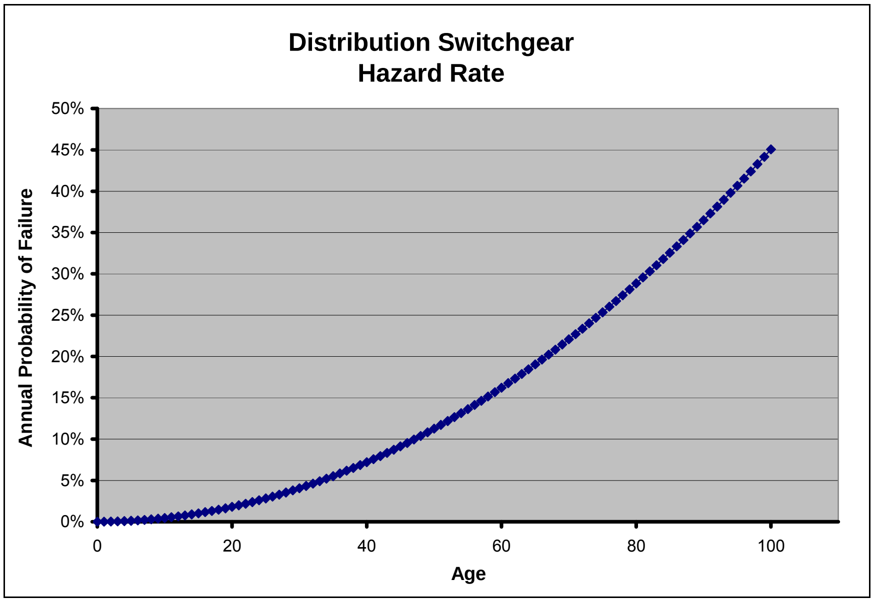


Figure 74. Distribution switchgear hazard rate curve.

Failure Effects

The failure effects by customers served are summarized below.

Description	Lookup	Loss of Peak Load (kW)	Outage Duration (hours)
Industrial and Commercial Customers	C&I	3,780	3
Residential Subdivisions	Residential	1,440	3
Mixed	Mixed	2,610	3

Figure 75. Distribution switchgear failure effects.

The failure effects are based on the following assumptions:

- For switchgear units supplying Industrial/Commercial Customers: On average each "loop" has a maximum of 10,000 connected kVA. On average there are 10 switchgears in a "loop", each switchgear supplies two customers each with an average XFMR size of 500 kVA at an assumed L.F. of 70% & 90% P.F. Upon a switchgear failure, one-half of the loop (on average 5 switchgears) will be lost for 3 hours, while the failed switchgear will take a total of 8 hrs for replacement. One-half of the loop means 5 x 2 x 500 kVA x

0.7 x 0.9 = 3150 kW for 3 hour (9,450 kWhrs). For the unit that failed we have 2 x 500 kVA x 0.7 x 0.9 = 630 kW for 5 hours (3 hours have already lapsed) = 3,150 kWhrs.

- For switchgear units supplying Residential Subdivisions: On average Switchgear-to-Switchgear there are thirty 50 kVA transformers and each transformer on average has 8 customers and each customer on average has a peak load of 4 kW. The Normal open point (N.O.) is located at midpoint, therefore 15 transformers per phase on each side or 45 transformers in total (for the 3-phases). Upon a switchgear failure, one-half of the loop (on average 45 transformers, 360 customers or 1440 kW) will be lost for 3 hours (time taken to isolate/switch & restore). This means 45 transformers x 8 customers x 4 kW or a peak load of 1,440 kW for 3 hours or 4,320 kWhrs.

Risk Matrix

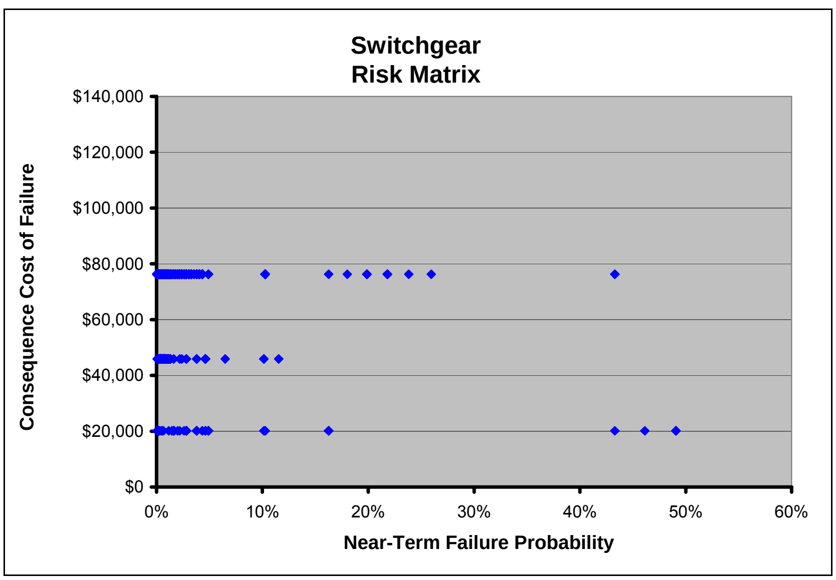


Figure 76. Risk matrix plotting consequence of failure versus failure probability.

Projected Failure Quantity and Reactive Capital

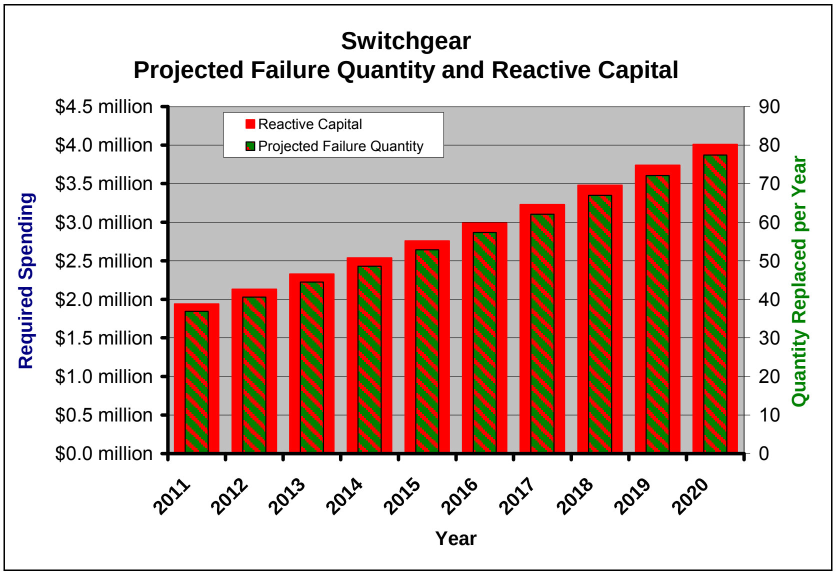


Figure 77. Distribution switchgear projected failure quantity and reactive capital.

The "Projected Failure Quantity" shows the estimated result for the total population, which assumes that the portion of Switchgear with missing data will have similar characteristics as those with data.

Intervention Mode

The intervention mode modeled for distribution switchgear is replacement in-kind. The replacement costs are summarized below.

Material Cost	Material Cost plus Overhead and Burden	Replacement Labour Hours	Replacement Labour Cost Plus Overhead and Burden	Truck Hours	Truck Cost plus Overhead and Burden	Type	Total
$41,000	$54,120	24	$1,368	12	$636	PMH	$56,124
$74,000	$97,680	24	$1,368	12	$636	Vista Gear	$99,684
	$0	24	$1,368	12	$636	FP	$2,004
	$0	24	$1,368	12	$636	CPP	$2,004
$18,000	$23,760	24	$1,368	12	$636	PMO	$25,764
$41,000	$54,120	24	$1,368	12	$636	PVI	$56,124
	$0	24	$1,368	12	$636	PNI	$2,004

Figure 78. Distribution switchgear replacement costs.

Econometric Replacement Results

PowerStream's switchgear population serves two types of customers – residential, and commercial/industrial. Customer type has an impact on the customer interruption cost calculation in the model and, therefore, on the econometric replacement results. PowerStream will validate and update customer type information.

The econometric replacement results were calculated for two scenarios:

- Assuming all loads are residential
- Assuming all loads are commercial/industrial

The results are shown below.

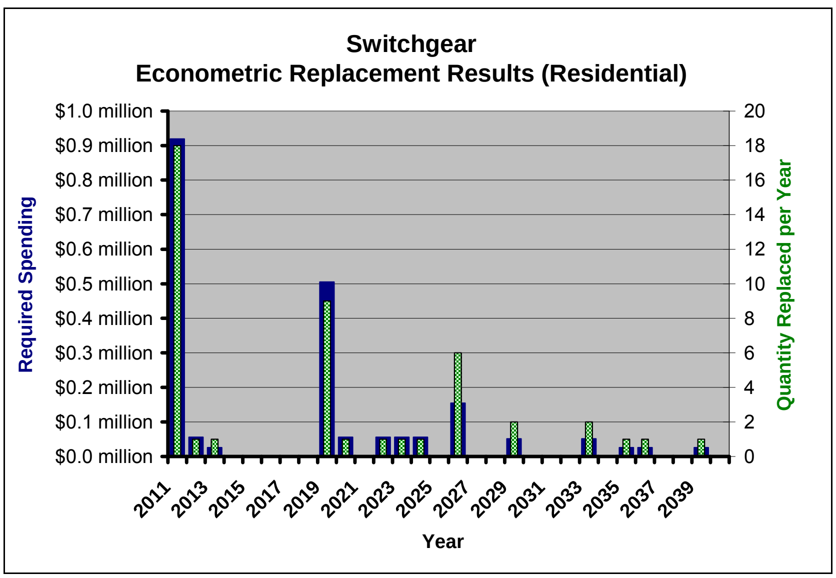


Figure 79. Distribution switchgear econometric replacement results – assumed residential.

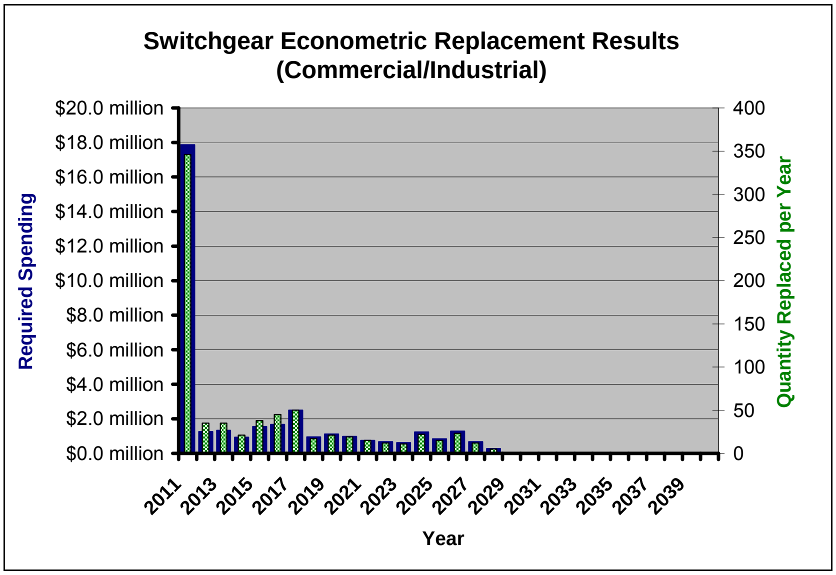


Figure 80. Distribution switchgear econometric replacement results – assumed commercial/industrial.

In the scenario of all loads assumed to be commercial/industrial, an immediate requirement for high spending is identified by the ACA model. The number and timing of switchgear replacement units is considered “optimal” or “ideal” from a pure economic viewpoint. For switchgear, we incorporated engineering judgment and operations input with the econometric model results to prudently spread out the switchgear replacement program over a longer period of time. The intent of spreading the replacement requirement over a number of years is to smooth out the budget, resource, and rate impacts while managing the incremental risk of asset failure.

In the near-term, PowerStream expects to replace on average 20 units per year under the planned switchgear replacement program. This is in addition to those units that will be replaced under emergency due to unit failure (3 year average for emergency replacement was 23 units per year). Rate of change of failure in future years is expected to be moderate and manageable. Any emerging significant deviations from expected reactive spend would trigger a program review.

PowerStream’s planned Switchgear replacement and Projected Failure Quantity are shown in the chart below.

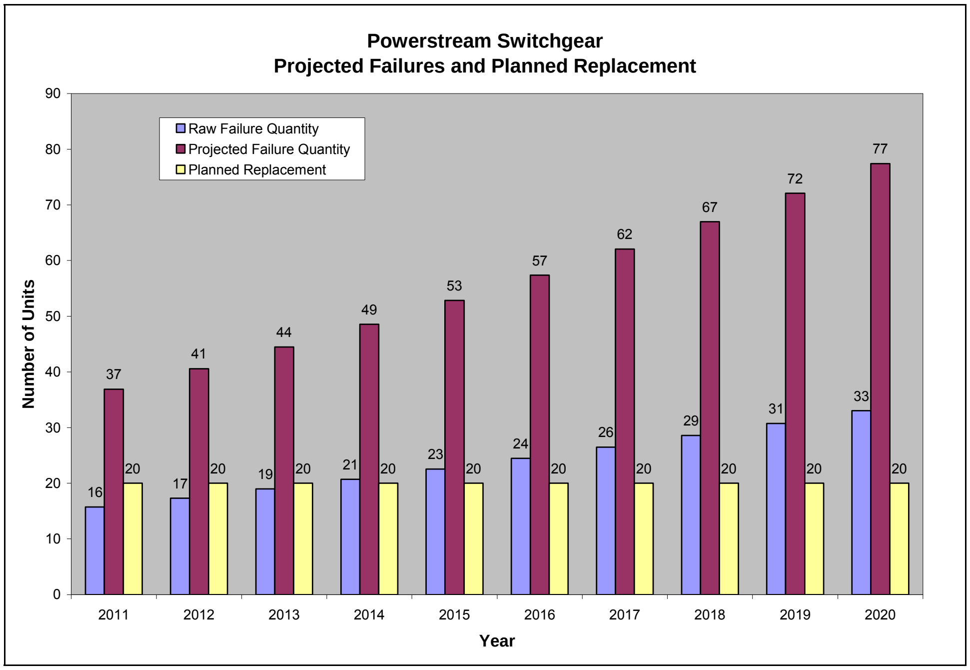


Figure 81. Distribution switchgear projected failures and planned replacements.

The "Projected Failure Quantity" shows the estimated number of failures for the total population, which assumes that the portion of Switchgear with missing data will have similar characteristics as those with data. The "Raw Failure Quantity" shows only the estimated number of failures for Switchgear with sufficient data.

Conclusions

- Recommendations:
  - Near-term switchgear replacements are warranted.
  - Update and validate customer type information.
  - Continue to collect nameplate and customer type data, and update the model (reduce "unknown" population).
  - Continue to capture condition data per health index formulation and update the model.
  - Capture switchgear condition and age at failure to support customized failure probability curves and health index correlations.
  - Continue to monitor annual failure rates to identify any emerging deviations from expected reactive spend.

- Gaps:
    - Demographic and condition data not available for entire population. Data collection is in progress.
    - Customer type information requires further validation.

3.10 Wood Poles

Summary of Asset Class

Wood poles are moderately complex assets with a low price per unit.

Wood pole failures are very rare due to comprehensive replacement programs. Wood pole testing contractors make replacement recommendations based on test results and minimum physical life remaining. Program recommendations are based on the pole testing results and PowerStream's pole replacement prioritization indices.

Health index formulation is based on industry best-practice.

Data Sources Available

General demographic and condition data acquired during wood pole test program.

Demographics

Number of units: 46,414

Typical life expectancy (years): 35-75 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 "Asset Amortization Study for the Ontario Energy Board"

Estimated replacement cost: $12,000

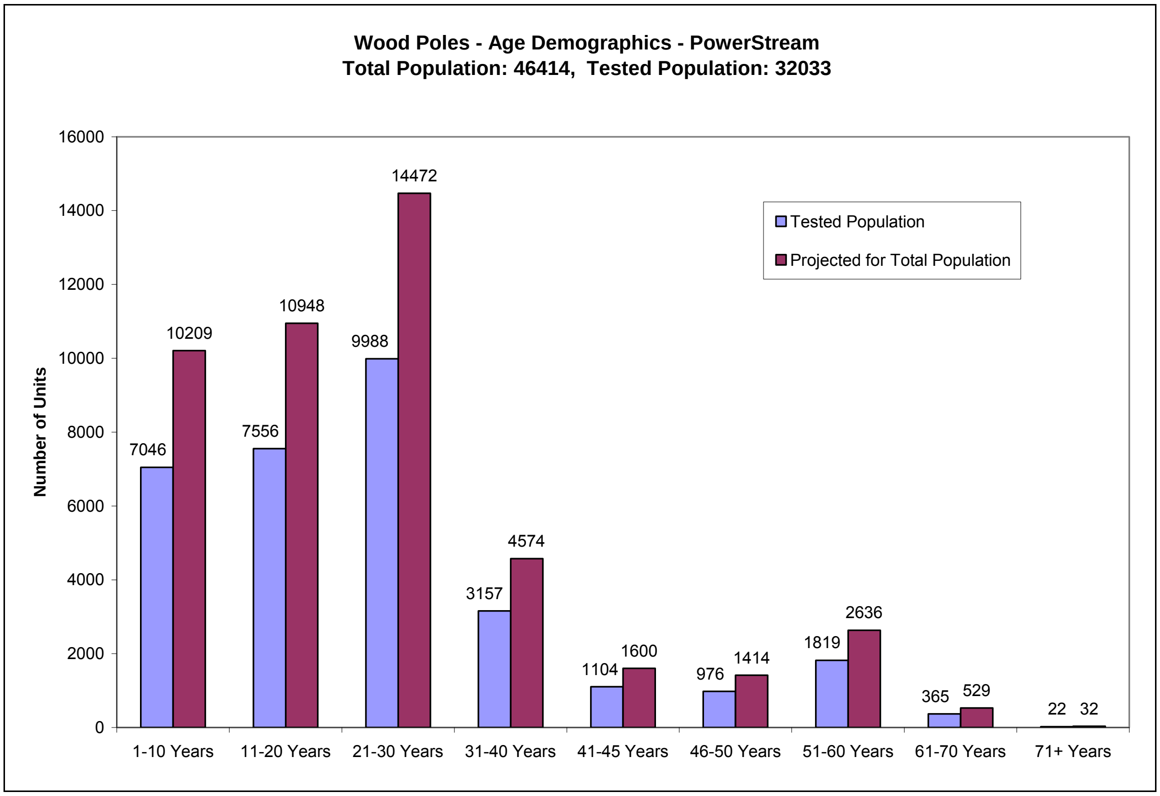


Figure 82. Wood poles age demographics.

There are some data gaps with respect to pole age. The "Projected" numbers show the estimated result, assuming that the portion of poles with missing data will have similar characteristics as those with data.

Asset Degradation

Overhead distribution lines consist of electrical conductors supported on insulators and mechanical structures. The support structure is usually a single wood or concrete pole. At locations with high mechanical loading, such as dead ends, angles and corners, the poles will be supported by guy wires attached to anchors installed in the ground.

Wood poles are the most common form of support for medium voltage overhead circuits as well as sub-transmission lines, however concrete poles are also used extensively especially in urban areas.

Wood Poles

Distribution line design dictates usage of the poles varying in height and strength, depending upon the number and size of conductors, the average length of adjacent spans, maximum loadings, line angles, appropriate loading factors and the mass of installed equipment. Poles are categorized into classes (1 to 7), which reflect the relative strength of the pole. Stronger poles (lower numbered classes) are used for supporting equipment and handling stresses associated with corner structures and directional changes in the line. The height of a pole is determined by a number of factors, such as the number of conductors it must support, equipment-mounting requirements, clearances below the conductors for roads and the presence of coaxial cable or other telecommunications facilities.

As wood is a natural material the degradation processes are somewhat different to those which affect other physical assets on electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot.

To prevent attack and decay of wood poles they are treated with preservatives prior to being installed. The preservatives have two functions, firstly to keep out moisture that is necessary to support the attacking fungus, and secondly as a biocide to kill off the fungus spores. Over the period of wood pole use in the electricity industry, the nature of the preservatives used has changed, as the chemicals previously used have become unacceptable from an environmental viewpoint. Nevertheless, effective and acceptable preservatives are available and poles well treated prior to installation have a long life (typically in excess of 50 years) prior to decay resulting in significant damage.

As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage. A particular problem when assessing wood poles is the potentially large variation in their original mechanical properties. Depending on the species, the mechanical strength of a new wood pole can vary greatly. Typically the first standard deviation has a width of ±15% for poles nominally in the same class.

However in some test programs the minimum measured strength has been as low as 50% of the average.

There are many factors considered by utilities when establishing condition of poles. These include types of wood, historic rates of decay and average lifetimes, environment, perceived effectiveness of available techniques and cost. However, perhaps the most significant is the policy of routine line inspections. A foot patrol of overhead lines undertaken on a regular cycle is extremely effective in addressing the safety and security obligations.

The following criteria can be used in establishing health and condition of poles:

- Pole strength (through lab testing on selected samples)
- Existence of cracks
- Woodpecker or insect caused damage for wood poles
- Wood rot
- Damage due to fire or mechanical damage
- Condition of guy wires
- Pole plumbness

The life expectancy of wood poles ranges from 35 to 75 years. Consequences of an in-service pole failure are quite serious, as they could lead to a serious accident involving the public. Depending on the number of circuits supported, a pole failure may also lead to a power interruption for significant number of customers.

Prioritization Index Formulation and Results

PowerStream has developed a wood pole replacement prioritization system to select pole replacement candidates. The details are described below.

The Wood Pole Prioritization method is shown on the following diagram.

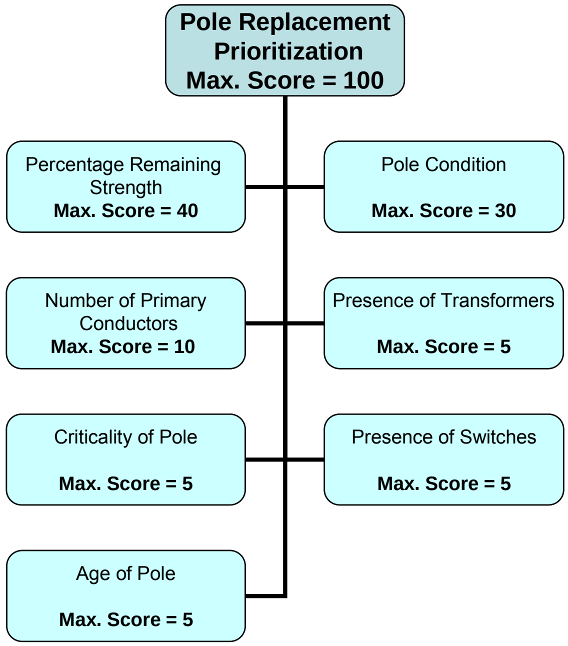


Figure 83. Wood poles Prioritization Index.

Wood Pole Prioritization Index Formulation

The parameters and scores used to form the overall prioritization score are shown in the following table.

Table 77. Wood poles Prioritization Index Parameters and Scores

POLE PRIORITIZATION CRITERIA SUMMARY		
Index	Criteria	Score Range
1	Percentage Remaining Strength	0 - 40
2	Condition	0 - 30
3	Presence of Transformers	0 - 5
4	Number of Primary Conductors	0 - 10
5	Presence of Switches	0 - 5
6	Criticality of Pole	0 - 5
7	Age of Pole	0 - 5
Maximum Score		100

The most important 2 parameters are Percentage Remaining Strength and Pole Condition. After these 2 parameters are considered to narrow down the candidate list, the remaining parameters will be used to further prioritize replacement among the candidates.

Pole Remaining Strength

This parameter references the percentage remaining strength of a pole from the pole test data and uses that number to assign a score. The scoring values are as follows:

Table 78. Wood poles Criteria #1: Remaining Strength

Remaining Strength (%)	Score
0 - 39	40
40 - 59	35
60 - 69	5
70 - 89	0
90 and Above	0

Remaining strength is scored heavily at a maximum of 40 due to the fact that it is based on a physical test of the pole and is the most accurate numerical representation of quality that can be obtained. This is the dominant field used in the priority determination.

Any pole that is ten years or less in age at the date of inspection will not be tested for remaining strength and therefore will be assumed to have 100% remaining strength by the model.

Pole Conditions

This parameter references the remarks and comments made by the pole testing contractor. Engineering judgment will be exercised to determine the overall Pole Condition score.

Table 79. Wood poles Criteria #2: Pole Condition

Pole Condition	Score
Extensive Cracks, Split Top, Rotten, Carpenter Ants, Fire, Bent Pole, Top Decay	0 - 30

Presence of Transformers

Pole top transformers add considerable weight to the top of pole and each transformer is an important asset that would be lost in pole failure.

This field checks the pole test data for the presence of transformers and returns a score based on the value.

The scoring values are as follows:

Table 80. Wood poles Criteria #3: Transformer Presence

Presence of Transformer	Score
YES	5
NO	0

Number of Primaries

This field references the number of primary conductors from the contractor's pole test data and returns a score based on the value. The more primary conductors present on a pole, the higher potential consequence of outages when the pole fails.

The scoring values are as follows:

Table 81. Wood poles Criteria #4: Number of Primaries

# of Primary Conductors	Score
0 - 2 primaries	0
3 - 5 primaries	2
6 - 8 primaries	6
9 - 11 primaries	8
12 primaries and over	10

Presence of Switches

The scoring values are as follows:

Table 82. Wood poles Criteria #5: Switch Presence

Switch Presence	Score
YES	5
NO	0

The intent of this column is to take into account poles with various types of switches/dips/risers on them. The scoring table will take into account various types of switches and give them a higher priority based on their type.

Criticality of Circuit

The scoring values are as follows:

Table 83. Wood poles Criteria #6: Criticality

Criticality of Circuit	Score
Low	0
High	5

The intent of this parameter is to assign values to poles based on the criticality of the services. The more critical the customer, the higher of a priority they become. For example a critical service might include a hospital, water supply, sewer system, etc.

Poles with high exposure to the public, such as schools malls, and bus stops, will also be taken into consideration to enhance public safety precautions. Engineering judgment will be exercised to determine the Criticality score.

Pole Age

The prioritization model calculates the poles age based on the install date and current year inputs and references it to the scoring table. The pole age is scored as follows:

Table 84. Wood poles Criteria #7: Pole Age

Pole Age	Score
0 - 19 Years	0
20 - 29 Years	2
30 - 39 Years	3
40 - 49 Years	4
50 - 59 Years	5

The pole age is scored relatively low because the age of a pole is not a strong indication of its condition, or its priority and importance to the distribution system. There is no definitive correlation between the age of a pole and its overall condition.

Final Pole Priority Score

This field sums the values of each of the scoring columns together to get a final score.

Pole Priority Rank Classification

This field takes the value of the final priority score and references a table to assign a pole Priority Ranking Category, listed below:

Table 85. Wood poles Classification

Priority Score	Rank
0 - 9	Very Low
10 - 19	Low
20 - 29	Medium
30 - 39	High
40+	Very High

Failure Probability

The wood pole failure probability (hazard rate) curve is based on a Weibull curve, using PowerStream's actual pole replacement data. The Weibull curve parameters are:

- Shape = 2.88, Scale = 45.54

Figure 84. Wood poles hazard rate curve.

Failure Effects

The dominant failure mode assessed for wood poles is catastrophic failure requiring replacement.

Intervention Mode

Wood poles are replaced based on pole testing recommendations and prioritization index results. Risk-based analyses are not used to justify pole replacements.

Replacement Program Results

The long-range replacement program is based on pole inspection and testing recommendations. Pole inspection and testing recommendations were analyzed to develop a pole prioritization tool to better manage the program.

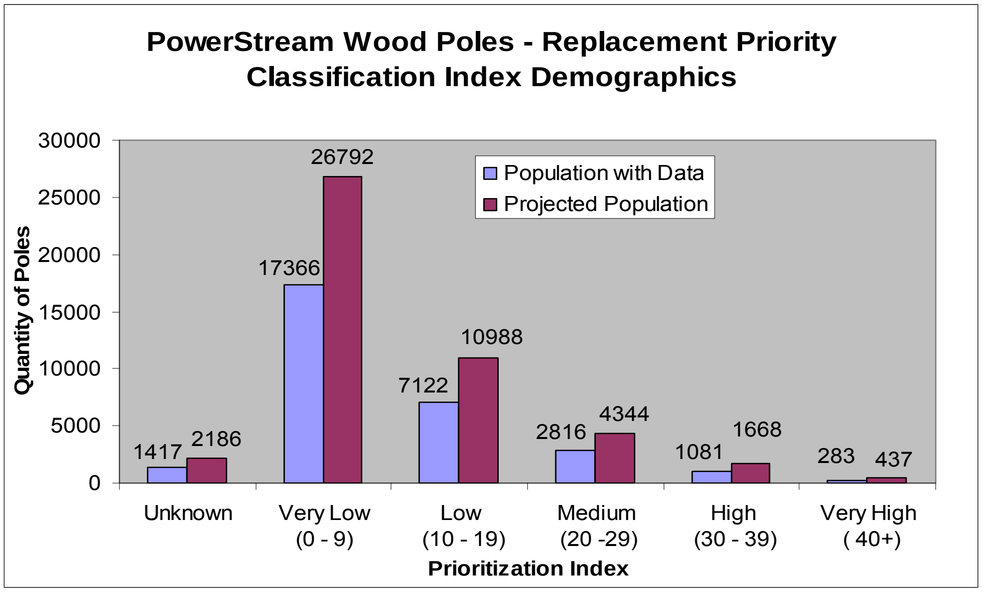


Figure 85. Wood poles Prioritization Index histogram.

Conclusions

- Recommendations:
  - Replace an average of 300 - 400 poles per year for the next five years to deal with the high and very high replacement priority groups.
  - Continue collecting inspection and failure data and updated customized wood pole failure curves.
  - Continue capturing condition data per pole prioritization formulation and update the model.
- Gaps:
  - Remaining wood pole demographics.
  - Discrepancies between GIS records and test data records.

3.11 Distribution Primary Cables

Summary of Asset Class

Underground Distribution primary cable is a moderately complex asset with a moderate price per meter.

Data Sources Available

Cable installation by drawing number, length, year, cable type, installation method (i.e., conduit, direct bury).

Demographics

Number of units: 7,836 km (cable meters)

Typical life expectancy (years): 20-55 as per Kinectrics Inc. Report No: K-418099-RA-001-R000 "Asset Amortization Study for the Ontario Energy Board"

Estimated replacement cost: $188 - $400/m (cable only), $340 - $660/m (in conduit)

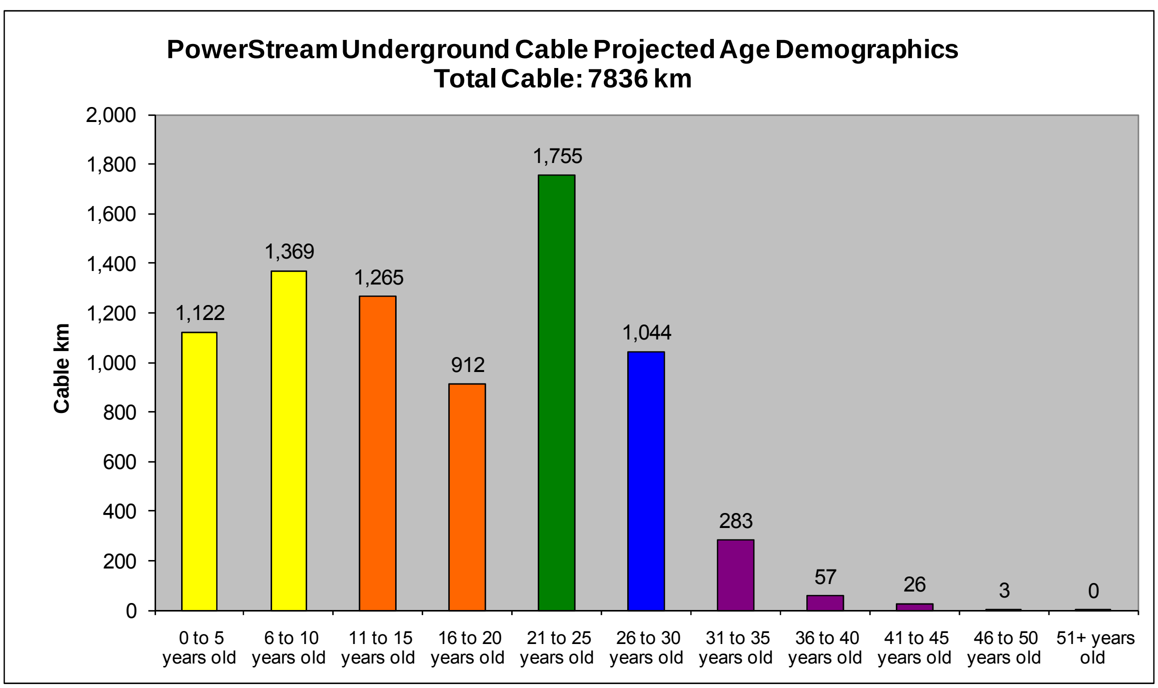


Figure 86. Distribution primary age demographics.

Asset Degradation

As cable is put in services, the following factors will affect the cable properties, performance, and degradation process:

- Mechanical Stress (e.g. the pulling of cable during transportation and installation)
- Electrical Stress (e.g. overloading cable under normal and emergency conditions)
- Operation Practices (e.g. emergency load transfer among feeders)
- Maintenance Practice (e.g. commissioning testing, fault locating, restoration practice, splicing practice)
- Environment Conditions (e.g. direct buried, chemical corrosion, water ingress)
- The forming of “water trees” which will reduce the strength of the insulation and eventually lead to insulation breakdown and cable failure
- Corrosion of concentric neutral wires
- External Factors (e.g. dig-in by contractors)
- Impurity, by-products, and contaminants, etc. and defect during manufacturing process

Health Index Formulation and Results

Age and installation conditions play a big part in determining cable health indices. It has been decided to use age grouping as a basis for our cable management plans as there is a strong correlation, in the general cable population, between cable age and end-of-life status. Within the age groupings, cable testing will provide additional information to determine the cable health index and, together with service quality data, will determine overall cable replacement priority. PowerStream has developed a cable prioritization system to select cable replacement and cable injection candidates.

The following factors are considered in developing the prioritization index for underground primary cable:

- Age

- Neutral Corrosion
- Insulation Corrosion
- Splices
- Number of Outages
- Customers Affected
- Restoration Time
- Cost Benefit

The Cable Prioritization method is shown on the following diagram.

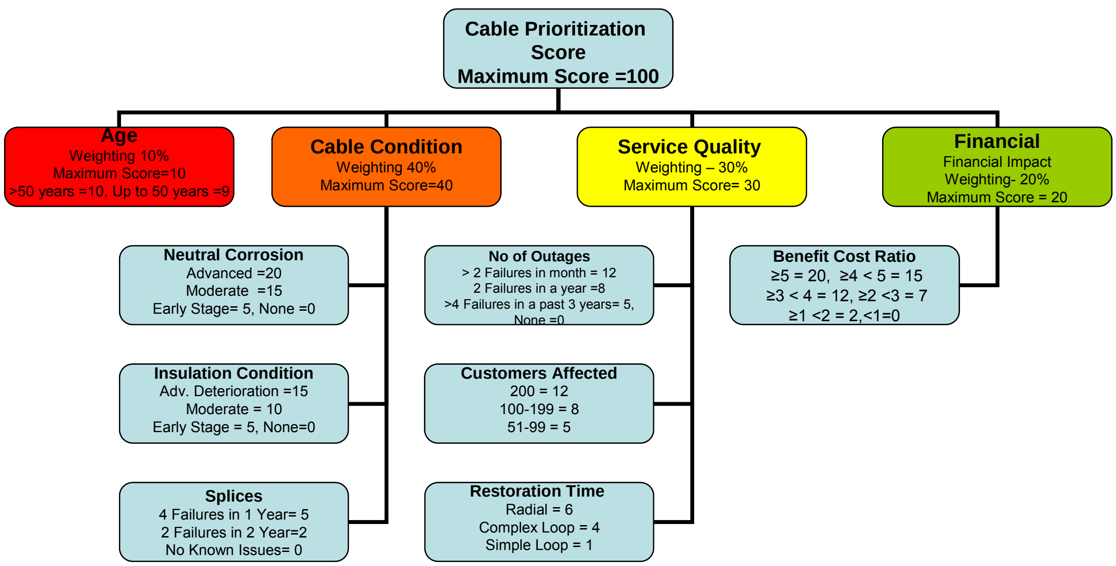


Figure 87. Cable Prioritization method.

Failure Probability

The Underground Cable failure probability (hazard rate) curves are based on a Weibull curve, which is calibrated to match the historic failures experienced by PowerStream. The Weibull curve parameters are:

- **Direct Buried Cables Unjacketed** - Shape = 4.39, Scale = 35.54
- **Direct Buried Jacketed** - Shape = 4.39, Scale = 37.39
- **Conduit Unjacketed Cables** - Shape = 2.51, Scale = 55.17

- **Conduit Jacketed Cables -** Shape = 2.51, Scale = 59.33

The underground cable failure probability (hazard rate) curves are based on failure histories from other utilities with similar cable:

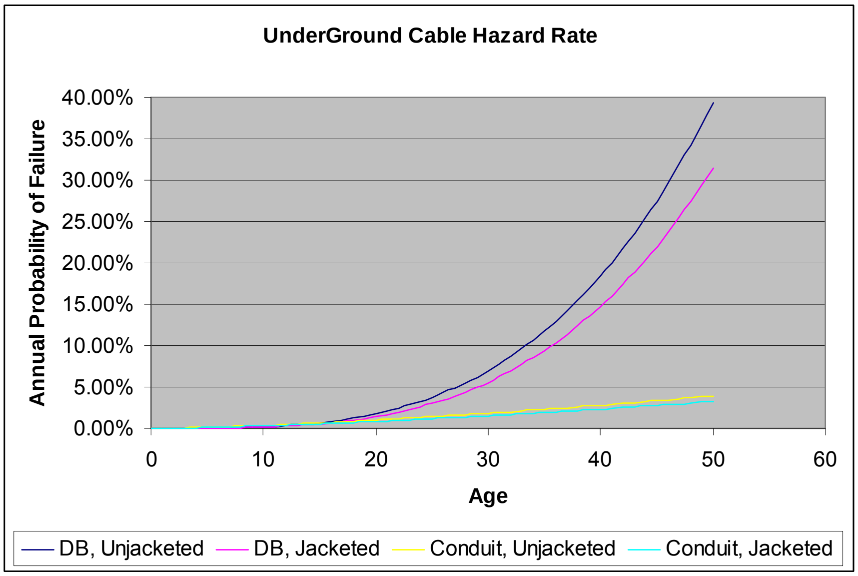


Figure 88. Distribution primary cable hazard rate curve.

Failure Effects

It is assumed that a cable fault on a 1-phase residential looped subdivision will impact 800 kVA (half the loop, 50 amps). For a 3-phase industrial/commercial subdivision, it is assumed that 3,350 kVA will be impacted (half the loop, 70 amps).

Intervention Mode

PowerStream will address the cable aging issue by a combination of cable injection and cable replacement on a prioritized basis. Cable injection is assumed to rejuvenate the cable by 20 years.

Replacement and Injection Program Results

There are two methods of intervention to address the cable aging issue:

- Cable Replacement – replace existing cable
- Cable Injection – extend existing cable service life

The Cable Replacement option is more expensive than the Cable Injection option with respect to initial capital cost. But it has the advantage of new cable that will be utilized for a longer time. In comparing the two options: the extra life expected from injected cable is 15-20 years; the life of new cable is expected to be 50-55 years; the cost/benefit ratio is 15% better for cable injection compared to new cable. Cable injection is viable for only a certain population of cable.

Currently, PowerStream is experimenting with Cable Injection technology to gain more experience. This plan is developed based on the assumption that Cable Injection is a viable option for a certain quantity of cable. If it is determined that Cable Injection is no longer a viable option, then Cable Replacement will become the only alternative. In that case, the quantity that is proposed for Injection will be proposed for Replacement.

The Cable Replacement plan will be ongoing as we will continually need to replace cable as it gets older. This report will cover the first 20 years of the plan. It is expected that the Cable Replacement plan will continue at a similar spending level after the first 20 years.

The Cable Injection plan will take place over a period of 10 years. After 10 years all suitable candidates for injection will be exhausted, therefore this plan will terminate after 10 years.

To develop a general plan to address the cable issue (a 20 year plan for cable replacement, and a 10 year plan for cable injection) the cable population is divided into the following 5 groups:

- Group 1: 31 years and older
- Group 2: Between 26 – 30 years
- Group 3: Between 21 – 25 years
- Group 4: Between 11 – 20 years
- Group 5: Between 1 – 10 years

Group 1: 31 years and older:

It is estimated that PowerStream has approx. 370 km of cable older than 30 years.

This population is the older generation of cable that was manufactured with old technologies and processes, using inferior insulation material (non tree-retardant XLPE). In addition, due to age, and installation method (direct buried) the neutral wires are likely corroded. Samples of recent cable failures show that the neutral wires have corroded beyond repair. Cables in this population may be at or close to end-of-life stage and are candidates for cable replacement. As a result Group 1 is excluded from Cable Injection.

Group 2: Between 26 – 30 years:

It is estimated that PowerStream has approx. 1,044 km of cable between 26 – 30 years.

This population is also the older generation of cable as described in Group 1 above. It is assumed that the cable components have not deteriorated significantly yet. Cables within this population could be candidates for cable injection. However, it should be noted that a significant portion of this group may not be viable candidates for cable injection, depending on forthcoming tests. For our purposes we assume that 50% (i.e. 522 km) of this population is not suitable for injection and must be replaced, this quantity will be managed under the Cable Replacement Program. The remaining quantity 50% (i.e. 522 km) of this population is suitable candidates for injection, this quantity will be managed under the Cable Injection Program. This issue is covered in detail in the next Section – Cable Injection.

Group 3: Between 21 – 25 years:

It is estimated that PowerStream has approx. 1,755 km of cable between 21 – 25 years.

This population is a newer generation of cable that was manufactured with new technologies and processes (similar to Group 4 and Group 5), for example, the use of tree-retardant XLPE for insulation and triple extrusion process. Because water trees are not a concern for this group of cable, and Injection’s main purpose is to repair water trees, Injection is not effective for this group of cable. In addition, this population has likely been manufactured using strand-filled material, which does not allow the injection fluid to flow through and therefore injection is not possible. This population of cable will need to be addressed at the end of the 20-year period once the first two groups of cable have been dealt with.

Group 4: Between 11 – 20 years:

It is estimated that PowerStream has approx. 2,177 km of cable between 11 – 20 years.

At the end of the 20-year proposed plan, this population should still maintain a low failure rate and it is estimated a portion of this group will still operate better than Group 3.

Group 5: Between 1 – 10 years:

It is estimated that PowerStream has approx. 2,501 km of cable between 1 – 10 years.

Because this cable is new, it is not an immediate concern. It is assumed it will last well beyond the end of the 20-year plan.

20-Year Cable Replacement Plan:

The intent of this program is to start to address the aging cable population in a timely manner so that the future spending level (after 20 years) will be manageable.

To address the Group 1 population of 370 km of cable older than 30 years, and 50% of the Group 2 population of 522 km of cable between 26 – 30 years (total = 370 km + 522 km = 892 km), it is recommended to:

- Replace 8.5 km in 2012 (same level as 2011)
- Replace 47 km per year for the subsequent 19 years from 2013 – 2031

At this rate, all of the 892 km will have been replaced by 2032.

Currently, PowerStream does not have sufficient physical condition and test data to determine the degree of deterioration and to estimate the remaining life of the cable population.

PowerStream, beginning in 2012, will conduct cable testing (e.g. Tan Delta tests, Partial Discharge tests) to further assess the condition of cable to:

- Determine which intervention method (replacement vs. injection) is more suitable to a specific location.

- Determine the appropriate quantity and timing of cable intervention (replacement/injection).
- Validate and prioritize the cable replacement/injection projects.

The following chart shows the cable age profile projections resulting from the proposed plan. The quantities are shown 10 years and 20 years into the program.

- The blue bars indicate the resulting age profiles 10 years into the program.
- The red bars indicate the resulting age profiles 20 years into the program.

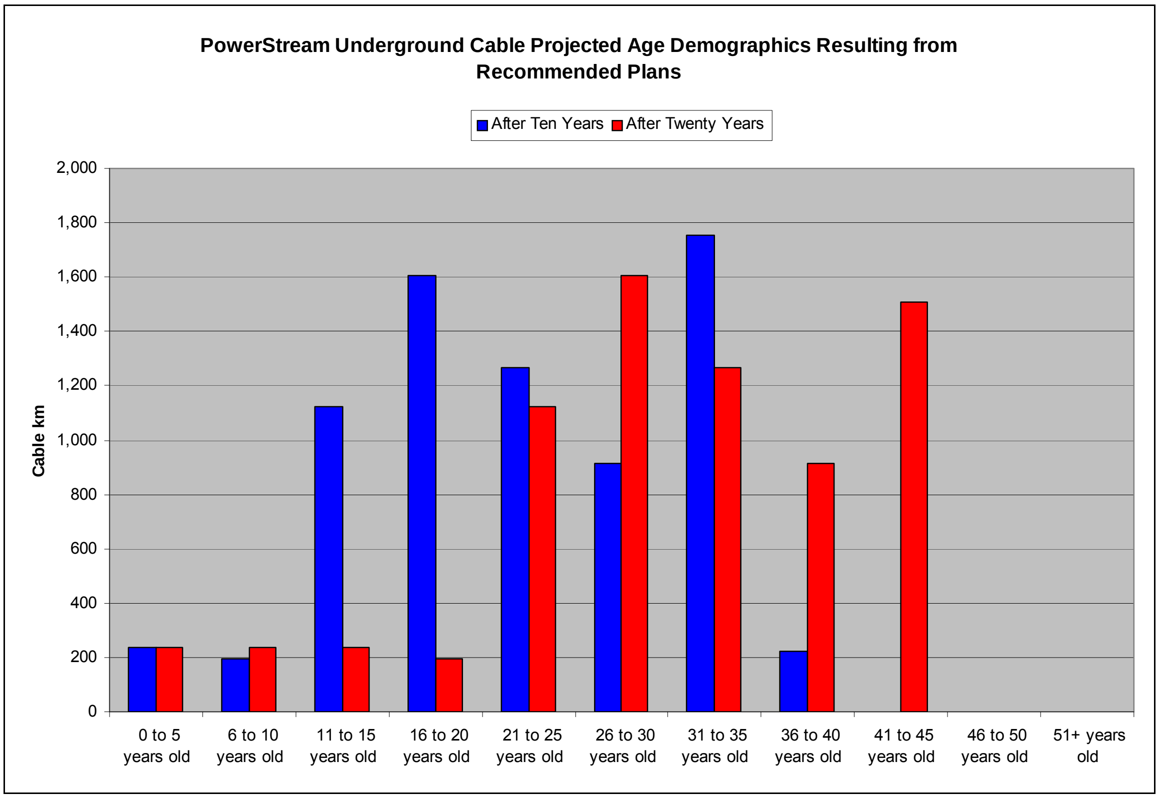


Figure 89. Underground cable projected age demographics.

Based on the above chart, after 20 years PowerStream will have 1,509 km of cable that is 41 to 45 years old. While this is a higher quantity of cable in the age range as compared to the quantity at the start of the program, these cables will be 2nd and 3rd generation cable with improved production quality and corresponding longer expected service life as compared to the cable being addressed in the first 20 year replacement program. At that time this group of cable will be in or entering end-of-life conditions, therefore the replacement program will likely continue at a suitable replacement level to address this population of cable.

The above demonstrates that the proposed 20 year Cable Replacement plan during the first 20 years will result in cable demographics that are reasonably well distributed after 20 years (similar to the first 20 years), supporting the premise that this is the correct level of cable replacement for this asset class.

The recommended cable replacement quantities and costs are shown in the chart below. 2012 costs include the costs of planned projects. For 2013 and onward, the average cost of $281 per meter is used.

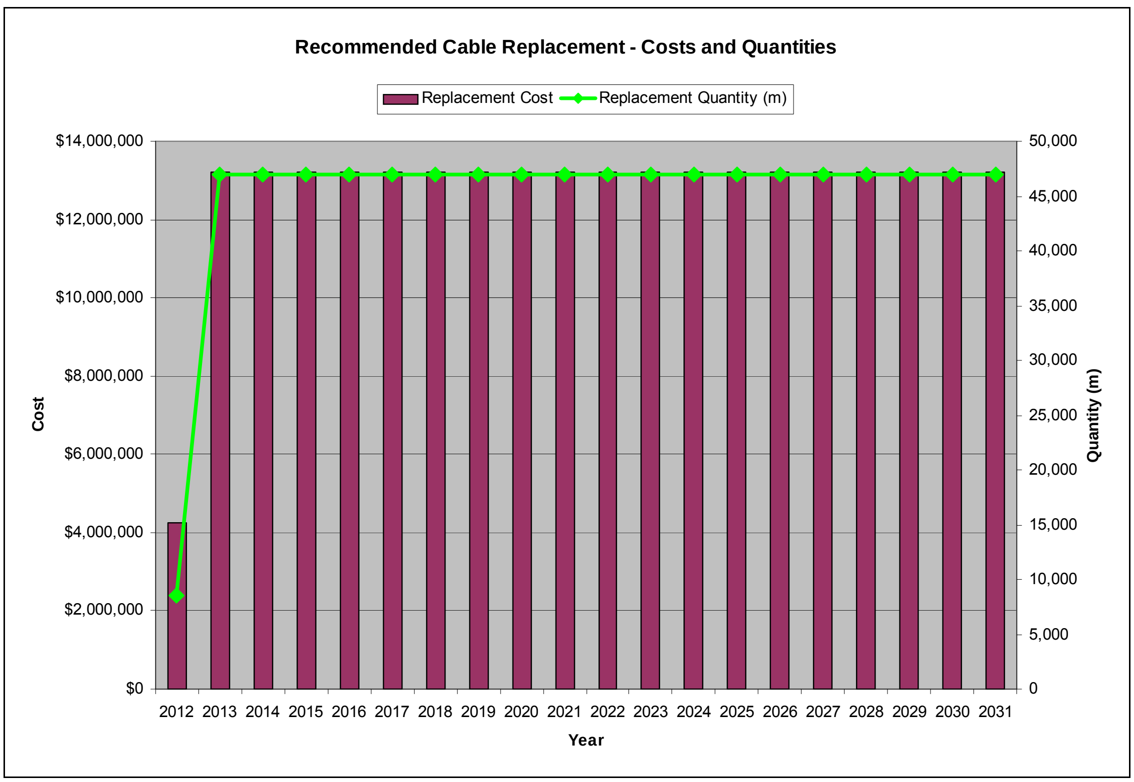


Figure 90. Recommended cable replacement costs and quantities.

Underground Cable Injection

The criteria for selecting Cable Injection candidates are listed below:

- Pre to mid 1980's (approx. 26 years old in 2011)
- Not solid core
- Non strand-filled
- Concentric neutral not corroded significantly
- No electrical trees present (Cable Injection can repair water trees and not electrical trees)
- Not having too many splices within a cable segment

Group 1 cables (31 years and older) are assumed to be close to end-of-life. Samples of recent cable failures show that the neutral wires have corroded beyond repair. As a result Group 1 is excluded from Cable Injection.

Group 2 cables (26-30 years) could be candidates for Cable Injection provided that the above conditions are met. It should be noted that a significant portion of this group may not be viable candidates for cable injection, depending on forthcoming tests. We assume that 50% (i.e. 522 km) of this population is suitable for injection.

Groups 3, 4 and 5 cables (25 years or younger in 2011) are assumed to have been manufactured with new technologies and processes using tree-retardant XLPE and triple extrusion process and strand-filled material. In general, water trees are not a concern and therefore injection is not effective. As a result Groups 3, 4, and 5 are excluded from cable injection.

Because the Cable Injection option has a number of limitations, a portion the Group 2 population may not be candidates for Cable Injection. For example, it may be more economical to replace cables if there are multiple phases in a trench, or multiple splices in a segment. Another example is during cable failure repair, operations staff adds two new splices to the segment, and one piece of new cable between the splices. As the new piece of cable is strand-filled, injection is not possible for this cable segment. Furthermore, depending on the design and condition of the cable at a specific location (e.g. strand-filled, neutral corrosion, electrical trees) the Cable Injection process may not be feasible at all.

To determine feasibility of cable injection, cable will be tested using cable diagnostic testing such as Tan Delta and Partial Discharge (PD) tests.

PowerStream will, beginning in 2012, conduct cable testing (e.g. Tan Delta tests, Partial Discharge tests) to further assess the condition of cable to:

- Determine which intervention method (replacement vs. injection) is more suitable to a specific location
- Determine the appropriate quantity and timing of cable intervention (replacement/injection)
- Validate and prioritize the cable replacement/injection projects

As PowerStream is still experimenting with cable injection technologies and processes, we will proceed with injection projects prudently. This plan is developed based on the assumption that Cable Injection is a viable option for a certain quantity of cable. If it is determined that Cable Injection is no longer a viable option, then Cable Replacement will become the only alternative. In that case, the quantity that is proposed for Injection will be proposed for Replacement.

10-Year Cable Injection Plan:

To address the 50% of the Group 2 population of 522 km of cable aging between 26 – 30 years, it is recommended to:

- Inject 8 km in 2012 (same level as 2011)
- Inject 57 km per year for the subsequent 9 years from 2013 – 2022

10 years is the optimal time period to get the benefit of the injection program for Group 2. If we extend the period beyond the 10 years, the remaining population of Group 2 may become too old to remain suitable candidates for injection.

At this rate all of the 522 km cable between 26-30 years will have been rehabilitated by 2022.

The recommended cable injection quantities and costs are shown in the chart below using the average cost of $72 per meter.

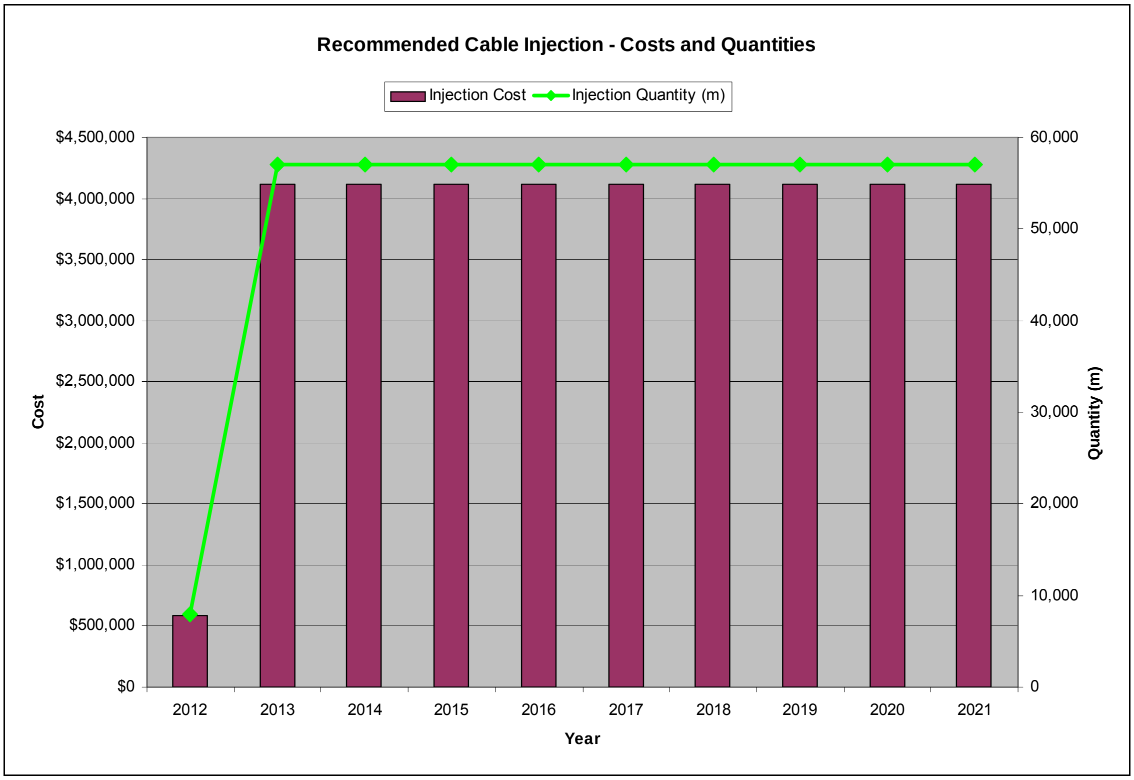


Figure 91. Recommended cable injection cost and quantities.

Conclusions

- Recommendations:
  - Proceed with injection and replacement plans as outlined above.
  - Conduct cable testing to identify candidates for cable replacement and cable injection.
  - Use cable prioritization to determine the appropriate quantity and timing of cable intervention (replacement/injection).
- Gaps:
  - Cable test data.
  - Cable demographic information.

FIXED ASSET CONTINUITY SCHEDULES

The fixed asset continuity schedules for 2009 through 2013 are provided in Appendix 1, Schedule 21, as OEB Appendix 2-B. In service additions and the changes in the net book value of fixed assets are discussed in Exhibit B1, Tab 1, Schedule 7.

Please note that there are two schedules for 2011, one under Canadian Generally Accepted Accounting Principles ("CGAAP") and one under Modified International Financial Reporting Standards ("MIFRS"). See Exhibit A3, Tab 1, Schedule 5 for more details regarding the changes resulting from MIFRS and the impact on this application.

FIXED ASSET CONTINUITY SCHEDULE (000's)
YEAR: 2009
CGAAP

CCA Class	PS GL Account	GL account to map	Detail Asset Class	Depreciation Rate	Notes	COST Opening Balance	COST Additions	COST Disposals/ Adjustments	COST Closing Balance	ACCUMULATIVE DEPRECIATION Opening Balance	ACCUMULATIVE DEPRECIATION Additions	ACCUMULATIVE DEPRECIATION Disposals/ Adjustments	ACCUMULATIVE DEPRECIATION Closing Balance	Net Book Value (000's
Distribution Assets														
47	1610	1610	Hydro One TS - Contributed Capital	4.00%		0	0	0	0	0	0	0	0	0
n/a	1805/1905	1805	Land	0		8,093	342	0	8,435	0	0	0	0	8,435
CEC	1806/1906	1806	Land Rights	0	1	657	148	0	730	178	1	0	179	551
47	1808	1808	Building & Fixtures	2.00%		43,527	440	0	43,967	14,319	853	0	15,171	28,795
47	1810	1810	Major spare parts (New 2008)	0		7,619	8,843	(7,619)	8,843	0	0	0	0	8,843
47	1815	1815	Transformer Stations	2.50%		95,767	0	0	95,767	26,586	2,393	0	28,979	66,788
47	1820	1820	Distribution Stations	3.33%		10,840	681	0	11,520	4,406	342	0	4,749	6,772
47	1830	1830	Poles, Towers & Fixtures	4.00%		114,186	10,564	0	124,750	41,207	4,290	0	45,497	79,253
47	1835	1835	O/H Cond & Devices	4.00%		155,040	2,124	0	157,164	75,433	5,754	0	81,186	75,979
47	1840	1840	U/G Conduit	4.00%		146,092	8,219	0	154,310	62,549	5,660	0	68,209	86,101
47	1845	1845	U/G Cond & Devices	4.00%		293,297	24,597	0	317,894	154,344	11,459	0	165,803	152,090
47	1849	1850	Line Transformers	4.00%		241,532	10,800	0	252,332	122,721	9,065	0	131,786	120,546
47	1855	1855	Services (OH and UG)	4.00%		48,874	2,668	0	51,542	21,897	1,733	0	23,630	27,912
47	1860	1860	Meters	4.00%		46,363	2,702	(9,297)	39,768	22,991	1,538	(4,715)	19,815	19,954
47	1862	1860	Smart Meters	6.67%		0	9,777	0	9,777	0	1,629	0	1,629	8,147
			Subtotal Distribution Assets			1,211,886	81,903	(16,916)	1,276,798	546,630	44,719	(4,715)	586,633	690,166
General Plant Assets														
13	1870	1870	Leased Property	2.50%		575	0	0	575	575	0	0	575	0
47	1908	1908	Building & Fixtures - Head office	2.00%		26,545	672	0	27,217	319	560	0	879	26,337
13	1910	1910	Leasehold Improvements	16.67%	2	2,171	0	0	2,171	1,354	310	0	1,664	507
8	1915	1915	Office Equipment	10.00%		6,650	283	0	6,933	3,222	230	0	3,452	3,481
10	1920	1920	Computer hardware	20.00%		15,108	1,835	0	16,943	10,657	1,834	0	12,490	4,453
12	1925	1925	Computer Software	33.33%		13,632	1,965	0	15,597	10,008	2,704	0	12,712	2,885
10	1930	1930	Transportation	16.67%	2	19,229	4,082	(1,733)	21,577	12,868	2,207	(1,714)	13,360	8,217
8	1935	1935	Stores Equipment	10.00%		652	0	0	652	581	11	0	592	60
8	1940/1945	1940	Tools, Shop & Garage	10.00%		5,535	411	0	5,946	3,719	347	0	4,066	1,880
8	1955	1955	Communication Equipment	14.29%	2	1,286	591	0	1,877	513	84	0	597	1,280
8	1960	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	1980	System Supervisory Equip	6.67%		17,794	548	0	18,342	9,445	913	0	10,358	7,984
47	1990	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
12	1961	1925	Process Re-engineering	33.33%		735	444	0	1,179	252	319	0	571	608
			Subtotal General Plant Assets			109,911	10,830	(1,733)	119,008	53,513	9,519	(1,714)	61,318	57,690
Other Capital														
47	2005	2005	Prop. Under Capital Lease-Addiscott	4.00%		0	0	0	0	0	0	0	0	0
			Subtotal Other Capital Assets			0	0	0	0	0	0	0	0	0
			Total Assets Before Contributed Capital	n/a		1,321,797	92,734	(18,649)	1,395,807	600,142	54,238	(6,429)	647,951	747,856
47	1995	1995	Contributed Capital	varies		(228,877)	(31,587)	0	(260,464)	(42,279)	(9,819)	0	(52,097)	(208,367)
			NET DISTRIBUTION ASSETS			1,092,920	61,146	(18,649)	1,135,342	557,864	44,419	(6,429)	595,853	539,489

NOTES:
1) Depreciation was recorded on land rights in prior years including 2009. This was removed in 2010 as it was determined that no depreciation should be applied.
2) More then one asset type in the class with different useful lives. Depreciation rate shown is based on the average useful life

FIXED ASSET CONTINUITY SCHEDULE (000's)
YEAR: 2010
CGAAP

						COST				ACCUMULATIVE DEPRECIATION				
CCA Class	**PS GL Account**	**GL account to map**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Opening Balance**	**Additions**	**Disposals/ Adjustments (3)**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals/ Adjustments (3)**	**Closing Balance**	**Net Book Value (000's**
Distribution Assets														
47	1610	1610	Hydro One TS - Contributed Capital	4.00%		0	0	0	0	0	0	0	0	0
n/a	1805/1905	1805	Land	0		8,435	1,952	0	10,386	0	0	0	0	10,386
CEC	1806/1906	1806	Land Rights	0	1	730	1	0	731	179	0	(179)	0	731
47	1808	1808	Building & Fixtures	2.00%		43,967	389	(37,185)	7,171	15,171	136	(14,070)	1,238	5,933
47	1810	1810	Major spare parts (New 2008)	0		8,843	(438)	0	8,404	0	0	0	0	8,404
47	1815	1815	Transformer Stations	2.50%		95,767	25,910	0	121,677	28,979	2,622	(0)	31,601	90,076
47	1820	1820	Distribution Stations	3.33%		11,520	426	22,170	34,116	4,749	1,106	9,401	15,256	18,860
47	1830	1830	Poles, Towers & Fixtures	4.00%		124,750	18,974	(3,615)	140,109	45,497	4,906	1,283	51,686	88,423
47	1835	1835	O/H Cond & Devices	4.00%		157,164	15,849	(2,436)	170,577	81,186	5,813	(4,127)	82,872	87,706
47	1840	1840	U/G Conduit	4.00%		154,310	3,640	(45,537)	112,414	68,209	4,069	(12,692)	59,587	52,827
47	1845	1845	U/G Cond & Devices	4.00%		317,894	16,418	1,399	335,710	165,803	12,163	(12,379)	165,587	170,123
47	1849	1850	Line Transfomers	4.00%		252,332	10,440	0	262,772	131,786	9,370	(4)	141,151	121,621
47	1855	1855	Services (OH and UG)	4.00%		51,542	3,538	50,189	105,268	23,630	3,798	27,915	55,342	49,926
47	1860	1860	Meters	4.00%		39,768	3,097	(26,439)	16,426	19,815	1,461	(22,156)	(880)	17,306
47	1862	1860	Smart Meters	6.67%		9,777	18,285	0	28,061	1,629	3,116	0	4,746	23,316
			Subtotal Distribution Assets			1,276,798	118,479	(41,453)	1,353,824	586,633	48,561	(27,008)	608,186	745,638
General Plant Assets														
13	1870	1870	Leased Property	2.50%		575	0	0	575	575	0	0	575	0
47	1908	1908	Building & Fixtures - Head office	2.00%		27,217	4,538	14,300	46,054	879	919	4,653	6,451	39,603
13	1910	1910	Leasehold Improvements	16.67%	2	2,171	0	(2,171)	0	1,664	89	(1,753)	(0)	0
8	1915	1915	Office Equipment	10.00%		6,933	12	(1,232)	5,712	3,452	476	(1,753)	2,175	3,538
10	1920	1920	Computer hardware	20.00%		16,943	1,211	0	18,154	12,490	1,791	(0)	14,282	3,873
12	1925	1925	Computer Software	33.33%		15,597	2,948	0	18,545	12,712	2,383	0	15,095	3,449
10	1930	1930	Transportation	16.67%	2	21,577	2,604	(1,386)	22,795	13,360	2,424	(1,472)	14,312	8,483
8	1935	1935	Stores Equipment	10.00%		652	0	(464)	187	592	4	(407)	189	(2)
8	1940/1945	1940	Tools, Shop & Garage	10.00%		5,946	415	(19)	6,342	4,066	363	(18)	4,412	1,931
8	1955	1955	Communication Equipment	14.29%	2	1,877	252	0	2,129	597	193	(1)	789	1,340
8	1960	1960	Miscelleneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	1980	System Supervisory Equip	6.67%		18,342	651	0	18,993	10,358	1,034	0	11,392	7,601
47	1990	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
12	1961	1925	Process Re-engineering	33.33%		1,179	614	0	1,793	571	424	0	996	797
			Subtotal General Plant Assets			119,008	13,244	9,028	141,280	61,318	10,100	(750)	70,668	70,612
Other Capital														
47	2005	2005	Prop. Under Capital Lease-Addiscott	4.00%		0	18,280	0	18,280	0	731	0	731	17,549
			Subtotal Other Capital Assets			0	18,280	0	18,280	0	731	0	731	17,549
			Total Assets Before Contributed Capital	n/a		1,395,807	150,003	(32,426)	1,513,384	647,951	59,392	(27,757)	679,585	833,799
47	1995	1995	Contributed Capital	varies		(260,464)	(22,889)	0	(283,353)	(52,097)	(10,630)	15	(62,712)	(220,641)
			NET DISTRIBUTION ASSETS			1,135,342	127,114	(32,426)	1,230,031	595,853	48,762	(27,742)	616,873	613,158

NOTES:

1) Depreciation was recorded on land rights in prior years including 2009. This was removed in 2010 as it was determined that no depreciation should be applied.
2) More then one asset type in the class with different useful lives. Depreciation rate shown is based on the average useful life
3) Review of account balances concluded that a number of accounts required reclassification. These reclassifications were included in this column

FIXED ASSET CONTINUITY SCHEDULE (000's)
YEAR: 2011
CGAAP

						COST				ACCUMULATIVE DEPRECIATION				
CCA Class	**PS GL Account**	**GL account to map**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Opening Balance**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Net Book Value (000's**
Distribution Assets														
47	1610	1610	Hydro One TS - Contributed Capital	4.00%		0	609	0	609	0	29	0	29	580
n/a	1805/1905	1805	Land	0		10,386	493	0	10,879	0	0	0	0	10,879
CEC	1806/1906	1806	Land Rights	0		731	30	0	761	0	0	0	0	761
47	1808	1808	Building & Fixtures	2.00%		7,171	154	0	7,325	1,238	143	0	1,381	5,945
47	1810	1810	Major spare parts (New 2008)	0		8,404	780	0	9,184	0	440	0	440	8,744
47	1815	1815	Transformer Stations	2.50%		121,677	4,918	0	126,595	31,601	3,071	0	34,671	91,923
47	1820	1820	Distribution Stations	3.33%		34,116	2,648	0	36,764	15,256	1,094	0	16,350	20,414
47	1830	1830	Poles, Towers & Fixtures	4.00%		140,109	13,557	0	153,666	51,686	5,370	0	57,057	96,609
47	1835	1835	O/H Cond & Devices	4.00%		170,577	7,384	0	177,961	82,872	6,057	0	88,929	89,032
47	1840	1840	U/G Conduit	4.00%		112,414	13,282	0	125,696	59,587	4,128	0	63,715	61,980
47	1845	1845	U/G Cond & Devices	4.00%		335,710	14,625	0	350,335	165,587	12,080	0	177,667	172,668
47	1849	1850	Line Transfomers	4.00%		262,772	12,677	0	275,449	141,151	9,267	0	150,419	125,031
47	1855	1855	Services (OH and UG)	4.00%		105,268	4,941	0	110,209	55,342	3,852	0	59,194	51,015
47	1860	1860	Meters	4.00%		16,426	4,170	(2,392)	18,204	(880)	803	(1,877)	(1,954)	20,158
47	1862	1860	Smart Meters	6.67%		28,061	22,970	0	51,031	4,746	3,754	0	8,499	42,532
			Subtotal Distribution Assets			1,353,824	103,237	(2,392)	1,454,668	608,186	50,088	(1,877)	656,397	798,271
General Plant Assets														
13	1870	1870	Leased Property	2.50%		575	0	0	575	575	0	0	575	0
47	1908	1908	Building & Fixtures - Head office	2.00%		46,054	151	0	46,205	6,451	481	0	6,933	39,272
13	1910	1910	Leasehold Improvements	16.67%	1	0	0	0	0	(0)	0	0	(0)	0
8	1915	1915	Office Equipment	10.00%		5,712	100	0	5,813	2,175	477	0	2,652	3,161
10	1920	1920	Computer hardware	20.00%		18,154	1,229	0	19,384	14,282	1,520	0	15,801	3,583
12	1925	1925	Computer Software	33.33%		18,545	6,118	0	24,662	15,095	4,055	0	19,150	5,512
10	1930	1930	Transportation	16.67%	1	22,795	1,145	(1,767)	22,173	14,312	2,531	(1,748)	15,096	7,078
8	1935	1935	Stores Equipment	10.00%		187	0	0	187	189	(0)	0	189	(2)
8	1940/1945	1940	Tools, Shop & Garage	10.00%		6,342	559	0	6,901	4,412	356	0	4,768	2,133
8	1955	1955	Communication Equipment	14.29%	1	2,129	279	0	2,408	789	212	0	1,001	1,407
8	1960	1960	Miscelleneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	1980	System Supervisory Equip	6.67%		18,993	450	0	19,443	11,392	1,022	0	12,414	7,029
47	1990	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
12	1961	1925	Process Re-engineering	33.33%		1,793	(1,793)	0	0	996	(991)	0	5	(5)
			Subtotal General Plant Assets			141,280	8,238	(1,767)	147,751	70,668	9,663	(1,748)	78,583	69,168
Other Capital														
47	2005	2005	Prop. Under Capital Lease-Addiscott	4.00%		18,280	0	0	18,280	731	731	0	1,462	16,818
			Subtotal Other Capital Assets			18,280	0	0	18,280	731	731	0	1,462	16,818
			Total Assets Before Contributed Capital	n/a		1,513,384	111,475	(4,159)	1,620,700	679,585	60,482	(3,625)	736,443	884,257
47	1995	1995	Contributed Capital	varies		(283,353)	(23,545)	0	(306,898)	(62,712)	(11,839)	0	(74,551)	(232,347)
			NET DISTRIBUTION ASSETS			1,230,031	87,930	(4,159)	1,313,802	616,873	48,643	(3,625)	661,891	651,911

NOTES:

1) More then one asset type in the class with different useful life. Depreciation rate shown is based on an average useful life

FIXED ASSET CONTINUITY SCHEDULE ($000's)
YEAR: 2011
MIFRS

					COST				ACCUMULATIVE DEPRECIATION				
CCA Class	**GL account**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Opening Balance (3)**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Opening Balance (3)**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Net Book Value (000's**
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	4.00%		0	609	0	609	0	29	0	29	580
n/a	1805	Land	0		10,386	581	0	10,968	0	0	0	0	10,968
CEC	1806	Land Rights	0		731	35	0	766	0	0	0	0	766
47	1808	Building & Fixtures	2.50%		5,933	187	0	6,120	0	191	0	191	5,929
47	1810	Major spare parts	0		8,404	780	0	9,184	0	0	0	0	9,184
47	1815	Transformer Stations	2.50%	1	90,076	4,906	0	94,982	0	4,970	(19)	4,951	90,031
47	1820	Distribution Stations	3.33%	1	18,860	2,667	0	21,527	0	2,079	0	2,079	19,448
47	1830	Poles, Towers & Fixtures	2.50%		88,423	12,676	(186)	100,913	0	2,331	0	2,331	98,581
47	1835	O/H Cond & Devices	2.50%		87,706	6,584	(1)	94,289	0	2,776	(171)	2,605	91,684
47	1840	U/G Conduit	2.50%		52,827	10,547	0	63,374	0	1,081	0	1,081	62,293
47	1845	U/G Cond & Devices	2.22%		170,123	15,516	(353)	185,286	0	5,021	218	5,240	180,046
47	1850	Line Transformers	2.92%	1	121,621	12,598	(1,172)	133,047	0	5,782	27	5,809	127,238
47	1855	Services (OH and UG)	3.25%	2	49,926	4,007	0	53,933	0	4,469	0	4,469	49,464
47	1860	Meters	5.33%	2	17,306	3,144	(515)	19,936	0	1,103	(2)	1,101	18,835
47	1860	Smart Meters	6.67%		23,316	23,220	0	46,536	0	3,735	0	3,735	42,801
		Subtotal Distribution Assets	n/a		745,638	98,058	(2,226)	841,470	0	33,566	54	33,620	807,850
General Plant Assets													
13	1870	Leased Property	6.25%		0	0	0	0	0	0	0	0	0
47	1908	Building & Fixtures - Head office	2.00%	1	39,603	282	0	39,884	0	919	0	919	38,966
13	1910	Leasehold Improvements	6.25%		0	0	0	0	0	0	0	0	0
8	1915	Office Equipment	10.00%		3,538	117	0	3,654	0	473	(10)	462	3,192
10	1920	Computer hardware	20.00%	1	3,873	1,227	0	5,100	0	1,568	0	1,568	3,532
12	1925	Computer Software	25.00%		4,247	4,503	0	8,750	0	2,137	16	2,153	6,597
10	1930	Transportation	8.33%	1	8,483	1,133	(25)	9,590	0	1,267	(74)	1,193	8,397
8	1935	Stores Equipment	10.00%		(2)	(2)	0	(4)	0	(0)	(1)	(2)	(2)
8	1940	Tools, Shop & Garage	10.00%		1,931	597	0	2,528	0	371	6	378	2,150
8	1955	Communication Equipment	25.00%	2	1,340	278	0	1,618	0	398	0	398	1,220
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	6.67%		7,601	512	(13)	8,099	0	1,452	30	1,482	6,617
47	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		70,612	8,647	(39)	79,220	0	8,584	(33)	8,551	70,668
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	0	731	0	731	16,818
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	0	731	0	731	16,818
		Total Assets Before Contributed Capital	n/a		833,799	106,705	(2,265)	938,239	0	42,882	21	42,902	895,336
47	1995	Contributed Capital	varies		(220,641)	(23,754)	516	(243,879)	0	(7,383)	(1,056)	(8,439)	(235,441)
		NET DISTRIBUTION ASSETS	n/a		613,158	82,951	(1,749)	694,360	0	35,499	(1,036)	34,462	659,898

NOTES:

(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.

(2) This is the average deprecation rate of the subclasses of assets within the asset group

(3) In accordance with IFRS the MIFRS opening cost balance in the transitional year (2011) shall be the net book value from the prior year closing CGAAP balance(2010).

FIXED ASSET CONTINUITY SCHEDULE ($000's)
YEAR: 2012
MIFRS

CCA Class	GL account	Detail Asset Class	Depreciation Rate	Notes	COST Opening Balance	COST Additions	COST Disposals/ Adjustments	COST Closing Balance	ACCUMULATIVE DEPRECIATION Opening Balance	ACCUMULATIVE DEPRECIATION Additions	ACCUMULATIVE DEPRECIATION Disposals/ Adjustments	ACCUMULATIVE DEPRECIATION Closing Balance	Net Book Value (000's
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	4.00%		609	0	0	609	29	32	0	61	548
n/a	1805	Land	0		10,968	0	0	10,968	0	0	0	0	10,968
CEC	1806	Land Rights	0		766	39	0	805	0	0	0	0	805
47	1808	Building & Fixtures	2.50%		6,120	6	0	6,126	191	196	0	387	5,739
47	1810	Major spare parts	0		9,184	0	0	9,184	0	0	0	0	9,184
47	1815	Transformer Stations	2.50%	1	94,982	2,115	0	97,097	4,951	4,299	0	9,249	87,848
47	1820	Distribution Stations	3.33%	1	21,527	298	0	21,825	2,079	1,165	0	3,245	18,580
47	1830	Poles, Towers & Fixtures	2.50%		100,913	11,179	(186)	111,906	2,331	2,637	(4)	4,965	106,941
47	1835	O/H Cond & Devices	2.50%		94,289	11,888	(1)	106,176	2,605	3,062	0	5,667	100,509
47	1840	U/G Conduit	2.50%		63,374	4,271	0	67,645	1,081	1,257	0	2,337	65,308
47	1845	U/G Cond & Devices	2.22%		185,286	24,556	(353)	209,489	5,240	5,547	(6)	10,781	198,708
47	1850	Line Transformers	2.92%	1	133,047	13,542	(1,172)	145,417	5,809	6,266	(32)	12,043	133,374
47	1855	Services (OH and UG)	3.25%	2	53,933	3,697	0	57,630	4,469	3,233	0	7,702	49,928
47	1860	Meters	5.33%	2	19,936	2,556	(85)	22,407	1,101	1,159	0	2,260	20,147
47	1860	Smart Meters	6.67%		46,536	759	0	47,295	3,735	3,417	0	7,152	40,143
		Subtotal Distribution Assets	n/a		841,470	74,906	(1,797)	914,579	33,620	32,270	(42)	65,848	848,731
General Plant Assets													
13	1870	Leased Property	6.25%		0	0	0	0	0	0	0	0	0
47	1908	Building & Fixtures - Head office	2.00%	1	39,884	1,513	0	41,397	919	939	0	1,858	39,540
13	1910	Leasehold Improvements	6.25%		0	0	0	0	0	0	0	0	0
8	1915	Office Equipment	10.00%		3,654	378	0	4,032	462	494	0	957	3,076
10	1920	Computer hardware	20.00%	1	5,100	3,758	0	8,858	1,568	1,679	0	3,247	5,611
12	1925	Computer Software	25.00%		8,750	1,243	0	9,993	2,153	2,626	0	4,779	5,214
10	1930	Transportation	8.33%	1	9,590	1,958	(63)	11,485	1,193	1,403	(21)	2,575	8,910
8	1935	Stores Equipment	10.00%		(4)	7	0	3	(2)	(0)	0	(2)	5
8	1940	Tools, Shop & Garage	10.00%		2,528	712	0	3,240	378	422	0	799	2,441
8	1955	Communication Equipment	25.00%	2	1,618	336	0	1,954	398	394	0	792	1,162
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	6.67%		8,099	580	(13)	8,666	1,482	963	(4)	2,441	6,226
47	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		79,220	10,485	(76)	89,629	8,551	8,919	(25)	17,445	72,184
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	731	733	0	1,464	16,085
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	731	733	0	1,464	16,085
		Total Assets Before Contributed Capital	n/a		938,239	85,391	(1,873)	1,021,757	42,902	41,922	(67)	84,757	937,000
47	1995	Contributed Capital	varies		(243,879)	(15,098)	516	(258,461)	(8,439)	(8,004)	10	(16,432)	(242,029)
		NET DISTRIBUTION ASSETS	n/a		694,360	70,293	(1,357)	763,296	34,462	33,918	(57)	68,325	694,971

NOTES:
(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.
(2) This is the average depreciation rate of the subclasses of assets within the asset group

FIXED ASSET CONTINUITY SCHEDULE ($000's)
YEAR: 2013
MIFRS

					COST				ACCUMULATIVE DEPRECIATION				
CCA Class	**GL account**	**Detail Asset Class**	**Depreciation Rate**	**Notes**	**Opening Balance**	**Additions**	**Disposals/ Adjustments**	**Closing Balance**	**Opening Balance**	**Additions (3)**	**Disposals/ Adjustments**	**Closing Balance**	**Net Book Value (000's**
Distribution Assets													
47	1610	Hydro One TS - Contributed Capital	4.00%		609	0	0	609	61	32	0	93	516
n/a	1805	Land	0		10,968	0	0	10,968	0	0	0	0	10,968
CEC	1806	Land Rights	0		805	41	0	846	0	0	0	0	846
47	1808	Building & Fixtures	2.50%		6,126	15	0	6,141	387	196	0	583	5,558
47	1810	Major spare parts	0		9,184	0	0	9,184	0	0	0	0	9,184
47	1815	Transformer Stations	2.50%	1	97,097	75	0	97,172	9,249	4,179	0	13,429	83,743
47	1820	Distribution Stations	3.33%	1	21,825	4,021	0	25,846	3,245	1,279	0	4,524	21,323
47	1830	Poles, Towers & Fixtures	2.50%		111,906	9,861	0	121,767	4,965	3,038	0	8,003	113,764
47	1835	O/H Cond & Devices	2.50%		106,176	17,940	(26)	124,090	5,667	3,669	(51)	9,285	114,806
47	1840	U/G Conduit	2.50%		67,645	2,957	(155)	70,447	2,337	1,343	0	3,680	66,767
47	1845	U/G Cond & Devices	2.22%		209,489	37,290	(700)	246,079	10,781	6,570	(198)	17,152	228,927
47	1850	Line Transformers	2.92%	1	145,417	11,683	(1,805)	155,295	12,043	6,809	(577)	18,274	137,020
47	1855	Services (OH and UG)	3.25%	2	57,630	3,789	0	61,419	7,702	3,339	0	11,041	50,378
47	1860	Meters	5.33%	2	22,407	3,195	0	25,602	2,260	1,424	0	3,684	21,918
47	1860	Smart Meters	6.67%		47,295	717	0	48,012	7,152	3,481	0	10,633	37,379
		Subtotal Distribution Assets	n/a		914,579	91,584	(2,686)	1,003,477	65,848	35,359	(826)	100,381	903,097
General Plant Assets													
13	1870	Leased Property	6.25%		0	0	0	0	0	0	0	0	0
47	1908	Building & Fixtures - Head office	2.00%	1	41,397	284	0	41,681	1,858	958	0	2,816	38,866
13	1910	Leasehold Improvements	6.25%		0	0	0	0	0	0	0	0	0
8	1915	Office Equipment	10.00%		4,032	29	0	4,061	957	510	0	1,466	2,595
10	1920	Computer hardware	20.00%	1	8,858	2,014	0	10,872	3,247	2,114	0	5,361	5,510
12	1925	Computer Software	25.00%		9,993	4,405	0	14,398	4,779	2,737	0	7,516	6,882
10	1930	Transportation	8.33%	1	11,485	2,893	(131)	14,247	2,575	1,806	(17)	4,364	9,883
8	1935	Stores Equipment	10.00%		3	0	0	3	(2)	1	0	(2)	4
8	1940	Tools, Shop & Garage	10.00%		3,240	538	0	3,778	799	472	0	1,272	2,506
8	1955	Communication Equipment	25.00%	2	1,954	65	0	2,019	792	420	0	1,213	806
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0	0	0	0
47	1980	System Supervisory Equip	6.67%		8,666	624	0	9,290	2,441	975	0	3,416	5,874
47	1990	Other Tangible property	20.00%		0	0	0	0	0	0	0	0	0
		Subtotal General Plant Assets	n/a		89,629	10,852	(131)	100,350	17,445	9,994	(17)	27,422	72,927
Other Capital													
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		17,549	0	0	17,549	1,464	731	0	2,195	15,354
		Subtotal Other Capital Assets	n/a		17,549	0	0	17,549	1,464	731	0	2,195	15,354
		Total Assets Before Contributed Capital	n/a		1,021,757	102,436	(2,817)	1,121,376	84,757	46,084	(843)	129,998	991,378
47	1995	Contributed Capital	varies		(258,461)	(17,734)	525	(275,671)	(16,432)	(8,763)	10	(25,185)	(250,486)
		NET DISTRIBUTION ASSETS	n/a		763,296	84,702	(2,292)	845,705	68,325	37,321	(833)	104,813	740,892

NOTES:
(1) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.
(2) This is the average depreciation rate of the subclasses of assets within the asset group
(3) Accumulated Depreciation for 2013 includes a full year depreciation on new 2013 additions

GREEN ENERGY ACT PLAN OVERVIEW AND DIRECT BENEFITS CALCULATION

Summary and Introduction

On September 9, 2009, the *Green Energy and Green Economy Act, 2009* ("GEA") was enacted. The GEA amended a number of Acts and Regulations including the *Ontario Energy Board Act, 1998* ("OEB Act") and the *Electricity Act 1998* ("Electricity Act") to enable distributors to do renewable generation connections and smart grid development.

The GEA requires that each licensee develop a GEA Plan. PowerStream is submitting its GEA Plan in accordance with the OEB "*Distribution System Plans - Filing Under Deemed Conditions of Licence*" ("Filing Requirements DSP"), EB-2009-0397 issued March 25, 2010. As part of these guidelines, a materiality threshold test based on a distributor's planned projects related to the connection of renewable generation and/or the development of smart grid is to be used to determine the type of plan to be submitted. If an LDC exceeds the materiality threshold it must file a detailed plan, otherwise a basic plan is required. The materiality threshold is described in Section II of the Filing Requirements DSP:

"*The materiality threshold is reached, for the purposes of these Filing Requirements, in either of the two following circumstances:*

> *1. The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid in any one year:*
>
> - *Are more than $100,000 and exceed 3% of the distributor's distribution rate base;*
>
>   *or*
>
> - *Exceed $5,000,000.*
>
> *2. The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid over five years:*

- *Are more than $100,000 and exceed 6% of the distributor's distribution rate base;*

or

- *Exceed $10,000,000.*

In all other circumstances, a distributor must file a Basic GEA Plan with its cost of service rate application, unless specifically exempted from filing by the Board."

PowerStream's annual and five year projected plan for both the connection of renewable generation and smart grid investments does not meet the threshold test for a detailed plan and therefore a Basic GEA Plan is filed as Exhibit B2, Tab 1, Schedule 2. The calculation of the materiality threshold is shown in the following paragraphs.

PowerStream's distribution rate base in 2010 was approximately $700.0 million. Applying the guidelines for the materiality threshold, PowerStream results are as follows:

1. Annual threshold test:

PowerStream's annual GEA planned expenditures for the plan period 2012-2016 are well below the annual threshold test of three percent of the rate base, ($21.0 million) or $5.0 million in annual investments.

2. Five year threshold test:

PowerStream's GEA planned expenditures for the five year period are well below the threshold test of six percent of the rate base ($42.0 million) or $10.0 million in investments over the period. PowerStream's total capital cost for the planned period related to the connection of renewable generation and/or the development of a smart grid amounts to $4.9 million.

PowerStream provided its Green Energy Act Basic Plan to the Ontario Power Authority ("OPA") on February 6, 2012. The OPA letter of comment is included as Appendix C in PowerStream's GEA Plan.

PowerStream's Green Energy Act Basic Plan includes capital and operating expenditures for the period 2012 through 2016.

The summary of the capital and operating expenditures is presented in the table 1 below.

Table 1: PowerStream Green Energy Act Capital and Operating Expenditures, $000's

		Actual 2010 - 2011	2012	2013	2014-2016	Total 2012-2016	Total 2010-2016
Capital							
Renewable Generation		525	756	77	155	988	1,513
Smart Grid		477	1,250	650	1,050	2,950	3,427
Total Capital		**1,002**	**2,006**	**727**	**1,205**	**3,938**	**4,940**
OM&A							
Renewable Generation		143	154	158	417	729	872
Smart Grid		462	207	230	600	1,037	1,499
Total OM&A		**605**	**361**	**388**	**1,017**	**1,766**	**2,371**

Calculation of Direct Benefits for Customers

As per the requirements from the Report of the Board "*Framework for Determining the Direct Benefits Accruing to Customers of a Distributor Under Regulation 330/09*" (EB-2009-0349, June 10, 2010), PowerStream has calculated the direct benefits accruing to PowerStream's customers over the proposed investment period.

PowerStream's Basic GEA Plan indicates that the anticipated capital investment needed to enable the connection of FIT generation amounts to $1,513,000. As per section 3.2.2.3 of the Board's Report, since PowerStream does not meet the threshold for filing a detailed GEA Plan, PowerStream has used the percentages for Expansion and Renewable Enabling Improvements (REI) investments based on Hydro One Distribution's detailed direct benefit assessment. The provisional percentages, based on the calculation by Hydro One Distribution in their Green Energy Plan (EB-2009-0096)[1], are as follows:

System Expansion – 17%

Renewable Enabling Improvements – 6%

[1] Report of the Board "Framework for Determining the Direct benefits Accruing to Customers of a Distributor under Regulation 330/09", issued June 10,2010,p.15-16

PowerStream's renewable generation connection costs comprise renewable enabling improvements only. These improvements are consistent with the Distribution System Code, section 3.3.2.

The calculation of direct benefits to PowerStream Customers is shown in Table 2 below:

Table 2: Calculation of Direct Benefits, $000's

		Actual 2010 - 2011	2012	2013	2014-2016	Total 2012-2016	Total 2010-2016
Capital spending							
WiMax Communication Network		425	280	-	-	280	705
CIS modifications for FIT		69	-	-	-	-	69
Fault Level Reduction and Station programming		30	477	77	155	709	739
Total		**525**	**756**	**77**	**155**	**988**	**1,513**
Benefits to PowerStream customers							
WiMax Communication Network	6%	26	17	-	-	17	42
CIS modifications for FIT	6%	4	-	-	-	-	4
Fault Level Reduction and Station programming	6%	2	29	5	9	43	44
Total Direct Benefits		**31**	**45**	**5**	**9**	**59**	**91**
To be recovered from Provincial rate payers		**493**	**711**	**73**	**145**	**929**	**1,422**

Relief Sought

- **Disposition of the Amounts in Deferral Accounts 2010-2011**

In this application, PowerStream is seeking a disposition of amounts relating to the deferral of renewable generation and smart grid capital and OM&A costs, spent until December 31, 2011. Summary of amounts for disposition is presented in Table 3 below.

Table 3: 2010-2011 Smart Grid and Renewable Energy Investment – Amounts for Disposition

Account	Account Descr.	% Direct benefits (OEB standard)	Total Balance in the account As of Dec. 31, 2011	Provincial recovery (2010-2011)	Balance for Disposal
1531	REI Capital	6%	$ 524,818	$ 493,329	$ 31,489
1532	REI OM&A	100%	$ 142,559	$ -	$ 142,559
Total Renewable Energy			$ 667,377	$ 493,329	$ 174,048
1534	Smart Grid - capital	100%	$ 476,808	$ -	$ 476,808
1535	Smart Grid - OM&A	100%	$ 462,016	$ -	$ 462,016
Total Smart grid			$ 938,824	$ -	$ 938,824
Total up to Dec. 31, 2011			**$ 1,606,201**	**$ 493,329**	**$ 1,112,872**

PowerStream has included the actual balances to December 31, 2011, net of the Provincial recovery amount, in the Deferral and Variance accounts for recovery. See Exhibit I, Deferral and Variance Accounts, for more details.

Rate Protection – Provincial Recovery

PowerStream requests that per Ontario Regulation 330/09, Section 3, the rate protection amount $1,422,000 be included in the calculation for recovery via the IESO protocols. As identified in Table 2 above, the direct benefits that accrue to PowerStream customers regarding renewable expenditures are $91,000 with the remaining amounts to be recovered by provincial rate payers. The funding of direct benefits will remain as deferred expenditures to be reviewed by the Board at a future date.

Funding Adder

Given the magnitude of the spending incurred to date and the ongoing work to be done regarding smart grid demonstration projects, PowerStream is applying for approval of a funding adder which will assist in the interim to fund these expenditures. The funding adder will address the plan period from 2012 – 2016 based on smart grid investments of $2,950,000 and OM&A expenditures for Smart Grid and REI of $1,766,000. The funding adder is calculated by estimating the average annual revenue requirement related to PowerStream's proposed spending, divided by the total number of forecasted customers for 2013. PowerStream calculated revenue requirement for each year of the plan and is requesting the funding adder be set for the plan period 2012-2016. Instead of changing the adder every year, PowerStream proposes to use the average rate adder of $0.20 per customer per month. PowerStream proposes this adder will be in effect for a four year period. Differences between actual spending and funding collected will be tracked in a variance account to be reviewed and approved for disposition at the end of the plan period.

YOUR CURRENT CONNECTION

Green Energy Act
Basic Plan 2012

Table of Contents

POWERSTREAM'S GEA PLAN

1 Executive Summary

In accordance with the Ontario Energy Board's filing requirements under condition of Licence, PowerStream Inc. ("PowerStream") has prepared the following Basic Green Energy Act Plan ("GEA") as part of its 2013 cost of service application. This Basic GEA Plan rationalizes PowerStream's future Renewable Generation expenditures from 2012 through 2016 by reviewing the state of PowerStream's existing distribution system, studying the current renewable generation load demand, creating a growth forecast, and developing the necessary infrastructure projects to meet the predicted renewable generation growth. The GEA Plan also addresses PowerStream's plans for smart grid spending.

Since the inception of the Ontario Power Authority's ("OPA") Feed-InTariff ("FIT") program, PowerStream's renewable generation demand has grown by over ten times from 5MW connected in 2009 to 68.4 MW connected and pending in 2011. Currently there are 1347 projects in PowerStream's territory that have applied for a contract with the OPA, of which, 379 projects or 26.9MW have been connected or are in the process of being connected.

PowerStream's distribution system is a robust network spread out over the area of eleven municipalities. Past planning and proactive infrastructure projects have resulted in a distribution network well equipped to handle renewable generation.

- The Northern region is an embedded configuration fed from Hydro One Transformer Stations. Currently there are 91 FIT/microFIT Projects connected or in the process of being connected. Hydro One Transformer Stations ("TS") TS's provide a significant amount of capacity for potential FIT customers; however there are some potential constraints due to the geographic availability of 44kV lines for larger projects.
- The Southern region is a host configuration with eleven PowerStream owned TS. There are currently 288 FIT/microFIT Projects connected or in the process of being connected with significant remaining Station Capacity. There are some limiting factors including Legacy Electronic Protections at some stations and a lack of digital communications with existing generation installations for transfer trip purposes.

Generally, both North and South PowerStream regions are in the position to accommodate the current demand of renewable generation.

Estimations based on PowerStream's renewable generation data from 2009, 2010, and 2011 indicate that the FIT program will follow two years of continued growth and then begin to drop off and stabilize. In order to accommodate and manage the renewable generation demand, PowerStream has identified four necessary expenditures for 2012-2016. The following table provides a summary of the project spending for 2010, forecasted 2011 spending, and expected 2012 to 2016 spending by PowerStream's GEA Plan.

Capital Projects	2010	2011	2012	2013	2014	2015	2016
WiMax Communication Network	$54,046	$371,057	$279,551	-	-	-	-
CIS modifications for FIT		$69,431					
Fault Level Reduction Reactor - MTS#1	-	$30,284-	$238,405	-	-	-	-
Fault Level Reduction Reactor - MTS#2	-	-	$238,405	-	-	-	-
Station Programming and Wiring	-	-	-	$77,250	$61,800	$51,500	$41,200

OM&A	2010	2011	2012	2013	2014	2015	2016
Renewable Generation OM&A	$30,753	$111,806	$153,738	$158,350	$149,716	$131,675	$135,625

Total	**$84,799**	**$582,578**	**$910,099**	**$235,600**	**$211,516**	**$183,175**	**$176,825**

2 <u>Introduction</u>

As part of the 2013 cost of service application PowerStream Inc. ("PowerStream") must file with the Ontario Energy Board a Green Energy Act Plan ("GEA Plan").

Since PowerStream's planned system investments, related to the connection of renewable generation and smart grid within the 2012 – 2016 years, are below the materiality threshold, a **Basic GEA Plan** has been filed.

PowerStream's Basic GEA Plan is intended to provide information, to the Board and interested stakeholders, regarding the readiness of PowerStream's distribution system to connect renewable generation and future expansion requirements or reinforcements necessary to accommodate renewable generation demand.

PowerStream's Basic GEA Plan covers a five year horizon from 2012 to 2016, and includes information regarding the Capital Expenditures PowerStream intends to make and any OM&A expenses PowerStream expects to incur during this time frame.

PowerStream is seeking funding for costs related to the connection of renewable generation and smart grid investments from ratepayers. PowerStream's Basic GEA Plan contains detailed costing information for specific projects for the five year horizon.

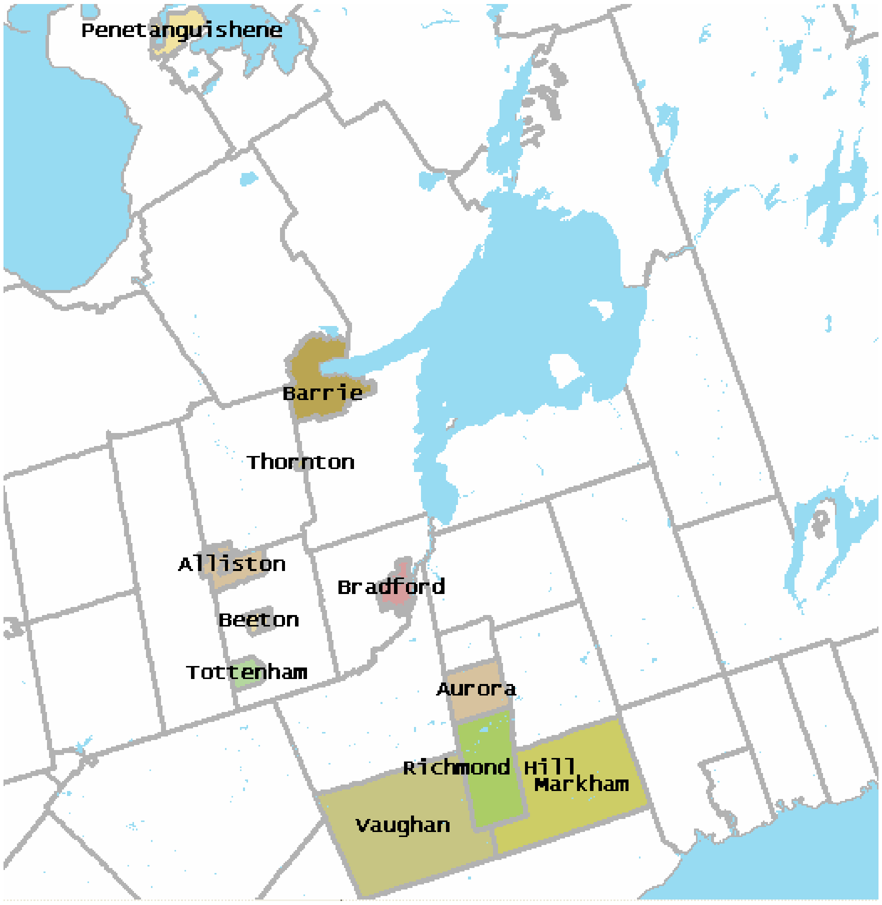
PowerStream's Basic GEA Plan contains two main elements:

1. Current assessment of PowerStream's distribution system based on a Northern and Southern region geographical context;
2. Planned development of the system to accommodate renewable generation connection based on a Northern and Southern region geographical context.

3 Current Assessment

3.1 The PowerStream Distribution System

PowerStream Inc. is the second largest municipally-owned electricity distribution company in Ontario, providing service to residential and business customers in Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Penetanguishene, Markham, Richmond Hill, Thornton, Tottenham and Vaughan.

1 
Penetanguishene
Barrie
Thornton
Alliston
Bradford
Beeton
Tottenham
Aurora
Richmond Hill
Markham
Vaughan

3.1.1 Assets

PowerStream owns and operates distribution assets valued at $950.6 million* as of December 31, 2010.

A distribution system consisting of -

Overhead circuit wires:	2,551 km
Underground cable:	4,830 km
Transformer stations:	11
Municipal substations:	55
Transformers:	40,682
Switchgear:	1,772
Poles and pole structures:	43,575

*Source: powerstream.ca

3.2 Existing Capacity for Generators

3.2.1 FIT/microFIT Data

As of November 2011, PowerStream has connected twenty-three Feed-In Tariff (FIT) and 142 MicroFIT projects for a total of 4.01MW of generation (item S3 from table). In addition, there are 214 projects, totaling 22.91MW (S4), that have been approved by PowerStream for connection and are currently being constructed. PowerStream's FIT and microFIT breakdowns are seen below:

<u>FIT Projects</u>

Item	Process Description	Project Count	Capacity (kW)
F1	Total FIT applications *received* by OPA	288	57,695
F2	Total FIT applications *approved* by OPA	120	25,506
F3	Total FIT applications *approved* by PowerStream	117	25,206
F4	Total FIT projects *connected* by PowerStream	23	3,140

MicroFIT Projects

Item	Process Description	Project Count	Capacity (kW)
µ1	Total microFIT applications *received* by OPA	1058	8,348
µ2	Total microFIT applications *approved* by OPA	369	2,401
µ3	Total microFIT applications *approved* by PowerStream	262	1,712
µ4	Total microFIT projects *connected* by PowerStream	142	870

FIT/microFIT Summary

Item	Process Description	Project Count	Capacity (kW)
S1	Total project applications *received* by OPA (F1+ µ1)	1346	66,043
S2	Total projects *connected or about to be connected* by PowerStream. (F3+ µ3)	379	26,918
S3	Total projects *connected* by PowerStream (F4+ µ4)	165	4,010
S4	Total projects approved but not yet connected by PowerStream (S2-S3)	214	22,908
S5	Remaining projects still to be connected (S1-S2)	967	39,125

PowerStream's 379 renewable generation connections (S2) account for only 28% of the 1346 total applications (S1) submitted to the OPA under the FIT and microFIT programs. Therefore, 72% of the FIT and microFIT applications received by the OPA are still in the review phase with either the OPA or PowerStream.

The 379 connected or about to be connected generators are dispersed throughout PowerStream's territory. Projects are located predominately in Markham, Richmond Hill, Barrie and Vaughan however, there are also scattered projects located in the smaller communities of Aurora, Alliston, and Bradford.

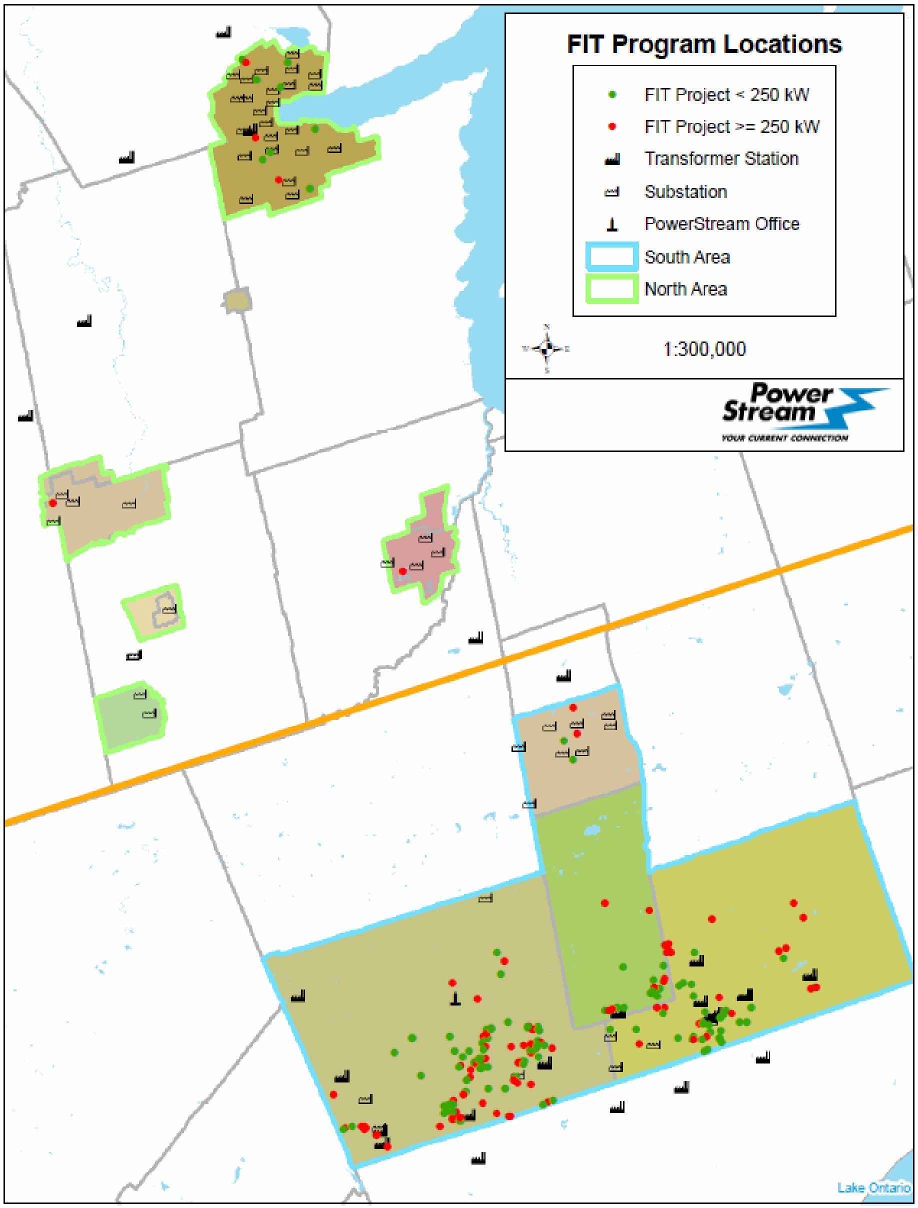
3.2.2 Connected Generators by Territory

The following table breaks down FIT and microFIT Generators by geographic region:

		FIT		microFIT	
		Projects	Generation (kW)	Projects	Generation (kW)
Northern Region	Allliston	-	-	8	67
	Barrie	11	1,648	56	407

		FIT		microFIT	
		Projects	Generation (kW)	Projects	Generation (kW)
	Beeton	-	-	4	20
	Bradford	1	250	2	12
	Penetang	-	-	2	13
	Thornton	-	-	1	10
	Tottenham	1	250	5	29
Northern Sub Total		13	2,148	78	558
Southern Region	Aurora	4	459	15	116
	Markham	33	5,908	73	467
	Richmond Hill	13	3,188	41	266
	Vaughan	54	13,503	55	305
Southern Sub Total		104	23,058	184	1,154
Total Projects		117	25,206	262	1,712

The following illustration identifies FIT Generator installations relative to PowerStream's territory:



* Penetanguishene currently has no FIT generation and is omitted from the illustration above.

3.2.3 North Distribution System Assessment

PowerStream North consists of the municipalities of Alliston, Barrie, Beeton, Bradford West Gwillimbury, Penetanguishene, Thornton, and Tottenham. The North area contains forty-two Municipal Stations and six Hydro One owned Transformer Stations ("TS"). Due to the size of FIT projects, most are connected directly to Hydro One TS's.

Station Capacity:

PowerStream North currently has ninety-one FIT and microFIT projects that are connected or about to be connected to four of Hydro One's TS's, resulting in the following TS allocation and capacity:

Connected Transformer Station Hydro One Owned	TS Thermal Capacity (kW) (Max Rating)	Hydro One Allocated Capacity (kW)	PowerStream Allocated Capacity (kW)	Estimated Remaining TS Capacity (kW)
EVERETT TS	63,800	750	250	62,800
HOLLAND TS	96,600	1,360	250	95,000
MIDHURST TS	119,400	43,800	272	75,300
BARRIE TS	68,500	36,230	1408	30,900

Maximum North Capacity (kW)	264,000 Max*

*Note: PowerStream North's Potential Capacity incorporates upstream Hydro One TS Capacity. Therefore, the stated capacity is shared with Hydro One on a first come, first serve basis.

Limiting Factors:

Customer accessibility to Hydro One Transformer Stations in and around the Barrie area provides a significant attraction for FIT projects.

There are potential access constraints for larger projects connecting in the North. Typically, PowerStream will require projects greater than 1MW to connect directly to 44kV lines which are only available in specific locations throughout the Northern region.

System Challenges and Opportunities:

Powerstream requires FIT projects greater than 250kW to maintain communication with PowerStream's control room via a WiMax Communication Network for the purpose of Data Monitoring and Generator Transfer Trip. There are currently seven FIT projects greater than 250kW that will require connection to the WiMax Communication Network. They are located in Barrie (five), Tottenham (one), and Bradford (one).

In order to accommodate the Northern FIT Generators, PowerStream began construction of two new WiMax Communication towers located in Barrie and Alliston. Construction of the Barrie tower was completed in 2011 and the Alliston tower will be constructed in 2012. The WiMax project is discussed further in section 3.3.1 and expanded project details can be found in Appendix B.

North Assessment summary

PowerStream North has the existing Station Capacity and Distribution infrastructure planned or in place to accommodate the current demand for Renewable Energy projects.

3.2.4 South Distribution System Assessment

PowerStream South consists of the municipalities of Aurora, Markham, Richmond Hill, and Vaughan. The South area contains eleven PowerStream owned Transformer Stations and six Hydro One Transformer Stations.

Station Capacity:

PowerStream South currently has 288 FIT and microFIT projects that have been connected or about to be connected, resulting in the following TS allocation and capacity:

PowerStream Owned TS:

Connected Transformer Station	TS Capacity (kW) (Max Rating)	Current Load from FIT projects (kW)	Remaining TS Capacity (kW)
PowerStream Owned			
VAUGHAN MTS #1	13,600	4,100	9,500
VAUGHAN MTS #1 E	97,500	2,000	95,500
VAUGHAN MTS #2	10,200	3,100	7,100
VAUGHAN MTS #3	125,500	5,300	120,200
RHMTS#1	12,000	1,600	10,400
RHMTS#2	48,000	1,200	46,800
MARKHAM MTS #1	1,340	1,340	0
MARKHAM MTS #2	1,380	1,380	0
MARKHAM MTS #3	2,500	500	2,000
MARKHAM MTS #3 E	2,900	900	2,000
MARKHAM MTS #4	97,500	700	96,800

Max PowerStream South Capacity (kW)	390,300 Max

Hydro One Owned TS:

Connected Transformer Station	TS Thermal Capacity (kW) (Max Rating)	Hydro One Allocated Capacity (kW)	PowerStream Allocated Capacity (kW)	Remaining TS Capacity (kW)
Hydro One Owned				
AGINCOURT TS	59,600	15,500	0	44,100
ARMITAGE TS DESN 1	119,600	9,700	500	109,400
BUTTONVILLE TS	72,800	8,800	1,800	62,200
FINCH TS DESN 1	40,700	7,650	250	32,800
LESLIE TS DESN 1	18,400	5,200	0	13,200
WOODBRIDGE TS DESN1	23,600	2,100	500	21,000

Maximum Hydro One South Capacity (kW)	282,700 Max*

*Note: PowerStream South's Potential Capacity incorporates upstream Hydro One TS Capacity. Therefore, the stated capacity is shared with Hydro One on a first come, first serve basis.

Limiting Factors:

Two Transformer Stations in Markham (Markham MST #1 and #2) currently have high fault levels due to their close proximity with Parkway TS, which limit the number of generators that the stations can accommodate. For 2012, PowerStream will be installing Fault Level Reactors to increase the overall capacity of these stations. Project details are discussed further in Appendix B.

System challenges and opportunities:

PowerStream requires FIT projects greater than 250kW to maintain communication with PowerStream's control room via a WiMax Communication Network for the purpose of Data Transfer and Generator Tripping. There are currently forty-seven FIT projects greater than 250kW that require connection to the WiMax Communication Network in PowerStream's south region. PowerStream South's Communication infrastructure construction upgrades began in 2011 and are scheduled to be completed in 2012. Further project details are discussed in section 3.3.1 and Appendix B.

South Assessment summary:

PowerStream South has the existing Station Capacity and Distribution infrastructure planned or in place to accommodate the current demand for Renewable Energy projects.

3.2.5 Existing Capacity Summary

Maximum Remaining Capacity for Renewable Resources:

Max South Capacity (kW) (PowerStream TS)	390,300
Max South Capacity (kW) (HONI TS)	282,700
Max North Capacity (kW) (HONI TS)	264,000
PowerStream's Maximum Remaining Capacity for Renewable Generation (kW)	937,000

A detailed list of Renewable generation load by Station Feeder is outlined in Appendix A.

3.3 Existing Renewable Generation Expenditures

The following tables summarize the Renewable Generation expenditures incurred in 2010 and 2011, or budgeted for 2012-2013.

Capital Projects	2010	2011	2012	2013	Total
WiMax Communication Network	$54,046	$371,057	$279,551	-	$704,654
CIS modifications for FIT	-	69,431	-	-	$69,431
Fault Level Reduction Reactor - MTS#1	-	30,284	$238,405	-	$268,689
Fault Level Reduction Reactor - MTS#2	-	-	$238,405	-	$238,405
Station Programming and Wiring	-	-	-	$77,250	$77,250
Total Capital	**$54,046**	**$470,772**	**$756,361**	**$77,250**	**$1,358,429**

OM&A	2010	2011	2012	2013	Total
Renewable Generation OM&A	$30,753	$111,806	$153,738	$158,350	$454,647

Total	$84,799	$582,578	$910,099	$235,600	**$1,813,076**

Individual project summaries are provided in the following sections.

3.3.1 Project Summaries

The following tables provide summaries of PowerStream's Projects between 2010 and 2013. Expanded Project details are available in Appendix B.

<table>
<tr><th>Year</th><th>Class</th><th>Project Title</th><th>Location</th><th>Expenditure</th></tr>
<tr><td rowspan="3">2010</td><td rowspan="3">Capital Project</td><td>WiMax - Proof of Concept</td><td>Markham</td><td>$54,046</td></tr>
<tr><td colspan="3"><u>Project Scope</u>: Construct a WiMax proof of concept model to confirm the functionality and reliability of WiMax for communicating with renewable generation facilities .</td></tr>
<tr><td colspan="3"><u>Justification:</u> Confirm technology and utility application prior to investing in a WiMax Network.</td></tr>
</table>

<table>
<tr><th>Year</th><th>Class</th><th>Project Title</th><th>Location</th><th>Expenditure</th></tr>
<tr><td rowspan="3">2011</td><td rowspan="3">Capital Project</td><td>WiMax Communication Network - Yr 1</td><td>Vaughan, Markham, Barrie</td><td>$371,057</td></tr>
<tr><td colspan="3"><u>Project Scope</u>: Establish a WiMax Communication Network for FIT Generators with 3 nodes located in Vaughan, Markham, and Barrie (Year 1).</td></tr>
<tr><td colspan="3"><u>Justification:</u> The WiMax Communication Network is required to provide communications for the remote trip and monitoring of FIT generators 250kW and larger in the PowerStream service area.</td></tr>
</table>

Year	Class	Project Title	Location	Expenditure
2011	Capital Project	**Customer Information System Modifications for FIT**	Vaughan	$69,431
		Project Scope: Update the Customer Information System ("CIS") to accurately track and bill renewable generators.		
		Justification: The existing CIS was not capable of managing Renewable Generation projects and upgrades were required to enable CIS to oversee generator sizes, configuration types, contract dates and billing rates.		

Year	Class	Project Title	Location	Expenditure
2011	Capital Project	**Fault Level Reduction Reactor - MTS#1**	Markham MTS#1	$30,284
		Project Scope: Contract Kinectrics Inc to perform a Feasibility/Impact Study for the implementation of a Series Reactor at Markham TS#1.		
		Justification: Renewable Generation Capacity at Markham TS#1 is limited due to high available fault levels at the station. Implementing a Series Reactor will increase the available station capacity however; an Engineering study is required to confirm there will be no ill effects to the distribution grid.		

Year	Class	Project Title	Location	Expenditure
2012	Capital Project	**WiMax Communication Network – Yr 2**	Aurora, Alliston	$279,551
		Project Scope: Establish a WiMax Communication Network for FIT Generators with two nodes located in Aurora and Alliston. (Year 2).		
		Justification: The WiMax Communication Network is required to provide communications for the remote trip and monitoring of FIT generators 250kW and larger in the PowerStream service area.		

Year	Class	Project Title	Location	Expenditure
2012	Capital Project	**Fault Level Reduction Reactor - MTS#1**	Markham MTS#1	$238,405
		Project Scope: Install Fault Level Reduction Reactor to improve fault current levels at Markham TS#1 in order to accommodate FIT Generator connections.		
		Justification: The available fault level at Markham TS#1 is high due to the close proximity of Parkway TS. Installing a current limiting reactor stack in series with the bus tie circuit breaker will effectively reduce the short circuit current to manageable levels.		

<table>
<tr><th>Year</th><th>Class</th><th>Project Title</th><th>Location</th><th>Expenditure</th></tr>
<tr><td rowspan="3">2012</td><td rowspan="3">Capital Project</td><td>Fault Level Reduction Reactor - MTS#2</td><td>Markham MTS#2</td><td>$238,405</td></tr>
<tr><td colspan="3"><u>Project Scope</u>: Install Fault Level Reduction Reactor to improve fault current levels at Markham TS#2 in order to accommodate FIT Generator connections.</td></tr>
<tr><td colspan="3"><u>Justification:</u> The available fault level at Markham TS#2 is high due to the close proximity of Parkway TS. Installing a current limiting reactor stack in series with the bus tie circuit breaker will effectively reduce the short circuit current to manageable levels.</td></tr>
</table>

<table>
<tr><th>Year</th><th>Class</th><th>Project Title</th><th>Location</th><th>Expenditure</th></tr>
<tr><td rowspan="3">2013</td><td rowspan="3">Capital Project</td><td>Station Programming and Wiring</td><td>Buttonville TS and Others</td><td>$77,250</td></tr>
<tr><td colspan="3"><u>Project Scope</u>: Feeder Protection upgrade at Buttonville TS and PowerStream TS's to accommodate Generator transfer trip scheme.</td></tr>
<tr><td colspan="3"><u>Justification:</u> Existing Feeder Protection designs within Stations are not configured to output a trip command to the remote tripping scheme. Buttonville TS will require relay upgrades and several PowerStream TS's require communication wiring upgrades.</td></tr>
</table>

<table>
<tr><th>Year</th><th>Class</th><th>Project Title</th><th>Location</th><th>Year</th><th>Expense</th></tr>
<tr><td rowspan="6">2010
2011
2012
2013</td><td rowspan="6">OM&A</td><td rowspan="4">Renewable Generation OM&A</td><td rowspan="4">Head Office and Field</td><td>2010</td><td>30,753</td></tr>
<tr><td>2011</td><td>$111,806</td></tr>
<tr><td>2012</td><td>$153,738</td></tr>
<tr><td>2013</td><td>$158,350</td></tr>
<tr><td colspan="4"><u>Scope</u>: The Renewable Generation program is managed by one full time Engineer who dedicates 25% of his time. Two full time contract Engineers coordinate customer applications, perform Connection Impact Assessments, and approve project designs. Service Layouts and Metering are handled by existing positions through varying degrees of effort.</td></tr>
<tr><td colspan="4"><u>Justification:</u> Generator Designs must be reviewed and approved by PowerStream Engineering prior to connection to ensure quality and safety.</td></tr>
</table>

4 Planned Development

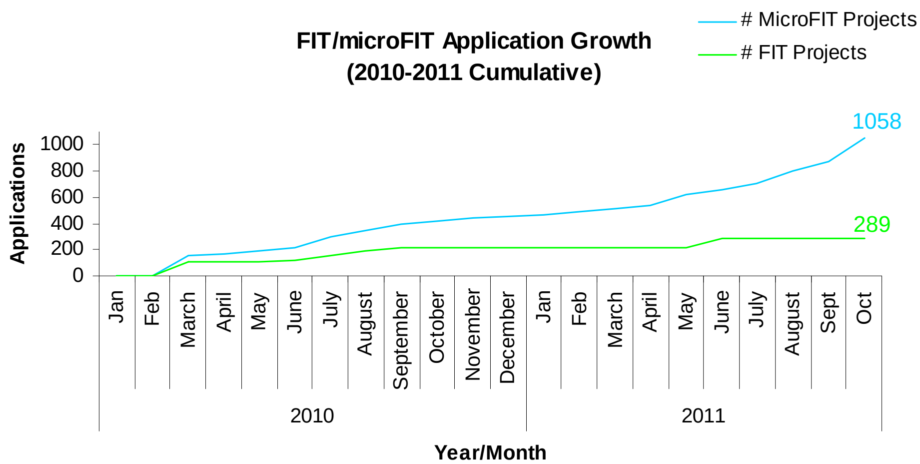
PowerStream has projected Renewable Generation growth for 2012-2016 based on existing FIT data and industry expectations. In preparation for this future demand, a corresponding five year infrastructure plan has been developed to accommodate Generator growth. The following sections outline projected growth, planned projects, and implementation timing.

4.1 Projected Renewable Generation Growth

Renewable Generation growth for 2012-2016 has been estimated based on PowerStream's existing FIT/MicroFIT data from 2010-2011 and the expected evolution of the OPA's FIT program.

4.1.1 2010/2011 FIT MicroFIT Data

As of November 2011, PowerStream customer FIT and microFIT submissions to the OPA have totaled 1346 applications, grossing over 66MW of potential generation. The 2010-2011 application data below illustrates a strong average monthly growth rate to date.

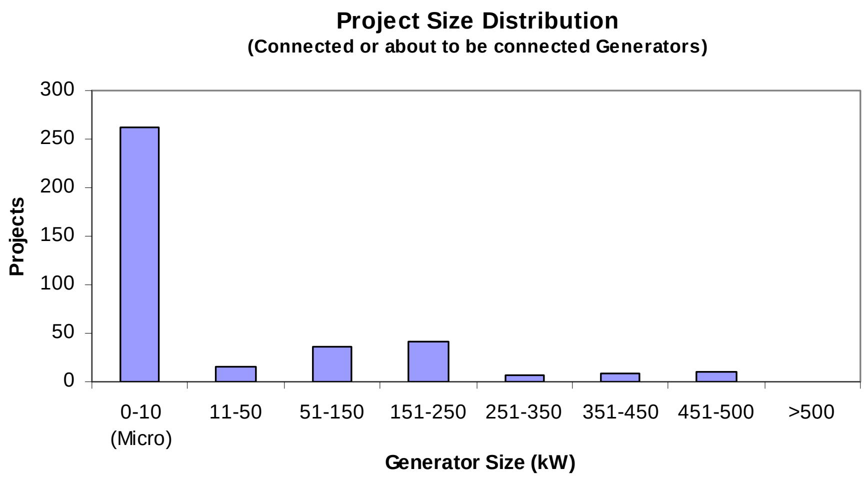


Source: OPA LDC Portal

Although Renewable Generation installations in PowerStream's service area have been increasing, they are mainly focused on roof top solar applications. Renewable Generation by source is broken down in the following table:

Fuel Type	FIT	MicroFIT
Solar photovoltaic - Roof Top	288	1032
Solar photovoltaic - Ground Mount	1	22
Wind	0	2
Bio Gas	0	1
Biomass	0	1

The data also shows that generator applications focus mostly on MicroFIT, with less than a quarter of the applications focused on FIT. The project size distribution is seen below which illustrates limited interest in projects over 250kW and no interest in projects greater than 500kW.



The balance between residential and commercial applications between 2010 and 2011 is another notable trend. In 2011, more applications came from commercial businesses than home owners indicating that the early 'environmentally conscious' adoption phase is nearing its end.

PowerStream's regions are predominantly made up of urban areas which are ideal for roof top solar, but less attractive larger ground mount solar or wind installations. Therefore, because there is limited potential for major wind or other ground mount projects, and economically viable roof tops are finite, installations are expected to become constrained over the next five years. This assumes that FIT program pricing continues to provide an eleven year payback for commercial rooftop installations.

4.1.2 Program Progression

In order to create a five year projection of FIT growth in PowerStream's distribution area, some assumptions were made regarding the program's future direction.

The OPA's FIT Program has been relatively unchanged since its inception in 2009. Following three years of Renewable Generation experience, valuable insight has been gained into the public demand for green energy and potential capacity constraints caused by the distribution grid. Based on these lessons learned, it is expected that the OPA will make adjustments to the FIT program in 2012, considering some of the following potential changes:

- Price Point Drop to reflect the current market per unit costs of retail generation equipment.
- New Funding Model to make smaller FIT projects more financially feasible.
- Generation Caps to slow the FIT program down to manageable levels but still maintain the current job creation model.

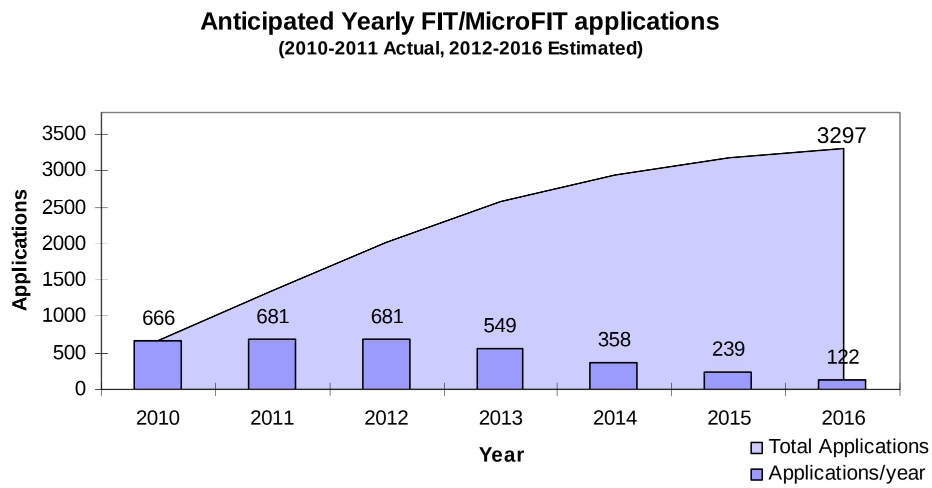
The above items were taken into consideration when developing PowerStream's five year Anticipated Generator Connections model.

4.1.3 Anticipated Generator Connections

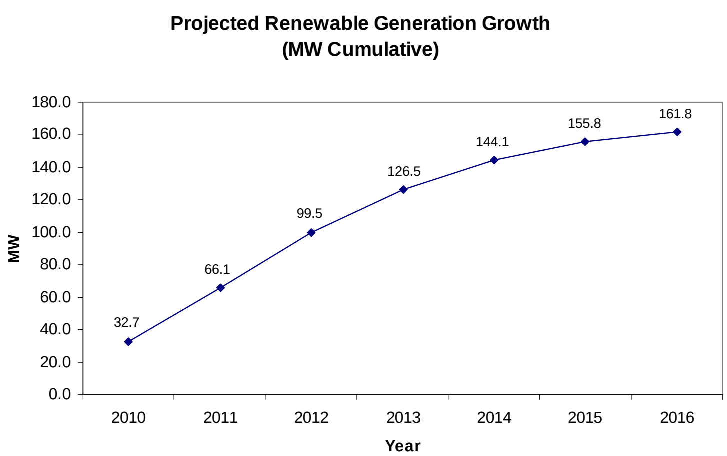
Based on PowerStream's 2010-2011 FIT/microFIT data and future assumptions regarding the OPA's FIT program, it is expected that application submissions will remain steady through 2012, begin to decline in 2013, and continue to descend through 2016. The following table outlines the expected decline:

Year	Projects	% of 2011
2011	681	100%
2012	681	100%
2013	549	81%
2014	358	53%
2015	239	35%
2016	122	18%

The anticipated year over year submission trend is shown below:



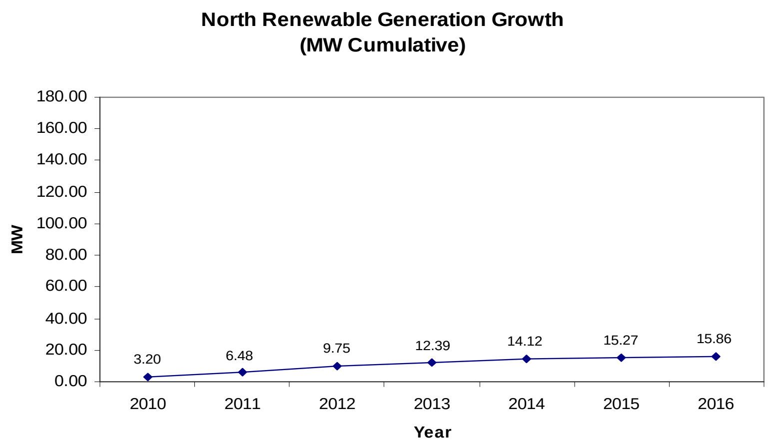
The OPA currently has Renewable Generation applications totaling 66.1MW for PowerStream's service territory. Based on PowerStream's anticipated FIT connection model, projected growth for Renewable Generation in PowerStream's territory will pursue the following trend:



Following steady growth through 2012, the Renewable Generation growth rate is expected to peak and begin to decline in 2013 through 2016. PowerStream's Renewable Generation load is expected to reach 161.8MW by 2016.

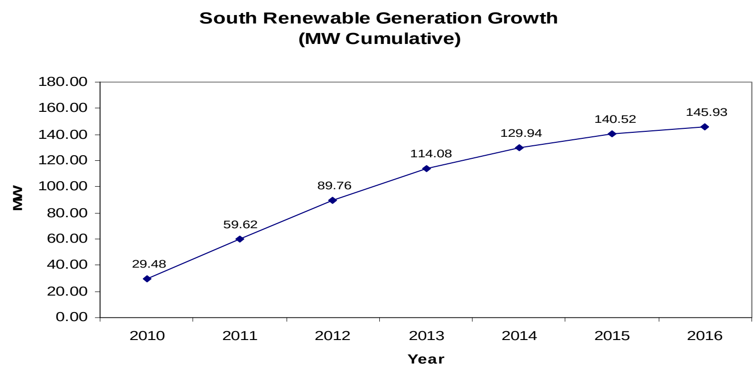
4.2 North System Development

The OPA currently has Renewable Generation applications totaling 6.48MW for PowerStream North. Based on projected growth PowerStream expects this number to reach **15.86 MW** by 2016. The following graph illustrates Renewable Generation growth in the North between 2010 and 2016:



4.3 South System Development

The OPA currently has Renewable Generation applications totaling 59.62MW for PowerStream South. Based on projected growth PowerStream expects this number to reach **145.93 MW** by 2016. The following graph illustrates Renewable Generation growth in the South between 2010 and 2016:



4.4 Future Infrastructure Projects and Activities

The following is a summary of Renewable Generation expenditures planned for 2012 to 2016.

Capital Projects	2012	2013	2014	2015	2016	Total
WiMax Communication Network	$279,551	-	-	-	-	$279,551
Fault Level Reduction Reactor - MTS#1	$238,405	-	-	-	-	$238,405
Fault Level Reduction Reactor - MTS#2	$238,405	-	-	-	-	$238,405
Station Programming and Wiring	-	$77,250	$61,800	$51,500	$41,200	$231,750

OM&A	2012	2013	2014	2015	2016	Total
Renewable Generation OM&A	$153,738	$158,350	$149,716	$131,675	$135,625	$729,105

Total	$910,099	$235,600	$211,516	$183,175	$176,825	**$1,717,216**

Individual Project details are provided in the following sections.

4.4.1 Project Summaries

The following tables provide summaries of PowerStream's projects between 2014 and 2016. 2012-2013 Project details are located in section 3.3, Existing Renewable Generation Expenditures. Expanded project details are available in Appendix B.

Year	Class	Project Title	Location	Expenditure
2014	**Capital Project**	**Station Programming and Wiring**	Four PowerStream TS's	$61,800
		Project Scope: Program Feeder Protections and install Fibre communication to accommodate Generator transfer trip scheme at four Transformer Stations. 2014 activity includes developing a transfer trip communication standard for PowerStream's relays.		
		Justification: Existing Feeder Protections at Stations are not programmed to output a trip command to the remote tripping scheme. Costs include consulting, programming, materials and installation.		

Year	Class	Project Title	Location	Expenditure
2015	**Capital Project**	**Station Programming and Wiring**	Four PowerStream TS's	$51,500
		Project Scope: Program Feeder Protections and install Fibre communication to accommodate Generator transfer trip scheme at four Transformer Stations.		
		Justification: Existing Feeder Protections at Stations are not programmed to output a trip command to the remote tripping scheme. Costs include consulting, programming, materials and installation.		

Year	Class	Project Title	Location	Expenditure
2016	**Capital Project**	**Station Programming and Wiring**	Three PowerStream TS's	$41,200
		Project Scope: Program Feeder Protections and install Fibre communication to accommodate Generator transfer trip scheme at three Transformer Stations.		
		Justification: Existing Feeder Protections at Stations are not programmed to output a trip command to the remote tripping scheme. Costs include consulting, programming, materials and installation.		

Year	Class	Project Title	Location	Year	Expense
2014 2015 2016	**OM&A**	**Renewable Generation OM&A**	Head Office and Field	2014	$149,716
				2015	$131,675
				2016	$135,625
		Scope: The Renewable Generation program is managed by one full time Engineer who dedicates 25% of his time. Two full time contract Engineers coordinate customer applications, perform Connection Impact Assessments, and approve project designs. Service Layouts and Metering are handled by existing positions through varying degrees of effort.			
		Justification: Generator Designs must be reviewed and approved by PowerStream Engineering prior to connection to ensure quality and safety.			

4.4.2 Project Selection

Due to a limited number of planned renewable enabling projects, an evaluation method to determine implementation prioritization is not required. Project timing has been determined based on renewable growth projections and individual station capacity demand.

4.5 OPA Consultation

PowerStream's five year Basic GEA plan has been reviewed and acknowledged by the OPA. The OPA confirmation letter can be found attached in Appendix C.

5 Conclusions – Renewables

5.1 Planned Spending

	2010	2011	2012	2013	2014	2015	2016	Total
Capital Projects	$54,046	$470,772	$756,361	$77,250	$61,800	$51,500	$41,200	$1,512,929
Renewable Generation OM&A	$30,753	$111,806	$153,738	$158,350	$149,716	$131,675	$135,625	$871,663
Total	$84,799	$582,578	$910,099	$235,600	$211,516	$183,175	$176,825	**$2,384,592**

The preceding table summarizes PowerStream's year to year Renewable Generation spending between 2010 and 2016. Based on generation demand projection, PowerStream requires $2,384,592 to implement the infrastructure and manpower necessary to accommodate Renewable Generation to 2016.

5.2 Capacity

Based on a calculated remaining maximum capacity of 937 MW and a projected load of only 161.8MW by 2016, PowerStream feels confident that it has capacity in place to accept future renewable generation projects.

5.3 Overall Assessment

PowerStream's proactive Renewable Generation planning since 2009 has created a solid foundation for generator connections in 2012, and has developed a robust strategy to accommodate generation in the next five years.

6 Smart Grid

When the *Green Energy and Green Economy Act, 2009* ("GEA") was given Royal Assent one of the provisions was the addition of an objective to the *Ontario Energy Board Act*, *1998* section 1.1; the "facilitation of the implementation of a smart grid in Ontario." The legislation also included a definition of smart grid to be reflected in *The Electricity Act* (Subsection 1.3) as follows:

For the purposes of this Act, the smart grid means the advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of,

(a) enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system;

(b) expanding opportunities to provide demand response, price information and load control to electricity customers;

(c) accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or

(d) supporting other objectives that may be prescribed by regulation.

For PowerStream, Smart Grid is the application of new technology to produce a more efficient and reliable distribution system, to enable renewable generation and to empower customers with more control over their energy usage. The Smart Grid touches most aspects of PowerStream's operations and enables changes in the way that PowerStream plans and operates its network and serves its customers.

PowerStream over the last twenty years has been designing and building its distribution system to facilitate the use of smart technologies in the efficient use and operation of its system. PowerStream's distribution network is somewhat unique in Ontario. It reflects an advanced design philosophy that was established with the construction of the first transformer station to be built, owned and operated by a municipally-owned Ontario local distribution companies in 1988. Owning and operating eleven transformer stations required PowerStream to rethink traditional methods of distribution network design, technologies and operational management in order to ensure the successful operation and integration of its distribution system to the overall grid. Smart technologies which have allowed PowerStream to integrate and operate its distribution network have been part of PowerStream's regular capital program for many years.

Over the past twenty years PowerStream has installed and effectively operated electricity distribution infrastructure and equipment that is consistent with the current description of Smart Grid. These technologies include:

- Advanced Protection and Control
- Advanced Station Maintenance
- Supervisory Control And Data Acquisition ("SCADA") system
- 24-7 Control Room covering PowerStream's entire service territory
- Advanced fibre-optic communications network (SONET Ring)
- Distribution automation
- Outage Management System ("OMS"), and
- Smart Meter and a two way Advanced Metering Infrastructure ("AMI") communication system.

Based on their successful application and proven performance, these technologies have moved far beyond the pilot stage and are now essential components of PowerStream's network and operations. PowerStream is fortunate to have a distribution network that is already relatively "smart." This advanced network and operational experience provide an ideal platform to realize immediate benefits from future Smart Grid investments. PowerStream frequently shares its experience with other LDCs including the Coalition of Large Distributors ("CLD") and Hydro One at their regular Smart Grid Information exchange meetings.

PowerStream's Smart Grid Strategy

PowerStream's initial Smart Grid Strategy and Plan was prepared by a cross-functional Smart Grid Strategy Task Force comprised of senior department representatives from across the company and approved by its Board of Directors in September 2010. The Strategy and Plan were subsequently updated and approved by the Board of Directors in October 2011. This strategy reflects the vision for an Ontario Smart Grid as identified by the Independent Electricity System Operator ("IESO") Smart Grid Forum in 2009 and updated in 2011 and is fully responsive to the requirements of the GEA and the Ontario Energy Board's Smart Grid policies/rules.

PowerStream's Strategy ensures that Smart Grid initiatives provide demonstrable value to PowerStream customers and to Ontario's broader electricity industry and leverages the capabilities of PowerStream's smart meter infrastructure.

The starting point in the development of PowerStream's Smart Grid Strategy was, and will continue to be, PowerStream's corporate vision:

> *"PowerStream will be a socially responsible company, committed to the environment and sustainable growth, leading the way into the future with boldness, innovation and industry best-in-class performance."*

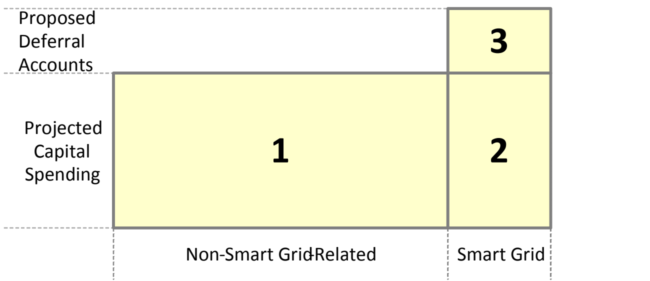
This vision drives PowerStream's planning and day-to-day operations and also drives its Smart Grid Strategy.

PowerStream's 2012 – 2016 Smart Grid Plan covers a broad range of initiatives that PowerStream's Smart Grid Task Force and others within PowerStream have put forward to support PowerStream's Smart Grid Strategy

PowerStream's Smart Grid Plan

With the exception of Smart Grid projects that are classified as pilot or demonstration initiatives, all Smart Grid initiatives are an integral part of PowerStream's Asset Investment Strategy and are assessed with all other capital requirements of the company through the 'optimization' process. No preferential treatment is given to these Smart Grid initiatives. As part of its prudence or good-practice check, Smart Grid initiatives are required to show benefit to the organization or customer over the operational life-time of the asset, similar to all other initiatives.

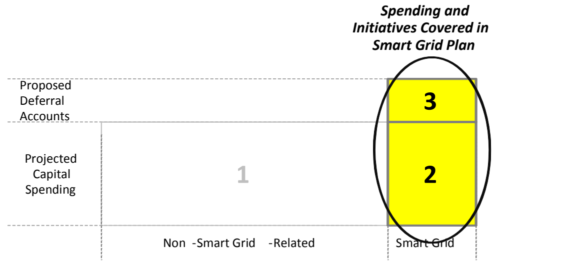
The following figure illustrates the relationship between normal rate based capital initiatives and smart grid initiatives.



Relationship of Smart Grid Projects to Stand Capital Initiatives

As shown in the block diagram above the Smart Grid Plan comprises all of the projects and initiatives in Boxes 2 and 3. Those initiatives in Box 2 represent initiatives in PowerStream's normal capital budget process that either are "smart" in whole or have a "smart" component aspect or benefit. For example, replacement switchgear installed with a motor operator and a communications device to "talk" to the control room represents "*distribution automation.*" Replacement technologies where there was no automation previously are determined to be a partial Smart Grid initiative. The Smart Grid initiatives included in PowerStream's projected capital spending (Box 2) compete with all other capital projects being considered by PowerStream. Another key advantage of treating proposed Smart Grid initiatives through the normal corporate capital prioritization and planning process is that synergies between Smart Grid initiatives and other capital projects can be identified, captured and evaluated in the capital plan.

Initiatives in Box 3 include pilot and demonstration initiatives representing technologies that have yet to be accepted for use throughout the distribution system. In many cases, these technologies will eventually become standard distribution system technology, however in some cases, the pilot project may demonstrate that the technology is not suitable for further advancement to the system.



PowerStream's Digital Fault Indicator initiative is an example of how successful demonstration pilots are expected to transition to implementation as a viable smart grid technology to be incorporated into the distribution network system design and operation. If successful, this technology will significantly improve the response to system failures, reduce maintenance and crew roll-out costs, and provide fault data to assist in forensic analysis of failures. This project started in 2011 and will be completed in 2012.

Rate-Based Smart Grid Initiatives

The table below shows the 2012 and 2013 capital budget by number of initiatives and dollar value. As shown, on a dollar basis, smart grid projects represent less than 10% of PowerStream's total budgeted capital expenditures for the two years.

PowerStream's Capital Budget for 2012 & 2013

Comment [A1]: I think this table should be updated to have the new capital costs for 2013.

	2012		2013	
	# of Projects	**$000**	**# of Projects**	**$000**
Non-Smart Grid Capital Projects	156	71,003	128	105,869
Projects with partial SG Component	20	1,737	42	2,892
100% Smart Grid Projects	28	3,960	39	5,517
Total Capital Budget	204	76,700	209	114,278
Total Smart Grid Projects	48	5,697	81	8,409
Percentage of Total Capital Budget	24	7	39	9

The seven Smart Grid investment categories provided in the Table below are consistent with those used by the IESO Smart Grid Forum and the OEB in its evaluation and assessment of

LDC GEA (and Smart Grid) Plans. The projected costs provided in this table are for initiatives and technologies that are part of PowerStream's rate based capital budget for 2012 and 2013. The forecast years of this plan (2014 –2016) are based on the assumption that total Smart Grid initiative spending is approximately 10% of the total capital spending in those years.

PowerStream's Smart Grid Rate Based Capital Plan

SG Technology Categories	2011	2012		2013		2014	2015	2016	5 Year Total
	$000	# of Projects	$000	# of Projects	$000	$000	$000	$000	$000
1. Consumer Technologies	1,432	4	1,432	6	697	697	838	786	4,450
2. Distribution	3,529	36	3,529	64	6,910	7,749	9,319	8,735	36,242
3. Distributed Energy Resource	0	0	0	0	0	0	0	0	0
4. Transmission	0	0	0	0	0	0	0	0	**0**
5. Communications	736	8	736	11	802	899	1,082	1,014	**4,533**
6. Electric Vehicles	0	0	0	0	0	0	0	0	**0**
7. Innovation & The Economy	0	0	0	0	0	0	0	0	**0**
Totals	**5,697**	**48**	**5,697**	**81**	**8,409**	**9,430**	**11,340**	**10,630**	**45,224**

Smart Grid Pilots and Demonstrations Initiatives

As has been PowerStream's practice in the past, successful Smart Grid pilots and demonstrations projects (Box 3) are expected to transition in the future to become an integral part of PowerStream's capital program (Box 2). As per OEB "*Filing requirements: Distribution System Plans – filing under deemed Conditions of Licence" (EB-2009-0397)*, currently "*the Smart Grid development activities and expenditures should be limited to SG demonstration projects, Smart Grid studies or planning exercises and Smart Grid education and training."* Accordingly, the following expenditures are included in the PowerStream Smart Grid Plan. These activities are incremental to the projects that were "optimized" and included in the core capital plan.

Smart Grid pilot and demonstration type initiatives are undertaken to demonstrate or trial the suitability of a technology or to understand the impact to PowerStream's distribution system. These initiatives, started in 2010, are undertaken only if it is clear that such technology can be scaled-up to apply to the rest of the distribution system for the end benefit of the customer should the trail/demonstration be deemed successful.

Five Year Incremental Smart Grid Capital Spending

		$ 000						
Smart Grid Project Title	**Smart Grid Category**	**2010 - 2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Five Year Total ('12-'16)**
		Net	**Net**	**Net**	**Net**	**Net**	**Net**	
Electric Vehicle Smart Charger Trial	Electric Vehicles	117	200	200	100	100	100	**700**
Grid Energy Management	Distribution	285	500	0	0	0	0	**500**
Data Mining	Communications	0	100	100	100	100	100	**500**
Home Energy Management Trial	Consumer Technologies	0	250	250	50	50	50	**650**
Storage Technologies	Distr. Energy Resources	0	100	100	100	100	100	**500**
Digital Fault Indicators	Distribution	75	100	0	0	0	0	**100**
Totals		**477**	**1,250**	**650**	**350**	**350**	**350**	**2,950**

Demonstration/trail expenditures are incremental to activities currently included in rates and are recorded in a Smart Grid Capital Deferral Account

Smart Grid Studies, Planning, Education and Training

Expenditures in this category include the development of PowerStream's Smart Grid Strategy, participation in Smart Grid conferences and summits, and formal studies relating to the development and /or application of Smart Grid technologies to the distribution system. Any reports or findings from these type of activities are openly shared amongst other LDC's or other interested parties.

Smart Grid Studies, Planning, Education and Training expenditures are incremental to activities included in rates and are recorded in a Smart Grid OM&A Deferral Account. Some of the 2011 activities under this heading include:

- Queen's University Study "Plug-In Electric Vehicle Grid Loading" completed in April 2011
- University Of Waterloo study "Benefits of Rotation Inertia Demonstration Project to PowerStream's Grid" started in 2011with completion in 2012
- Georgian College electric vehicle partnership started in 2011 and continuing in 2012
- multiple presentations to PowerStream Staff on smart grid technologies

PowerStream's Smart Grid OMA Spending

Expenditure	2010	2011	2012	2013	2014	2015	2016	5 Year Total
	$000	$000	$000	$000	$000	$000	$000	$000
Manage Smart Grid Strategy	194	201	200	200	190	190	190	970
Conferences and Summits	8	3	5	20	5	5	5	40
Miscellaneous	4	52	2	10	5	5	5	27
Totals	206	256	207	230	200	200	200	1,037

Description of Smart Grid Pilot and Demonstration Initiatives

Electric Vehicle Trial

In 2010, PowerStream undertook an Electric Vehicle ("EV") Smart Charger demonstration trial in partnership with Better Place Inc., a leading electric vehicle services provider. This project demonstrates smart charging network capabilities, remote monitoring and control with user identification, validation and support. It will also provide stakeholder education and a limited scale demonstration site for government, business and the public and develop PowerStream's system operational experience with EV's. This project also demonstrates good environmental leadership.

Three EV smart charger stations have been installed at each of PowerStream's facilities in Barrie, Markham and Vaughan. Two purchased Nissan LEAF EV have been deployed between these centres as part of PowerStream's pool fleet. Veridian Connections are also participants in this EV trial with PowerStream and Better Place.

PowerStream will use this trial to better understand the impact of EV technology on its distribution system assets and will investigate a number of potential business models for the LDC going forward.

Staff expect the same level of activity in this trail for the next two years, with some tapering off of activities over the final three years of this plan. Areas of other EV investigations include smart charger control, vehicle-to-grid technology, EVs as storage devices, EV for load shifting purposes and re-purposing of spent EV battery equipment.

While there is much information from numerous trials associated with EV technology throughout the industry, for the most part, the nature and the detail of the issues are unique to PowerStream's distribution system and system operation.

Grid Energy Management Program

Using one of the twenty distribution feeders in the Lazenby Transformer Station this project would install smart meter technology in each of the transformer locations to provide information on the electricity supply along this feeder. This information would be retrieved from PowerStream's operational data store and used to report a number of electrical performance characteristics to determine efficiency of the feeder performance. The characteristics include:

i. Advanced Metering Infrastructure ("AMI") system performance by the reduction of communication latency issues of the Outage Management System ("OMS") via the reduction of AMI traffic by 80 to 90 % of present traffic volumes

ii. alarm and indication of low voltage and outage conditions

iii. transformer energy loading profile (kwh's versus time of day)

iv. measuring and reporting line losses from transformer to residential meter

v. power factor of the total transformer load

vi. KVA loading of transformer (KVA versus time)

vii. transformer loading profile (KVA versus time of day) to allow identification of any transformer overloaded for any amount of time (A monthly report of overloaded transformers could provide information for remedial action prior to transformer failure)

viii. phase current balancing to three phase feeder supply to subdivision

ix. feeder load reconciliation to the station feeder that will permit calculation of feeder losses, feeder power factor, feeder phase balance, and feeder load profiling

x. identification of power diversion (theft) by reconciling loads connected to transformer

In 2012, it is expected that this trial will be expanded somewhat over its 2011 program as staff determine if this technology can be used to significantly reduce frequency bandwidth capacity requirements and improve latency issues on the AMI systems during the reporting of customer outages on the OMS. This project provides powerful tools to operations staff and planners to better understand and optimize the distribution system operation.

It is expected that, if this technology is suitable for expansion to the other areas of the distribution system without detrimental effects to the performance of the existing AMI system, then any planned expansion of this technology past 2013 will be achieved via PowerStream's normal rate-based capital expenditure process.

The scope and the results of this demonstration project have been shared with Hydro One and the CLD at regular Smart Grid information exchange meetings.

Data Mining

The Smart Meter/AMI system collects an enormous amount of data on customer energy usage, power quality and system performance. To be useful, this data must be made accessible to several key departments within PowerStream, namely System Planning, Engineering Design and Operations Control.

Over the five year plan period, PowerStream, with the assistance of contract personnel, will develop user friendly Geographic User Interface ("GUI") type database queries to provide easy access to those personnel requiring this data. This real information on customer loading and operational performance (outages, voltage levels, power quality, system & equipment loading, efficiency and losses) will enhance existing tools used by technical staff and provide more comprehensive and accurate information for planning, design and operational purposes.

This project will use data accumulated form Smart Meters, currently stored in an Operational Data Store ("ODS") which is managed by Savage Data located in Thunder Bay, Ontario.

PowerStream staff anticipates the development of this application technology will continue throughout the five year period of this plan.

This project will provide better information to staff and customers and will be a powerful tool in optimizing the performance of existing operational technologies such as GIS, CIS, SCADA, and AMI systems.

Home Energy Management Trials (Behind the Meter SG Applications)

Recently, the provincial government, the Ontario Energy Board and the IESO Smart Grid Forum have placed an increased emphasis on Home Energy Management ("HEM") applications and have suggested that LDC's participate in some manner.

Over the next five year period, PowerStream intends to provide Smart Grid information and opportunities to the customer and to provide in-home demonstration initiatives to demonstrate this technology. Working with the IESO and using a number of residential homes in its service territory, PowerStream will undertake a Home Care Network demonstration project in 2012 that will demonstrate various means of communicating customer energy usage information obtained from the Sensus Smart Meter to various monitoring and control devices downstream (or in-home) from the meter. Part of the scope of this trail is to investigate the privacy and cyber security issues with the various communication technologies as well as evaluating the impact on the performance of the AMI system.

Information and trail results obtained from this initiative is open to the industry stakeholders and is being shared with Hydro One and the CLD at regular Smart Grid information exchange meetings.

Feasibility of Storage Technologies

As renewable energy sources continue to be developed throughout PowerStream's service territory and as electric vehicles continue to be introduced to the Southern Ontario marketplace, there is an increased need to better understand the electricity storage options available to local distribution companies. There have been significant technical advances in electricity energy storage systems such as inertial flywheels, pneumatic storage, hydraulic storage and advanced battery systems.

PowerStream considers energy storage to be integral component of its Smart Grid strategy. In that regard, it plans to investigate specific applications of various storage technologies and, where practical and justifiable from operational and financial viewpoint, recommend larger scale deployment of the technology to the distribution grid as part of PowerStream rate based capital expenditure program.

PowerStream smart grid plan includes spending to investigate and report on these technologies.

Digital Fault Indicators

The digital fault indicator project is a demonstration project that will notify the control room operator whenever a line fault indicator has detected a fault current on the distribution system and provide the approximate fault location.

Coupling the Sensus Flexnet AMI communications technology with Horstmann line fault indicator technology, this project will install twenty three-phase fault indicators on PowerStream's distribution system and one three-phase fault indicator in the P & C work shop. The intent of this project is to determine the impact of using the Sensus Flexnet AMI system to deliver fault location, magnitude and other information to the control room operator. The AMI system performance relating to capacity, latency and prioritization are issues that will be evaluated during this trial. Successful demonstration of this technology will improve system reliability by reduction of customer outage duration times. It will also provide another application for the existing Smart Meter AMI communications system.

As this technology is new, there was no information throughout the industry relating to the scope or objective of this project.

The installation and commissioning of this project was completed in the first quarter 2012. The system operated as designed with acceptable latency reporting times and without affecting the billing information and other operational data channels on the AMI system. PowerStream concluded that this technology is viable for future application to the distribution system. A final report is being prepared. Post 2012, any application of this technology will be included in PowerStream's rate-based capital expenditure program, not as a specific Smart Grid demonstration initiative.

The final report containing scope, costing information, trail results, conclusions and recommendations obtained from this initiative is open to the industry stakeholders and will be shared with Hydro One and the CLD at its regular Smart Grid information exchange meetings.

7 Appendix A – Station Capacity for Renewable Generation

PowerStream Owned Stations – South:

This list represents the allocated renewable generation capacity of PowerStream owned Transformer Stations. Projects must have completed a connection impact assessment to contribute to allocated capacity. Station Capacity is the lesser of either the thermal or short circuit capacity.

Vaughan MTS # 1												
Station Voltage (kV): 27.6												
Station Thermal Capacity (MW) (A + B Bus) = 13.6												
Bus Capacity (MW)	A = 6.8						B = 6.8					
Feeder	M1	M3	M5	M7	M9	M11	M4	M6	M8	M10	M12	M14
Allocated Capacity (MW)	0	0.5515	0.00825	0	0.225	0.008325	0	0.288815	1.20988	0.75	0.02175	1
Remaining Station Capacity (MW) = 9.5												

Vaughan MTS # 1E												
Station Voltage (kV): 27.6												
Station Thermal Capacity (MW) (C + D Bus) = 97.5												
Feeder	M15	M17	M19	M21	M23	M25	M16	M18	M20	M22	M24	M26
Allocated Capacity (MW)	0.3	0.2	0	0.031	0	0	0	1.15	0	0.34	0	0
Remaining Station Capacity (MW) = 95.5												

Vaughan MTS # 2												
Station Voltage (kV): 27.6												
Station Thermal Capacity (MW) (A + B Bus) = 10.2												
Feeder	M1	M3	M5	M7	M9	M11	M2	M4	M6	M8	M10	M12

Allocated Capacity (MW)	N/A	0.66	0	0	0.14	0.0099	0	0.006825	0.415	0.755	1.07057	N/A
Remaining Station Capacity (MW) = 7.1												

Vaughan MTS # 3												
Station Voltage (kV): 27.6												
Station Thermal Capacity (MW) (A + B Bus) = 125.5												
Feeder	M1	M3	M5	M7	M9	M11	M2	M4	M6	M8	M10	M12
Allocated Capacity (MW)	0	2	0.468775		0.019	0.142	0	0.022625	1.972	0.456	0.2599	0.01
Remaining Station Capacity (MW) = 120.2												

Richmond Hill MTS # 1												
Station Voltage (kV): 27.6												
Station Thermal Capacity (MW) (A + B Bus) = 12.0												
Feeder	M1	M3	M5	M7	M9	M11	M2	M4	M6	M8	M10	M12
Allocated Capacity (MW)	0.1	0.01	0.015	0.3	0.608	0.1	0	0.04602	0.01	0.02	0.47231	0.02
Remaining Station Capacity (MW) = 10.4												

Richmond Hill MTS # 2												
Station Voltage (kV): 27.6												
Station Thermal Capacity (MW) (C + D Bus) = 48.0												
Feeder	M1	M3	M5	M7	N/A	N/A	M2	M4	M6	M8	N/A	N/A
Allocated Capacity (MW)	0.3	0.0991	0.02714	0.5			0	0	0	0.25		
Remaining Station Capacity (MW) = 46.8												

Markham MTS # 1
Station Voltage (kV): 27.6

Station Short Circuit Capacity (MW) (B + Y Bus) = 1.34												
Feeder	M1	M3	M5	M7	N/A	N/A	M2	M4	M6	M8	N/A	N/A
Allocated Capacity (MW)	0.1	0.16752	0	0			0.584	0.0068	0.4773	0		
Remaining Station Capacity (MW) = 0.0												

1

Markham MTS # 2												
Station Voltage (kV): 27.6												
Station Circuit Capacity (MW) (J + Q Bus) = 1.38												
Feeder	M1	M3	M5	M7	N/A	N/A	M2	M4	M6	M8	N/A	N/A
Allocated Capacity (MW)	0	0.12437	0.3083	0.095			0.127	0.02089	0.68	0.02		
Remaining Station Capacity (MW) = 0.0												

Markham MTS # 3												
Station Voltage (kV): 27.6												
Station Short Circuit Capacity (MW) (E + Z Bus) = 2.5												
Feeder	M1	M3	M5	M7	N/A	N/A	M2	M4	M6	M8	N/A	N/A
Allocated Capacity (MW)	0	0.01622	0	0.01			0.404	0	0	0.018		
Remaining Station Capacity (MW) = 2.0												

2

Markham MTS # 3E												
Station Voltage (kV): 27.6												
Station Short Circuit Capacity (MW) (J + Y Bus) = 2.9												
Feeder	M11	M13	M15	M17	N/A	N/A	M12	M14	M16	M18	N/A	N/A
Allocated Capacity (MW)	0	0.005	0.1	0			0.02	0.02844	0.45	0.26		
Remaining Station Capacity (MW) = 2.0												

3

Markham MTS # 4

Station Voltage (kV): 27.6												
Station Thermal Capacity (MW) (P + R Bus) = 97.5												
Feeder	M1	N/A	N/A	N/A	N/A	N/A	M2	M4	N/A	N/A	N/A	N/A
Allocated Capacity (MW)	0						0.1	0.65				
Remaining Station Capacity (MW) = 96.8												

Hydro One Owned Stations - South:

This list represents the allocated renewable generation capacity for PowerStream, on Hydro One owned Transformer Stations. Estimated Remaining Capacities are PowerStream's best estimate based on station and generator data available on Hydro One's website.

Agincourt TS												
Station Voltage (kV): 27.6												
Station Thermal Capacity (MW) (B + Y Bus) = 59.6												
Hydro One Allocated Capacity (MW) = 15.5												
Feeder	M1	N/A	N/A	N/A	N/A	N/A	M2	N/A	N/A	N/A	N/A	N/A
PowerStream Allocated Capacity (MW)	0						0					
Estimated Remaining Capacity (MW) = 44.1												

Armitage TS DESN 1												
Station Voltage (kV): 27.6												
Station Thermal Capacity (MW) (JQ Bus) = 119.6												
Hydro One Allocated Capacity (MW) = 9.7												
Feeder	M11	M14	M34	M41	M43	M44	N/A	N/A	N/A	N/A	N/A	N/A
PowerStream Allocated Capacity (MW)	0	0.459	0	0	0	0						
Estimated Remaining Capacity (MW) = 109.4												

Buttonville TS												
Station Voltage (kV): 27.6												
Station Thermal Capacity (MW) (Q + Z Bus) = 72.8												
Hydro One Allocated Capacity (MW) = 8.8												
Feeder	M1	M2	M3	M4	M5	M7	M9	M10	M11	M12	N/A	N/A

PowerStream Allocated Capacity (MW)	0	0.5	0	0.03	0.4	0.45	0.1	0.09	0	0.25		
Estimated Remaining Capacity (MW) =	62.2											

Finch TS DESN 1

Station Voltage (kV): 27.6

Station Thermal Capacity (MW) (B + Y Bus) = 40.7

Hydro One Allocated Capacity (MW) = 7.65

Feeder	M11	M12	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PowerStream Allocated Capacity (MW)	0.25	0										
Estimated Remaining Capacity (MW) =	32.8											

Leslie TS DESN 1

Station Voltage (kV): 27.6

Station Thermal Capacity (MW) (BY Bus) = 18.4

Hydro One Allocated Capacity (MW) = 5.2

Feeder	M1	M2	M31	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PowerStream Allocated Capacity (MW)	0	0	0									
Estimated Remaining Capacity (MW) =	13.2											

Woodbridge TS DESN 1

Station Voltage (kV): 27.6

Station Thermal Capacity (MW) (BY Bus) = 23.6

Hydro One Allocated Capacity (MW) = 2.1

Feeder	M2	M3	M5	M6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PowerStream Allocated Capacity (MW)	0.05	0.5	0	0								
Estimated Remaining Capacity (MW) =	21.0											

Hydro One Owned Stations - North:

Everett TS

Station Voltage (kV): 44

Station Thermal Capacity (MW) (BY Bus) = 63.8

Hydro One Allocated Capacity (MW) = 0.75

Feeder	M5	M6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

PowerStream Allocated Capacity (MW)	0	0.25										
Estimated Remaining Capacity (MW) = 62.8												

Holland TS												
Station Voltage (kV): 44												
Station Thermal Capacity (MW) (BY Bus) = 96.6												
Hydro One Allocated Capacity (MW) = 1.36												
Feeder	**M3**	**M4**	**M5**	**M6**	**M7**	**M8**	**M9**	**M10**	**N/A**	**N/A**	**N/A**	**N/A**
PowerStream Allocated Capacity (MW)	0	0	0	0	0	0	0.25					
Estimated Remaining Capacity (MW) = 95.0												

Midhurst TS												
Station Voltage (kV): 44												
Station Thermal Capacity (MW) (BY Bus) = 119.4												
Hydro One Allocated Capacity (MW) = 43.8												
Feeder	**M3**	**M4**	**M5**	**M6**	**M7**	**M8**	**M9**	**M10**	**N/A**	**N/A**	**N/A**	**N/A**
PowerStream Allocated Capacity (MW)	0	0.272	0	0	0	0	0					
Estimated Remaining Capacity (MW) = 75.3												

Barrie TS												
Station Voltage (kV): 44												
Station Thermal Capacity (MW) (BY Bus) = 68.5												
Hydro One Allocated Capacity (MW) = 36.23												
Feeder	**M1**	**M2**	**M3**	**M4**	**M5**	**M6**	**M7**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
PowerStream Allocated Capacity (MW)	0.25	0.28	0.25	0.07	0	0.28	0.28					
Estimated Remaining Capacity (MW) = 30.9												

8 Appendix B – Project Details

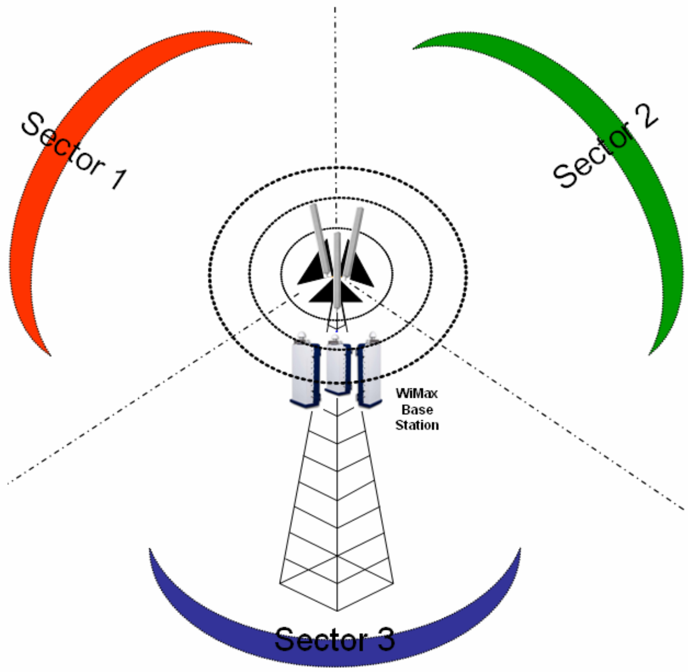
8.1 WiMax Communication Network

Generating power onto the electricity grid adds complexities to daily system operations. For this reason, PowerStream Operations requires real time contact with Generators to monitor output power and have the ability to shut a generator down in the event of an emergency. In order to facilitate communication between PowerStream's 24hr/day Control Room and Generators, it has been determined that a WiMax Communication Network is required to cover the extent of PowerStream's distribution territory.

WiMAX ("Worldwide Interoperability for Microwave Access") is a wireless standard used for broadband wireless access ("BWA") networks. In comparison, a WiMax network functions similarly to a common WiFi wireless network by linking digital users to a computer network. However, WiFi network coverage is measured in meters where a WiMax network's coverage area is measured in kilometers. PowerStream's WiMax network consists of two parts:

- WiMax Transmitter, consisting of a high power base station and antenna mounted at a height of approximately 30m, transmitting information from PowerStream's control room to a number of customers up to a distance of forty kilometres away.
- WiMax Receiver, consisting of a compact directional antenna mounted at a height of approximately 7m that connects PowerStream directly to a generator's Power Inverter.

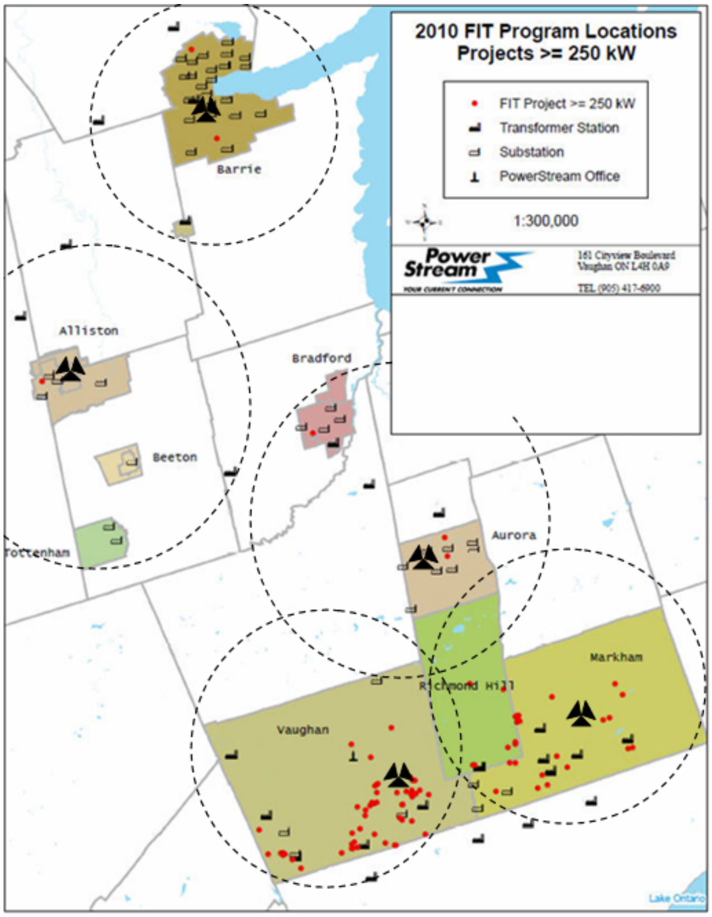
- Project Scope: Construct a WiMax Communication Network consisting of five Base Station nodes located in Vaughan, Markham, Aurora, Alliston and Barrie.
- Project Benefit: Will allow PowerStream Control Room to monitor Generators to maintain system security, shutdown a generator in the event of an emergency, and confirm a Generator is off during maintenance, ensuring the safety of staff working on the distribution system.
- Opportunity: The WiMax Network's bandwidth is scalable and can be expanded if required to accommodate future generators.



3-Sector WiMax Base Station Node

Network Design

PowerStream's WiMax Communication Network will consist of five Base Station nodes located in Vaughan, Markham, Aurora, Alliston and Barrie as illustrated below:



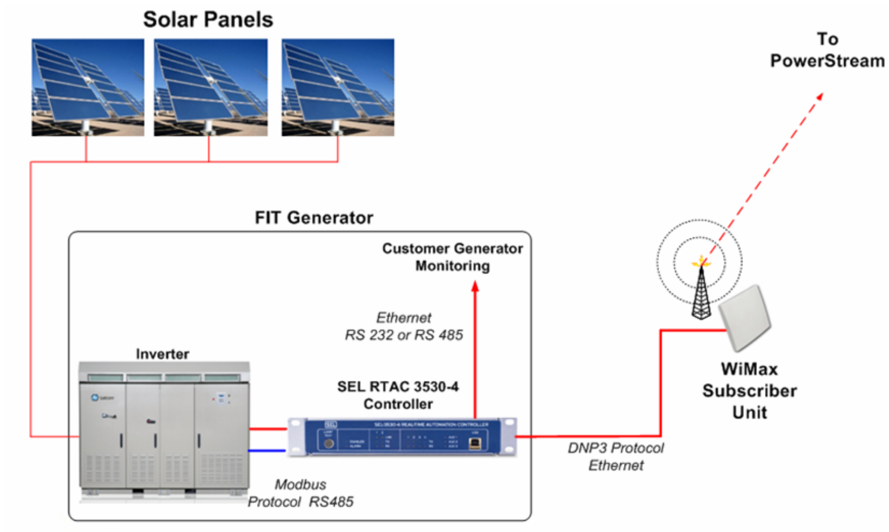
* Network coverage zones are generalized for illustration purposes.

Each of the five nodes will consist of three communication sectors creating a mesh network through PowerStream's territory. All five Nodes will be located at existing PowerStream Stations and be mounted on communication towers at a height of 30m.

PowerStream classifies customer Generators in one of two Categories; greater than 250kW which require real time communication with the PowerStream Control Room, or less than 250kW which are considered low risk generators and currently are not required to have a communication link with PowerStream's control room. Generator Classification totals are seen below:

Generator Classification	
Projects > 250kW	54
Projects < 250kW	325
Total Generators	379

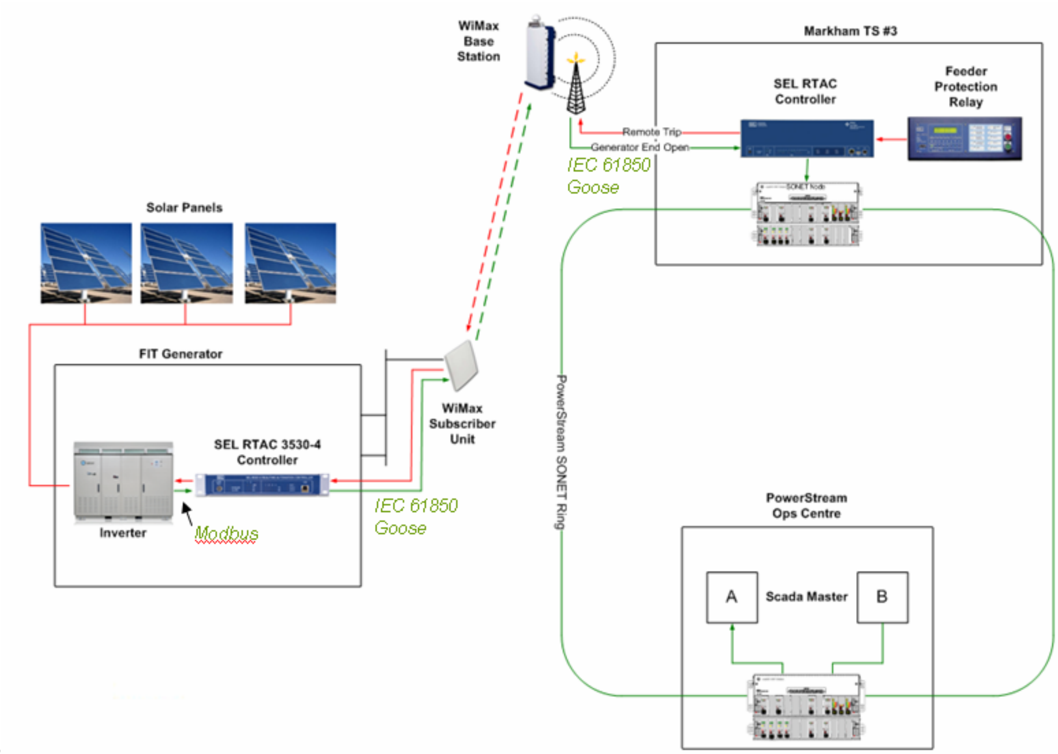
The existing fifty-four Generators greater than 250kW will be required to purchase a WiMax Receiver (Subscriber Unit) and a Signal Controller (SEL-3530 RTAC) at their own expense, as part of their generator's connection agreement with PowerStream. The following diagram illustrates the expected equipment layout to be located at a customer owned generator.



The RTAC controller polls the Generator's Power Inverter for operating data and transmits it to PowerStream's network via the WiMax Subscriber unit.

Projects greater the 250kW will be required to have an active transfer trip function available to PowerStream's Control Room allowing the generator to be tripped off (shut down) in the event of a safety concern. The following diagram illustrates how PowerStream's transformer station is able to access the Generator's shutdown function via the WiMax Network.

Generator PowerStream



In the event where a Generator's supply feeder trips off, the Transformer Station's protective relay will initiate a trip command directly to the Generator's inverter using Goose (IEC61850) messaging, instructing the generator to shutdown. This will ensure that the Generator is off, preventing the possibility of "islanding", and eliminating any safety concerns for lines crews working in the area.

2010 - Proof of Concept:

In 2010, PowerStream constructed a WiMax proof of concept project to confirm the functionality and reliability of WiMax communication.

A WiMax Base Station was constructed at PowerStream's Fabro Transformer Station and was linked with a Subscriber unit mounted at PowerStream's JV Fry Transformer Station.

Base Station + Antenna
(Fabro TS)

Subscriber/Antenna
(JV Fry TS)

In conjunction with RuggedCOM Inc and Schweitzer Engineering Laboratories (SEL), PowerStream tested and confirmed the WiMax technology. Test data proved that WiMax communication speeds were adequate to meet transfer trip guidelines and that there was ample operating bandwidth to accommodate PowerStream's Generator demand.

- Proof of concept link was dismantled following testing and the equipment was redeployed into active service at MS407 in 2011.

<u>2011 – WiMax Network Construction – Year One</u>

In 2011, PowerStream constructed three WiMax Nodes at Transformer Stations in Barrie, Markham and Vaughan.

1. Municipal Station MS407 - 43 Cundles Rd. E, <u>Barrie</u>
2. Transformer Station MTS3 - 7932 Kennedy Road, <u>Markham</u>

3. Transformer Station VTS1 - 8000 Dufferin St., Vaughan.

MS407 - Barrie: Replace existing 19m tower with new 29.26m tower and install 3-Sector WiMax Base Station.

MS407 - Barrie WiMax Tower

3-Sector WiMax Base Station
(Base Station + Antenna's)

MTS3 - Markham: Reinforce existing 30m tower and install 3-Sector WiMax Base Station.

MTS3 WiMax Tower
(Under Construction)

VTS3 – Vaughan: Construct new 29.26m tower and install 3-Sector WiMax Base Station (Under construction).

- Year 1 Cost: $371,057

2012 – WiMax Network Construction – Year Two

In 2012, PowerStream plans to construct the final two WiMax Nodes at Stations in Alliston and Aurora:

1. Municipal Station MS 431 - Dufferin St. South, Alliston
2. Municipal Station AMS4 - 14025 Bathurst St., Aurora

MS431 - Alliston
(Replace existing 18m Tower with new 29.26m WiMax Tower)

AMS4 - Aurora
(Replace existing 21m Pole with 29.26m WiMax Tower)

- Year 2 Cost: $279,551.00

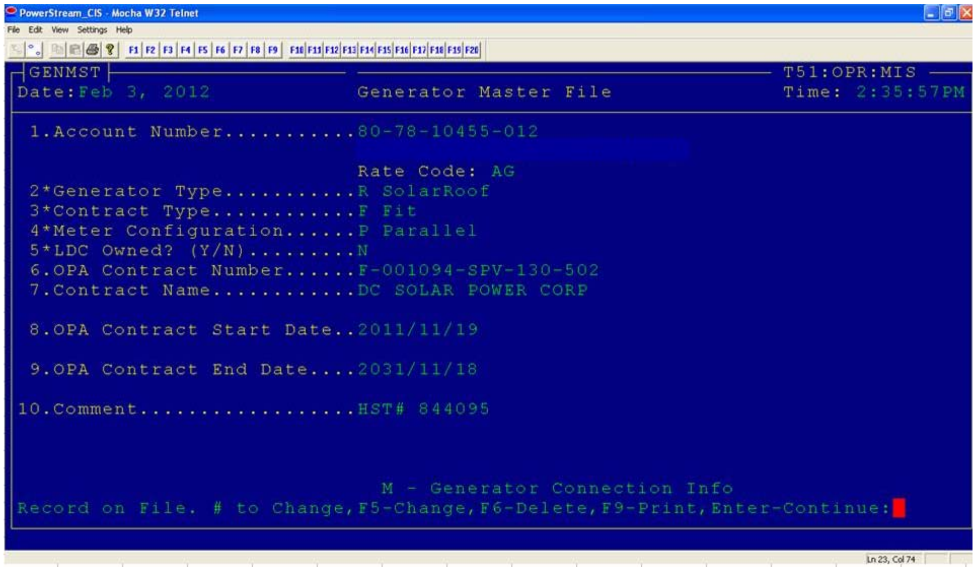
8.2 Customer Information System Modifications for FIT

PowerStream's existing Customer Information System ("CIS") was deemed not capable of managing Renewable Generation in an effective manner. Therefore, upgrades were required to enable CIS to oversee generator sizes, configuration types, contract dates and billing rates.

- Project Scope: Update CIS to accurately track and bill renewable generators.
- Project Benefit: Will enable CIS to manage generator sizes, configuration types, contract dates and billing rates.

- Opportunity: No additional opportunities have been considered.

The following illustration is an example of the new 'Generator Master File' screen created in CIS to manage Renewable Generation data.



Costing:

- 2011: $69,431

8.3 Fault Level Reduction Reactors

Due to their close proximity with Hydro One's Parkway Transformer Station in Markham, PowerStream's Markham TS#1 and Markham TS#2 Transformer Stations are subject to high fault currents causing them to reach their short circuit limiting capacity in September 2011. In order to provide short circuit capacity for potential generators in the area, PowerStream intends to install fault level reduction reactors at both stations by June 2012. This countermeasure will increase each station's available generation connection capacity by 15MW, providing an overall addition of 30MW of generation capacity in the Markham area.

- <u>Project Scope:</u> Install three phase fault level reduction reactors at Markham TS#1 and Markham TS#2 to improve fault current levels.
- <u>Project Benefit:</u> Will increase Renewable Generation capacity in Markham by 30MW.
- <u>Opportunity:</u> The reactors will supply additional protection for three-phase load customers on the feeder by limiting phase to phase fault current.

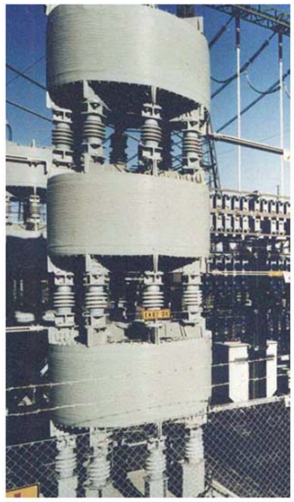
<u>Technical Study:</u>

In September 2011, Kinectrics Inc. was contracted to perform a feasibility study of PowerStream's Reactor Implementation strategy and its impact to the distribution grid.

<u>Study Results:</u>

Powerstream can reduce the three-phase fault level at the 28kV bus to less than 17 kA, by adding a reactor of 0.5 Ohm or higher. The actual size of the series reactor needs to be determined by PowerStream.

The following photo illustrates a three-phase stacked current limiting reactor.



Three-phase stacked current limiting reactor
(courtesy of Trench)

Conclusions:

For 2012, PowerStream has budgeted for a 0.5 ohm series reactor for both Markham TS#1 and Markham TS#2 at a cost of $238,405.00 each.

8.4 Station Programming and Wiring

In order to meet PowerStream's Generator Transfer Trip requirements, Transformer Station upgrades are required for existing feeder protection relays and their wiring in order to make Stations capable of delivering trip commands to Generators.

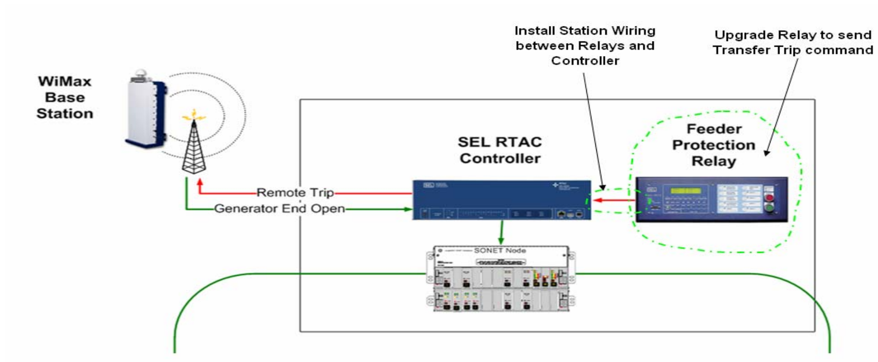
- Project Scope: Upgrade feeder protection relays at various Transformer Stations and install necessary wiring to enable transfer trip capability.
- Project Benefit: Will facilitate the fast shutdown of Generators by the Control Room.
- Opportunity: No additional opportunities have been considered.

Station Programming: In the event that a Generator's load feeder trips off, the Transformer Station's protective relay will need to initiate a trip command directly to the

Generator's inverter instructing the generator to shutdown. This feature is not currently active on existing station relays and therefore the relay's programming will need to be upgraded to include the trip command.

Station Wiring: Currently there are no physical connections between the Station protective relays and the Station RTAC Controller. Fibre optic cable will need to be installed from each relay to the controller to allow the high speed trip signal to be sent from the relay to the Generator.

The following schematic illustrates the protective relay and wiring locations in the transfer trip scheme:



Costing:

- 2013: $77,250 (Buttonville TS)
- 2014: $61,800 (four PowerStream TS)
- 2015: $51,500 (four PowerStream TS)
- 2014: $41,200 (three PowerStream TS)

8.5 Renewable Generation OM&A

PowerStream's approach to Renewable demand has been to manage workload through existing positions and contract staff rather than create new permanent positions. In 2011, there were 3.86 full time equivalent manpower in three different departments working to connect renewable generators.

8.5.1 Manpower Allocation

In 2010, PowerStream solicited feedback from various LDC's to study their renewable organizational strategy. Based on the information from Toronto Hydro, Hydro Ottawa, Enersource, and Newmarket-Tay Hydro, and the projected future demand for renewable generation, PowerStream created two distinct working groups, "Engineering" and the "FIT Support Team".

Engineering

Engineering is the lead contact for Renewable Generation applications at PowerStream. This responsibility includes project design review, application administration, and overall project management. The Engineering team equates to 2.25 full time equivalent manpower working in the following three roles:

A. Renewable Generation Administration – Responsible for overseeing and facilitating the FIT and MicroFIT program at PowerStream, including the creation of PowerStream's GEA plan. This role is filled by an existing Stations Engineer who dedicates 25% of his time to Renewable Generation.

B. MicroFIT Program Coordination - Responds to microFIT program inquiries, coordinates customer applications and approves project designs. This position is currently filled by one full time contractor.

C. FIT Program Coordination - Responds to FIT program inquiries, coordinates customer applications and approves project designs. In addition, this role is responsible for performing Connection Impact Assessments ("CIAs") for new Generators connecting to the distribution grid. This position is currently filled by one full time contractor.

FIT Support Team

The FIT support team is comprised of the several office and field staff in the Service Layout and Metering groups. Their responsibility is to connect Generators to PowerStream's distribution grid by developing Service Designs, connection costs, and determining metering requirements. The FIT support Team equates to 1.61 full time equivalent manpower working in the following two departments:

D. Service Layouts - Develops generator service layout designs and calculates connection costs. There are currently three existing positions contributing through varying degrees of effort.

E. Metering - Installs generator bi-directional generation meters and manages generation data. This work is performed by several technicians and technologists contributing through varying degrees of effort.

A breakdown of manpower effort allocation in 2011 can be seen in the following table:

Department	Full Time Manpower	Part time Manpower		Full Time Equivalent (FTE)
		# of Manpower	RG workload vs. Core Job	
Engineering	2	1	25%	2.25
Service Layouts	-	3	6%	0.18
Metering	-	13	11%	1.43

Renewables Manpower = **3.86**

8.5.2 Cost Allocation

Recoverable Costs

Generators are required to pay a 'Connection Fee' when connecting to PowerStream's Distribution Grid. These fees are structured to cover Service Design and Metering costs incurred by the FIT Support Team. In addition, projects requiring a Connection Impact Assessment are charged a 'CIA Fee', equivalent to the Engineering burden incurred by the FIT Program Coordinator.

Therefore, costs incurred by the Service Layout group, Metering and the FIT Program Coordinator are recovered through Generator processing Fees as follows:

Service Layout Costs (D.) + Metering Costs (E.) – 'Connection Fees' = $0.00

FIT Program Coordinator Salary (C.) – 'CIA Fees' = $0.00

Incremental Costs

Renewable Generation administration, coordination and maintenance costs are OM&A labour costs funded by the OM&A deferral account. The 2010 and 2011 breakdown of OM&A labour costs are seen below:

2010			
Labour	**Full Time Equivalent (FTE)**	**Salary Including Burdens**	**Total Cost**
Administration Renewable Gen.	20%	$153,765	$30,753
Coordination MicroFIT	0%	$77,748	$0
		2010 Total	**$30,753**

2011			
Labour	**Full Time Equivalent (FTE)**	**Salary Including Burdens**	**Total Cost**
Administration Renewable Gen.	25%	$155,428	$38,857
Coordination MicroFIT	90%	$81,054	$72,949
		2011 Total	**$111,806**

In 2012, two additional roles will be introduced to existing positions to administer and maintain the WiMax Communication Network.

F. WiMax Administration - Direct and regulate the WiMax Network growth, Internet Protocol address allocation, and equipment configuration files.

G. WiMax Maintenance - Perform and support activities necessary to sustain the WiMax Network's equipment.

The 2012 to 2016 breakdown of OM&A labour costs are seen below:

2012			
Labour	**Full Time Equivalent (FTE)**	**Salary Including Burdens**	**Total Cost**
Administration Renewable Gen.	25%	$160,091	$40,023
Coordination MicroFIT	100%	$82,482	$82,482
Administration WiMax	10%	$160,091	$16,009
Maintenance WiMax	10%	$152,239	$15,224
		2012 Total	**$153,738**

2013			
Labour	**Full Time Equivalent (FTE)**	**Salary Including Burdens**	**Total Cost**
Administration Renewable Gen.	25%	$164,894	$41,223
Coordination MicroFIT	100%	$84,957	$84,957
Administration WiMax	10%	$164,894	$16,489
Maintenance WiMax	10%	$156,806	$15,681
		2013 Total	**$158,350**

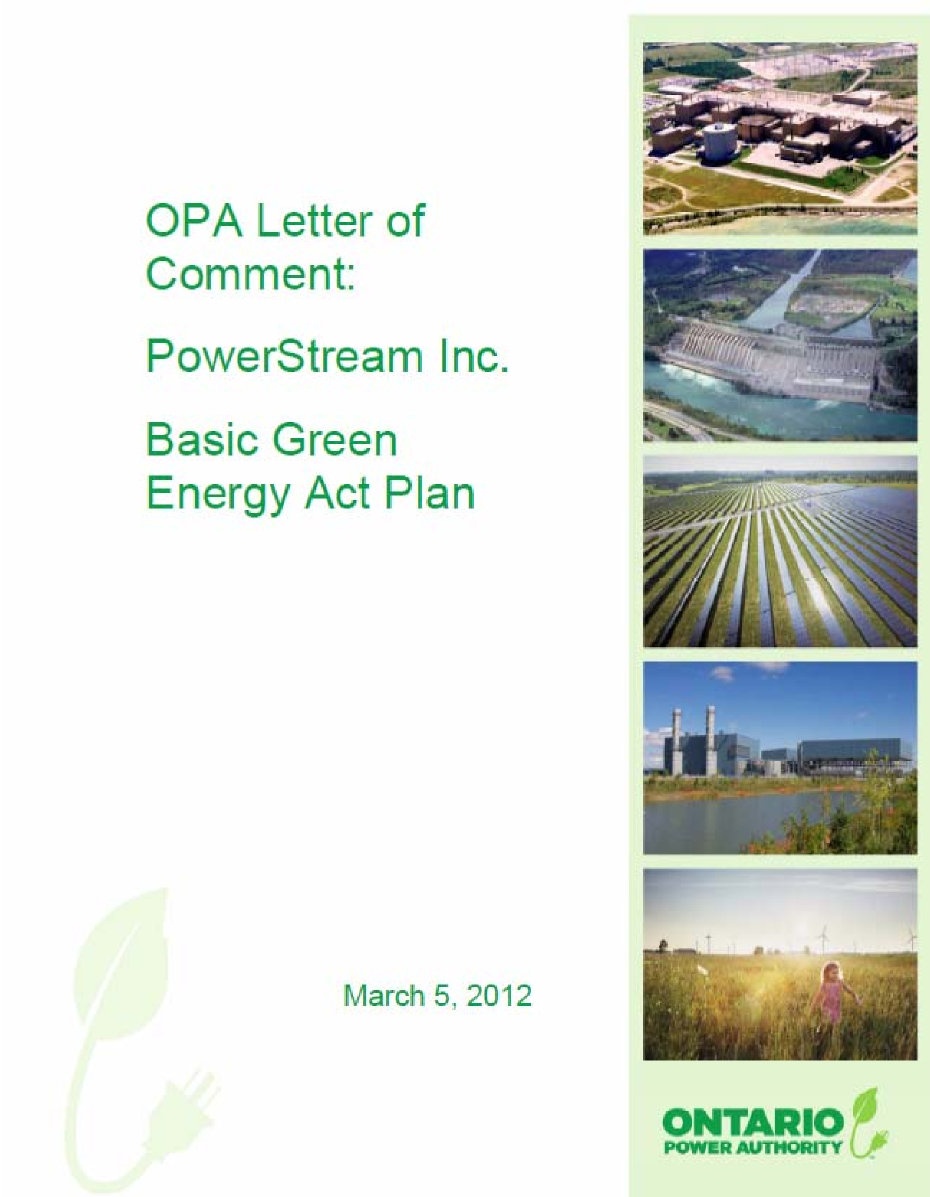
2014			
Labour	**Full Time Equivalent (FTE)**	**Salary Including Burdens**	**Total Cost**
Administration Renewable Gen.	20%	$169,840	$33,968
Coordination MicroFIT	75%	$87,506	$65,629
Administration WiMax	20%	$169,841	$33,968
Maintenance WiMax	10%	$161,510	$16,151
		2014 Total	**$149,716**

2015			
Labour	**Full Time Equivalent (FTE)**	**Salary Including Burdens**	**Total Cost**
Administration Renewable Gen.	15%	$174,936	$26,240
Coordination MicroFIT	50%	$90,131	$45,065
Administration WiMax	25%	$174,936	$43,734
Maintenance WiMax	10%	$166,356	$16,636
		2015 Total	**$131,675**

2016			
Labour	**Full Time Equivalent (FTE)**	**Salary Including Burdens**	**Total Cost**
Administration Renewable Gen.	15%	$180,184	$27,028
Coordination MicroFIT	50%	$92,835	$46,417
Administration WiMax	25%	$180,184	$45,046
Maintenance WiMax	10%	$171,346	$17,135
		2016 Total	**$135,625**

PowerStream’s organizational strategy for Renewable Generation has been effective and is expected to remain relatively unchanged through 2016.

9 Appendix C – OPA Review Confirmation Letter



OPA Letter of Comment:

PowerStream Inc.

Basic Green Energy Act Plan

March 5, 2012

ONTARIO POWER AUTHORITY

Introduction

On March 25, 2010, The Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

PowerStream Inc. - Basic Green Energy Act Plan

The OPA has reviewed the Basic GEA Plan from PowerStream Inc. ("PowerStream") dated March 2, 2012, and has provided its comments below.

OPA FIT/microFIT Applications Received

PowerStream's Plan indicates that as of November 2011 it has connected 23 FIT and 142 microFIT projects for a total of 4.01 MW. Additionally its Plan indicates that 214 FIT and microFIT projects totalling 22.91 MW have been approved by PowerStream for connection and are currently being constructed. A tally of both FIT and microFIT projects show that there is a potential 968 projects with a combined capacity of 39,197 kW still to be connected. PowerStream's Plan contains tables showing the number of FIT and microFIT applications received by the OPA, compared to those received, approved and connected by PowerStream. The tables also show the number of remaining projects still to be connected. This information can be found on page 8, section 3.2 *Existing Capacity for Generators* of PowerStream's GEA Plan.

To date, the OPA has received and offered contracts to 288 FIT applications totalling 57.76 MW within the Powerstream service territory, of which 224 FIT applications totalling 44.91 MW still remain active. As of February 9, 2012, the OPA has also received 1393 still active microFIT applications totalling 10.12 MW of capacity, of which, 589 microFIT applications totalling 4.53 MW have been offered a contract. The variation among microFIT numbers between the OPA and Powerstream can be attributed to new applications received and contracts offered by the OPA between November 2011 and February 2012 which is not reflected in PowerStream's Plan.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
info@powerauthority.on.ca www.powerauthority.on.ca

Upstream Transmission Constraints

There are no currently known upstream transmission constraints applicable to PowerStream's service territory.

Economic Connection Test Results

There has been no Economic Connection Test performed to date.

Opportunities for Integrated Solutions

There are no known corresponding expansions among neighbouring LDCs that could be addressed through integrated transmission solutions at this time.

Conclusion

The OPA finds that PowerStream's GEA Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

The OPA appreciates the opportunity to comment on PowerStream's Basic GEA Plan.

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WORKING CAPITAL OVERVIEW

In its most recent (“COS”) filings, PowerStream used the Board’s default working capital allowance (“WCA”) of 15% of the cost of power and controllable expenses.

In calculating the WCA for 2012 and 2013, PowerStream has used the default of 13% of the cost of power and controllable expenses. This is based on the Board’s letter, *Update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications – Allowance for Working Capital*, dated April 12, 2012.

Table 1 below shows the changes in working capital allowance from 2009 to 2013.

Table 1: Changes in Working Capital Allowance from 2009 to 2013 ($ Millions)

	CGAAP			**MIFRS**		
Working Capital Allowance	**2009**	**2010**	**2011**	**2011**	**2012**	**2013**
Cost of Power	$ 621.7	$ 691.3	$ 751.5	$ 751.5	$ 819.1	$ 857.8
Distribution Expenses	$ 59.7	$ 56.8	$ 62.1	$ 73.9	$ 81.6	$ 85.7
Total for WCA Calculation	$ 681.4	$ 748.2	$ 813.5	$ 825.3	$ 900.7	$ 943.5
WCA %	15%	15%	15%	15%	13%	13%
WCA $	**$ 102.2**	**$ 112.2**	**$ 122.0**	**$ 123.8**	**$ 117.1**	**$ 122.7**

The change in the WCA amount from $102.2 million in 2009 to $116.5 million in 2013 is an increase $14.3 million in rate base. This is driven by the increase in the cost of power, increases in distribution expenses and is offset by the reduction in the working capital allowance from 15% to 13%. The impacts are summarized in Table 2 below.

Table 2: Summary of Changes in Working Capital Allowance ($ Millions)

Description	**2013**	**2009**	**Change**	**WCA Factor**	**WCA ($000)**
Cost of Power	$ 857.8	$ 621.7	$ 236.1	15.0%	$ 35.4
Distribution Expenses	$ 85.7	$ 59.7	$ 26.0	15.0%	$ 3.9
Subtotal	**$ 943.5**	**$ 681.4**	**$ 262.1**		**$ 39.3**
Change in WCA factor	$ 943.5		$ 943.5	13.0%	$ 122.7
	$ 943.5		$ 943.5	-15.0%	$ (141.5)
WCA Factor impact					**$ (18.9)**
Net WCA Impact					**$ 20.5**

See Exhibit B3, Tab 1, Schedule 2, for details regarding the cost of power. See Exhibit D1, Tab 1, Schedule 1, for an overview of distribution expenses.

Table 3 below provides further details on the distribution expenses used in the calculation of working capital allowance above.

Table 3: Distribution Expenses for Working Capital Allowance ($ Millions)

	CGAAP			MIFRS		
Distribution Expenses	**2009**	**2010**	**2011**	**2011**	**2012**	**2013**
Distribution expenses - Operation	$ 13.4	$ 10.8	$ 12.3	$ 19.6	$ 23.6	$ 25.0
Distribution expenses - Maintenance	$ 9.3	$ 8.5	$ 9.2	$ 7.4	$ 7.0	$ 7.6
Billing and Collecting	$ 10.0	$ 11.9	$ 12.5	$ 15.7	$ 14.6	$ 15.8
Community Relations	$ 1.1	$ 1.3	$ 2.2	$ 2.1	$ 1.2	$ 1.3
Administrative and General Expenses	$ 25.0	$ 23.2	$ 24.7	$ 27.6	$ 33.4	$ 34.3
Other Distribution expenses	$ 1.0	$ 1.1	$ 1.2	$ 1.6	$ 1.7	$ 1.8
TOTAL EXPENSES	$ 59.7	$ 56.8	$ 62.1	$ 73.9	$ 81.6	$ 85.7

Table 4 compares the 2009 Actual WCA for the amalgamated PowerStream to the most recently Board Approved WCA for Barrie and the predecessor PowerStream.

Table 4: Board Approved vs. Actual WCA ($ Millions)

Working Capital Allowance	**Barrie 2008 Board Approved**	**South 2009 Board Approved**	**Total Board Approved**	**2009 Actual Combined**	**Difference**
Cost of Power	$ 119.7	$ 421.6	541	$ 621.7	$ (80.4)
Distribution Expenses	$ 10.0	$ 43.2	53	$ 59.7	$ (6.4)
Total for WCA Calculation	130	465	595	681	$ (86.8)
WCA %	15%	15%	15%	15%	15%
WCA $	$ 19.5	$ 69.7	$ 89.2	$ 102.2	$ (13.0)

Table 4 shows a substantial increase in the WCA for 2009 Actual versus the sum of the Board Approved WCA. This increase is mainly driven by a significantly higher cost of power.

COST OF POWER FORECAST

PowerStream's cost of power forecast for 2013 was derived by applying the appropriate unit cost of power, IESO related charges and Hydro One charges to the 2013 forecasted energy sales and demand. More specifically, the following steps were followed:

Energy Purchases

- The forecasted monthly purchases in kWh, produced by the load forecasting model and adjusted for the impact of CDM activities were used (Exhibit C1, Tab 1, Schedule 2).
- The monthly forecast kWh purchases are multiplied by the monthly forecast commodity price provided by the OEB. The commodity price estimate used to calculate the Cost of Power was determined in a way that bases the split between RPP and non-RPP customers on actual data. The Board Minimum Filing Requirements indicate that *"the RPP Price that should be used should be the most current RPP Price issued by the Board and should apply to the entire test period forecast".* The most recent source document by Navigant Consulting (Ontario Wholesale Electricity Market Price Forecast Report) was presented to the OEB on April 9, 2012. According to the report, Navigant is projecting an average Hourly Ontario Electricity Price ("HOEP") of $0.02105/kWh for May 2012 to April 2013 and $0.02362/kWh for May 2013 through October 2013. An average increase of 7%, as based on a three-year (2009-2011) average, is applied to the HOEP effective November 1, 2013 in order to project the commodity cost for the reminder of the test year period. The Global Adjustment is calculated using the forecasted rate of $0.05772/kWh as contained in the Board's April 2, 2012 Regulated Price Report, further adjusted by an average rate increase of 7% effective May 1, 2013. The forecast of RPP rates is based on the rate of $0.08069/kWh, as contained in the above-noted report and is applied to the entire test period forecast, as per Board direction.

IESO Related Charges

- The average ratio (based on three years (2009-2011) of billing data) between total energy purchases in kWh and total system demand in kW was calculated. This historic ratio was then applied to the total energy purchases forecast to derive the Transmission Network demand forecast.

- The average ratios between Transmission System Line Connection demand and system demand and between Transmission System Transformer Connection demand and system demand were calculated. These historic ratios were then applied to the forecast system demand to obtain the Transmission System Line Connection and Transmission System Line Transformer Connection demand projections.

- The 2012 bridge year the 2013 test year IESO transmission charges calculation reflected the most recent Uniform Transmission Rates approved by the Board (EB-2011-0268), issued on December 20, 2011 and effective January 1, 2012.

- The Wholesale Market Service ("WMS") charge was determined by forecasted rates for WMS and the Rural Rate Assistance ("RRA") charge to the forecast of total kWh purchases;

    - The forecasted WMS rate represents a historic three year average (2009-2011) of $0.045/kWh and applies to the entire test period forecast;

    - The forecasted RRA reflected an OEB rate order (EB-2011-0405); and the Rural or Remote Electricity Rate Protection Charge will be reduced to $0.001/kWh on May 1, 2012. Until that time, the rate will continue to be $0.0013/kWh.

Hydro-One Related Charges

- Ratios, similar to those described above for *IESO Related Charges*, were calculated based on historic cost of power statistics from Hydro One.

- Average ratios between Transmission System Line Connection demand and system demand, between Transmission System Transformer Connection demand and system kW and between Low Voltage demand and system demand were calculated. These historic ratios are then applied to the forecast system demand to obtain Transmission System Line Connection, Transmission System Line Transformer Connection and Low Voltage projections.

- Hydro One Sub-Transmission ("ST") class rates are applied to the relevant transmission quantities noted above to obtain the Hydro One Transmission component of cost of power. The 2012 bridge year ST charges calculation reflected the most recent Hydro One ST rates approved by the Board (EB-2009-0096) effective January 1, 2011.

- The Low Voltage ("LV)" forecasted rate represents a January 2011 approved rate of $0.0668/kW as per EB-2009-0096 and applies to the entire test period.

As a final step, the overall 2013 cost of power expense was entered into the working capital calculation in the 2013 Rate Model.

The cost of power forecast is provided in Table 3, below. The full month-by-month development of the cost of power is provided in Table 3.

Table 3: Cost of Power Historic and Forecast

Component	2008 Board Approved Barrie	2009 Board Approved PS South	2009 Actuals	2010 Actuals	2011 Actuals PS Consolidated	2012 Bridge	2013 Test
Commodity	$94,308,494	$323,417,461	$ 510,184,215	$ 569,467,839	$ 627,553,141	$ 680,649,981	$ 719,562,631
WMS including RRA	8,589,143	45,067,863	50,921,155	47,590,790	48,080,106	49,035,401	48,588,145
Transmission Network	7,837,821	35,857,433	41,961,048	51,006,312	54,603,031	60,073,206	60,222,853
Transmission Connection	7,771,804	16,430,166	22,392,162	24,847,123	25,559,804	26,608,338	26,674,622
Low Voltage	1,215,380	860,825	1,660,627	1,582,384	2,255,421	2,725,152	2,731,456
Total	**$119,722,642**	**$421,633,749**	**$ 627,119,207**	**$ 694,494,448**	**$ 758,051,503**	**$ 819,092,077**	**$ 857,779,706**

Table 4: 2013 Cost of Power by Month

Components	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total
VOLUMES													
Energy Purchased PS South (kWh)	617,476,156	569,598,420	591,803,052	541,274,829	558,665,478	607,259,720	666,814,018	646,775,091	582,708,254	556,445,191	575,852,133	607,939,329	**7,122,611,670**
Energy Purchased PS North(kWh)	139,859,452	129,015,060	134,044,448	122,599,716	126,538,729	137,545,411	151,034,566	146,495,713	131,984,460	126,035,830	130,431,537	137,699,344	**1,613,284,267**
Total Purchases (kWh)[1]	*757,335,608*	*698,613,479*	*725,847,500*	*663,874,545*	*685,204,207*	*744,805,131*	*817,848,585*	*793,270,804*	*714,692,714*	*682,481,021*	*706,283,670*	*745,638,673*	**8,735,895,937**
RPP Customer Base	44.43%	44.43%	44.43%	44.43%	44.43%	44.43%	44.43%	44.43%	44.43%	44.43%	44.43%	44.43%	
Spot Customer Base[2]	55.57%	55.57%	55.57%	55.57%	55.57%	55.57%	55.57%	55.57%	55.57%	55.57%	55.57%	55.57%	
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
RPP kWh	336,484,211	310,393,969	322,494,044	294,959,460	304,436,229	330,916,920	363,370,126	352,450,218	317,537,973	303,226,318	313,801,835	331,287,262	**3,881,358,565**
Non-RPP kWh	420,851,397	388,219,510	403,353,456	368,915,085	380,767,978	413,888,211	454,478,459	440,820,586	397,154,741	379,254,704	392,481,836	414,351,410	**4,854,537,372**
Historic Ratios (kW)[3]													
System kW/Energy Purchased kWh - IESO	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	
System Line/System kW - IESO	106.20%	106.20%	106.20%	106.20%	106.20%	106.20%	106.20%	106.20%	106.20%	106.20%	106.20%	106.20%	
System Transformer/System kW - IESO	29.40%	29.40%	29.40%	29.40%	29.40%	29.40%	29.40%	29.40%	29.40%	29.40%	29.40%	29.40%	
System kW/Energy Purchased kWh - HONI	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	
System Line/System kW - HONI	100.54%	100.54%	100.54%	100.54%	100.54%	100.54%	100.54%	100.54%	100.54%	100.54%	100.54%	100.54%	
Low Voltage/System kW - HONI	135.79%	135.79%	135.79%	135.79%	135.79%	135.79%	135.79%	135.79%	135.79%	135.79%	135.79%	135.79%	
kW Quantities													
Transmission Network - IESO	1,282,429	1,182,992	1,229,109	1,124,167	1,160,286	1,261,211	1,384,898	1,343,280	1,210,220	1,155,675	1,195,981	1,262,622	**14,792,870**
Transmission Line - IESO	1,361,941	1,256,339	1,305,315	1,193,867	1,232,225	1,339,407	1,470,763	1,426,564	1,285,255	1,227,328	1,270,133	1,340,906	**15,710,044**
Transmission Transformation - IESO	376,996	347,765	361,322	330,472	341,090	370,758	407,119	394,884	355,769	339,734	351,583	371,173	**4,348,665**
Transmission Network - HONI	242,487	223,685	232,405	212,562	219,392	238,475	261,862	253,993	228,833	218,520	226,141	238,742	**2,797,097**
Transmission Line - HONI	243,795	224,891	233,658	213,709	220,575	239,761	263,275	255,363	230,068	219,698	227,361	240,029	**2,812,183**
LV Charges - HONI	329,271	303,740	315,581	288,637	297,910	323,823	355,581	344,895	310,731	296,726	307,075	324,186	**3,798,155**
RATES													
Commodity (RPP)	0.08069	0.08069	0.08069	0.08069	0.08069	0.08069	0.08069	0.08069	0.08069	0.08069	0.08069	0.08069	**0.08069**
Commodity (Spot)	0.02464	0.01941	0.01941	0.01941	0.02193	0.02193	0.02193	0.02531	0.02531	0.02531	0.02708	0.02708	**0.02323**
Global Adjustment Rate/kWh	0.05772	0.05772	0.05772	0.05772	0.06176	0.06176	0.06176	0.06176	0.06176	0.06176	0.06176	0.06176	**0.06041**
Transmission Network - IESO	3.5700	3.5700	3.5700	3.5700	3.5700	3.5700	3.5700	3.5700	3.5700	3.5700	3.5700	3.5700	**3.5700**
Transmission Line - IESO	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000	**0.8000**
Transmission Transformation - IESO	1.8600	1.8600	1.8600	1.8600	1.8600	1.8600	1.8600	1.8600	1.8600	1.8600	1.8600	1.8600	**1.8600**
Transmission Network - HONI	2.6500	2.6500	2.6500	2.6500	2.6500	2.6500	2.6500	2.6500	2.6500	2.6500	2.6500	2.6500	**2.6500**
Transmission Line - HONI	0.6400	0.6400	0.6400	0.6400	0.6400	0.6400	0.6400	0.6400	0.6400	0.6400	0.6400	0.6400	**0.6400**
Transmission Transformation - HONI	1.5000	1.5000	1.5000	1.5000	1.5000	1.5000	1.5000	1.5000	1.5000	1.5000	1.5000	1.5000	**1.5000**
LV Charges - HONI	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	0.6680	**0.6680**
Wholesale Market Charge (per kWh)	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056	**0.0056**
Monthly Service charges (fixed per account)	292.56	292.56	292.56	292.56	292.56	292.56	292.56	292.56	292.56	292.56	292.56	292.56	**292.56**
LVDS (per kW)	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	**1.9440**
Specific ST Lines (per km)	633.28	633.28	633.28	633.28	633.28	633.28	633.28	633.28	633.28	633.28	633.28	633.28	**633.28**
COP EXPENSE													
Commodity (RPP)	$ 27,150,911	$ 25,045,689	$ 26,022,044	$ 23,800,279	$ 24,564,959	$ 26,701,686	$ 29,320,335	$ 28,439,208	$ 25,622,139	$ 24,467,332	$ 25,320,670	$ 26,731,569	**$ 313,186,823**
Commodity (Spot)	34,661,321	29,943,371	31,110,652	28,454,420	31,866,624	34,638,470	38,035,484	38,382,425	34,580,422	33,021,859	34,868,910	36,811,849	**$ 406,375,808**
Transmission Network - IESO	4,578,272	4,223,283	4,387,919	4,013,278	4,142,221	4,502,522	4,944,087	4,795,509	4,320,486	4,125,758	4,269,651	4,507,561	**$ 52,810,546**
Transmission Line - IESO	1,089,553	1,005,071	1,044,252	955,094	985,780	1,071,526	1,176,611	1,141,252	1,028,204	981,862	1,016,106	1,072,725	**$ 12,568,035**
Transmission Transformation - IESO	701,213	646,842	672,058	614,678	634,427	689,611	757,241	734,485	661,730	631,905	653,944	690,383	**$ 8,088,516**
Transmission Network - HONI	642,590	592,765	615,873	563,290	581,388	631,959	693,935	673,081	606,408	579,077	599,274	632,666	**$ 7,412,307**
Transmission Line - HONI	156,029	143,931	149,541	136,774	141,168	153,447	168,496	163,432	147,243	140,607	145,511	153,619	**$ 1,799,797**
Transmission Transformation - HONI	365,692	337,337	350,488	320,563	330,862	359,642	394,912	383,044	345,101	329,547	341,041	360,044	**$ 4,218,274**
LV Charges - HONI	219,953	202,898	210,808	192,809	199,004	216,314	237,528	230,390	207,568	198,213	205,126	216,556	**$ 2,537,168**
Wholesale Market Charge	4,212,222	3,885,616	4,037,088	3,692,401	3,811,035	4,142,529	4,548,789	4,412,090	3,975,047	3,795,888	3,928,276	4,147,165	**$ 48,588,145**
Monthly Service charges (24 accounts)	7,021	7,021	7,021	7,021	7,021	7,021	7,021	7,021	7,021	7,021	7,021	7,021	**$ 84,257**
LVDS (on average 1,850 kW)	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596	**$ 43,157**
Specific ST Lines (8.8 km)	5,573	5,573	5,573	5,573	5,573	5,573	5,573	5,573	5,573	5,573	5,573	5,573	**$ 66,874**
Total Cost of Power	**$ 73,793,947**	**$ 66,042,994**	**$ 68,616,915**	**$ 62,759,776**	**$ 67,273,658**	**$ 73,123,896**	**$ 80,293,609**	**$ 79,371,106**	**$ 71,510,539**	**$ 68,288,240**	**$ 71,364,700**	**$ 75,340,327**	**$ 857,779,706**

SERVICE QUALITY AND RELIABILITY PERFORMANCE

PowerStream measures Ontario Energy Board prescribed service quality indicators and reliability performance metrics and reports these to the Board on an annual basis. In all categories, PowerStream performance is at or above the Board's standard. Table 1 below summarizes these metrics for the past three years.

Table 1: Service Quality and Reliability Measures

Service Quality Indicator	Minimum Standard	2009	2010	2011	Average
Connection of New Services Low Voltage	90% or better	97.60%	97.60%	93.10%	96.10%
Connection of New Services High Voltage	90% or better	N/A	N/A	N/A	N/A
Underground Cable Locates	90% or better	N/A	N/A	N/A	N/A
Appointments Scheduling	90% or better	100%	99.90%	99.95%	99.95%
Appointments Met	90% or better	100%	99.30%	98.73%	99.34%
Rescheduling a Missed Appointment	100%	N/A	100%	100%	100.00%
Telephone Accessibility (Telephone Service Factor)	65% or better	69.20%	68.30%	77.20%	71.57%
Telephone Call Abandon Rate	less than 10%	4.10%	4.90%	2.40%	3.80%
Written Response to Inquires	80% or better	99.10%	99.10%	98.80%	99.00%
Emergency Response -Urban	80% or better	87.25%	95.12%	94.22%	92.20%
Emergency Response -Rural	80% or better	n/a	n/a	n/a	n/a
SAIDI (System Average Interruption Duration Index)	Within the range of performance over the previous 3 years	1.975	0.813	1.201	1.330
SAIFI (System Average Interruption Frequency Index)	Within the range of performance over the previous 3 years	1.233	0.923	1.231	1.129
CAIDI (Customer Average Interruption Duration Index)	Within the range of performance over the previous 3 years	1.601	0.881	0.976	1.153
SAIDI (System Average Interruption Duration Index) - Exclude Code 2 Loss of supply	Within the range of performance over the previous 3 years	1.585	0.537	1.046	1.056

SAIFI (System Average Interruption Frequency Index) - Exclude Code 2 Loss of supply	Within the range of performance over the previous 3 years	1.070	0.801	1.003	0.958
CAIDI (Customer Average Interruption Duration Index) - Exclude Code 2 Loss of supply	Within the range of performance over the previous 3 years	1.481	0.670	1.043	1.065

Notes: PowerStream does not distinguish between low voltage and high voltage connections. The data for both types of connections is included in the low voltage category. Similarly underground cable locates have been included in the Appointment Scheduling category. PowerStream does not have any rural classification in its service territory.

PowerStream is a member of the Canadian Electricity Association ("CEA") Service Continuity Committee as a means to perform peer comparisons and discuss best practices in performance management and improvement. PowerStream reliability performance compares favourably within this group of provincial, international, regional, and local utilities.

PowerStream tracks and reports internally reliability performance on a regular basis. Weekly performance is measured and reviewed by key Operations and Engineering groups. Monthly reliability performance and analysis is performed by the Operations and Planning groups and reviewed at the PowerStream Reliability Committee at monthly meetings. The Reliability Committee:

- Reviews the performance of the distribution network as a whole;
- Determines the worst performing feeders;
- Provides direction for PowerStream's maintenance efforts;
- Identifies plant for capital refurbishment or replacement;
- Investigates and reviews extraordinary outages; and
- Identifies equipment outage patterns and formulates strategies for these to be addressed.

In addition, PowerStream has completed an Asset Condition Analysis ("ACA") of its distribution network. The ACA provides an annual "roadmap" for capital replacement and refurbishment of PowerStream plant. The ACA program is reviewed at the Reliability Committee and further refinement of the roadmap is provided.

Marked improvement in reliability performance has been exhibited in 2010 and 2011 in the PowerStream North service areas since the merger of Barrie Hydro and PowerStream. This is due in part to the enabling of 24/7 control of the former Barrie Hydro assets from the main PowerStream control room.

"Defective Equipment" and "Loss of Supply" continue to be the most significant contributors to both the System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") categories. In addressing "Defective Equipment" the PowerStream Reliability Committee reviews and identifies patterns of failure, manufacturer issues, and age related failures to focus maintenance and capital efforts. Most "Loss of Supply" issues refer to Hydro One 44 kV supplies into the PowerStream service areas. Regular discussions are held with Hydro One to address the reliability performance of these feeders and affirm Hydro One's efforts for improvement.

Moving forward, reliability performance continues to be a significant driver of PowerStream operations, planning, and maintenance efforts. Migration has begun towards a Computerized Maintenance Management System ("CMMS") coupled with a Reliability Centered Maintenance regimen for PowerStream's Transformer Station and Distribution Station assets. The CMMS will also commence being leveraged for downstream network assets commencing in 2012.

THROUGHPUT REVENUE OVERVIEW

The components that derive revenue at current rates are identified in Exhibit C1, Tab 1, Schedules 1 to 4. PowerStream has applied current approved rates to the test year customer and sales forecast in order to derive the test year distribution revenue. At current approved rates PowerStream's distribution revenue including smart meter incremental revenue rate riders ("SMIRR") is $162,044,558 which is a 1.1% increase over 2012.

In 2010 and 2011, PowerStream filed applications EB-2010-0209 and EB 2011-0128, respectively, for recovery of costs associated with the installation of smart meters. The Board approved an annual incremental revenue requirement of $3,661,000 in 2010 and $3,089,000 in 2011. This incremental distribution revenue generated by these "mini-rebasing" applications has contributed to year over year variances of approximately 3.0% annually from 2010 to 2012. The year over year changes are identified in Table 1.

Table 1: Distribution Revenue at Current Rates

			PowerStream Consolidated				
	2008 OEB Approved PS North	2009 OEB Approved PS South	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Total Distribution Revenue	$31,571,927	$114,713,479	$143,065,672	$148,579,942	$154,614,796	$160,263,125	$162,044,558
% Change Year over Year				3.9%	4.1%	3.7%	1.1%
$ Change Year over Year				$5,514,270	$6,034,854	$5,648,330	$1,781,433

The schedules included in this Exhibit outline and describe PowerStream's load, customer, and distribution revenue forecasts. The load forecast methodology and assumptions are described in detail in Exhibit C1, Tab 1, Schedule 2. PowerStream's purchase forecast is based on a linear regression model. The load forecasting model relates monthly historical purchases to monthly weather conditions (measured in cooling-degree-days ("CDD") and heating-degree-days (HDD)), and Ontario Gross Domestic Product ("GDP") as a proxy for service area customer growth and economic activity. The values for Ontario GDP for 2012 and 2013 are 1.9 and 2.3 percent, respectively based on publicly available publications by six major banks as of January 11, 2012. Further adjustments for projected Conservation and Demand Management ("CDM") reductions and estimated distribution losses are made to derive distribution sales.

PowerStream's customer forecast is derived based on historic trending by rate class. The customer forecast methodology is described in detail in Exhibit C1, Tab 1, Schedule 3. Customer growth is slowing from historic levels to approximately 2.0% in both the bridge and test years. PowerStream has peaked in terms of high growth single family developments and therefore residential customer growth is beginning to reduce as the availability of "green field" development becomes less. In addition, economic factors in recent years have contributed to the slower pace of growth for all classes.

Table 2 summarizes the 2013 test year forecast inputs that are used to derive distribution revenue and illustrates the year over year changes in distribution sales (kWh and kW) and customer growth.

Table 2: Distribution Sales (kWh and kW) and Customers

			PowerStream Consolidated				
	2008 OEB Approved PS North	2009 OEB Approved PS South	2009 Actuals	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Consumption, KWH	1,607,487,329	6,829,307,310	8,039,883,040	8,334,777,460	8,394,821,657	8,446,902,913	8,467,944,830
Demand, KW	2,106,590	10,400,971	11,721,833	12,177,393	12,303,354	12,455,585	12,496,684
Customer Count	85,976	311,829	394,514	403,943	412,262	421,644	430,475
Variance Analysis (units)			2010 vs. 2009	2011 vs. 2010	2012 vs. 2011	2013 vs. 2012	
Consumption, KWH			294,894,420	60,044,197	52,081,256	21,041,917	
Demand, KW			455,561	125,961	152,231	41,099	
Customer Count			9,429	8,319	9,383	8,831	
Variance Analysis (%)			2010 vs. 2009	2011 vs. 2010	2012 vs. 2011	2013 vs. 2012	
Consumption, KWH			3.7%	0.7%	0.6%	0.2%	
Demand, KW			3.9%	1.0%	1.2%	0.3%	
Customer Count			2.4%	2.1%	2.3%	2.1%	

Year over year data analysis is showing that consumption per customer is trending lower which may be attributable to a variety of factors including the 2009 economic recession and slow economic recovery, CDM initiatives, smart meters and an increase in general knowledge regarding energy pricing, general efficiencies regarding appliances and home/business construction and a shift from single family dwellings to building intensification. As a result, PowerStream is experiencing lower consumption per customer and a tempering in distribution revenue growth. Figure 1 below illustrates the sales per customer trend. The data are adjusted or normalized for weather.

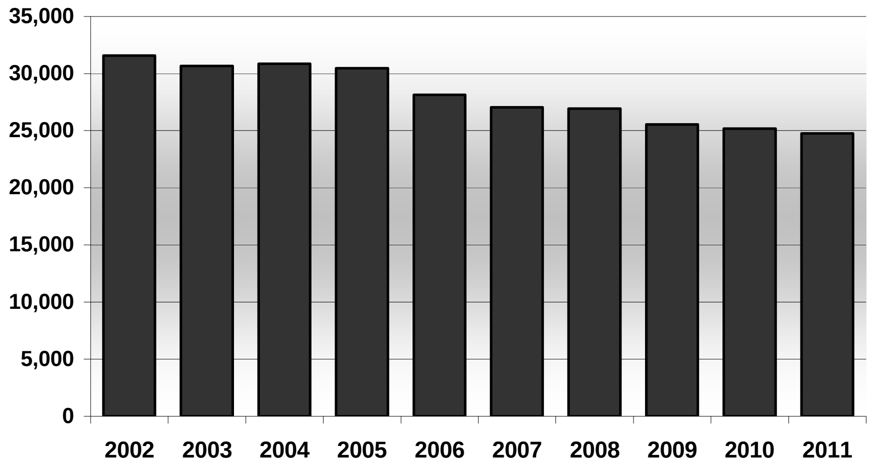


Figure 1: Normalized Energy Sales per Customer (2002 – 2011)

PowerStream anticipates that the impacts of CDM and energy efficiencies will persist as the Province continues to pursue this initiative. As a result, various pressures either economic or industry related are contributing to lower trends in consumption, customer and distribution revenue growth.

LOAD FORECAST

Introduction

In the 2009 Electricity Distribution Rate ("EDR") Application, PowerStream used a load forecasting methodology which was developed in-house using a SSPS software platform. This methodology performed reasonably well and was accepted by the Board in its last cost of service application EB-2008-0244 In addition to use for rate filing purposes, this load forecast model was used for setting revenue targets in the annual budgeting process between 2008 and 2011. Table 1 below shows 2009-2011 forecast energy purchases compared to the 2009-2011 actuals.

Table 1: Forecast vs. Actual Energy Purchases

	Forecast	Actuals	Variance, MWH	Variance, %
2009	7,040,674	6,729,444	(311,230)	-4.6%
2010	8,455,128	8,648,433	193,305	2.2%
2011	8,847,148	8,697,308	(149,840)	-1.7%

Note: 2009 - PowerStream South, 2010-2011 - PS Consolidated

Given that PowerStream continues to strive to improve its load forecasting methodology, PowerStream explored the ability to forecast class-specific loads, as suggested by the Board in 2009, EB-2008-0244 Draft Rate Order, Schedule H, Section 3.5. Class specific sales models were not nearly as strong statistically as the total purchase model. There is significant variation in monthly billing data as it reflects bi-monthly readings for residential customers. In addition, the data includes various billing adjustments and the historic data set is too short (2006-2011) in order to normalize this variation. As a rough guide, there is a possibility of overfitting the data if there are less than ten data points per coefficient estimated. Therefore, the decision was made to continue working with a modelling approach using total monthly energy purchases. PowerStream explored various forecasting options and tools available in the market. As a result, PowerStream selected a comprehensive energy forecasting tool, MetrixND supported by Itron Inc. PowerStream is confident that this forecasting tool will assist in providing greater efficiencies in deriving its load forecast results based on MetrixND focus for use in the energy sector.

MetrixND is a comprehensive energy forecasting tool that can be used for all energy forecasting applications with market share of over 700 users from 170 utilities and energy companies primarily in North America. The following is a list of other Canadian users of MetrixND software:

- Alberta Electricity System Operator
- BC Hydro
- Enersource Hydro Mississauga
- Enmax Power Corp
- Hydro One Networks Inc
- Hydro Ottawa
- Hydro Quebec
- Independent Electricity System Operator
- Manitoba Hydro
- New Brunswick
- Nova Scotia Power
- Ontario Power Generation
- TransAlta
- Union Gas

Modelling Approach

PowerStream has adopted a relatively straightforward approach for forecasting short-term energy purchases. PowerStream's purchase forecast is based on a linear regression model**.** PowerStream is cognisant that Conservation and Demand Management ("CDM") is a key initiative in the Province of Ontario since the enacting of the *Green Energy and Green Economy*

Act, 2009. As a result, CDM programs will impact future electricity loads. Therefore, a considerable amount of time was spent determining a robust, effective and accurate methodology for measuring the expected impacts of CDM programs on future loads in order to ensure that the load forecast reflects this change from historical levels. Three commonly used forecast methods, explored were:

- Method 1: Forecast using actual load (without any CDM adjustment)**;**
- Method 2: Incorporate CDM impacts as an explanatory variable in the regressions equation; and
- Method 3: Add back historical CDM impacts to the actual load and then forecast forward.

Various purchase models under each method were specified and assessed. Table 2 compares the model results.

Table 2: Purchase Models Comparison

Model Statistics	Method 1 Actual Purchases	Method 2 CDM as a variable	Method 3 Gross Actual Purchases
Adjusted R^2	96.20%	96.20%	96.40%
MAPE	1.22%	1.20%	1.19%
AIC	18.712	18.705	18.697
BIC	18.945	18.960	18.929

While the statistics are comparable across the three methods, PowerStream concluded that Method 3 is the most robust and technically sound and it produces a reliable and accurate load forecast. PowerStream has adopted Method 3 and has grossed up the historical load based on reported CDM results.

In order to estimate the gross load utilizing Method 3, the following steps were performed:

Step 1: Derive historic total electricity volume reductions resulting from CDM initiatives using data from following sources:

a. Historic Ontario Power Authority ("OPA") programs *(source: OPA Report, Section 2.7.10 of Chapter 2 of the Board's "Filing Requirements for Transmission and Distribution Applications", dated June 22, 2011);*

b. 3rd Tranche LDC programs *(source: PowerStream and former Barrie Hydro Annual CDM Reports for 2005-2008);*

c. 2011-2014 CDM targets – each licensed distributor must, as a condition of its license, meet its respective CDM targets as established by the Board *(source: EB-2010-0215, EB-2010-0216).*

Table 3 below presents the historic volume reductions by source.

Table 3: Historic CDM Savings (kWh)

Year	OPA Programs	3rd Tranche	CDM Targets 2011-2014	Total CDM Savings
2005	0	3,130,723	0	**3,130,723**
2006	23,745,838	24,080,564	0	**47,826,403**
2007	37,320,287	33,881,792	0	**71,202,078**
2008	74,910,984	33,568,782	0	**108,479,766**
2009	118,966,981	0	0	**118,966,981**
2010	125,158,173	0	0	**125,158,173**
2011	114,674,894	0	14,637,000	**129,311,894**

The gross forecast assumes some level of embedded "natural conservation". The scope and rate of natural conservation cannot be measured but may be driven by such factors as relative price effects, industrial plant growth and productivity improvements, incremental technology improvements, changes in the economy that reduce energy intensity, old energy-consuming assets being replaced with new and more efficient technologies, and the availability and performance of energy management measures. There is insufficient evidence to determine how each of these factors impacts the load forecast.

Step 2: The historic loads were grossed up by CDM savings. Table 4 below provides a summary of historic actual load, CDM savings (as per Table 3), and historic actual load grossed up by CDM (Gross Load) by year.

Table 4: Historic Actual Load, CDM Savings and Gross Load

Year	Actual MWH	CDM Savings MWH	Gross Load MWH
2002	7,866,380	0	7,866,380
2003	7,916,829	0	7,916,829
2004	8,134,620	0	8,134,620
2005	8,609,993	3,131	8,613,124
2006	8,506,707	47,826	8,554,534
2007	8,709,989	71,202	8,781,191
2008	8,564,465	108,480	8,672,944
2009	8,287,391	118,967	8,406,358
2010	8,648,433	125,158	8,773,591
2011	8,697,308	129,312	8,826,620

<u>Step 3:</u> Develop gross purchases forecast using grossed-up historic values for load.

A resulted gross purchase forecast is adjusted by projected CDM reductions. PowerStream supports the Provincial Government's CDM initiatives and is currently delivering CDM programs funded by the OPA. By 2014, the cumulative planned energy savings from new CDM targets is 407 GWH, with a peak savings of 96 MW for PowerStream. PowerStream has forecasted that these targets will be met over the period of 2011-2014 as shown in Table 5. Table 5 shows the adjustments to be made to the gross purchases forecast to account for CDM reductions resulting from the historic OPA programs and CDM targets.

Table 5: Future CDM Savings

Year	OPA Programs	CDM Targets 2011-2014	Total CDM Reductions
2011A	114,674,894	14,637,000	129,311,894
2012F	112,573,489	63,374,000	**175,947,489**
2013F	112,089,533	141,438,000	**253,527,533**
2014	108,636,708	187,851,000	296,487,708
2011-2014	**447,974,624**	**407,300,000**	**855,274,624**

CDM Targets Allocation %
4%
16%
35%
46%
100%

Modelling Process and Weather Normalization

PowerStream's energy purchase forecast is based on a linear regression model. Distribution sales/consumption is derived from purchases based on an adjustment for estimated distribution losses. Distribution consumption is then allocated to the rate classes based on historical billing trends. For those rate classes that use kW consumption as a billing determinant, sales for these customer classes are then converted to kW based on the historical volumetric relationship between kWh and kW.

Below are the details of the modelling process:

The energy purchases forecasting model relates monthly historical purchases to monthly weather conditions (measured in cooling-degree-days ("CDD") and heating-degree-days ("HDD")), and Ontario GDP as a proxy for service area customer growth and economic activity. The following historical monthly data were used as inputs into the model:

- monthly system load (i.e. purchases) grossed up by CDM data for January 2002 to December 2011
- weather data: HDD and CDD;
- Real Gross Domestic Product (GDP) growth index for Ontario.

The forecast is then derived by using the estimated model (i.e. estimated parameters) to predict monthly purchases for projected GDP and normal CDD and HDD. The total gross energy purchases forecast is adjusted to account for the impact of CDM. The net energy purchase forecast is allocated to rate zones (i.e. PowerStream South and PowerStream North) based on the 3-year average for the 2009-2011 period. The allocation between rate zones is done to determine distribution at current rates as historical line losses have been approved at separate levels prior to harmonization in 2013.

Table 6 provides a comparison of the forecasted, actual and weather-normalized purchases GWHs over the past ten years and presents the 2012-2013 forecasts (not adjusted by CDM). In accordance with the Filing Requirements, PowerStream has also provided a 2013 forecast assuming twenty-year normal weather conditions.

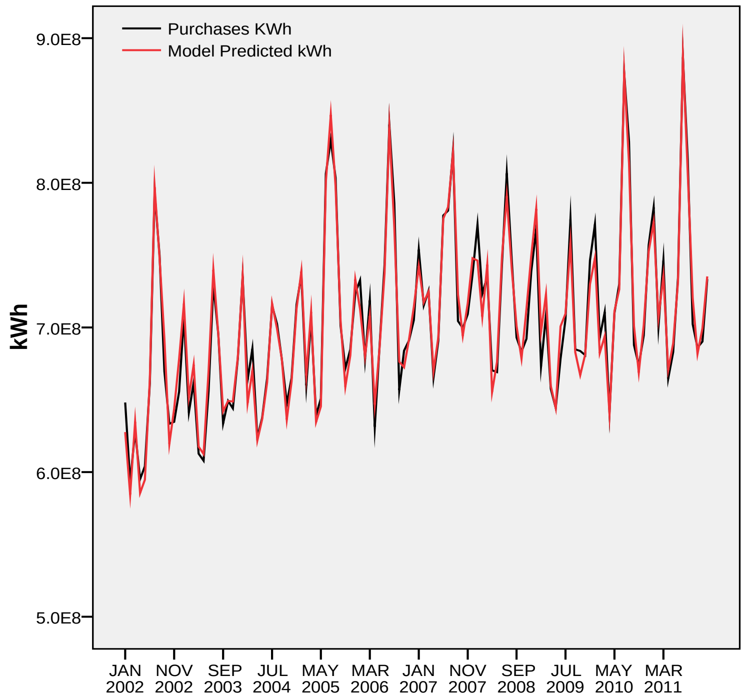
1 **Table 6: Total System Purchases, GWH**

Year	Actual Gross	Model Predicted	Variance, Actual to Predicted, %	Weather-Normal (WN) Actual Gross	Variance, WN Actual to Predicted, %
2002	7,866	7,870	0.0%	7,751	-1.5%
2003	7,917	7,996	-1.0%	7,930	-0.8%
2004	8,135	8,080	0.7%	8,274	2.4%
2005	8,613	8,619	-0.1%	8,425	-2.3%
2006	8,555	8,533	0.3%	8,613	0.9%
2007	8,781	8,809	-0.3%	8,689	-1.4%
2008	8,673	8,651	0.3%	8,774	1.4%
2009	8,406	8,436	-0.3%	8,586	1.8%
2010	8,774	8,715	0.7%	8,739	0.3%
2011	8,827	8,837	-0.1%	8,774	-0.7%
2012 Bridge - Forecast		**8,890**			
2013 Test - Forecast - Normalized 10-year		**8,989**			
2013 Test - Forecast - Normalized 20-year		**8,951**			

2

3 Figure 1 graphically displays actual vs. predicted load for the 2002-2011 period.

Figure 1: Gross Actual vs. Predicted -2002-2011 (kWh)



The load forecast model was populated with the actual energy purchase data from January 2002 through December 2011. Table 7, below, provides historical actual (grossed up by CDM) and historical normalized annual energy purchased data for PowerStream. The heading “normalized actual” shows the purchases adjusted to reflect “normal” weather conditions. PowerStream considers “normal” weather conditions to be the average of the weather characteristics for the ten-year time period, 2002 to 2011.

PowerStream normalizes energy purchases using a “use per degree” methodology. This methodology uses the weather-related coefficients in the regression equation to estimate normalized volumes. The difference between actual and normal degree-days is determined. The weather related coefficients are applied to that difference to derive weather-sensitive volume. Actual volumes are adjusted by the weather sensitive volume.

The formula is:

Normalized Volume = Actual Volume – (Actual HDD *or/and* CDD – Normal HDD *or/and* CDD) x Corresponding Regression Coefficient

Table 7: Historic Annual Energy Purchases Grossed up by CDM (GWH)

Year	Actual Gross	Normalized Actual Gross	Change	% Change	Compounded AVG Growth
2002	7,866	7,751			
2003	7,917	7,930	178	2.3%	2.3%
2004	8,135	8,274	345	4.3%	1.7%
2005	8,613	8,425	151	1.8%	3.1%
2006	8,555	8,613	188	2.2%	2.1%
2007	8,781	8,689	76	0.9%	2.2%
2008	8,673	8,774	85	1.0%	1.6%
2009	8,406	8,586	(188)	-2.1%	1.0%
2010	8,774	8,739	153	1.8%	1.4%
2011	8,827	8,774	35	0.4%	1.3%
Average 2003-2006				**2.7%**	
Average 2007-2011				**0.4%**	

Table 8 provides the same information for actual historic loads not adjusted for CDM.

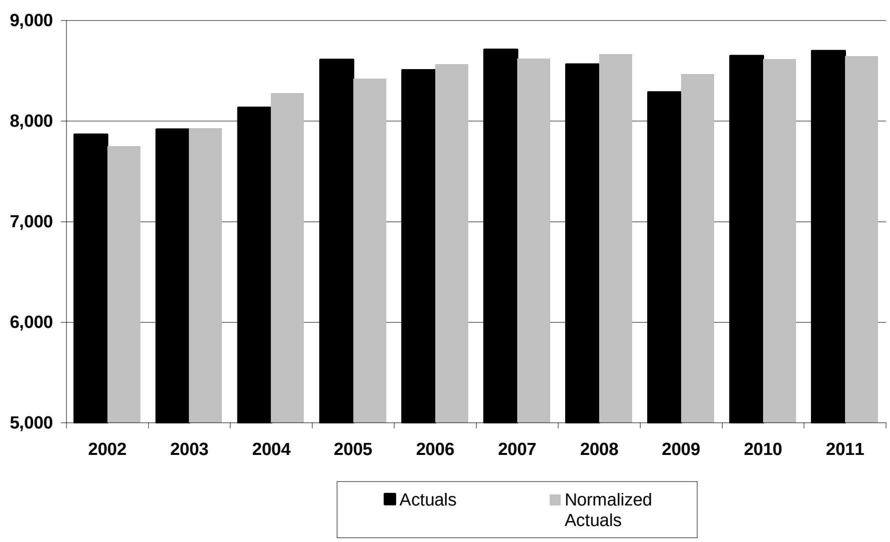
Table 8: Historic Annual Energy Purchases (GWH)

Year	Actuals	Normalized Actuals	Change	% Change	Compounded AVG Growth
2002	7,866	7,749			
2003	7,917	7,929	180	2.3%	2.3%
2004	8,135	8,277	348	4.4%	1.7%
2005	8,610	8,420	143	1.7%	3.1%
2006	8,507	8,566	146	1.7%	2.0%
2007	8,710	8,618	52	0.6%	2.1%
2008	8,564	8,665	47	0.5%	1.4%
2009	8,287	8,465	(200)	-2.3%	0.7%
2010	8,648	8,614	149	1.8%	1.2%
2011	8,697	8,646	32	0.4%	1.1%
Average 2003-2006				**2.5%**	
Average 2007-2011				**0.2%**	

Until recently, PowerStream had relatively strong sales growth experiencing both strong population and economic growth. Between 2002 and 2006, normalized actual purchases averaged 2.5% annual growth. However, since 2006 there has been a trend of dampened sales with the most significant decline in 2009. This is likely attributable to a variety of factors which include "natural conservation", a focus on CDM initiatives and most pointedly the global economic slowdown. Between 2007 and 2011, normalized actual purchases averaged 0.2% annual growth.

Figure 2 graphically depicts variances between actual and weather-normalized energy purchases for 2002 to 2011.

Figure 2: Consumption Variance between Actuals and Weather-Normalized Energy Purchases, 2002 – 2011 (GWH)



Model Specifications

The purpose of a multiple regression equation is to predict a single dependent variable from multiple independent variables. Many variables (e.g., electricity prices, changes in gross domestic product, per capita incomes, employment levels, population and weather patterns), and the interactions among these variables, may affect overall electricity purchases. Given the complexity of load forecasting, the task is to find a specific set of explanatory (independent) variables that reflect PowerStream's circumstances and that can be used to generate the most accurate load forecast.

Different economic drivers were tested using different model specifications, as well as a stepwise regression technique. Stepwise regression is a procedure that adds and deletes one independent variable at a time. The decision to add/delete a variable is made on the basis of whether that variable improves the accuracy of the model. The variables listed in Table 9 were used as initial inputs for the purpose of regression analysis.

Table 9: Initial Set of Explanatory Variables

Dependent Variable	**Y**	Monthly Energy Purchases (KWh)
Independent (Explanatory) Variables		
	X_1	Heating Degree-days
	X_2	Cooling Degree-days
	X_3	Real Gross Domestic Product for Ontario
	X_4	Real Gross Domestic Product for Toronto CMA
	X_5	Real Personal Income per Capital for Toronto CMA
	X_6	Population (York Region and Barrie)
	X_7	Simple Trend
	X_8	Monthly Peak Hours
	X_9	Manufacturing GDP for Toronto CMA
	X_{10}	Population for Toronto
	X_{11}	Total Empoyment for Toronto CMA
	X_{12}	Manufacturing Empoyment for Toronto CMA

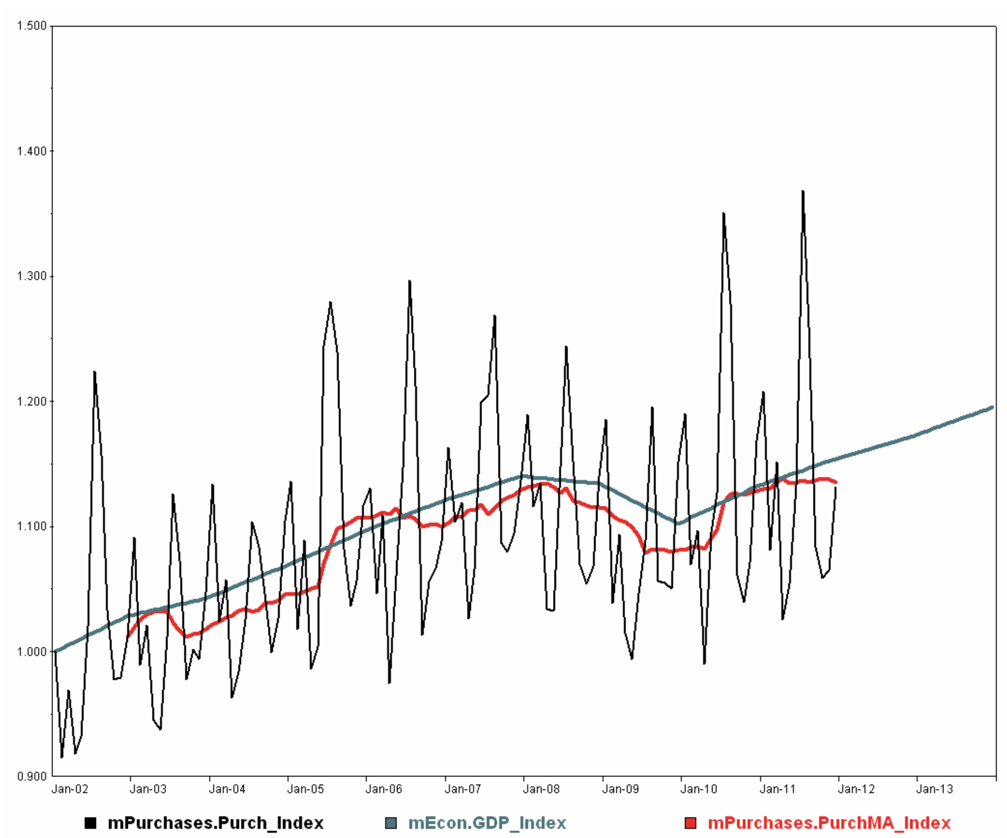
Several monthly models of energy purchases were specified, estimated and tested to derive the energy purchases forecast. The statistical software generated the coefficients that were used in the variables suitability assessment. The detailed results of the model testing are presented in Table 10. Model 5, using Ontario GDP as a proxy for service area customer growth and economic activity, was selected as the most accurate.

Table 10: Evaluation of Alternative Forecast Drivers

	Model 1	Model 2	Model 3	Model 4	Model 5	Model 6	Model 7
Constant	370,575,047	159,351,496	272,652,614	8,123,908	**548,429,022**	(45,500,832)	599,974,522
Independent Variables							
HDD10	193,469	190,285	192,125	191,658	**191,205**	217,255	167,879
CDD18	1,083,304	1,079,122	1,079,805	1,055,681	**1,058,759**	1,083,813	1,086,992
Ontario GDP Index					**33,399,922**		
GDP for Toronto				498,899,989			
Population (York Region, Barrie)	308,709						
Toronto population		90,958					
Manufacturing GDP for Toronto							
Non-Manufacturing GDP for Toronto							
Total Empoyment for Toronto						1,083,813	
Manufacturing Employment for Toronto							
Non-Manufacturing Employment for Toronto							
Real Income for Toronto			2,074,191				
Peak Hours				266,561		267,877	
Simple Trend							751,354
Feb	(49,793,149)	(51,368,921)	(52,103,062)	(45,860,506)	**(48,419,833)**	(45,983,238)	
Apr	(21,261,409)	(23,092,071)	(22,638,531)	(19,463,044)	**(21,384,508)**	(19,227,744)	
Aug-03	(60,821,280)	(63,528,355)	(50,653,367)	(46,388,505)	**(55,797,432)**	(58,142,589)	
Oct-03			33,488,858	26,084,471	**26,189,682**		
May-09					**(28,890,187)**		
Jul-10				27,279,518	**35,629,314**		
Model Statistics							
Adjusted R-Squared	92.80%	90.40%	93.10%	95.60%	**96.40%**	92.70%	85.10%
SEE	15,648,172	18,090,092	15,257,725	12,161,655	**11,033,665**	15,713,428	22,487,937
F-Test	255.963	186.783	231.749	291.071	**356.253**	217.588	227.448
DW	1.033	0.778	1.002	1.179	**1.904**	0.797	1.645

Figure 3 presents graphically Ontario GDP with its values indexed to 1.0 in 2002. Actual gross purchases and the moving average of those purchases have also been indexed so the economic driver and purchases can be illustrated on the same graph. This graph demonstrates that the selected economic driver tracks actual purchases relatively well.

Figure 3: Indexed GDP Variable against Gross Actual Load and Moving Average purchases



The selected model included the following variables:

- Ontario GDP: Ontario Real GDP Index;
- HDD10: Monthly HDD with a base of 10 degrees;
- CDD18: Monthly CDD with a base of 18 degrees;
- Feb: Binary variable for the month of February;

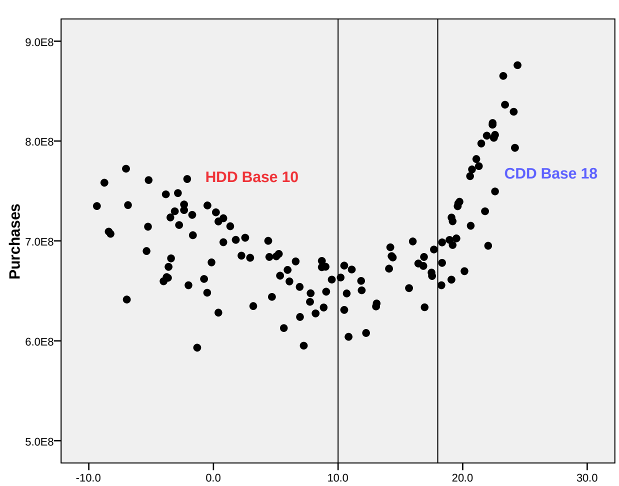
- Apr: Binary variable for the month of April.

The most significant independent variable for the model is GDP, actual values for which (2002 – 2010) were obtained from Statistics Canada. The forecasted values of Ontario GDP are based on a survey of long-term forecasts prepared by six major chartered banks of Canada (as of January 12, 2012).

Heating Degree Days ("HDD") are summations of negative differences between the mean daily temperature and the 10 °C base; Cooling Degree Days ("CDD") are summations of positive differences from the 18 °C base. The number of HDDs influences electricity use for space heating, while the number of CDDs influences electricity use for space cooling. The HDD variable also picks up some of the increased lighting load that results from shorter winter days. PowerStream uses the degree days count for the Toronto Lester B. Pearson International Airport Data Point as published by Environment Canada as this provides the most updated data on a monthly basis.

The appropriate basis for defining the HDD and CDD temperature breaks was determined by evaluating average monthly purchases against average monthly temperature. Figure 4 shows this relationship.

Figure 4: Purchases vs. Average Temperature



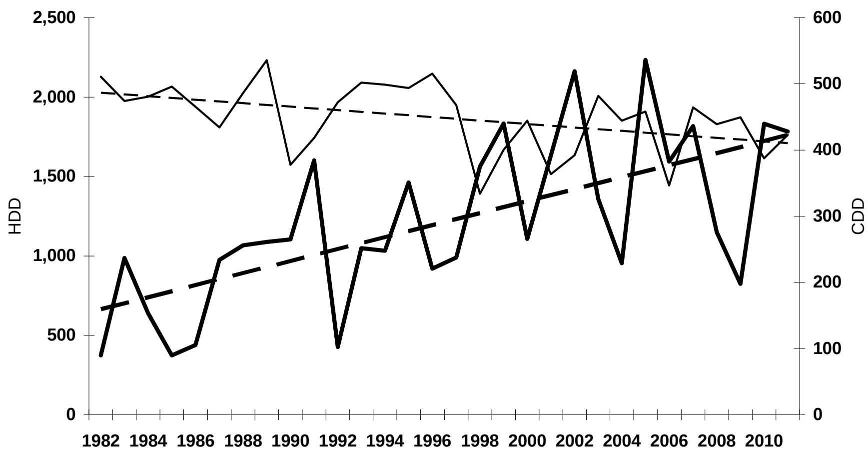
As Figure 4 shows, cooling load begins where average temperature is above 18 degrees and heating load can be seen with average temperature below 10 degrees.

For purposes of PowerStream's load forecast, weather is not forecasted. Weather inputs are based on monthly normal HDD and CDD data. The decision was made to move from traditional 30-year to 10-year (2002 – 2011) weather time series for defining normal weather.

The 10-year average has been used in other electricity distribution rate applications in recent years as an acceptable approach for weather normalization. Looking at the details, the 10-year time series weather data is also more representative of the general weather trend of milder winters and warmer summers. Winters in PowerStream's service area are generally mild with annual HDDs averaging 1,786 from 2002 through 2011. The extremely cold winter of 2003 was followed by relatively mild winters through 2011 with very mild winter in 2006. From 2002 through 2011, HDDs have ranged from 1,444 in 2006 to 2,007 in 2003. The general trend has been downward, i.e. winters generally are getting warmer.

Summers in PowerStream's service area are generally hot and humid with average annual CDDs of 377 for the period 2002 through 2011. The cool summer in 2004 was followed by extremely hot summer in 2005 and 2007 and again, by unseasonably cold summer of 2009. From 2002 to 2011, cooling degree-days have ranged from 536 in 2005 to 198 in 2009 with the general trend upward, i.e. summers generally are getting warmer (see Figure 5).

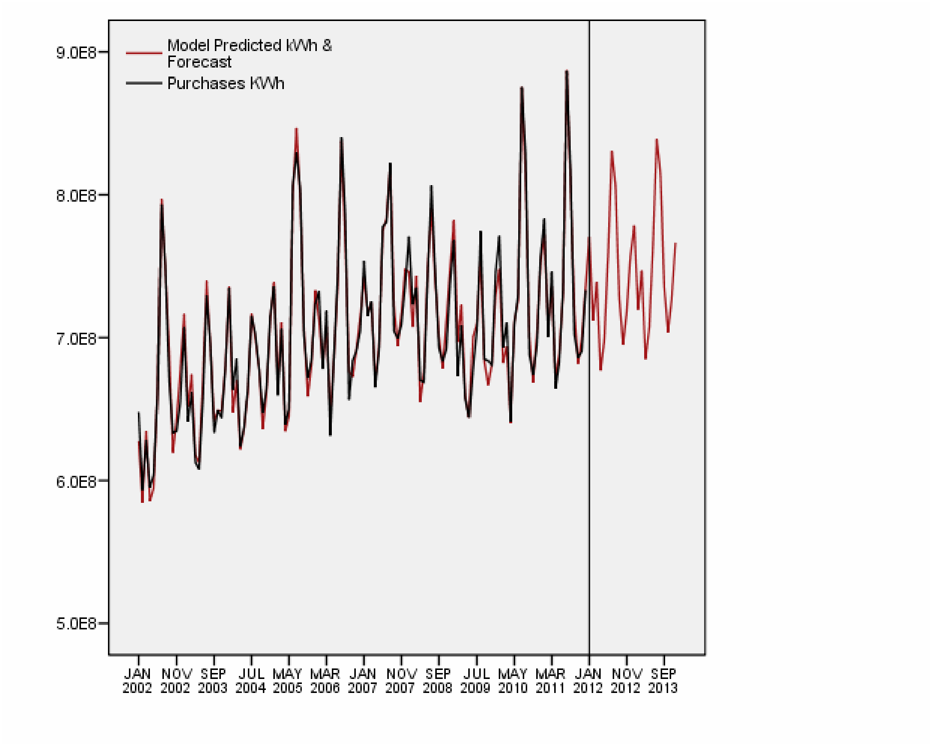
Figure 5: Historic HDD & CDD, 1990 – 2011



Calendar factors, such as the number of days in a month or seasonality, tend to influence energy use. In order to incorporate these effects two binary variables were introduced to the model. The binary variable for February is used to capture an effect of a shorter month and binary variable for April is used to capture the effect of seasonality.

The load forecasting model, using GDP, HDD, CDD, and two shoulder month variables, has tracked historic experience quite well in terms of both levels and peaks. Moreover, it captures the historical pattern of energy purchases with respect to economic and weather conditions. Figure 6 shows the selected equation's ability to capture historic monthly energy purchases. It shows the historic time series (Purchases kWh) and presents the current forecast (Model Predicted kWh).

Figure 6: Monthly Actual vs. Predicted Energy Purchases Forecast (kWh)



The selected model specifications are summarized in Table 11.

Table 11: Summary of Monthly Load Forecast Regression Model

Dependent Variable: Monthly Energy Purchases grossed up by CDM Form: Multiple Regression Sample: 01/2002 - 12/2011 Included observations: 120 Degree of Freedom for Error: 110			
Variable	**Coefficient**	**t-Statistics**	**Sig.**
(Constant)	548,429,023	126.98	0.00%
Real GDP	33,399,922	27.23	0.00%
CDD18	1,058,759	42.08	0.00%
HDD10	191,205	26.04	0.00%
Feb	(48,419,831)	(11.95)	0.00%
Apr	(21,384,509)	(5.54)	0.00%
Adjusted R-squared	96.4%	**MAD**	8,321,180
Standard Error of regression	11,033,670	**MAPE**	1.2%
F-test	356.3	**Durbin-Watson statistics**	1.9

As shown, the model variables are all statistically significant at the 5% level of confidence and the model fit is strong with an adjusted R-squared of 96.4%, and an in-sample Mean Absolute Percentage Error ("MAPE") of 1.2%. From the statistical perspective, the Ontario GDP-based model explains purchases exceptionally well.

Regression coefficients generated by the model were used to predict future energy purchases. Coefficients describe the average amount of change to be expected in purchases given a unit change in the value of the particular independent variable while holding other variables constant. Combining the results of the coefficient table into a regression equation, the monthly purchases are expressed as:

Monthly kWh = 548,429,023 + (33,399,922*Real GDP) + (1,058,759*CDD) + (191,205*HDD) + ((48,419,831)*Feb) + ((21,384,509)*Apr)

The key results of the monthly energy purchases forecast are summarized in Table 12. Data from January 2002 to December 2011 was used to help select the model and to estimate its parameters. Forecasts are made for time periods beyond the end of the available data. To estimate the average energy purchases for any particular combination of predictor variable values, the values of the predictor variables are simply substituted in the estimated regression equation itself.

Table 12: Monthly Gross Energy Purchases Forecast (kWh)

Month	kWh Purchases	GDP	CDD	HDD	Feb	Apr
Model Coefficient	**548,429,023**	**33,399,922**	**1,058,759**	**191,205**	**(48,419,831)**	**(21,384,509)**
Jan-12	770,717,025	3.98	0.0	467.0	0	0
Feb-12	711,896,347	4.00	0.0	409.2	1	0
Mar-12	739,032,613	4.02	0.0	294.5	0	0
Apr-12	676,962,680	4.04	1.2	71.7	0	1
May-12	698,196,126	4.06	13.4	0.0	0	0
Jun-12	757,701,582	4.08	69.0	0.0	0	0
Jul-12	830,650,298	4.10	137.3	0.0	0	0
Aug-12	805,978,497	4.12	113.4	0.0	0	0
Sep-12	727,307,090	4.14	38.5	0.0	0	0
Oct-12	695,002,770	4.15	4.2	17.7	0	0
Nov-12	718,713,469	4.17	0.0	161.7	0	0
Dec-12	757,977,184	4.19	0.0	363.8	0	0
Total 2012	**8,890,135,681**					
Jan-13	778,462,902	4.21	0.0	467.0	0	0
Feb-13	719,740,774	4.24	0.0	409.2	1	0
Mar-13	746,974,794	4.26	0.0	294.5	0	0
Apr-13	685,001,839	4.28	1.2	71.7	0	1
May-13	706,331,501	4.30	13.4	0.0	0	0
Jun-13	765,932,426	4.32	69.0	0.0	0	0
Jul-13	838,975,879	4.35	137.3	0.0	0	0
Aug-13	814,398,098	4.37	113.4	0.0	0	0
Sep-13	735,820,009	4.39	38.5	0.0	0	0
Oct-13	703,608,316	4.41	4.2	17.7	0	0
Nov-13	727,410,965	4.43	0.0	161.7	0	0
Dec-13	766,765,967	4.45	0.0	363.8	0	0
Total 2013	**8,989,423,470**					

Table 13 presents gross actual and normalized gross energy purchases for 2002 through 2011 and forecasts for 2012-2013. In 2011 the total weather-normalized energy was 8,774 GWH. In 2012 the total weather-normalized gross energy for PowerStream amounted to 8,890 GWH, an increase of 1.3%. For the 2013 Test Year, the forecast predicts a 1.1% decrease from 2012.

Table 13: Annual Gross Energy Purchases (GWH) 2002 to 2013

Year	Actuals Gross	Normalized Actuals Gross	Growth Rate (GWH)	Growth Rate (%)
2002	7,866	7,751		
2003	7,917	7,930	178	2.3%
2004	8,135	8,274	345	4.3%
2005	8,613	8,425	151	1.8%
2006	8,555	8,613	188	2.2%
2007	8,781	8,689	76	0.9%
2008	8,673	8,774	85	1.0%
2009	8,406	8,586	-188	-2.1%
2010	8,774	8,739	153	1.8%
2011	8,827	8,774	35	0.4%
2012 Forecast		**8,890**	**116**	**1.3%**
2013 Forecast		**8,989**	**99**	**1.1%**

To evaluate the model performance the last two years of actual purchases were held out of the estimation period (Jan 2010 – Dec 2011). Predicted purchases were then compared with actual purchases for this period. The two-year out-of-sample MAPE is 1.35% and the average forecast error is 0.5%.

The following analysis compares the out-of-sample forecast outcomes to a reasonable expectation for outcomes of forecasts generally. Forecasts will normally vary from actual (“error”), either higher or lower, and it is reasonable to expect that the load forecasting methodology is unbiased, if the average error of many forecasts (the “Mean Percentage Error”) is close to zero. Table 14 provides a summary of the outcomes of forecasted gross energy purchases compared to actual energy purchases for the period January 2010 to December 2011.

Column 1 (“WN Actual Gross”) is the weather-normalized actual electricity grossed up by CDM for PowerStream in 2011. Column 2 (“Model Predicted”) is the forecasted annual energy purchased. Column 3 and Column 4 (Error and Error % respectively) is the percentage difference between the actual outcome and the forecast. This percentage error is expressed as a fraction of the weather-normalized actual load.

Table 14: Energy Purchases Actual vs. Forecast (GWH)

Year	WN Actuals Gross	Model Predicted	Error	Error %
Jan-10	770	744	26	3.4%
Feb-10	700	688	12	1.7%
Mar-10	735	715	20	2.7%
Apr-10	657	656	2	0.2%
May-10	674	678	(4)	-0.6%
Jun-10	742	737	5	0.6%
Jul-10	845	809	36	4.2%
Aug-10	800	786	15	1.8%
Sep-10	696	709	(13)	-1.9%
Oct-10	682	678	5	0.7%
Nov-10	694	701	(7)	-1.0%
Dec-10	744	739	6	0.8%
Jan-11	771	758	12	1.6%
Feb-11	696	702	(5)	-0.8%
Mar-11	740	728	12	1.6%
Apr-11	662	668	(7)	-1.0%
May-11	683	690	(7)	-1.0%
Jun-11	753	749	4	0.6%
Jul-11	817	821	(3)	-0.4%
Aug-11	806	797	10	1.2%
Sep-11	701	719	(19)	-2.7%
Oct-11	692	688	4	0.6%
Nov-11	703	710	(8)	-1.1%
Dec-11	750	748	2	0.3%
	17,513	**17,417**	**96**	**0.5%**

PowerStream has performed due diligence testing of its load forecast methodology using both internal and external resources. The evaluation and validation process included analytical assessment of the forecast results, one-step-ahead forecasts to actual, statistical measures, residual analysis and external review. PowerStream has determined that its current methodology produces reasonable forecasts for the test period.

CDM Adjustment

The load forecast as described above does not take into account the impacts on energy purchases arising from CDM programs undertaken by PowerStream customers. The gross load forecast is a forecast of the expected level of electricity purchases that would occur over the specified period in the absence of any CDM initiatives.

The forecasted gross energy purchases are further adjusted to reflect CDM reductions. The CDM reduction breakdown by year is shown in Table 15.

Table 15: Energy Conservation Savings: Historic and Proposed

Year	OPA Programs	3rd Tranche	CDM Targets 2011-2014	Total
2005	0	3,130,723	0	**3,130,723**
2006	23,745,838	24,080,564	0	**47,826,403**
2007	37,320,287	33,881,792	0	**71,202,078**
2008	74,910,984	33,568,782	0	**108,479,766**
2009	118,966,981	0	0	**118,966,981**
2010	125,158,173	0	0	**125,158,173**
2011	114,674,894	0	14,637,000	**129,311,894**
2012	112,573,489	0	63,374,000	**175,947,489**
2013	112,089,533	0	141,438,000	**253,527,533**
2014	108,636,708	0	187,851,000	**296,487,708**

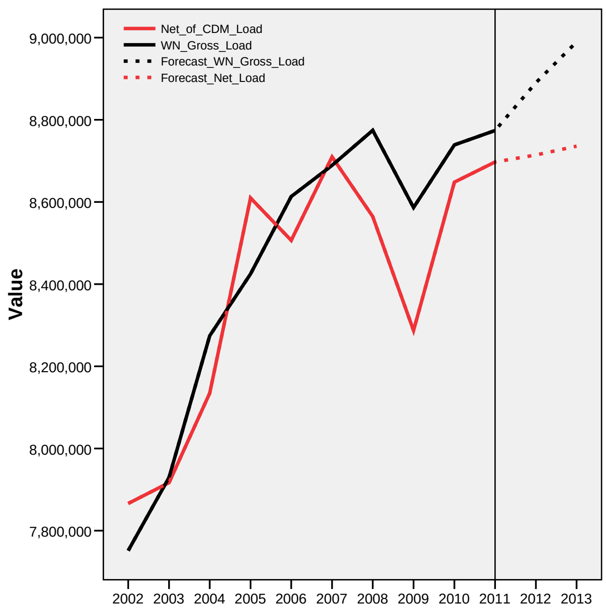
The results show that for 2013, 254 GWH will be saved. Accordingly, the energy purchases would decline by about 2.8% relative to the gross forecast. In absolute terms, this is a reduction in 2013 from 8,989 GWH to 8,736 GWH as shown below in Table 16. Weather-normal forecasted net values are derived by subtracting CDM reductions from weather-normal forecasted gross values.

Table 16: 2012-2013 CDM Reductions to Forecast

Year	Actual Gross	CDM Reduction	Actuals	WN Actual Gross	WN Actual Net	Growth, %
2002	7,866,379,972	0	7,866,379,970	7,751,492,170	7,751,492,170	
2003	7,916,829,431	0	7,916,829,430	7,929,636,020	7,929,636,020	2.3%
2004	8,134,619,559	0	8,134,619,560	8,274,389,550	8,274,389,550	4.3%
2005	8,613,124,001	3,130,721	8,609,993,280	8,424,990,830	8,421,860,109	1.8%
2006	8,554,533,739	47,826,399	8,506,707,340	8,613,410,100	8,565,583,701	1.7%
2007	8,781,190,983	71,202,083	8,709,988,900	8,689,191,980	8,617,989,897	0.6%
2008	8,672,944,378	108,479,768	8,564,464,610	8,774,325,000	8,665,845,232	0.6%
2009	8,406,357,788	118,966,978	8,287,390,810	8,586,280,120	8,467,313,142	-2.3%
2010	8,773,591,029	125,158,169	8,648,432,860	8,739,051,790	8,613,893,621	1.7%
2011	8,826,619,555	129,311,895	8,697,307,660	8,774,096,460	8,644,784,565	0.4%
2012 Bridge		**175,947,483**		**8,890,135,384**	**8,714,187,901**	**0.8%**
2013 Test		**253,527,536**		**8,989,423,173**	**8,735,895,637**	**0.2%**
2013 Test - Normalized 20-year		**253,527,536**		**8,950,597,850**	**8,697,070,314**	**-0.2%**

Figure 7 shows the gross and net forecasts graphically.

Figure 7: Gross vs. Net Forecast



Allocation of Purchases by Rate Zone

Since the distribution rates for PowerStream rate zones are not yet harmonized, revenues at current rates for each rate zone are required to be calculated separately, using the 2012 PowerStream North and PowerStream South approved distribution rates and forecasted loads. In order to derive forecasted loads by rate zone PowerStream used a three-year average of actual loads for each territory for 2009-2011 periods. Based on the analysis, on average 81.5% of the total load is allocated for PowerStream South and the remaining 18.5% for PowerStream North. Table 17 below provides the details of the allocation percentages.

Table 17: Energy Purchases Percentages by Rate Zones (2009-2011)

Month	PS South	PS North	PS Consolidated	PS South, %	PS North, %
Jan-09	608,853,588	149,450,610	758,304,198	80.29%	19.71%
Feb-09	531,656,744	131,434,700	663,091,444	80.18%	19.82%
Mar-09	563,766,322	134,953,110	698,719,432	80.69%	19.31%
Apr-09	526,473,875	121,145,650	647,619,525	81.29%	18.71%
May-09	516,893,729	117,491,700	634,385,429	81.48%	18.52%
Jun-09	550,770,053	117,611,800	668,381,853	82.40%	17.60%
Jul-09	572,164,352	123,694,369	695,858,721	82.22%	17.78%
Aug-09	627,387,984	137,447,554	764,835,538	82.03%	17.97%
Sep-09	551,533,361	123,395,492	674,928,853	81.72%	18.28%
Oct-09	545,756,960	128,031,094	673,788,054	81.00%	19.00%
Nov-09	542,337,532	128,658,916	670,996,448	80.83%	19.17%
Dec-09	591,849,965	144,631,347	736,481,312	80.36%	19.64%
Jan-10	611,863,979	149,045,019	760,908,998	80.41%	19.59%
Feb-10	549,851,186	132,727,908	682,579,094	80.55%	19.45%
Mar-10	567,589,938	132,518,229	700,108,167	81.07%	18.93%
Apr-10	514,429,721	116,578,054	631,007,775	81.53%	18.47%
May-10	577,720,492	121,802,114	699,522,606	82.59%	17.41%
Jun-10	593,765,785	125,909,971	719,675,756	82.50%	17.50%
Jul-10	715,687,229	149,430,332	865,117,561	82.73%	17.27%
Aug-10	674,008,090	144,035,177	818,043,267	82.39%	17.61%
Sep-10	555,414,382	121,995,190	677,409,572	81.99%	18.01%
Oct-10	542,073,961	121,316,280	663,390,241	81.71%	18.29%
Nov-10	558,208,453	125,811,084	684,019,538	81.61%	18.39%
Dec-10	604,232,090	142,418,194	746,650,284	80.93%	19.07%
Jan-11	624,253,342	148,005,729	772,259,071	80.83%	19.17%
Feb-11	558,416,140	131,418,890	689,835,029	80.95%	19.05%
Mar-11	597,823,034	137,675,899	735,498,934	81.28%	18.72%
Apr-11	534,147,852	119,802,131	653,949,983	81.68%	18.32%
May-11	551,601,102	120,606,764	672,207,866	82.06%	17.94%
Jun-11	597,595,454	125,819,517	723,414,971	82.61%	17.39%
Jul-11	723,917,259	151,978,641	875,895,900	82.65%	17.35%
Aug-11	665,623,560	139,729,422	805,352,982	82.65%	17.35%
Sep-11	567,928,849	123,496,668	691,425,517	82.14%	17.86%
Oct-11	551,126,546	124,168,013	675,294,559	81.61%	18.39%
Nov-11	553,506,338	126,026,260	679,532,597	81.45%	18.55%
Dec-11	583,605,952	139,034,298	722,640,250	80.76%	19.24%
			AVERAGE	**81.53%**	**18.47%**

Derivation of Demand (KW)

The 2013 energy purchases forecasts for each rate zone are composites of monthly kWh forecasted volumes for all rate classes. Estimated total losses are subtracted from these forecasts to determine the distribution sales forecast. This distribution sales forecast is apportioned to various rate classes based on the historical relationships between energy and demand by rate class obtained from billing data for each service territory.

There are different billing determinants for various classes: Residential and GS<50kW customers are billed based on kWh units, whereas charges for other Commercial Accounts (GS>50, Large User, TOU, Street Lighting and Sentinel) are based on kW units. The historical relationship between kWh and kW for each rate class is used to translate forecasted kWh to kW for these accounts. Tables 18 through 21 show the historic (three-year average) billed energy (kWh) allocation, by rate class, and a ratio of historic kW to historic kWh, by rate class, as an average for the period 2009 through 2011 for each rate zone.

Table 18: PowerStream South Historic kWh Allocation by Rate Class (2009 – 2011)

Year	Residential	GS <50 kW	USL	GS>50 kW	TOU	Large User	Street-Lighting	Sentinel	Total
2005	29.54%	11.97%	0.13%	56.56%	0.70%	0.51%	0.58%	0.01%	**100.00%**
2006	29.46%	11.63%	0.11%	56.98%	0.74%	0.47%	0.61%	0.01%	**100.00%**
2007	29.59%	11.68%	0.12%	56.63%	0.87%	0.47%	0.63%	0.01%	**100.00%**
2008	30.31%	11.97%	0.13%	55.63%	0.88%	0.44%	0.63%	0.01%	**100.00%**
2009	31.33%	12.12%	0.14%	55.28%	0.00%	0.42%	0.70%	0.01%	**100.00%**
2010	31.36%	12.25%	0.14%	55.16%	0.00%	0.41%	0.68%	0.01%	**100.00%**
2011	31.00%	12.13%	0.14%	55.62%	0.00%	0.40%	0.70%	0.01%	**100.00%**
Average 2009-2011	**31.23%**	**12.17%**	**0.14%**	**55.35%**	**0.00%**	**0.41%**	**0.69%**	**0.01%**	**100.00%**
2012	**31.23%**	**12.17%**	**0.14%**	**55.35%**	**0.00%**	**0.41%**	**0.69%**	**0.01%**	**100.00%**
2013	**31.23%**	**12.17%**	**0.14%**	**55.35%**	**0.00%**	**0.41%**	**0.69%**	**0.01%**	**100.00%**

Table 19: PowerStream South Historic Relationship between Billed kWh and kW Demand by Rate Class (2009 – 2011)

Year	GS>50 kW	TOU	Large Users	Street-Lighting	Sentinel
2005	0.25%	0.16%	0.26%	0.25%	0.23%
2006	0.25%	0.16%	0.27%	0.28%	0.22%
2007	0.26%	0.16%	0.27%	0.30%	0.29%
2008	0.27%	0.15%	0.25%	0.32%	0.26%
2009	0.27%	0.00%	0.30%	0.32%	0.26%
2010	0.27%	0.00%	0.29%	0.25%	0.27%
2011	0.27%	0.00%	0.30%	0.31%	0.26%
Average 2009-2011	**0.27%**	**0.00%**	**0.30%**	**0.29%**	**0.26%**
2012	**0.27%**	**0.00%**	**0.30%**	**0.29%**	**0.26%**
2013	**0.27%**	**0.00%**	**0.30%**	**0.29%**	**0.26%**

Table 20: PowerStream North Historic kWh Allocation by Rate Class (2009 – 2011)

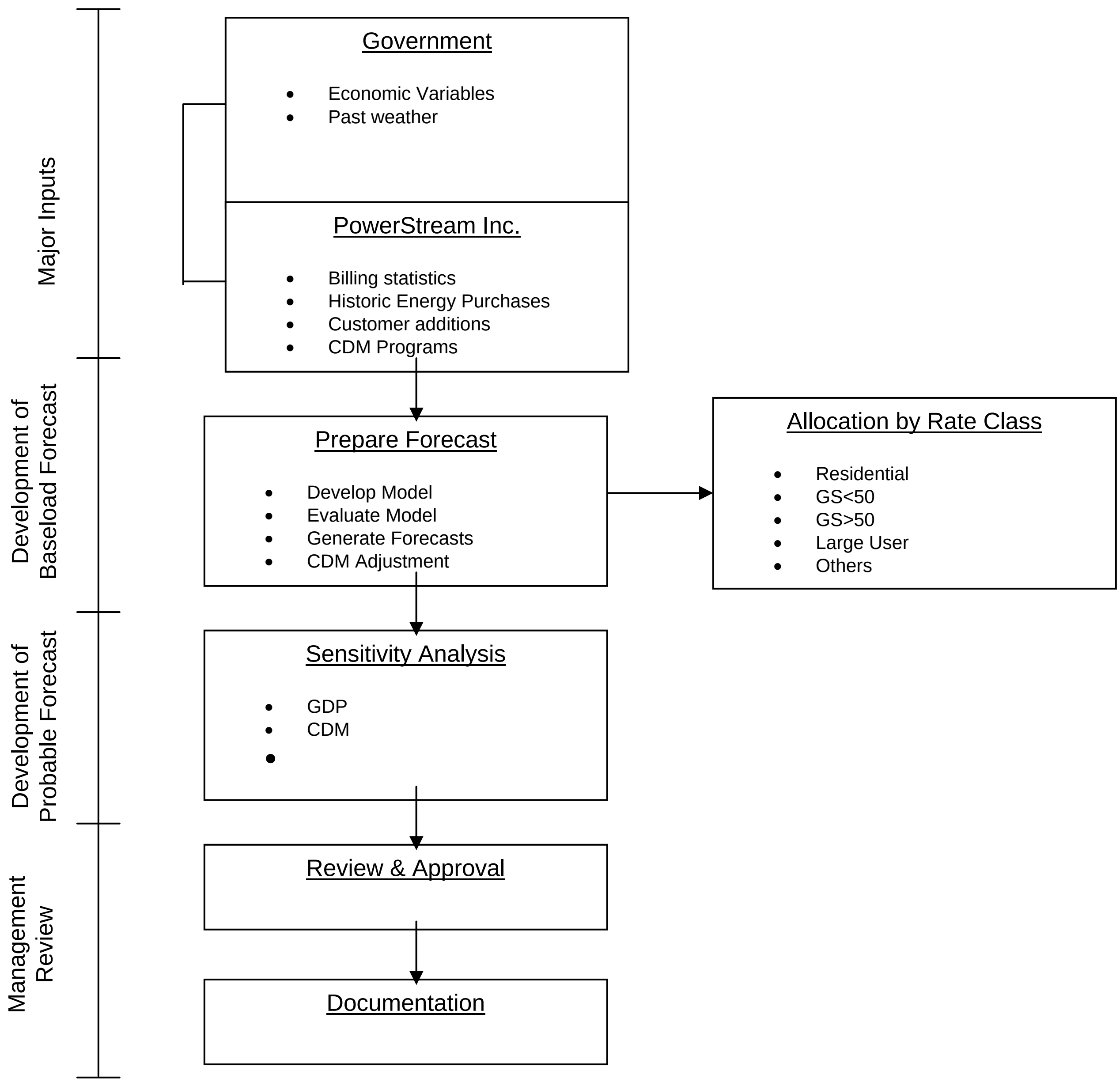
Year	Residential	GS <50 kW	USL	GS>50 kW	TOU	Large User	Street-Lighting	Sentinel	Total
2006	35.49%	12.84%	0.28%	50.66%			0.73%		**100.00%**
2007	35.89%	13.18%	0.23%	49.99%			0.71%		**100.00%**
2008	35.64%	13.06%	0.20%	50.38%			0.70%		**100.00%**
2009	36.52%	12.95%	0.20%	49.54%			0.78%		**100.00%**
2010	36.57%	13.42%	0.22%	48.99%			0.81%		**100.00%**
2011	36.58%	13.86%	0.20%	48.56%			0.81%		**100.00%**
Average 2009-2011	**36.55%**	**13.41%**	**0.21%**	**49.03%**			**0.80%**		**100.00%**
2012	**36.55%**	**13.41%**	**0.21%**	**49.03%**			**0.80%**		**100.00%**
2013	**36.55%**	**13.41%**	**0.21%**	**49.03%**			**0.80%**		**100.00%**

Table 21: PowerStream North Historic Relationship between Billed kWh and kW Demand by Rate Class (2009 – 2011)

Year	GS>50 kW	TOU	Large Users	Street-Lighting	Sentinel
2006	0.26%			0.31%	
2007	0.26%			0.32%	
2008	0.26%			0.31%	
2009	0.24%			0.29%	
2010	0.26%			0.33%	
2011	0.26%			0.30%	
Average 2009-2011	**0.25%**			**0.30%**	
2012	**0.25%**			**0.30%**	
2013	**0.25%**			**0.30%**	

The overall forecast process is illustrated in Figure 3 below.

Figure 3: Load Forecast Process Flowchart



CUSTOMER FORECAST

In order to determine the fixed distribution charges, PowerStream requires customer counts by class. PowerStream's derives the forecast of new customers based on historic averages. The three year average is used for the Residential and General Service < 50kW classes. A five year historic average is used for the General Service > 50kW class. The economic slowdown has impacted the General Service > 50kW class such that the three year average is not considered representative of future growth patterns. Overall, the total number of customers for 2013 is expected to be 2.1% higher than 2012.

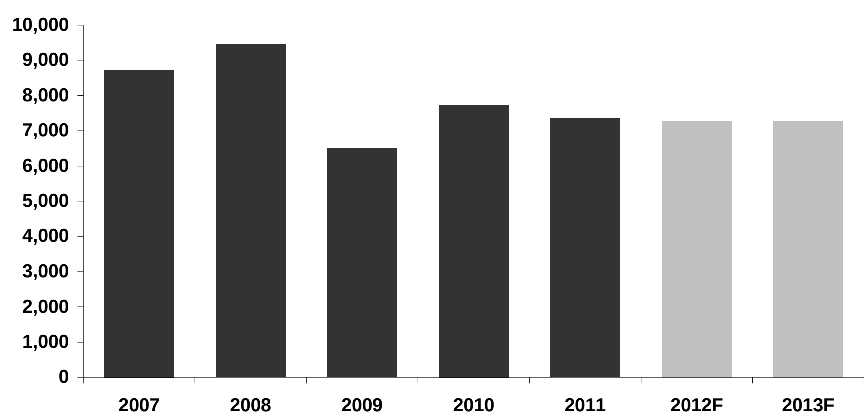
PowerStream has been experiencing reduced growth trends in its service territory over recent years. The peak growth period was in 1999-2003 and averaged 5.9% in customer growth rates, followed by a more moderate growth rate of 3.5% over the 2003-2008 periods. The 2009 -2011 growth rates averaged only 2.2%. Table 1 below summarizes historic and forecast growth rates.

Table 1: Historic and Projected Customer Additions Growth Rates (1999 – 2013)

Period	1999-2003	2003-2008	2009	2010	2011	2012F	2013F
Growth Rate	5.9%	3.6%	2.1%	2.4%	2.2%	**2.1%**	**2.1%**

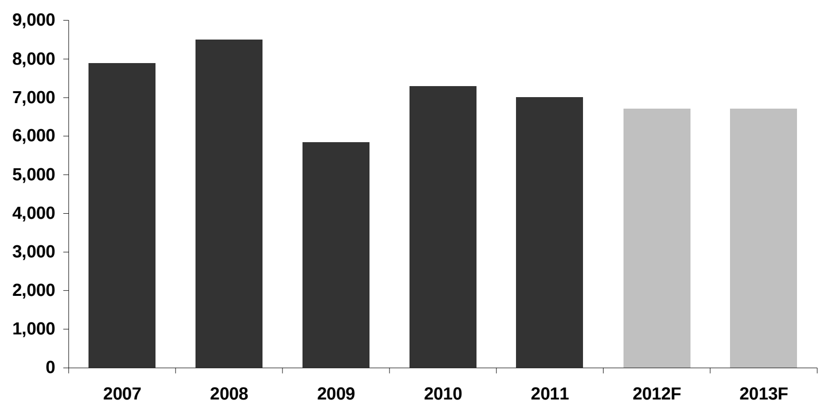
Figure 1 below presents the historic and projected total customer additions in the graphical format.

Figure 1: Historic and Projected Total Customer Additions (2007 – 2013)



Residential customer additions in PowerStream's service territory have been relatively flat over the recent three year period. This is attributed to the economic slowdown, the introduction of Harmonized Sales Tax on new homes and the limited availability of land for new subdivisions. Figure 2 below shows historical and forecasted net residential additions in the graphical format.

Figure 2: Historic and Projected Residential Customer Additions (2007 - 2013)



Commercial and Industrial customers and their respective loads are typically known only when the connection is requested. It is difficult to forecast or anticipate the general service customer rate class required for revenue billing purposes in a proposed commercial area. PowerStream considers the best method to forecast future General Service < 50kW growth to be a three year historical average. The General Service >50 kW customer additions forecast is based on a five year average, since there has been significant volatility in the historic data for the last three years due mainly to the economic slowdown. Figure 3 below shows historic and projected customer additions for General Service <50kW, General Service >50kW and Large User rate classes. PowerStream currently bills one large user based on its customer specific approved rates however it does have another customer that is greater than 5MW that it proposes to move to the large user class in 2013.

Figure 3: Historic and Projected General Service Customer Additions (2007-2013)

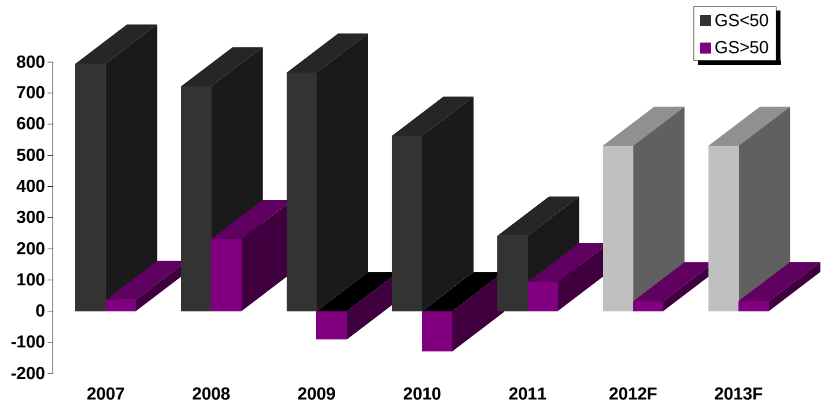


Table 2 below summarizes the 2012 bridge and 2013 test year customer additions by the three major customer categories.

Table 2: Net Customer Additions

Year	Total	Res	GS<50	GS>50
2007	8,722	7,891	795	36
2008	9,445	8,492	722	231
2009	6,512	5,837	766	(91)
2010	7,720	7,286	563	(129)
2011	7,346	7,011	242	93
2012F	7,273	6,711	531	31
2013F	7,274	6,711	531	32

The detailed forecast of customers by rate class is presented in Table 3.

Table 3: Customers by Rate Class

	2008 Board Approved	2009 Board Approved	2009 Actuals	2010 Actual	2011 Actual	2012 -Bridge	2013 - Test
Residential	63,820	218,157	283,665	290,951	297,962	304,673	311,385
GS Less Than 50 kW	5,515	23,700	29,594	30,076	30,416	30,924	31,432
GS 50 to 4,999 kW	844	3,903	4,656	4,512	4,614	4,645	4,676
GS 50 to 4,999 kW Legacy	0	0	0	0	0	0	0
Large Use	1	1	1	1	1	1	2
Unmetered Scattered Load	892	2,121	2,781	2,868	2,779	2,802	2,824
Sentinel Lighting	0	142	135	129	120	120	120
Street Lighting Connections	14,904	63,805	78,116	79,347	80,969	82,526	84,084
Street Lighting Customers			37	52	43	43	43
Total Customers	**71,072**	**248,024**	**320,869**	**328,589**	**335,935**	**343,208**	**350,482**
Total Connections	**14,904**	**63,805**	**78,116**	**79,347**	**80,969**	**82,526**	**84,084**
TOTAL	**85,976**	**311,829**	**398,985**	**407,936**	**416,904**	**425,734**	**434,566**

DISTRIBUTION REVENUE

The year over year comparison of PowerStream's distribution revenue is summarized in Table 1, below. At current approved rates, PowerStream's revenue requirement including smart meter increment revenue rate riders ("SMIRR") is $162,044,558 which is a 1.1% increase over 2012. The 2012 and 2013 revenue amounts were calculated by applying current rates (December 1, 2011 and May 1, 2012 for 2012 and May 1, 2012 for 2013) to the forecast sales and customer numbers.

Table 1: Distribution Revenue at Current Rates

			PowerStream Consolidated				
	2008 OEB Approved PS North	2009 OEB Approved PS South	2009 Actuals	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Fixed and Variable Charge	32,121,483	116,542,907	145,502,024	150,852,789	152,778,189	155,581,872	157,268,080
Transformer Credit	(549,556)	(1,829,428)	(2,436,352)	(2,272,847)	(2,234,875)	(2,384,296)	(2,435,656)
Distribution Revenue w/o SMIRR	**31,571,927**	**114,713,479**	**143,065,672**	**148,579,942**	**150,543,314**	**153,197,576**	**154,832,424**
% growth Year over Year				**3.9%**	**1.3%**	**1.8%**	**1.1%**
SMIRR Revenue					4,071,481	7,065,550	7,212,135
Total Distribution Revenue	**31,571,927**	**114,713,479**	**143,065,672**	**148,579,942**	**154,614,796**	**160,263,125**	**162,044,558**
% growth Year over Year				**3.9%**	**4.1%**	**3.7%**	**1.1%**

Year over year variances in distribution revenue based on weather normalized sales for the period 2009 to 2013 are mainly attributable to growth of PowerStream's customer base. Weather normalized sales have tapered in recent years which can be attributable to various external and uncontrollable industry or economic factors. Some of these factors include slow economic growth due to 2009 recession and subsequent slow recovery, Conservation and Demand Management ("CDM") initiatives, and energy price increases. In addition, as a result of low inflation rates, Incentive Regulation Mechanism ("IRM") adjustments in 2011 were fairly negligible which contributed to lower growth in base distribution rates (0.18% for the South and 0.38% for the North). The IRM adjustment remained low in 2012, 0.88% for both South and North service areas which continues to mitigate the distribution revenue increases from base rates. The distribution revenue at current rates in 2013 is forecasted to trend lower as PowerStream continues to pursue CDM initiatives in order to meet its licence obligations.

In 2010, PowerStream filed an application (EB-2010-0209) for recovery of costs associated with the installation of smart meters for the South rate zone. The Board approved an annual incremental revenue requirement of $3,661,000. In 2011, PowerStream had completed its Smart Meter program and filed an application (EB-

2011-0128) for final recovery of costs associated with the installation of smart meters for both the Barrie (former Barrie territory) and South rate zones. The Board approved an annual incremental revenue requirement of $1,722,000 for Barrie and $1,367,000 for the South. This incremental distribution revenue generated by these "mini-rebasing" applications has contributed to year over year variances of approximately 3.0% annually from 2010 to 2012. During the IRM period (2010-2012), when capital additions were made, distribution revenue from IRM and customer and load growth alone do not provide the appropriate level of funding for the capital outlay.

PowerStream recovers revenue based on a fixed and variable rate methodology. The fixed revenue component is derived based on a customer forecast and the variable revenue component is derived based on a sales forecast. PowerStream has applied current approved rates to the test year customer and sales forecast in order to derive the test year distribution revenue. A summary of the consumption, demand and customer count is outlined in Table 2.

Table 2: Energy Sales, Demand and Customers

		PowerStream Consolidated				
	2009 OEB Approved PS South	2009 Normalized Actuals	2010 Normalized Actual	2011 Normalized Actual	2012 Bridge Year	2013 Test Year
Consumption, KWH	6,829,307,310	8,207,640,604	8,302,881,333	8,346,993,130	8,446,902,913	8,467,944,830
Demand, KW	10,400,971	12,095,130	12,250,349	12,318,083	12,455,585	12,496,684
Customer Count	311,829	394,514	403,943	412,262	421,644	430,475

Note: PS = PowerStream

The details regarding forecast distribution revenue are supported by following Tables:

Table 3: Distribution Revenue by Rate Class

Table 4: Demand and Consumption

Table 5: Unit Revenues

Table 6: Customer Count by Rate Class

Table 7: Residential and General Service Classes – Average Normalized Consumption per Customer

Table 3: Distribution Revenue by Rate Class

Distribution Revenue, $					Variance Analysis							
Actual Normalized 2009	Actual Normalized 2010	Actual Normalized 2011	Bridge Year Normalized 2012	Test Year 2013	2010 Actual Norm vs 2009 Actual Norm.		2011 Actual Norm vs 2010 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.	
$	$	$	$	$	$	%	$	%	$	%	$	%
78,091,025	79,673,985	80,747,389	82,705,737	84,026,515	1,582,960	2.0%	1,073,405	1.3%	1,958,348	2.4%	1,320,778	1.6%
21,731,070	22,120,096	22,290,927	22,732,589	22,984,970	389,026	1.8%	170,831	0.8%	441,662	2.0%	252,381	1.1%
45,184,440	45,972,263	46,361,869	47,117,659	47,056,496	787,822	1.7%	389,606	0.8%	755,790	1.6%	(61,163)	-0.1%
26,506	0	0	0	0	(26,506)	-100.0%	0		0		0	
141,442	108,528	110,905	113,714	249,195	(32,914)	-23.3%	2,377	2.2%	2,808	2.5%	135,482	119.1%
557,396	558,459	555,543	564,157	569,762	1,064	0.2%	(2,916)	-0.5%	8,613	1.6%	5,605	1.0%
13,107	14,477	14,371	14,457	14,528	1,370	10.4%	(106)	-0.7%	86	0.6%	72	0.5%
1,650,633	1,958,349	2,203,178	2,333,559	2,366,613	307,716	18.6%	244,828	12.5%	130,381	5.9%	33,055	1.4%
147,395,619	**150,406,156**	**152,284,182**	**155,581,872**	**157,268,080**	**3,010,537**	**2.0%**	**1,878,026**	**1.2%**	**3,297,690**	**2.2%**	**1,686,208**	**1.1%**

Table 4: Demand and Consumption

Demand

Load (kW)				
Actual Normalized 2009 kW	Actual Normalized 2010 kW	Actual Normalized 2011 kW	Bridge Year Normalized 2012 kW	Test Year 2013 kW
0	0	0	0	0
0	0	0	0	0
11,841,293	11,993,106	12,059,393	12,194,106	12,130,724
0	0	0	0	0
81,160	82,797	83,361	83,894	187,932
0	0	0	0	0
1,197	1,221	1,229	1,237	1,240
171,479	173,224	174,100	176,348	176,787
12,095,130	12,250,349	12,318,083	12,455,585	12,496,684

Variance Analysis							
2010 Actual Norm vs 2009 Actual Norm.		2011 Actual Norm vs 2010 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.	
kW	%	kW	%	kW	%	kW	%
0		0		0		0	
0		0		0		0	
151,813	1.3%	66,286	0.6%	134,713	1.1%	(63,381)	-0.5%
0		0		0		0	
1,637	2.0%	564	0.7%	533	0.6%	104,038	124.0%
0		0		0		0	
24	2.0%	8	0.7%	8	0.6%	3	0.2%
1,745	1.0%	877	0.5%	2,248	1.3%	439	0.2%
155,219	**1.3%**	**67,735**	**0.6%**	**137,502**	**1.1%**	**41,099**	**0.3%**

Consumption

Consumption (kwh)				
Actual Normalized 2009 kWh	Actual Normalized 2010 kWh	Actual Normalized 2011 kWh	Bridge Year Normalized 2012 kWh	Test Year 2013 kWh
2,645,607,890	2,673,270,148	2,686,931,286	2,721,123,173	2,727,901,711
1,017,968,580	1,029,072,171	1,034,413,080	1,047,268,438	1,049,877,268
4,445,407,912	4,500,600,497	4,525,154,776	4,576,906,372	4,553,483,283
0	0	0	0	0
27,221,419	27,770,469	27,959,582	28,138,353	63,032,980
12,540,625	12,648,823	12,709,369	12,886,447	12,918,549
457,217	466,439	469,615	472,618	473,795
58,436,961	59,052,787	59,355,422	60,107,512	60,257,245
8,207,640,604	8,302,881,333	8,346,993,130	8,446,902,913	8,467,944,830

Variance Analysis							
2010 Actual Norm vs 2009 Actual Norm.		2011 Actual Norm vs 2010 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.	
kwh	%	kWh	%	kWh	%	kWh	%
27,662,258	1.0%	13,661,138	0.5%	34,191,887	1.3%	6,778,537	0.2%
11,103,591	1.1%	5,340,909	0.5%	12,855,357	1.2%	2,608,830	0.2%
55,192,585	1.2%	24,554,279	0.5%	51,751,596	1.1%	(23,423,089)	-0.5%
0		0		0		0	
549,050	2.0%	189,112	0.7%	178,772	0.6%	34,894,627	124.0%
108,198	0.9%	60,547	0.5%	177,078	1.4%	32,101	0.2%
9,222	2.0%	3,176	0.7%	3,003	0.6%	1,177	0.2%
615,826	1.1%	302,635	0.5%	752,090	1.3%	149,733	0.2%
95,240,730	**1.2%**	**44,111,797**	**0.5%**	**99,909,783**	**1.2%**	**21,041,917**	**0.2%**

Table 5: Unit Revenues

Revenue per Customer, $					Variance Analysis							
Actual Normalized 2009	Actual Normalized 2010	Actual Normalized 2011	Bridge Year Normalized 2012	Test Year 2013	2010 Actual Norm vs 2009 Actual Norm.		2011 Actual Norm vs 2010 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.	
$/Customer	$/Customer	$/Customer	$/Customer	$/Customer	$	%	$	%	$	%	$	%
$278.34	$276.90	$274.36	$274.23	$272.54	$ (1.43)	-0.5%	$ (2.55)	-0.9%	$ (0.13)	0.0%	$ (1.69)	-0.6%
$742.84	$737.88	$735.97	$740.69	$736.72	$ (4.95)	-0.7%	$ (1.91)	-0.3%	$ 4.71	0.6%	$ (3.97)	-0.5%
$9,652.56	$10,182.12	$10,150.57	$10,174.68	$10,094.44	$ 529.56	5.5%	$ (31.55)	-0.3%	$ 24.11	0.2%	$ (80.24)	-0.8%
$17,670.67												
$141,442.19	$108,528.00	$110,905.20	$113,713.64	$124,597.65	$ (32,914.20)	-23.3%	$ 2,377.20	2.2%	$ 2,808.44	2.5%	$ 10,884.01	9.6%
$203.14	$198.65	$199.57	$202.11	$202.48	$ (4.49)	-2.2%	$ 0.92	0.5%	$ 2.55	1.3%	$ 0.36	0.2%
$95.61	$109.67	$116.44	$120.47	$121.07	$ 14.06	14.7%	$ 6.77	6.2%	$ 4.03	3.5%	$ 0.60	0.5%
$21.40	$24.86	$27.48	$28.52	$28.39	$ 3.46	16.2%	$ 2.62	10.5%	$ 1.05	3.8%	$ (0.14)	-0.5%
$373.61	**$372.34**	**$369.39**	**$368.99**	**$365.34**	**$ (1.27)**	**-0.3%**	**$ (2.96)**	**-0.8%**	**$ (0.40)**	**-0.1%**	**$ (3.65)**	**-1.0%**

Table 6: Customer Count by Rate Class

CUSTOMER COUNT

(12-months average, Jan. 1st - Dec. 31)

Number of Customers (Connections)					Variance Analysis							
Actual Normalized	Actual Normalized	Actual Normalized	Bridge Year Normalized	Test Year	2010 Actual Norm vs 2009 Actual Norm.		2011 Actual Norm vs 2010 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.	
2009	2010	2011	2012	2013								
#	#	#	#	#	$	%	$	%	$	%	$	%
280,560	287,731	294,314	301,597	**308,309**	7,170	2.6%	6,583	2.3%	7,284	2.5%	6,711	2.2%
29,254	29,978	30,288	30,691	**31,199**	724	2.5%	310	1.0%	404	1.3%	508	1.7%
4,681	4,515	4,567	4,631	**4,662**	(166)	-3.5%	52	1.2%	63	1.4%	31	0.7%
2	0	0	0	**0**	(2)	-100.0%	0		0		0	
1	1	1	1	**2**	0	0.0%	0	0.0%	0	0.0%	1	100.0%
2,744	2,811	2,784	2,791	**2,814**	67	2.5%	(28)	-1.0%	8	0.3%	23	0.8%
137	132	123	120	**120**	(5)	-3.7%	(9)	-6.5%	(3)	-2.8%	0	0.0%
77,135	78,776	80,185	81,813	**83,370**	1,641	2.1%	1,409	1.8%	1,628	2.0%	1,557	1.9%
394,514	**403,943**	**412,262**	**421,644**	**430,475**	**9,429**	**2.4%**	**8,319**	**2.1%**	**9,383**	**2.3%**	**8,831**	**2.1%**

Table 7: Residential and General Service Classes – Average Normalized Consumption per Customer

Average consumption (kwh/customer)					Variance Analysis							
Actual Normalized	Actual Normalized	Actual Normalized	Bridge Year Normalized	Test Year	2010 Actual Norm vs 2009 Actual Norm.		2011 Actual Norm vs 2010 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.		2012 Actual Norm vs 2011 Actual Norm.	
2009	2010	2011	2012	2013								
kWh/customer	kWh/customer	kWh/customer	kWh/customer	kWh/customer	kwh/customer	%	kwh/customer	%	kwh/customer	%	kwh/customer	%
9,430	9,291	9,129	9,022	8,848	(139)	-1.5%	(161)	-1.7%	(107)	-1.2%	(174)	-1.9%
34,797	34,328	34,153	34,123	33,651	(470)	-1.3%	(175)	-0.5%	(30)	-0.1%	(472)	-1.4%
11,825	**11,653**	**11,464**	**11,341**	**11,127**	**(172)**	**-1.5%**	**(189)**	**-1.6%**	**(124)**	**-1.1%**	**(214)**	**-1.9%**

OTHER REVENUE - OVERVIEW

Other Revenue is defined as sources of utility revenue other than Distribution Revenue. PowerStream divides Other Revenue, or “Revenue Offsets” into the following categories: Specific Service Charges, Late Payment Charges, Other Distribution Revenue and Other Income and Deductions.

These are the same categories that were used in PowerStream’s 2009 Cost of Service Application.

Table 1 below shows PowerStream’s Revenue Offsets from the last Board Approved Cost of Service Rate Application through the 2013 Test Year.

Table 1: PowerStream Revenue Offsets ($000’s)

	PowerStream Barrie	**PowerStream South**	**PowerStream Combined**					
	2008 Board Approved	**2009 Board Approved**	**2009 Actual**	**2010 Actual**	**2011 Actual**	**2011 Actual**	**2012 Estimate**	**2013 Forecast**
	CGAAP					**MIFRS**		
Specific Service Charges	951	2,292	4,445	4,163	3,907	3,909	3,270	3,385
Late Payment Charges	642	1,834	2,295	2,458	2,187	2,187	2,400	2,500
Other Distribution Revenue	555	1,285	1,932	1,938	1,986	1,986	2,008	2,032
Other Income and Deductions	408	1,159	1,383	386	1,087	1,809	1,121	1,145
Total Revenue Offsets	**2,546**	**6,568**	**10,055**	**8,945**	**9,167**	**9,891**	**8,799**	**9,062**

A detailed account level breakdown of Other Revenues is provided in Exhibit C2-1-3 (OEB Appendix 2-C).

PowerStream presents the information in this table, as per Chapter 2 of the OEB minimum filing requirements. The historical trend analysis, however is distorted by the accounting changes due to Internal Financial Reporting Standards ("IFRS") implementation. The 2008 Barrie Approved amounts, as well as PowerStream Approved and Actual 2009 and 2010 amounts are not comparable to the 2013 amounts as the 2008 - 2011 information is shown in CGAAP and 2011 - 2013 is shown in MIFRS. In addition, the 2009 PowerStream Board-Approved levels do not include Barrie data, which was merged with PowerStream in 2009. The 2009 PowerStream actual results include Barrie.

The 2013 Test Year revenue offsets are $9,062,000 or $829,000 lower than the revenue offsets in 2011 Actual (under MIFRS), the decrease is mainly due to the 2012 change in the accounting treatment of gains on work orders, and the decrease in the Other Income, as explained in the detailed variance analysis in Exhibit C2, Tab 1, Schedule 2.

Revenue Offsets are deducted from the Service Revenue Requirement to derive the Base Revenue Requirement. The latter is used to determine distribution rates.

The Revenue Offsets are not equal to the "Other Revenue" as shown in PowerStream's Financial Statements since the "Other Revenue" line in the Financial Statements includes non-distribution items. In particular, the revenues and expenses of PowerStream's Solar Business are separated from the distribution business and recorded in accounts 4375 and 4380, as per the OEB's *"Guidelines: Regulatory and Accounting Treatments for Distributor – Owned Generation Facilities"* (G-2009-0300) issued on September 15, 2009. The revenues and expenses related to Conservation and Demand Management ("CDM") activities are also recorded in subaccounts of 4375 and 4380 and are not included in the amounts to be recovered in the distribution rates and in the revenue offsets. A reconciliation is provided in Appendix 1, Schedule 19. CDM activities are discussed in Exhibit C2, Tab 1, Schedule 4 and the Solar Business is discussed in Exhibit D3, Tab 1, Schedule 1.

Specific Service Charges

The Specific Service Charges are approved fixed rates charges to a customer for a specific activity or service, or as a penalty, as per the *2006 Electricity Distribution Rate Handbook.* The Specific Service Charges that PowerStream is using are listed in Table 2 below.

Table 2: Specific Service Charges

Service	PowerStream South			PowerStream North		
	Applicable	charge		Applicable	charge	
Arrears certificate	Y	$	15.00	Y	$	15.00
Statement of account	Y	$	15.00	N	$	-
Duplicate invoices for previous billing	Y	$	15.00	N	$	-
Request for other billing information	Y	$	15.00	N	$	-
Easement letter	Y	$	15.00	Y	$	15.00
Income tax letter	Y	$	15.00	N	$	-
Account history	Y	$	15.00	N	$	-
Returned cheque charge (plus bank charges)	Y	$	15.00	Y	$	15.00
Legal letter charge	Y	$	15.00	N	$	-
Account set up charge/change of occupancy charge	Y	$	30.00	Y	$	15.00
Special meter reads	Y	$	30.00	N	$	-
Collection of account charge - no disconnection	Y	$	30.00	Y	$	15.00
Disconnect/Reconnect at meter - during regular hours	Y	$	65.00	Y	$	30.00
Disconnect/Reconnect at meter - after regular hours	Y	$	185.00	Y	$	185.00
Disconnect/Reconnect at pole - during regular hours	N	$	-	Y	$	185.00
Disconnect/Reconnect at pole - after regular hours	N	$	-	Y	$	415.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	Y	$	30.00	Y	$	30.00
Temporary service install & remove - overhead - no transformer	Y	$	500.00	N	$	-
Specific Charge for Access to the Power Poles $/pole/year	Y	$	22.35	Y	$	22.35

In its 2009 Cost of Service ("COS") Application (EB-2008-0244) PowerStream South (former PowerStream territory) sought and received approval to use the above subset of default Specific Service Charges in the Board's *2006 Electricity Distribution Rate Handbook* ("EDR"). The specific Service Charges in PowerStream North (former Barrie Hydro territory) were approved by OEB in its decision on the Barrie Hydro 2008 COS application (EB-2007-0681).

PowerStream proposes the following changes to these Specific Service Charges:

- Harmonize the Specific Service Charges in the South and North rate zones, using the Board default amounts from 2006 EDR Handbook, as currently used in PowerStream South.
- Introduce new specific service charges for "Disconnect/Reconnect at meter during/after regular hours" to be used in the cases of vacant rental properties with no active account.

The charges are equal to the default charges "Disconnect/Reconnect at meter during/after Regular hours" in the cases of non-payment.

- Introduce new specific charges for "Install/Remove load control devices during/after regular hours to be used in cases when a load control device is installed during the winter time instead of disconnecting the service.

Late Payment Charges

PowerStream proposes to continue to charge interest of 1.5 % per month (19.56 % annually) on overdue accounts.

Other Distribution Revenue

The main components of other distribution revenue are: the Standard Supply Service Administration charge, Retail Services Revenues and Rent from Electric Property (Pole attachments).

PowerStream proposes to charge $0.25 per month for all customers under Standard Supply Service, as currently approved by OEB.

PowerStream proposed to continue to charge the currently approved retailer service charges.

PowerStream proposes to charge the current OEB approved rate of $22.35 per pole per month for pole attachments.

Other Income and Deductions

This category comprises Interest and Dividend Income, Gain on Disposition of Property, and Miscellaneous Non-Operating Income.

In its 2009 COS Rate Application, PowerStream proposed to exclude interest income on Customer Deposits from the Revenue Offsets. PowerStream earns interest on these deposits and this interest is returned to those customers through payment of the interest on their deposit. In the *2006 Electricity Distribution Rates Handbook Report of the Board*, dated May 11, 2005 (RP-2004-0188), the Board decided that this interest should not be a revenue offset (Chapter 8, p.64). In this Application, PowerStream followed the same approach and excluded the interest income on Customer Deposits from the revenue offsets (in the test year, interest income on Customer Deposits is forecast to be $225,000).

REVENUE OFFSETS - VARIANCE ANALYSIS

The variance analysis of Revenue Offsets is distorted by the accounting changes due to Modified International Financial Standards (“IFRS”) implementation and the 2009 merger with Barrie Hydro. The 2008 Barrie Board Approved amounts, as well as PowerStream Board Approved and Actual 2009 and 2010 amounts are not directly comparable to the 2013 test year Revenue Offsets as the 2008 - 2011 information is shown in Canadian Generally Accepted Accounting Principles (“CGAAP”) and 2011 to 2013 is shown in MIFRS. In addition, the 2009 PowerStream Board Approved levels do not include Barrie, which was merged with PowerStream during 2009. The 2009 PowerStream actual results include Barrie.

SPECIFIC SERVICE CHARGES

The Specific Service Charges are recorded in USofA account 4235 and are summarized in table 1, below.

Table 1: PowerStream Specific Service Charges – Summary, $000s

	PS Barrie	PS South			PowerStream Combined			
	2008 Board Approved	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2011 Actual	2012 Forecast	2013 Test
	CGAAP					MIFRS		
Specific Service Charges (account 4235)	951	2,292	4,445	4,163	3,907	3,909	3,270	3,385

Specific Service Charges in the 2013 test year are forecast to be $3,385,000. This is an increase of $142,000 or 4.3% over the combined 2008 and 2009 Board Approved amounts of $3,243,000. The increase is the result of an increased quantity of service charges to customers, offset in part by the decrease in gains on work orders. The gains on work orders decrease is explained below.

2009 Actual vs. 2009 Approved

Specific Service Charges in 2009 amounted to $4,445,000. This is $2,153,000 higher than the 2009 Board Approved (for PowerStream South) amount of $2,292,000. This variance is mainly due to inclusion of specific service charges for the customers in Barrie Hydro territory, amounting to $1,480,000. The PowerStream South Specific Service Charges were $2,965,000, an increase of $0.7M or 30% as compared to 2009 Board Approved amount.

This increase is due to the increase in gains on work orders, which PowerStream also recorded in account 4235. In 2009, a significant number of work orders from previous years were closed and an overall gain of $0.7M was recorded.

2010 Actual vs. 2009 Actual

The 2010 Specific Service Charges are slightly lower than 2009 Actual by $282,000, mainly due to the lower volume of charges to the customers.

2011 Actual vs. 2010 Actual

The 2011 Specific Service Charges were lower than 2010 Actual by $256,000. The charges related to the services provided to the customers are relatively stable, the variance is mainly due to decreased gains on work orders.

2011 Actual (MIFRS) vs. 2011 Actual (CGAAP)

The 2011 Actual under MIFRS is slightly higher by $2,000 than the 2011 Actual under CGAAP due to the changes in burden allocation under MIFRS, as explained in Exhibit A3, Tab 1, Schedule 3. As a result, the costs charged to work orders are lower under MIFRS with a corresponding increase in the amount for gains on work orders.

2012 Bridge Year vs. 2011 Actual

The 2012 Specific Service Charges are lower than 2011 Actual by $639,000. The charges related to the services provided to the customers are estimated to be stable; the variance is mainly due to the decrease in gains on work orders to $0, as explained below, a decrease of about $667,000.

Gains on work orders relate to industrial, commercial and institutional (“ICI”) projects where customers are billed based on an estimate by the Engineering Department. If the costs come in less than the estimate, the difference or gain on the work order has been historically recorded in account 4235, Specific Service Charges. If the costs are more than the estimate, the actual costs are capitalized and the billed amount recorded as part of capital contributions, as an offset to capital additions, resulting in the difference being amortized over the life of the asset.

In 2011, PowerStream reviewed the treatment of the differences on these work orders. The individual gains and losses on work orders are fairly small and in total tend to offset each other. PowerStream decided that these should be treated the same. Treating some of the differences as income understates the contributed capital on these projects.

It was determined that, effective January 1, 2012, both the gains and losses on these work orders are to be recorded as part of the capital contribution, a reduction of fixed asset cost and thereby rate base. This change not only brings consistency to the accounting treatment of contributed capital, but also properly reflects the estimation accuracy of the Engineering group for these ICI projects.

2013 Test Year vs. 2012 Bridge Year

The test year Specific Service Charges are $3,288,000, an increase of $115,000 over the Bridge year. The charges associated with services to customers such as new account setup charges and arrears certificates are expected to be fairly constant in 2012 and 2013. Some increases due to the harmonization of the service charges between the South and North rate zones in 2013 are anticipated to be offset by slight decreases forecast in collections charges, as a result of the Low Income Emergency Assistance Program (“LEAP”).

Harmonization of Specific Service Charges Between PowerStream’s Rate Zones

PowerStream South and PowerStream North have slightly different Specific Service Charges, as presented in the Table 2 below.

Table 2: PowerStream Specific Service Charges by Rate Zone – 2011

Service	PowerStream South Applicable	PowerStream South Charge	PowerStream North Applicable	PowerStream North Charge
Arrears certificate	Y	$ 15.00	Y	$ 15.00
Statement of account	Y	$ 15.00	N	$ -
Duplicate invoices for previous billing	Y	$ 15.00	N	$ -
Request for other billing information	Y	$ 15.00	N	$ -
Easement letter	Y	$ 15.00	Y	$ 15.00
Income tax letter	Y	$ 15.00	N	$ -
Account history	Y	$ 15.00	N	$ -
Returned cheque charge (plus bank charges)	Y	$ 15.00	Y	$ 15.00
Legal letter charge	Y	$ 15.00	N	$ -
Account set up charge/change of occupancy charge	Y	$ 30.00	Y	$ 15.00
Special meter reads	Y	$ 30.00	N	$ -
Collection of account charge - no disconnection	Y	$ 30.00	Y	$ 15.00
Disconnect/Reconnect at meter - during regular hours	Y	$ 65.00	Y	$ 30.00
Disconnect/Reconnect at meter - after regular hours	Y	$ 185.00	Y	$ 185.00
Disconnect/Reconnect at pole - during regular hours	N	$ -	Y	$ 185.00
Disconnect/Reconnect at pole - after regular hours	N	$ -	Y	$ 415.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	Y	$ 30.00	Y	$ 30.00
Temporary service install & remove - overhead - no transformer	Y	$ 500.00	N	$ -
Specific Charge for Access to the Power Poles $/pole/year	Y	$ 22.35	Y	$ 22.35

Historically, Barrie Hydro charged a lower Collection Charge, Disconnect/Reconnect Charge and Account Setup charge than the standard amount, due to an internal decision to standardize all of the administrative type charges at $15.

In this application, PowerStream proposes to harmonize the Specific Service Charges in the South and North rate zones, using the Board's standard amounts, as is the current policy in PowerStream South.

Disconnect/Reconnect at Meter Charge – During/After Regular hours

Currently, PowerStream charges a standard disconnect/reconnect at meter charge ($65 during regular hours/ $185 after regular hours) for the reconnection of a meter following disconnection in cases of customer non-payment. A different situation arises in the instances where PowerStream disconnects a service in the case of tenant vacancies. Section 2.8.3 of the Distribution System Code stipulates that *"Despite any other provision of this Code, with the exception of the parties mentioned in section 2.8.1.1 or an agreement under section 2.8.3A, where a distributor receives a request to close or transfer an account in relation to a rental unit in a residential complex as defined in the Residential Tenancies Act, 2006 or another residential property, the distributor shall not seek to recover any charges for service provided to that rental* *unit or residential property after closure of the account from any person, including the landlord for the residential complex or a new owner of the residential property, unless the person has agreed to assume responsibility for those charges."*

Where the landlord takes the option to not assume the responsibility for those charges, PowerStream has to disconnect the service and reconnect it later when the rental unit is occupied. This charge has been proposed to recover the associated costs. The charge would be applied to the incoming customer

Consistent with the OEB's Decision in the Veridian Connections (EB-2009-0140) rate application, PowerStream proposes that the following two charges be added to address the concerns noted above.

Both proposed charges are set at the Board's standard amounts, and are identical to those currently charged for disconnections and reconnections as a result of non-payment:

- Disconnect/Reconnect at meter – during regular hours $65.00
- Disconnect/Reconnect at meter – after regular hours $185.00

Install/Remove Load Control Device – During/After Regular hours

PowerStream currently has a disconnect/reconnect charge for non payment of accounts in the amount of $65 for regular hours and $185 for after hours. As an assistance to customers during the winter months and when other conditions warrant, PowerStream installs load control devices as opposed to full disconnection so that heat and basic necessities are available to customers. In an effort to avoid any confusion for customers in regards to fees being charged for this process, PowerStream proposes that a new Specific Service Charge be approved for "Install/Remove Load Control Device". PowerStream proposes that the fee for this activity be in the same amount as the Disconnect/Reconnect for non payment fee, $65 during regular hours and $185 for after hours, since the time and effort to perform this activity mirrors those associated with the Disconnect/Reconnect process.

The proposed harmonized list, including new proposed charges is shown in the Table 3 below.

Table 3: PowerStream Proposed Specific Service Charges

Service		charge
Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge	$	30.00
Special meter reads	$	30.00
Collection of account charge - no disconnection	$	30.00
Disconnect/Reconnect at meter - during regular hours (for non-payment)	$	65.00
Install/Remove load control device - during regular hours	**$**	**65.00**
Disconnect/Reconnect at meter - after regular hours (for non-payment)	$	185.00
Install/Remove load control device - after regular hours	**$**	**185.00**
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Disconnect/Reconnect at meter - during regular hours	**$**	**65.00**
Disconnect/Reconnect at meter - after regular hours	**$**	**185.00**

LATE PAYMENT CHARGES

The late payment charges are recorded in USofA account 4225 and are presented in Table 4 below.

Table 4: Late Payment Charges 2009-2013, $000's

	PS Barrie	PS South			PowerStream Combined			
	2008 Board Approved	**2009 Board Approved**	**2009 Actual**	**2010 Actual**	**2011 Actual**	**2011 Actual**	**2012 Estimate**	**2013 Forecast**
Specific Service Charges	**CGAAP**					**MIFRS**		
(account 4225)	642	1,834	2,295	2,458	2,187	2,187	2,400	2,500

Notes The amount of Late Payment charges is not affected by implementation of MIFRS.

The 2009 actual Late Payment Charges for PowerStream combined are $2,295,000, which is $461,000 higher than the 2009 Board-approved amount for PowerStream South. This 2009 amount includes $514,000 of Late Payment Charges for PowerStream Barrie customers. Therefore, the 2009 Actual Late Payment Charges have a slight decrease of $53,000, as compared to Board approved amounts that were based on the forecast made in 2008. In 2009 Barrie and PowerStream merged and the integration of the Customer Information Systems ("CIS") occurred. Due to conversion issues and timing, some Late Payment Charges were not charged.

The Year 2010 represents the first full year of CIS integration and a return to normal practices, and charges returned to a normalized level.

In 2011 the Late Payment Charges went down, due to amendments to the Distribution System Code (section 2.4.26A) issued on July 2, 2010 and effective January 1, 2011, which directed that for any residential customers scheduled for disconnection, security deposits for that customer must be applied to the account in the case of non-payment. The return of security deposits created a one-time reduction in charges, and Late Payment Charges for 2012 and 2013 are forecast to moderately increase over 2010 levels.

OTHER DISTRIBUTION REVENUE

The detailed breakdown of PowerStream's Other Distribution Revenues is presented in Table 5 below.

Table 5: Other Distribution Revenue, 2009-2013, $000's

		PS Barrie	PS South	PowerStream Combined					
		2008 Board Approved	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2011 Actual	2012 Estimate	2013 Forecast
		CGAAP					MIFRS		
4078	SSS Admin charge	0	617.7	839.5	856.3	889.0	889.0	915.6	932.4
4082	Retail Services Revenues	150.8	325.7	412.4	371.8	327.1	327.1	392.4	399.6
4084	Service Transaction Requests Revenues	5.0	.1	1.8	0	0	0	0	0
4090	Electric Services Incidental to Energy Sales	166.2	0	0	0	0	0	0	0
4210	Rent from Electric Property	224.7	341.0	678.0	708.9	770.4	770.4	700.0	700.0
4215	Other Utility Operating Income	0	0	.2	.4	0	0	0	0
4220	Other electric Revenues	7.8	0	0	0	0	0	0	0
Total		**554.5**	**1,284.5**	**1,932.0**	**1,937.4**	**1,986.5**	**1,986.5**	**2,008.0**	**2,032.0**

Notes

1. The amount of Other Distribution Revenue is not affected by implementation of MIFRS.

2. Only accounts with non-zero balance are included in this table. The account grouping is as per the 2006 EDR model grouping, with addition of account 4078 "SSS Admin charge"

3.The amounts in Account 4084 are very small and round to zero

2009 Actual vs. 2009 Approved

The Actual Other Distribution Revenue in 2009 amounted to $1,932,000, with $479,000 related to the PowerStream Barrie territory. The remaining 2009 Other Distribution Revenue for PowerStream South was $1,453,000, which represents a $169,000 (13%) increase over the approved Board amount of $1,284,500.

The main factor contributing to the increased revenues is increased rent from electric property, mainly from pole rentals to communications companies. PowerStream also has expenses related to pole rentals from some of the same companies. The increase in account 4210 is a result of an accounting change. Starting in 2009, pole rental revenues are recorded in account 4210 and pole rental expense are recorded in OM&A account 5095. Previously pole rental revenues and expenses were both recorded in account 4210 which then reflected the net revenue from pole rentals.

Actual years : 2009-2011

The level of Other Distribution Revenue was relatively stable in the 2009-2011 period. The SSS administration charge increases due to the customer growth were offset by the decreases in retail services revenue due to the declining number of customers enrolled with retailers.

Forecast years : 2012 Bridge and 2013 Test Year

The Other Distribution Revenue in the 2012 bridge year increases by 1.1% as compared to 2011 Actual. The 2013 forecast amount of $2,060,000 represents an increase of 1.2% over the 2012 level. The estimated increases are mainly for SSS administration charges and retail service revenue and are consistent with the forecasted customer growth.

OTHER INCOME AND DEDUCTIONS

This category comprises "Gain on Disposition of Property", "Miscellaneous Non-Operating Income" and "Interest and Dividend Income", as shown in Table 6, below.

Table 6: Other Income and Deductions 2009-2013, $000's

		PS Barrie	PS South	PowerStream Combined					
		2008 Board Approved	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2011 Actual	2012 Estimate	2013 Forecast
		CGAAP					MIFRS		
4355	Gain on Disposition of utility and other Property			218.3	(532.5)	255.7	249.6	0	0
4390	Miscellaneous Non-Operating Income	233.0	322.9	581.0	577.0	686.0	1,414.3	1,020.0	1,020.0
4405	Interest and Dividend Income	175.0	835.0	583.7	341.9	145.0	145.0	100.8	125.0
		408.0	**1,157.9**	**1,383.0**	**386.4**	**1,086.7**	**1,808.9**	**1,120.8**	**1,145.0**

Notes:
"Other Income and Deductions" includes other accounts; however, only accounts with non-zero balance are shown in the table.
The details of actual and forecast amounts in accounts 4390 and 4405 are shown in Exhibit C2-1-3 (OEB Appendix C-2).
The amounts in account 4405 are net of interest on customer deposits and on Regulatory Assets

2009 Actual vs. 2009 Board-Approved

The 2009 Actual Costs of $1,383,000 include $242,000 of Other Income for the PowerStream Barrie rate zone. The remaining 2009 Other Income of $1,141,000 represents a slight decrease of $16,900 or 1.5 percent over the 2009 Board-approved amount for PowerStream South. This difference was mainly attributable to the following two items. The interest income in 2009 was lower than the Board Approved amount by $250,000 due to a lower cash level than was budgeted. This was offset by an increase over the Board Approved amount in “Gain on disposition of Utility and Other Property” of $218,000 due to the sale of used vehicles.

2010 Actual vs. 2009 Actual

The Other Income in 2010 was $997,000 lower than in 2009, mainly due to the recorded loss on disposition on fixed assets. In 2010, there was a loss on disposition on fixed assets of $533,000, compared to the net gain of $218,000 in 2009.

Interest and dividend income also decreased in 2010. The combination of slightly higher interest rates and significantly lower cash balance resulted in a decrease in interest income of $241,800.

2011 Actual vs. 2010 Actual

In 2011, the Other Income amounted to $1,087,000, which represents a $700,000 increase over 2010. This increase is mainly driven by the gain of disposition on fixed assets. In 2011, there was a gain on disposition on fixed assets of $255,000, as compared to net loss on disposition on fixed assets of $533,000 in 2010.

This increase was partially offset by the decrease in interest income of $196,900, due to lower cash balances than in 2010.

2011 Actual (MIFRS) vs. 2010 Actual (CGAAP)

2011 Actual Other income under MIFRS is $1,808,900, $722,000 higher than 2011 Actual under CGAAP, due to revenue on damage claims, which was recorded as contributed capital under CGAAP but is recognized as “other income” under MIFRS.

2012 Estimate vs. 2011 Actual

In 2012, the Other Income forecast is $1,020,000, which represents a $394,000 decrease over 2011. This variance is mainly driven by the forecasted decrease in miscellaneous non-operating income and lower forecasted sales of scrap.

Gains and losses on disposition are forecasted at zero, since historically they tend to offset one another over time; for example, the average loss on disposition in 2009-2010 is less than $20,000.

2013 Forecast vs. 2012 Estimate

In 2013 test year, the Other Income is forecast to slightly increase, as compared to the 2012 bridge year, due to higher forecasted interest rates and higher cash balances.

OTHER DISTRIBUTION REVENUE AND OTHER INCOME

DETAILED SCHEDULE (APPENDIX 2-C)

Other Operating Revenue	**Historic Actual**				**Bridge Year**	**Test Year**
	2009	**2010**	**2011**	**2011 MIFRS**	**2012 MIFRS**	**MIFRS 2013**
4235 Miscellaneous Service Revenues	4,445,387	4,162,933	3,906,959	3,908,690	3,270,000	3,385,000
4225 Late Payment Charges	2,294,927	2,458,215	2,187,137	2,187,137	2,400,000	2,500,000
4078 SSS Admin charge	839,530	856,269	888,956	888,956	915,600	932,400
4082 Retail Services Revenues	412,435	371,835	327,076	327,076	392,400	399,600
4084 Service Transaction Requests (STR) Revenues	1,820	30	15	15	-	-
4090 Electric Services Incidental to Energy Sales	-	-	-	-	-	-
4205 Interdepartmental Rents	-	-	-	-	-	-
4210 Rent from Electric Property	678,036	708,903	770,366	770,366	700,000	700,000
4215 Other Utility Operating Income	163	396	-	-	-	-
4220 Other Electric Revenues	-	-	-	-	-	-
4324 Special Purpose Charge Recovery	-	291,411	27	27	-	-
4355 Gain on Disposition of Utility and Other Property	218,280	(532,505)	255,701	249,605	-	-
4360 Loss on Disposition of Utility and Other Property	-	-	-	-	-	-
4375 Revenues from Non-Utility Operations	19,165,456	12,993,100	15,787,841	15,787,841	23,213,000	32,211,000
4380 Expenses of Non-Utility Operations	(17,506,265)	(11,437,064)	(13,700,788)	(13,148,290)	(19,600,000)	(28,500,000)
4385 Non-Utility Rental Income	6,417	6,316	8,120	8,120	-	-
4390 Miscellaneous Non-Operating Income	581,064	576,974	685,960	1,414,261	1,020,000	1,020,000
4405 Interest and Dividend Income	583,650	341,915	144,973	144,973	100,800	125,000

"other Revenue - not classified"						
4105 Transmission Charges Revenue	-	-	-	-	-	-
4110 Transmission Services Revenue	-	-	-	-	-	-
4230 Sales of Water and Water Power	-	-	-	-	-	-
4324 Special Purpose Charge Recovery	-	291,411	27	27	-	-
4375 *Revenues from Non-Utility Operations*	19,165,456	12,993,100	15,787,841	15,787,841	23,213,000	32,211,000
4380 *Expenses of Non-Utility Operations*	(17,506,265)	(11,437,064)	(13,700,788)	(13,148,290)	(19,600,000)	(28,500,000)
4385 *Non-Utility Rental Income*	6,417	6,316	8,120	8,120	-	-
subtotal	1,665,608	1,853,763	2,095,199	2,647,697	3,613,000	3,711,000

Revenue offsets *

Specific Service Charges	**4,445,387**	**4,162,933**	**3,906,959**	**3,908,690**	**3,270,000**	**3,385,000**
Late Payment Charges	**2,294,927**	**2,458,215**	**2,187,137**	**2,187,137**	**2,400,000**	**2,500,000**
Other Distribution Revenue	**1,931,984**	**1,937,434**	**1,986,413**	**1,986,413**	**2,008,000**	**2,032,000**
Other Income & Expenses	**1,382,995**	**386,384**	**1,086,634**	**1,808,839**	**1,120,800**	**1,145,000**
Total	**10,055,292**	**8,944,966**	**9,167,142**	**9,891,078**	**8,798,800**	**9,062,000**

**** For Revenue Offsets calculation, the amounts in accounts 4105,4110,4230, 4324 ,4375,4380,4385 are not included in Other Income and Expenses .***
***** The amounts in account 4405 are net of interest on Regulatory Assets and interest on Customer Deposits***

OTHER DISTRIBUTION REVENUE AND OTHER INCOME

- DETAILED BREAKDOWN FOR SELECTED ACCOUNTS

PowerStream Combined

		Historic Actual				Bridge Year	Test Year
		2009	2010	2011	2011 MIFRS	2012 MIFRS	2013 MIFRS
4405	**Interest and Dividend Income**						
	Bank deposit Interest	(551,708)	(213,887)	(144,973)	(144,973)	(100,800)	(125,000)
	Interest on regulatory Assets	306,156	(65,226)	324,602	324,602	-	-
	Tax Assessment	(28,280)	(128,028)	-	-	-	-
	Interest - MAR	2,024					
	Interest on Customer deposits	(50,000)	(90,000)	(145,000)	(145,000)	(150,000)	(225,000)
	Discounts earned	(5,686)					
	Total	(327,494)	(497,141)	34,629	34,629	(250,800)	(350,000)
	Less Interest on Reg. Assets	(306,156)	65,226	(324,602)	(324,602)	-	-
	Less Interest on Customer deposits	50,000	90,000	145,000	145,000	150,000	225,000
	Total included in Revenue Offsets	**(583,650)**	**(341,915)**	**(144,973)**	**(144,973)**	**(100,800)**	**(125,000)**

		Historic Actual				Bridge Year	Test Year
		2009	2010	2011	2011 MIFRS	2012 MIFRS	2013 MIFRS
4390	**Miscellaneous Non-Operating Income**						
	Sale of scrap	(175,743)	(294,610)	(265,948)	(265,948)	(200,000)	(200,000)
	Damage claims	(102,965)	(67,786)	(91,703)	(820,004)	(700,000)	(700,000)
	Miscellaneous	(302,356)	(214,578)	(328,309)	(328,309)	(120,000)	(120,000)
	Total	(581,064)	(576,974)	(685,960)	(1,414,261)	(1,020,000)	(1,020,000)

CDM REVENUE AND COSTS

Distributors have had their licences amended to include the requirement to meet specific Conservation and Demand Management ("CDM") targets by the end of 2014. PowerStream's targets are a net annual peak demand savings of 95.570 MW and a net cumulative energy savings of 407.340 GWh.

PowerStream filed its CDM Strategy with the OEB in accordance with the *CDM Code for Electricity Distributors* in the fall of 2010. In 2011, PowerStream began delivering CDM programs in 2011 in order to meet the mandated targets. The emphasis has been on Ontario Power Authority ("OPA") Contracted Province-Wide Programs to residential, commercial/institutional and industrial customers. The OPA provides funding for PowerStream's CDM programs. PowerStream's funding portfolio for 2011 to 2014 is approximately $92 million. PowerStream has not sought approval for Board-approved CDM programs.

Funding and expenditures for the delivery of OPA Contracted Province-Wide Programs are kept separate and tracked in Non-Distribution Revenue Accounts in accordance with the guidance in Chapter 5, *Accounting Treatment of the CDM Code*. In addition, PowerStream has ensured that any function performed within the distribution company for CDM activity has been attributed and tracked in the non-distribution accounts. Therefore, CDM activities are not included in the calculation revenue requirement or revenue offsets.

OPERATIONS, MAINTENANCE AND ADMINISTRATION COST OVERVIEW AND DRIVERS

Introduction

PowerStream's Operations, Maintenance and Administration ("OM&A") expenditures from 2009 Board Approved to the 2013 Test Year are summarized in Table 1 below. A direct OM&A comparison from 2009 to 2013 is not possible as PowerStream is required to move to Modified International Financial Reporting Standards ("MIFRS") in 2012. The impacts of MIFRS on the financial results are detailed in Exhibit A3, Tab 1, Schedule 5.

PowerStream has reported its 2011 financial results in both Canadian Generally Accepted Accounting Principles ("CGAAP") and MIFRS, allowing meaningful comparisons to be made in two steps, first from 2009 approved (CGAAP) to 2011 actuals (CGAAP) and then from 2011 actuals (MIFRS) to 2013 the Test Year forecast (MIFRS). The major factors leading to the increase over the period 2009-2013 are discussed in this Exhibit, and the detailed variance analysis is provided in Exhibit D1, Tab 2, Schedule 2 (for Operations and Maintenance Costs) and Exhibit D1, Tab 3, Schedule 2 (for Administration and General Costs).

Table 1: PowerStream OM&A Costs 2009 – 2013

	PowerStream South	PowerStream Combined					
In $000	2009 Approved	2009 Actual	2010 Actual	2011 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
	GAAP				MIFS		
Operation & Maintenance	**15,889**	**22,680**	**19,320**	**21,528**	**26,932**	**30,644**	**32,601**
Administration Expenses	**27,327**	**36,997**	**37,518**	**40,558**	**46,955**	**50,952**	**53,100**
Total OM&A	**43,216**	**59,677**	**56,838**	**62,086**	**73,887**	**81,596**	**85,701**
$ change		16,461	($2,839)	5,248	11,801	7,709	4,105
% change		38%	-5%	9%	N/A	10%	5%

PowerStream notes that the 2009 Actual amount includes spending for the former Barrie Hydro. The 2009 Board Approved amount is for the predecessor PowerStream and excludes Barrie. PowerStream's approach to variance analysis for this merger period is explained in Exhibit D1, Tab1, Schedule 4.

The overall increase in OM&A spending from 2009 to 2013 is related to several factors. One significant contributing factor is the conversion from CGAAP to MIFRS as required by the external accounting reporting bodies. Compensation costs have also increased by approximately 12% since 2009 due to inflationary increases. Staff levels in several areas increased to deal with growth, workforce demographics, and additional administrative requirements of a more complex regulatory environment. An increase in customer count of approximately 9.1% from 2009 to 2013 has driven cost increases in billing and customer services. Another significant factor is PowerStream's aging asset base which has resulted in additional costs to operate and maintain the distribution system in a safe and reliable manner.

There have been additional customer demands for cable locates as well as other programs to increase system reliability. The increasing complexity in the regulatory environment, including the introduction of smart meters, and financial pressures in specific areas such as bad debts has influenced the spending in the OM&A area. Specific programs at PowerStream aimed at increasing effectiveness and long term success including training and succession planning, process reviews and the implementation of PowerStream's new Information Services Strategy have resulted in increased OM&A expenses in the period of review.

A detailed description of PowerStream's Operation and Maintenance programs is provided in Exhibit D1, Tab 2, Schedule 1, while a detailed description of PowerStream's Administrative and General work activities is contained in Exhibit D1, Tab 3, Schedule 1.

OM&A COST DRIVERS

Table 2, below, outlines the key drivers of OM&A costs over the 2009 to 2013 period. In accordance with the OEB's minimum filing requirements, the key cost drivers table is also submitted with other forms in an Appendix 1 to this Application.

Discussions of the cost drivers follow Table 2.

Table 2: OM&A Cost Driver Summary

OM&A Change from 2009 PowerStream Approved to 2013 Budget ($000)				
2009 PowerStream South Approved	$	43,216		
2009 Barrie Actual	$	9,845		
			$	**53,061**
IFRS	$	12,441		
Compensation	$	4,275		
Additional Staff	$	2,626		
Asset Maintenance	$	3,539		
Smart Meter	$	2,731		
Customer Services / Regulatory	$	2,052		
IS Strategy	$	1,519		
Locates	$	1,191		
Corporate Development	$	1,251		
Insurance	$	737		
Other	$	278		
Net Change			**$**	**32,640**
Ending Balance			**$**	**85,701**

IFRS : $12,441,000 increase (Over 2009-2013 period)

Since 2009 PowerStream has had to respond to externally driven requirements that have increased OM&A costs.

The requirement to move from CGAAP to MIFRS has created significant changes in PowerStream's financial reporting. The total impact represents an increase of $12,441,000 in the OM&A costs, due to the change in the Capitalization/Burden Policy and the requirement to remove Shared Services revenue from OM&A and report it as Other Revenue. Please refer to Exhibit A3, Tab 1, Schedule 5 for a detailed discussion on the conversion to MIFRS.

Compensation: $4,275,000 increase (Over 2009-2013 period)

In the period 2009 to 2013, the annual inflationary wage adjustment under the Collective Agreements for the Bargaining Unit Staff was 3% for 2009 and 2010 and 2.9% for 2011 and 2012 (the current three year Collective Agreement ends March 31, 2013). Management and non-union staff compensation has changed on a comparable basis. Wages of the management and non-union staff were adjusted by 1.5% in 2009 and 3% each year from 2010 through to 2013. These annual increases result in a 12% increase in the total compensation over the period of 2009 to 2013. The overall compensation increase related to OM&A is $4,275,000 including inflationary wage increases, merit increases and benefit increases. See Exhibit D1, Tab 5, Schedule 4 for detailed information on compensation and benefits.

Additional Staff: $2,626,000 increase (Over 2009-2013 period)

The total increase in OM&A related to additional staffing is $2,626,000 over the period from 2009 to 2013. See Exhibit D1, Tab 5, Schedule 4 for more information on headcount.

Since 2009, PowerStream has been experiencing increasing upward pressure on staff levels to cope with the increasing demand in many areas of its distribution business.

Growth: By the end of 2013, PowerStream expects its total customer base to have grown to 355,030, an increase of 9.1% from 2009. A staff increase of fifteen headcount or 2.9% is growth related.

Workforce Demographics: 63% of PowerStream's outside workforce is over 40 years of age, of which 28% are expected to retire within next six years and an additional 19% are expected to retire over the following ten years. To address the demographic reality and ensure the continued technical skills required to serve its customers in a safe and effective manner, PowerStream will need to hire a total of thirteen apprentices through the period from 2009 to 2013, representing an increase of 6% of the total staff increase.

Regulatory Requirements: To comply with new regulatory requirements from OEB such as Low Income Emergency Assistance Program ("LEAP") funding, Low Income Code Amendments, OEB Distribution System Code ("DSC") Amendments, smart meters and time of use ("TOU") rates, a net additional staff of two were hired over this period.

Organizational Effectiveness/Technology Efficiency: In its efforts to improve organizational efficiency and ensure that good governance practices are in place, PowerStream created the Project Management Office ("PMO"), Enterprise Risk and Internal Audit, and the Legal department. PowerStream has also developed a business-driven technology strategy to support growing business needs and enable better customer service and efficiency in the future. Eighteen additional staff were hired in this period to implement these organizational initiatives.

Health & Safety and Human Resources: To ensure a safe and healthy workplace in the face of continued growth in customer services and workforce management, four additional staff were added to assist Health & Safety programs management, labour relations management and training.

Asset Maintenance: $3,539,000 increase (Over 2009-2013 period)

PowerStream's infrastructure installed in the 1970s and 1980s is starting to reach end of life and as such failure of equipment, particularly underground cables and splices are occurring on an increasing basis. The frequency of cable and cable splice failures started to increase in 2008 and has reached a steady level over the past three years. PowerStream's Asset Condition Assessment Program has identified the need to repair and replace cable over the next twenty years. With the vast amount of cable installed on the system, a cable condition testing program has been initiated for 2012 to identify and prioritize which areas of the system are in need of cable replacement. However, as this program is in its infancy, cable failure rates are expected to continue in 2012 and 2013 at rates similar to the past three years driving an increase in repair and operating expenses of $939,000. The cable condition testing program described above requires an increase in expense of $361,000.

PowerStream has also embarked on a program to address its Worst Performing Feeders ("WPF"). This program has grown from 2009 to 2013 with spending primarily focused on tree trimming activities. By addressing these worst performing feeders PowerStream will help avoid customer interruptions and continue to enhance system reliability. This has resulted in an increase of $200,000 over this period.

PowerStream is experiencing increased environmental changes and weather patterns that are increasing costs in the OM&A area. The storm damage experienced in 2009 and 2011 resulted in expanded damage repair and restoration activities. PowerStream has also seen an increase in costs related to repainting and repairing equipment due to vandalism, and an increased volume of motor vehicle accidents in its service territory with the corresponding need to repair damaged distribution equipment. There is an increased cost of $454,000 relating to the items mentioned above.

Over this period, in an effort to better manage system outages to ensure reliability, PowerStream implemented a new Outage Management System ("OMS"). The OMS, working in conjuction with smart meter technology better positions PowerStream to more quickly identify outage locations and as such more effectively dispatch crews to improve response and restoration times. The implementation and maintenance of this system resulted in an increase in maintenance costs of $375,000.

Soil testing has identified the need for soil remediation at several Municipal Substations in 2012 and 2013 to ensure that PowerStream continues to meet its legislated/regulatory environmental obligations and continues to operate in an environmentally responsible manner. The total financial impact on OM&A in this area is an increase of $797,000. PowerStream is reviewing many of its sites and expects this expenditure will continue in the near future.

Over this period, PowerStream has experienced increasing building maintenance expenses related to property maintenance, general building repairs and security control, which resulted in an increase in OM&A cost of $413,000.

Smart Meters: $2,731,000 increase (Over 2009-2013 period)

PowerStream has increased its OM&A spending to meet other externally driven obligations. The *Green Energy Act* ("GEA"), and, more specifically, the smart meter initiative led to increased costs over this period.

Subsequent to the OEB's approvals of PowerStream's Smart Meter cost recovery applications (EB-2010-0209 and EB-2011-0128), the operating costs related to the Smart Meters installed from 2008 through to 2011 were no longer deferred and have become part of the OM&A costs. This resulted in an increase of $2,731,000 from 2009 to 2012.

Customer Service/Regulatory: $2,052,000 increase (Over 2009 – 2013 period)

Since 2009, the customer growth has been 29,613 customers or an increase of 9.1%. As new customers have been added to PowerStream's territory there have been higher administration costs such as postage, billing, customer care and sundry costs associated with customer communication programs. PowerStream has continued its practice of completing customer satisfaction surveys and each year creates an action plan to enhance the customer service experience. The total cost increased $696,000 over this period.

The implementation of the new regulatory requirements from OEB such as LEAP funding, Low Income customer-related Code Amendments, and the OEB Distribution System Code ("DSC") Amendments for Move in/Move out process resulted in increase in the 3rd party call center activities. In addition, the Ontario Clean Energy Benefit ("OCEB") reporting required additional CIS programming & reporting changes as well as education for customer service staff. The overall impact is an increase of $313,000 in OM&A costs.

The growth in customer base in PowerStream's service territory also led to increasing volume of meter checks and suite metering activities, resulting in an OM&A increase of $422,000 in 2012.

Due to the economic environment, the bad debt expense has increased $621,000 over the past four years. PowerStream continues to review its processes in this area and is diligent in its collection activity.

Information Systems ("IS") Strategy: $1,519,000 Increase (Over 2009-2013 period)

In 2011, PowerStream developed a business-driven five year technology strategy and Roadmap. The process involved extensive input from PowerStream's senior management team. The plan supports PowerStream's overall corporate strategy, and outlines business drivers, business needs and technology solutions.

A series of interviews and workshops resulted in a roadmap identifying thirty-three projects grouped into five strategic imperatives which will guide IS investments to ensure alignment with overall business direction. The goal is to automate and create efficiencies with the use of technology, enabling better customer service and efficiency in the future.

While the majority of projects will require a capital investment, there will be upward pressure on the operating costs required to maintain and support new systems and processes. The OM&A costs for implementation of the IS strategy have resulted in an OM&A increase of $1,019,000 over the period of 2011 to 2013.

Part of the IS strategy is the update of the CIS system. The current CIS system dates back to the 1970's. For a detailed discussion of the CIS project see Exhibit B1, Tab 1, Schedule 5. The total license fees for the new CIS system are approximately $500,000 annually.

Cable Locates: $1,191,000 Increase (Over 2009-2013 period)

PowerStream has been experiencing an increase in demand for cable locates as a result of continued growth of the customer base in its service territory; the infrastructure replacement projects by municipalities and other third parties; and continued education and promotion by the Electrical Safety Authority and the Ontario Regional Common Ground Alliance on the need for locates. The total cost in cable locates and inspection has increased by $1,191,000 since 2009.

Corporate Development: $1,251,000 (Over 2009-2013 Period)

PowerStream continues its commitment to the elements of BSI 18001. This standard sets out procedures and a methodology for an occupational health and safety management system to ensure a safe workplace. In 2011 a Health and Safety training program was in place to enhance reporting for health and safety. This resulted in an increase in training cost in this area of $90,000 in 2012.

As part of the mandate of the Organizational Effectiveness department, resources were devoted to the development of the "strategic management system" that supports the implementation of corporate strategies - prioritize organizational efforts, initiatives and resources that are critical to the level of services provided by PowerStream to its customers and its long term success. The PMO is part of this area and is responsible for the implementation of consistent project management process, ensuring PowerStream's projects are aligned with the corporate strategy, and are managed on time and on budget. The development of corporate strategy, business process improvement initiatives and the PMO project management resulted in an increase in consulting costs of $200,000 in 2011 and $40,000 in 2013 respectively. In 2011, there is also an increase of OM&A cost of approximately $217,000 in consulting costs for strategic planning, Labour Relations and Employee Survey. There is no further cost increase forecasted in this area in 2013.

A new initiative from an organizational excellence perspective is PowerStream's Journey to Excellence Program. This initiative is to work through Excellence Canada (formerly the National Quality Institute) Progressive Excellence Program, a frame work consisting of four levels of certification - Foundational, Transformation, Role Model and World Class. Currently PowerStream is working on completing Level 2. Level two focuses on building a commitment to continuous improvement as well as nurturing a culture for a healthy workplace. Enhanced training and education is required to ensure that PowerStream's workforce has improved skills and knowledge base to achieve the excellence in business process efficiency, customer service, and meeting increasing external and regulatory demands. This has resulted in an increase in training costs of $544,000 corporate wide including IS, Human Resource, Finance, Customer Services and Supply Chain; and $160,000 in apprentice programs over 2011 to 2013.

Insurance: $737,000 increase (Over 2009-2013 period)

PowerStream has been experiencing increases in insurance premium costs, mainly driven by the increase in property value with the addition of the new operation centre, and Markham TS#4, as well as the appreciation on a number of other station assets. The premium in liability insurance has gone up as well due to the increase in revenue. In 2012, in an effort to mitigate the rapidly growing risk of information and data security, and protect its customer information, PowerStream has purchased a new privacy and network security insurance policy. The policy provides $10 million coverage for each occurrence with an annual aggregate. Overall, the increase in the OM&A insurance costs over the period from 2009 to 2013 is approximately $737,000.

OPERATIONS, MAINTENANCE & ADMINISTRATIVE COST PRODUCTIVITY INFORMATION

Table 1 below shows PowerStream's Operations, Maintenance and Administrative ("OM&A") cost productivity information as required by the OEB's filing guidelines.

Due to the change in accounting standard from Canadian Generally Accepted Accounting Principles ("CGAAP") to International Financial Reporting Standards ("IFRS"), the reader must use caution when making certain year over year comparisons. Most notably, IFRS requires that certain costs be expensed rather than applied as burdens to capital projects. This has the effect of significantly increasing OM&A under IRFS as opposed to CGAAP. PowerStream's transition to IFRS is outlined in Exhibit A3, Tab 1, Schedule 5.

The basis for PowerStream's customer forecast is in Exhibit C1, Tab 1, Schedule 3.

Information on forecast full time equivalent ("FTE") employees is in Exhibit D1, Tab 5, Schedule 4.

A discussion on the OM&A cost drivers is in Exhibit D1, Tab 1, Schedule 1.

Table 1: OM&A Cost Productivity Information

	Board Approved		Historic (Actual)				Bridge Year	Test Year
	2008 Barrie Hydro	2009 Power Stream	2009	2010	2011	2011	2012	2013
	CGGAP					MIFRS		
Number of Customers	71,079	247,895	317,475	324,595	332,135	332,135	339,452	346,725
Total OM&A, $000's	10,048	43,216	59,677	56,551	62,071	73,869	81,457	85,561
OM&A Cost per Customer	$141.4	$174.3	$188.0	$174.2	$186.9	$222.4	$240.0	$246.8
OM&A / Customer - % change			7.8%	-7.3%	7.3%	NA	7.9%	2.8%
Number of FTEs	123	434	516	528	529	529	549	570
Customers/FTEs	578	572	615	615	628	628	618	608
OM&A Cost per FTE,	$81,687	$99,646	$115,653	$107,105	$117,336	$139,639	$148,371	$150,107
OM&A / FTE - % change			16.1%	-7.4%	9.6%	NA	6.3%	1.2%

MERGERS AND ACQUISITIONS

PowerStream's corporate strategy includes an initiative to grow through mergers and acquisitions. PowerStream was in fact created on June 1, 2004 by the amalgamation of Hydro Vaughan Distribution Inc. ("Hydro Vaughan"), Markham Hydro Distribution Inc. ("Markham Hydro"), and Richmond Hill Hydro Inc. ("Richmond Hill Hydro"). PowerStream completed the acquisition of Aurora Hydro Connections Limited ("Aurora Hydro") on November 1, 2005 thus adding a fourth municipality to the service territory.

In 2009 PowerStream merged with Barrie Hydro Distribution Inc. ("Barrie Hydro"). Prior to this merger, Barrie Hydro had acquired four smaller distributors in Simcoe County. PowerStream-Barrie Hydro made PowerStream the second largest municipally owned distribution utility in the province of Ontario.

In 2011 PowerStream formed a strategic partnership with the Town of Collingwood, pending regulatory approval.

PowerStream – Barrie Hydro Merger

Negotiations between PowerStream and Barrie Hydro began in 2008 and the public was advised of the pending merger through news releases, advertisements, council meetings and public consultation sessions.

Following the approval of the merger application by the Ontario Energy Board ("OEB") on December 15, 2008, PowerStream Inc. and Barrie Hydro Distribution Inc. merged effective January 1, 2009 to become the second largest, municipally owned Local Distribution Company ("LDC") in Ontario. The new entity was jointly owned by the City of Barrie, the Town of Markham and the City of Vaughan through their respective holding companies.

The synergies realized through combining the two LDCs and achieving economies of scale were expected to result in operating savings of between $5.0 and $5.5 million annually with $0.4 million in annual capital savings. Merger transition costs (i.e. the one time costs to integrate the two utilities) were estimated to be the equivalent of approximately one year's projected savings.

The merger transition was managed in a planned and controlled manner under which customer service, employee relations and health and safety were of the utmost priority. A “best practice” business process philosophy was adopted whereby the best practices of Barrie Hydro or PowerStream were adopted, or in some cases a better alternative was adopted.

PowerStream and Barrie Hydro established a joint merger integration structure which included oversight by the Board of Directors, the Executive Management Team (“EMT”), and a Merger Integration Team (“MIT”) with sub-committees established to execute specific integration plans. Highlights of the integration included:

- Creation of a new Vision, Mission, and Values;
- Barrie Hydro was integrated with PowerStream’s Enterprise Resource Planning System (JD Edwards financial, payroll and procurement system) on target in May 2009;
- PowerStream began to provide control room operations during business and after hours for the former Barrie Hydro. The integration of the “Avalanche” system allowed the control room to take after hour’s calls in the north service territory (former Barrie Hydro territory), enhancing customer service for the former Barrie Hydro customers;
- The Customer Information System (“CIS”) conversion was completed according to plan in November 2009. Billing activity was harmonized ahead of schedule. This was a significant achievement lead by a cross functional transition team consisting primarily of customer service and information services staff;
- Negotiation of a transitional agreement and a three year Collective Agreement with the bargaining unit, consolidating three collective agreements into one;
- Implementation of revised position profiles and a management compensation structure;
- Integration of all Human Resources and Health and Safety policies;
- Implementation of a co-branding strategy to assist customers with the transition;
- Integration of the phones, email, internet and intranet sites;.
- Installation of a fibre network to link the north and south service areas enabling local voice and data connectivity; and.

- Creation of a “Champions of Change” team to demonstrate, influence and promote a positive culture for the new company.

The financial results of the merger were tracked and reported to the EMT, the Board of Directors and the Shareholders.

After effectively completing the merger, a review of the transition showed that the actually merger savings were $6.2 million, slightly higher than the $5.0 to $5.5 million range expected and noted above.

Similarly, annual capital savings of $0.8 million were achieved, an improvement to the $0.4 million anticipated. The one time capital savings were estimated at $0.6 million and the actual savings achieved was $1.8 million.

Transitions costs estimated at $4.6 million were slightly higher at $5.2 million.

Each year it becomes increasing difficult to precisely analyze the merger savings due to organic growth and the impact of government, regulatory and other changes to the business. In order to complete our analysis of the merger savings we reviewed the savings we projected to achieve in 2011 and beyond that were considered “ongoing”. We determined that the estimated amount of ongoing savings of at least $5 to $5.5 million will be $5.8 million for 2011 and will continue into the future and as such the expected merger savings will have been achieved.

The Director of Enterprise Risk and Internal Audit reviewed the 2010 synergy savings and transition costs and also reviewed the net estimated savings for 2011 and beyond and has determined that the assumptions and amounts are reasonable.

Collingwood – PowerStream Strategic Partnership

In January 2011 the Town of Collingwood (“Collingwood”) and PowerStream announced their intention to form a strategic partnership, subject to OEB approval. PowerStream was selected by Collingwood through a competitive bid process.

Collingwood intends to sell 50% of the shares of Collingwood Utility Services Corp., the holding company for Collus Power Inc., Collus Solutions Corp. and Collus Energy Corp. to PowerStream. PowerStream is purchasing the 50% of the shares for $8.0 million.

Collus Power Inc., the distribution company, serves 15,860 customers (as of December 31, 2011) in Collingwood, Thornbury, Stayner and Creemore. Collus Solutions Corp. provides services to Collus Power Inc. Collus Energy Corp. is dormant.

On March 9, 2012 Collingwood Utility Services Corp. applied to the OEB for approval of the transaction (EB-2012-0056).

NOTES ON OPERATING, MAINTENANCE AND ADMINISTRATIVE COST VARIANCE EXPLANATIONS

An important aspect of a cost of service rate application is reconciling differences in costs back to the last Board-approved amounts. Barrie Hydro had rates rebased in 2008. PowerStream had rates rebased in 2009. The Barrie-PowerStream merger, approved in December 2008 and effective January 1, 2009 added a complication to the required variance analysis.

This exhibit addresses the Operating, Maintenance and Administrative ("OM&A") cost variance explanations for 2008 to 2009 merger transition period. Subsequent exhibits, starting with Exhibit D1, Tab 2, Schedule 2 (for Operations & Maintenance costs) and Exhibit D1, Tab 3, Schedule 2 (for Adminstrative costs) have fulsome variance analysis starting "post merger."

Barrie 2008 Actual vs. 2008 Board-Approved

The Barrie Hydro 2008 actual OM&A expenses were $10,164,000; this was $117,000 or 1.1% higher than the 2008 Board-approved amount of $10,047,000. This variance is below the materiality threshold of $170,000.

Merger Transition in 2009

On January 1, 2009, Barrie Hydro and PowerStream merged and started to combine operations. Early in 2009 the decision was made to combine the OM&A budgets since the merged entity would be run as one business. As as result it is not practical to separate the actual OM&A costs for the former Barrie Hydro and PowerStream in a way that would allow comparisons to the previously approved budgets and Board approved amounts for the two predecessor companies. As a result of combining the tracking of OM&A spending for the former Barrie Hydro and the former PowerStream in 2009, it would not be meaningful to compare:

- Barrie 2009 Actual to Barrie 2008 Actual; and
- Former PowerStream 2009 Actual to PowerStream 2009 Board-Approved.

Note that while the OM&A cost tracking was combined for the merged entities, the tracking of capital additions was kept separate for each of the two “rate zones”. This was done to enable the potential filing for an Incremental Capital Module for additional capital funding during the Incentive Regulation period. Also, the location of the assets permits easy matching with the rate zone.

In 2009 the organizational and accounting structures of the two predecessor companies were consolidated based on PowerStream’s chart of accounts and practices. PowerStream’s accounting structure was more aligned with the Board’s Uniform System of Accounts than was the accounting system of Barrie Hydro. This adds to the difficulty of comparing 2009 actual OM&A cost to budgets and approved amounts prepared on a different basis.

In the subsequent detailed variance analysis, PowerStream starts with comparing the 2009 actual spending for the merged PowerStream with the 2009 Board-approved amounts for the former PowerStream.

If 2009 OM&A spending for the merged entity is compared to the sum of Barrie Board-approved (2008) and PowerStream Board-approved (2009) amounts, then the variance is in two categories, one of which is the added costs for Barrie Hydro. The total OM&A attributed to Barrie of $9,845,000 is not significantly different from the 2008 Board Approved OM&A for Barrie of $10,047,000.This is illustrated in Table 1 below.

Table 1: 2009 OM&A Variance Analysis ($000)

Description	Amount
PowerStream Combined 2009 Actual	$ 59,677
Less:	
2008 Barrie Board-approved	$ 10,047
2009 PowerStream Board-approved	$ 43,216
Subtotal "Combined Board-approved"	$ 53,263
Variance	**$ 6,414**
PowerStream Combined 2009 Actual	$ 59,677
Former PowerStream 2009 Board-approved	$ 43,216
Total Variance	$ 16,461
Variance attributed to Barrie merger	$ 9,845
Variance explained for former PowerStream (detailed in D1-2-3)	$ 6,616
Other not identified	$ (202)
Variance	**$ 6,414**

OPERATIONS AND MAINTENANCE ACTIVITIES OVERVIEW

PowerStream's Operations and Maintenance activities are in three main areas:

- System Operations - activities related to operating the distribution network, including system monitoring, switching for purposes of load management and plant isolation, underground cable locates and metering.
- Planned Inspection and Maintenance Programs – activities associated with PowerStream's annual distribution plant inspection and preventative maintenance program.
- Unplanned or Reactionary Maintenance - activities typically limited to outage troubleshooting and restoration.

A description of PowerStream's typical Operation activities and Maintenance programs follows.

OPERATIONS ACTIVITIES OVERVIEW

System Operations

Daily activities affecting PowerStream's distribution network are coordinated by the System Control Centre, which acts as the controlling authority for any switching and operations activities to be performed to the system. These daily activities could range from a work crew needing to have a section of the power distribution system isolated in order to work safely, to an unplanned outage due to a storm. PowerStream's System Control Centre is a twenty four hour, seven days per week operation. System Controllers monitor and control the distribution system remotely via the Supervisory Control and Data Acquisition ("SCADA") system. The SCADA remotely monitors all of PowerStream's eleven 230kV transformer stations as required by the Transmission System Code and Independent Electricity System Operator ("IESO") requirements. There are also fifty-five municipal substations on the PowerStream distribution system that are monitored and controlled via SCADA, as well as 350 remotely controlled switches deployed strategically through the distribution network.

The System Controllers monitor the distribution network, ensuring voltage levels and system loading are maintained within system limits. On a daily basis, switching is carried out on the system for different purposes - load management, circuit isolation for construction and general maintenance purposes, as well as power restoration. System Control directs all system switching operations, issues all work protection required to isolate plant and manages PowerStream's power restoration activities.

Metering

PowerStream's Metering activities can be grouped into three main areas: Wholesale Metering, Retail Metering and Data Acquisition.

As a registered Meter Service Provider with the IESO, PowerStream performs wholesale metering activities related to PowerStream-owned Transformer Stations and provides the same services to customers who qualify to participate in the wholesale market. These activities include the installation of metering equipment, troubleshooting and data acquisition.

Retail metering activities include the daily operations of installing meters, changing meters (due to Measurement Canada reverification requirements, sample testing program or non-functioning meters) and troubleshooting meters for our Commercial/Industrial and Residential installations and administrative duties related to these functions.

Data is acquired from wholesale, retail and interval meters by use of our MV90 System. The data is gathered on a daily basis to be delivered to Customer Service monthly in order to generate a bill to the customer.

Cable Locates

PowerStream provides cable locates for PowerStream-owned underground cable for customers and third parties at no charge. PowerStream generally provides the locates within five days of request in accordance with the Distribution System Code ("DSC") and Ontario Regulation 22/04. PowerStream is experiencing an increase in the number of requests for cable locates relative to prior years as a result of: continued growth of PowerStream's customer base, the economic development within PowerStream's service area; the infrastructure replacement projects by Municipalities and other third parties. Continued education and promotion by organizations such as the Electrical Safety Authority ("ESA") and the Ontario Regional Common Ground Alliance ("ORGCA") on the importance of locates has also increased the number of locates.

INSPECTION AND MAINTENANCE PROGRAM OVERVIEW

PowerStream's annual inspection and maintenance program is designed in accordance with good utility practice, historical experience and regulatory requirements, as defined in Section 4 of the DSC. Under the program, major equipment items (transformers, overhead switches and switchgear) are selected for cyclic inspection and/or maintenance based on their electrical and mechanical characteristics, manufacturers' guidelines, exposure to environmental contamination, and operating performance. The level of inspection, testing or maintenance required varies depending upon the type of equipment. Mechanical devices, such as switches and switchgear, require maintenance and cleaning to ensure operability. Transformers, which do not have moving parts, only require a visual inspection, whereas poles ten years and older are not only visually inspected, but also tested for mechanical soundness. Maintenance cycles are also adjusted to account for exposure to the elements, for instance insulators on main roads are cleaned annually to remove dirt and salt contamination.

In addition to the annual cyclic maintenance programs, PowerStream introduced a reliability focused initiative that identifies the "Worst Performing Feeders" which are feeders that demonstrate a pattern of higher incidence of outages over a three year period. A focused inspection and maintenance of these feeder circuits is undertaken to improve feeder performance. The Worst Performing Feeder program was initiated in 2010 and the resulting improvement in feeder performance is expected to reduce outage restoration activities on these circuits and over time improve the overall reliability of the distribution system.

PowerStream is also transitioning toward Reliability-Centered Maintenance ("RCM") or a Condition-Based Maintenance ("CBM") approach to system maintenance. This was initiated in 2011 in the Station Maintenance Department and directed toward transformer station maintenance. This program will also be expanded to distribution system maintenance in 2012 and 2013. RCM is a more scientific approach to maintenance based on equipment use, loading, criticality, and wear and tear, as opposed to purely time-based or cyclic maintenance.

The following evidence describes PowerStream's inspection and preventative maintenance programs.

Insulator Washing Programs

Overhead line insulator washing is required annually to prevent failure in the distribution system. Insulators become contaminated by road salt, vehicle exhaust or other airborne contaminants which can result in flashovers and interruption of power. Insulator washing is carried out without necessitating isolation of the overhead circuits and the resulting customer interruptions. It also includes visual inspection and identification of any damaged equipment in the main feeder infrastructure.

Dry-Ice Cleaning

The dry-ice cleaning program for air-insulated pad-mounted switch gear is a cleaning method that allows an efficient and cost effective maintenance of switchgear. Air-insulated switchgear located adjacent to roadways become contaminated with dirt, dust and road salt that can lead to flashovers and equipment failure. The high pressure dry ice method of cleaning allows for air-insulated switchgear to be cleaned without the necessity of isolating the equipment and removing the unit from service. Switchgear is typically cleaned on a five year cycle unless a location is determined to require more frequent cleaning due to high levels of contamination.

Infrared Scanning

The Station Maintenance Department uses infrared scanning technology (i.e., heat detection technology) in transformer stations and municipal stations as an early detection tool to find and prevent possible plant failure. PowerStream's Lines Department also uses infrared scanning to identify overheating components on its overhead and underground distribution system. As a result of the infrared scanning, equipment showing signs of overheating is scheduled for repair or replacement on a priority level based on the severity of the overheating.

Tree Trimming

PowerStream's tree trimming program is based on a five-year cycle, with adjustments for more densely treed, overhead areas. For example, PowerStream has established a three-year cycle for the Aurora downtown area, which is heavily treed. Targeted tree trimming that is not part of the regular five-year cycle is carried out directly as a result of outages caused by trees and as part of the worst performing feeder program.

Overhead Switch Maintenance

Maintenance of three phase gang operated switches, both manually operated and remotely operated, is required to ensure the switches are free of contamination and operate smoothly and efficiently. PowerStream currently has over 300 overhead switches which are maintained on a five year cycle. Maintenance of overhead switches requires isolation of the switches.

Wood Pole Testing

As part of PowerStream's Asset Condition Assessment ("ACA") Program, wood poles are inspected. This work is performed by a contractor who submits electronic records of their inspections to the Engineering Planning department. Poles with less than 60% remaining life are then identified for replacement in future years as part of PowerStream's annual capital program.

Underground Cable Testing

In 2012, PowerStream will commence a program to perform Very Low Frequency ("VLF") testing of its underground cable to determine if there has been any deterioration in the cable insulation. Targeted areas for testing will be identified based upon cable age and performance. The testing forms part of PowerStream's ACA Program and will be used to more proactively identify cables that are reaching end of life. Currently cables are replaced only once a pattern of failure is clearly established in an area as a result of multiple outages.

Transformer Station Maintenance

PowerStream has eleven transformer stations that are supplied from the Hydro One Networks Inc. 230kV transmission system. These large transformer stations each supply a significant number of customers. Maintenance at the Transformer Stations is performed on a regular basis. Not only does this ensure the continued safe, reliable and economic operation of the facilities, but also many components within the facilities require routine maintenance as per schedules dictated by the North American Electric Reliability Corporation ("NERC"). Maintenance schedules for the major components adhere to manufacturer recommended guidelines. Site maintenance is also important for safety, access, and functional purposes. In 2011 PowerStream initiated development of a reliability centered maintenance program for its transformer stations with the long term objective of moving away from purely cyclic maintenance programs. Further development of this program will occur over 2012 and 2013.

Supervisory Control and Data Acquisition (SCADA) Maintenance

The SCADA system is used to monitor and control PowerStream's power distribution system. It is comprised of a master control computer system as well as remote components installed throughout the PowerStream's distribution system. All components require periodic maintenance. For example, communication devices are in need of periodic repair and batteries on remote devices need to be periodically replaced. Regular maintenance, testing and re-configuration is also required on the radio and fibre communication networks and system database and server infrastructure.

UNPLANNED OR REACTIONARY MAINTENANCE

Outage Troubleshooting and Restoration

Power interruptions on the distribution system result from a variety of causes such as equipment failure, foreign interference (e.g. vehicle contact with poles or padmounted transformers), adverse weather, and tree and animal contact with overhead lines. Outage notification is received by System Control through various means – indication from the SCADA system, smart meter communication to the Outage Management System, or through phone calls from customers.

In most cases, the bulk of customers impacted by an outage have their power restored through remote switching carried out by System Controllers. However, most outages also require field troubleshooting activities performed by Lines staff to identify and isolate the faulted equipment or section of circuit. This includes patrolling the system to find the failed equipment, typically followed by switching to isolate the fault and restore power to customers once the faulted equipment has been isolated. Replacement of most failed equipment, once isolated, is capitalized, it is only the troubleshooting and failure assessment that is included as an O&M expense.

Response to outages is carried out by Trouble Crews which provide coverage during weekdays and evenings. Weekend and night time coverage is performed by on-call Lines staff.

Although PowerStream has an ACA program in place and performs extensive inspection and maintenance programs, system reliability performance can be impacted by adverse weather or aging infrastructure that fails.

Although PowerStream plans and budgets for storm related restoration activities based upon historical averages, weather conditions can significantly impact system performance year over year. In years with higher than normal lightening and high wind activity, storm related power interruptions are correspondingly higher and power restoration activities are increased. In years with less active weather, restoration activities are correspondingly lower.

Another significant factor that impacts reliability and power restoration activity levels is failed equipment. PowerStream's infrastructure installed in the 1970's and 1980's is starting to reach end of life and as such failure of equipment, particularly underground cables and cable splices is starting to manifest itself. The frequency of cable and cable splice failures started to increase in 2008 and has reached a steady level over the past three years, impacting both primary high voltage cables and low voltage secondary service cables. When a cable fault occurs and the affected section of cable has been isolated, maintenance and repair activities include locating the fault with fault detection equipment, excavating at the location of the fault, replacing the failed section of cable or failed splice with new splices, re-energization and restoration. PowerStream has developed a long term Cable Replacement and Testing Program to address this issue over the next twenty years, but the recent activity levels in this area are expected to continue for some time as cable is upgraded under the replacement program.

OPERATION & MAINTENANCE EXPENSES – DETAILED VARIANCE ANALYSIS

	CGAAP					MIFRS		
	PS South		Combined				Bridge Year	Test Year
Function within O&M	2009 Board Approved	2009 PS South Actual	2009 Comb Actual	2010 Actual	2011 Actual	2011 MIFRS	2012 MIFRS	2013 MIFRS
System Control	**$2,496**	**$2,376**	**$2,523**	**$2,851**	**$3,411**	**$3,246**	**$3,214**	**$3,341**
$ Increase		($119)	$147	$328	$560	($165)	($32)	$127
% Increase		-5%	6%	13%	20%	-5%	-1%	4%
Lines	**$6,697**	**$8,552**	**$11,731**	**$9,894**	**$10,460**	**$11,173**	**$12,286**	**$12,942**
$ Increase		$1,855	$3,180	($1,837)	$566	$713	$1,113	$656
% Increase		28%	37%	-16%	6%	7%	10%	5%
Protection & Control	**$1,484**	**$1,015**	**$1,015**	**$837**	**$1,289**	**$1,286**	**$1,445**	**$1,486**
$ Increase		($470)	$0	($178)	$452	($3)	$159	$41
% Increase		-32%	0%	-18%	54%	0%	12%	3%
Stations	**$1,741**	**$1,321**	**$1,721**	**$1,334**	**$1,700**	**$1,634**	**$2,137**	**$2,567**
$ Increase		($419)	$399	($386)	$366	($66)	$502	$430
% Increase		-24%	30%	-22%	27%	-4%	31%	20%
Metering	**$1,285**	**$1,412**	**$2,022**	**$1,405**	**$1,404**	**$1,645**	**$3,464**	**$3,512**
$ Increase		$127	$611	($617)	($1)	$241	$1,819	$48
% Increase		10%	43%	-31%	0%	17%	111%	1%
Cable Locates	**$1,703**	**$2,239**	**$2,347**	**$2,402**	**$2,861**	**$2,729**	**$2,753**	**$2,894**
$ Increase		$536	$107	$56	$459	($132)	$23	$141
% Increase		31%	5%	2%	19%	-5%	1%	5%
Engineering	**$323**	**$316**	**$1,016**	**$251**	**$218**	**$4,748**	**$4,557**	**$4,921**
$ Increase		($6)	$699	($764)	($34)	$4,530	($191)	$364
% Increase		-2%	221%	-75%	-13%	2081%	-4%	8%
Other	**$160**	**$147**	**$306**	**$345**	**$186**	**$468**	**$789**	**$939**
$ Increase		($13)	$159	$39	($159)	$283	$321	$150
% Increase		-8%	108%	13%	-46%	152%	68%	19%
Total	**$15,889**	**$17,379**	**$22,680**	**$19,320**	**$21,528**	**$26,930**	**$30,644**	**$32,601**
$ Increase		$1,490	$5,302	($3,360)	$2,208	$5,402	$3,714	$1,957
% Increase		9%	31%	-15%	11%	25%	14%	6%

Board Approved vs. 2009 Actual

Actual 2009 Operation and Maintenance ("O&M") expense increased $6,791,000 or 43% over the Board approved amount for PowerStream South (former PowerStream territory). After adjusted for the PowerStream North (former Barrie Hydro territory) O&M expense of $5,302,000, the actual expenses for PowerStream South were $17,379,000 in 2009 representing an increase of $1,490,000 compared with the Board-approved budget. The Barrie merger occurred after the submission of the 2009 PowerStream South rate case.

The details of this variance are explained below..

- **System Control**

The System Control 2009 expenses were within 5% of the 2009 Board approved amount. The variance of $119,000 below Board-approved amounts was mainly attributable to the delay in implementing the Outage Management System ("OMS"). The associated licensing and maintenance fees related to the implementation of the system did not materialize in 2009. The OMS was implemented in 2010.

- **Lines**

The 2009 actual O&M expenses in Lines were higher than anticipated by $1,855,000 or 28% above the Board-approved amount. This was largely due to higher than normal non-controllable costs such as storm damage and primary cable faults ($520,000 and $765,000 respectively). These costs are generally estimated based on historical averages; however 2009 had abnormally high storm activity in the PowerStream South service territory, including the August 2009 Vaughan tornado, causing a $520,000 increase in storm damage expenses. In addition, an increasing trend in primary cable faults due to aging cable began to emerge in 2009, increasing the expenses in this area by $765,000. The spending trend for primary cable and splice failures realized in 2009 has continued to materialize in 2010 and 2011. PowerStream's Asset Condition Assessment Program has identified the need to remediate and replace cable over the next twenty years.

There was also higher than normal rain in 2009. Wetter than normal ground conditions lead to an increase in failures of underground secondary service cables. This resulted in a increase in repair costs to secondary cables in the order of $380,000.

- **Protection & Control**

Protection & Control ("P&C") actual 2009 expenses were lower than 2009 Board- approved by $470,000 or 32%. This decrease is mainly attributable to the fact that in 2009 construction commenced on Markham TS#4. Construction of a transformer station is a project of significant scope and is a draw on the specialized resources of P&C. In the years in which these projects are underway there is a shift from maintenance activities to capitalized construction and commissioning activities in this group. In 2009, this shift was higher than originally planned.

- **Stations**

The 2009 actual Operating & Maintenance expenses in Stations were decreased by $419,000 relative to the 2009 Board-approved amount. This decrease is mainly attributable to fact that in 2009 construction commenced on Markham Transformer Station (“TS”) #4. Construction of a transformer station is a project of significant scope and is also a draw on the specialized resources of Stations staff. Years in which these projects are underway there is a shift from maintenance activities to capitalized construction and commissioning activities in this group. In 2009, this shift was higher than originally planned.

- **Metering**

Actual 2009 expenses in this category increased by $127,000 over the 2009 Board- approved amount. The increase is mainly attributable to operation activities related to Metering Services Provider registration, trouble calls, and inspecting, testing, disconnecting and reconnecting meters.

- **Cable Locates**

Actual 2009 expenses in this category increased by $536,000 over the Board- approved amount. In 2009, the Canadian government offered two incentives: 1) a tax rebate to homeowners related to renovations up to January 31, 2010. 2) a stimulus package to Municipalities for infrastructure improvement, in an effort to stimulate the economy. This, combined with the Dig Smart campaign started January 2008 by the Ontario Regional Common Ground Alliance (“ORCGA”), created an increased demand for locates in 2009. This caused the operating costs to increase relative to the budget.

- **Engineering**

The work activities and associated spending were consistent with the 2009 Board- approved amount.

- **Other**

Costs are consistent with the 2009 Board approved amount.

2010 Actual vs. 2009 Actual

Actual 2010 Operations and Maintenance expense decreased over the 2009 actual expense by $3,360,000 or (15%). This decrease was partially attributed to the harmonization of burden methodology between PowerStream South and North operations being completed. This resulted in a decrease of actual O&M expenses of approximately $1,562,000. This impacted the results under System Control, Lines, and Engineering.

- **System Control**

Actual 2010 expenses in this category represented an increase of $328,000 or 13% over 2009 actual expenses. A portion of this variance ($268,000) is attributable to the burden policy harmonization activities mentioned above. The work in this function was consistent with previous years other than the items detailed below:

  - Continued implementation of the succession planning strategy resulted in the hiring of seven apprentice System Controllers over the course of 2010. It takes three years of training and development for an apprentice System Controller to be deemed qualified and competent. This program was initiated in anticipation of pending retirements of senior staff over the next five to ten years.
  - Increase in software maintenance costs related to the introduction of the new Outage Management System ("OMS").
  - Harmonization of the burden methodology between PowerStream South and North operations in 2010 resulted in an increase of actual O&M expenses of approximately $268,000.

- **Lines**

Actual 2010 expenses in this category represent a decrease of $1,837,000 or 16% lower than 2009 actual expenses. The variances are attributable to the following items:

- o A return to more normal levels of secondary cable faults accounted for a $306,000 decrease in repair costs.
- o Lower than normal storm activity in the PowerStream territory also lead to a reduction in storm damage and resulting repair costs by $316,000 over the prior year.

In addition to these reductions, and the harmonization mentioned above, it was identified that soil assessments and remediation was required at specific municipal substations. This program was initiated in 2010 to address critical issues and addressed high risk stations within the year. The impact in 2010 was an increase in cost of $562,000 within the Lines function due to an error in accounting treatment, however this work was performed by Stations.

- o Harmonization of the burden policy between PowerStream South and North operations as a result of the merger resulted in a decrease of actual 2010 expenses of approximately $1,066,000 for similar reasons as outlined in the system control variance analysis above.

- **Protection & Control**

The construction and commissioning of the Markham TS work continued in 2010 diverting resources from O&M to capital. Actual 2010 expenses in this category represented a decrease of $178,000 or 18% less than 2009 actual expenses.

- **Stations**

Work continued on the construction and commissioning of Markham TS diverting resources from O&M to capital. Actual 2010 expenses in this category represented a decrease of $386,000 or 22% less than 2009 combined actual expenses.

- **Metering**

Actual 2010 expenses in this category represent a decrease of $617,000 or 31% less than 2009 actual expenses. The focus for the Metering department in 2010 was on smart meters installation where the majority of these costs were being deferred in the regulatory accounts based on OEB directives.

- **Cable Locates**

Actual 2010 expenses in this category represent an increase of $56,000 or 2% more than 2009 actual expenses.

The government infrastructure program ended in the first quarter of 2010, reducing the pressure of increased demands for locates. However, the continuous education of the risk to the public of not locating utilities in advance of digging has increased awareness and therefore demand.

- **Engineering**

Costs in Engineering decreased due to the harmonization of the Barrie and PowerStream work forces. The costs after the merger decreased from 2009 to 2010 by $764,000 as a result of the harmonization of policies and procedures. Under Barrie, Engineering costs were part of O&M and had a portion allocated to capital based on an hourly rate. The PowerStream methodology captures Engineering costs as a burden and allocates them across both O&M and capital using applied rates.

- **Other**

The 2010 actual costs are consistent with historical trends.

2011 Actual vs. 2010 Actual

2011 actual O&M expense increased $2,208,000 or 11% from 2010 Actual expenses due to the factors listed below.

- **System Control**

System Control expenses increased $560,000 or 20% in 2011 over the actual 2010 expenses. This variance is mainly attributable to the hiring of the System Control apprentices during the latter half of 2010. The expenditures for 2011 include a full year salaries for the seven System Controller apprentices hired in the latter half of 2010.

- **Lines**

The variance in Lines expenditures was an increase of $566,000 or 6% from 2010 to 2011. In 2011, the Worst Performing Feeder program identified the need for increased tree trimming to feeders experiencing lower than normal reliability. This increase in tree trimming activity resulted in a variance over 2010 of $200,000.

In 2011 there was a return to more normal levels of storm activity over the very light storm activity of the prior year, leading to an increase in storm related restoration activities at an increase in cost of $250,000.

- **Protection & Control**

With the completion of Markham TS in 2010, resources were shifted back to regular O&M work. A combination of labour and material costs focused on O&M activities in 2011 increased expenses by $452,000. These activities included:

- o Increased focus on Supervisory Control and Data Acquisition (“SCADA”) maintenance as a result of the migration of the North service area to the SCADA system. This initial work included extensive graphical editing and merging of databases to ensure efficient management of North distribution assets, ultimately enabling uniform system reliability for the customers of Barrie and surrounding communities. This work totalled $200,000 in costs.
- o Assumption of all fibre optic link costs between Vaughan and Barrie increased cost by $120,000 in 2011.

- **Stations**

After the completion of the Markham TS project, activity in Stations returned to normal maintenance and operating activities, increasing spending approximately $366,000 in 2011 over 2010.

- **Metering**

The work activities and related spending in 2011 was consistent with those in 2010.

- **Cable Locates**

The demand for cable locates increased in 2011 with expenses increasing $459,000 or 19% over the previous year spending. The number of locates increased 26% over 2010. This was offset by the decrease in average cost of locates due to the Alternate Locate Agreement ("ALA") for specific contractors being introduced in 2011. The ALA permits certain types of work to go ahead without an actual field locate. For example, an ALA can be used under circumstances where the contractor is using non-destructive types of excavation. In these situations it is not necessary to incur the cost of a locate, therefore reducing expenses.

- **Engineering**

The 2011 Engineering costs decreased $34,000 due to the reduction of rail agreement costs. In 2010 CN Rail back billed for the years 2007 to 2010 for specific rail agreements causing increased costs in 2010 compare to 2011.

- **Other**

Other decreased in costs by $159,000 as a result of the North building costs being moved to Administration to be consistent with other building costs.

2011 Actual (MIFRS) vs. 2011 Actual (CGAAP)

The increase of $5,402,000 between CGAAP costs and MIFRS costs are related to the exclusion of certain expenses from the burden pool partially offset by a reduction in burden rates. See Exhibit A3, Tab 1, Schedule 5 for a more detailed discussion of the changes due to the implementation of MIFRS.

2012 Bridge Year (MIFRS) vs. 2011 Actual (MIFRS)

The 2012 bridge year expenses for Operations and Maintenance increased 14% or $3,750,000 under MIFRS from the 2011 MIFRS Actual expenses. This was largely within Metering, Lines and Stations and explained in more detail below.

- **System Control**

In the System Control area the work activities are consistent between 2012 and 2011 with the bridge year forecast for 2012 decreasing by $32,000 or 1% from the 2011.

- **Lines**

In 2012 there is a continued focus on reliability initiatives such as Worst Performing Feeder activities (e.g. infrared scanning, tree trimming) along with the commencement of cable condition testing. A cable testing program has been initiated for 2012 to identify cables in need of replacement. Even with these programs in place, however, cable failure rates are expected to continue in 2012 and 2013 at rates similar to the past three years. In addition, as part of succession planning, headcount is increased by four apprentices. The overall impact results in costs increasing $1,113,000 or 10%.

The capital program requiring Stations and Protection & Control functions are cyclic based on large capital projects such as the construction of transformer stations. In the years where those projects are completed the resources are redeployed back into O&M to complete maintenance work that was unable to be completed within the larger capital spending years. The capital program in 2012 has a lesser requirement for Stations and Protection & Control expertise.

- **Protection & Control**

Preventative and corrective maintenance activities are expected to increase over 2011 by $159,000 due to the above mentioned work allocation.

- **Stations**

Stations maintenance activities increased $502,000 from 2011 Actual (MIFRS) to 2012 Budget (MIFRS) largely related to the above mentioned work allocation. As well, additional costs for 2012 include the transfer of the substation transformer painting program into OM&A (historically in the Capital budget), new ongoing security costs, and a proactive underground cable testing program. These costs combined with the higher focus on maintenance work required the O&M cost to increase.

- **Metering**

The metering budget in 2012 has increased $1,819,000 over 2011 actual spending. The ongoing operating costs of Automated Metering Infrastructure ("AMI") and Operational Data Store ("ODS") have been transferred from Administration to O&M causing an increase in the Metering expense by $600,000. An additional $600,000 is related to Smart Meters approved in 2011. As a result, these related costs are no longer deferred and become a part of the OM&A costs.

Suite metering project management and data acquisition activities also increased costs by $322,000 in 2012 due to the connection of new suite meter customers. Metering checks costs increased by $100,000, primarily driven by the increase in customer volume.

- **Cable Locates**

The demand for locates is expected to remain relatively consistent with the 2011 level while the average cost per locate decreases slightly causing the overall impact of expenses to increase $23,000.

- **Engineering**

The $191,000 decrease between 2011 MIFRS and 2012 is a result of decreases in rail agreement costs due to final payment of contract, and reduction in consulting costs with improvement projects completing within 2011 and 2012.

- **Other**

Other 2012 costs are increasing over 2011 under MIFRS by $321,000. This is due to the anticipated write off of obsolete inventory as well as an increase in fleet costs related to additional leases.

2013 Budget (MIFRS) vs. 2012 Budget (MIFRS)

Operations and Maintenance Expenses in 2013 increased over the 2012 by $1,957,000 or 6% for the following reasons.

- **System Control**

The work activities and associated spending in 2013 are relatively consistent with that of 2012.

- **Lines**

In 2013, activities are similar to those in 2012 but with the addition of another four lines apprentices as part of the succession planning initiative leading to a 5% increase over 2012 of $656,000.

- **Protection & Control**

The 2013 work activities and associated spending are expected to be consistent with those in 2012.

- **Stations**

The 2013 spending in the Stations area is expected to increase over 2012 approximately $430,000. There is an increase of $235,000 related to ongoing soil assessment and soil remediation at two municipal substations. This is a program to minimize environmental risk and remediate any known contaminants found in soil surrounding PowerStream stations.

In 2013 succession planning in the skilled technical trades' functions has identified the need to add two apprentice station maintenance technicians to prepare for pending retirements in Stations anticipated over the next several years.

- **Metering**

The 2013 work activities and related spending are relatively consistent with 2012.

- **Cable Locates**

The 2013 forecast for locates increases slightly over the 2012 levels. Demand is expected to increase modestly in line with the increase in the number of new customers that PowerStream will connect.

- **Engineering**

The 2013 costs are 8% higher than 2012 or $364,000. This increase is to support succession planning for pending retirements as well as additional costs to support engineering work related to asset condition assessments to ensure capital spending on asset replacement is optimal. In addition, to work towards being best in class in managing and scheduling Lines construction projects, a project coordinator position has been added that will assist PowerStream to ensure completion of capital projects on time and on budget.

- **Other**

The 2013 forecast increased $150,000 over 2012 with the expected increase in inventory obsolescence.

ADMINISTRATION AND GENERAL COSTS OVERVIEW

Administrative and General ("A&G") expenses include the cost for these three main activities:

1) Customer Service, Rates and Regulatory and Finance/Accounting;

2) Corporate Services, including: Human Resources, Health, Safety and Environmental Services, Organizational Effectiveness, Information Services, Legal, Supply Chain Management, Corporate Communications, and Enterprise Risk and Internal Audit; and

3) Operations and Engineering head office expenses (not directly charged or allocated to capital and OM&A work).

The following is an overview of the work activities for the functions listed above.

1. CUSTOMER SERVICE, RATES AND REGULATORY AND FINANCE/ACCOUNTING

Customer Service

Customer Service includes the functional areas of Customer Relations (contact centre), Billing Services, Payments and Collections.

PowerStream's customer-facing services, including contact centre and cashiering services, operate Monday to Friday, 8:00 am to 4:30 pm. The contact centre manages multiple channels of customer inquiries, including; mail, fax, electronic communications and telephone calls. PowerStream continues to meet and exceed the "telephone accessibility" service quality indicator as set by the Ontario Energy Board ("OEB"), with over 289,000 calls answered in 2011 at an average service level of 77 percent of calls answered within 30 seconds.

PowerStream has strategically aligned itself with an external contact centre vendor to assist in coping with an increasing number of customer inquiries. The arrangement was made to assist in managing the sustained increase in complex and involved customer inquiries related to PowerStream's smart meter deployment and customer migration to a time-of-use ("TOU") rate structure. More recently, the engagement has expanded to offset significant effort in managing new regulatory obligations including those which introduced requirements for call recording technologies. The strategic alliance with the external contact centre vendor facilitates regulatory compliance, enables contact centre resource and technology redundancy, and positions PowerStream to be more dynamic in responding to fluctuations in call volumes in a seamless manner while controlling costs.

To further improve the customer contact experience, PowerStream has recently implemented a new Interactive Voice Response ("IVR") telephone system. The new system introduces additional opportunities for customers to access account information at their convenience and on a 24/7 basis.

In addition to general account inquiry management, Customer Relations also provides operation and technical assistance for customers who have inquiries related to system reliability, construction and restoration activity and coordinates scheduled power interruptions with customers. Moreover, this team also acts as the main contact point and coordinates activities for new customer connections.

The Billing Services department functions include meter reading, meter data management through manual meter readings as well as billing quantities obtained through the provincial Meter Data Management and Repository ("MDM/R"), retailer Electronic Business Transactions ("EBT"), retailer service agreements, customer account activation, monthly reconciliation processes, assessment and implementation of regulatory change, OEB quarterly reporting, testing, training, process documentation and water billing services.

The Billing Services area process invoices for multiple customer classifications, including residential, general service, generation, Feed-In Tariff ("FIT"), microFIT, interval, flat rate, streetlight, sentinel light, suite metering, water, settlement and invoice market participant.

Meter Reading is completed by three in house staff with a percentage of the work being outsourced to a third-party provider. Conventional meters are scheduled and read manually while consumption data related to TOU customers is obtained by and managed through a local Advanced Metering Infrastructure ("AMI") as well as the Provincial MDM/R. Billing is performed bi-monthly for residential customers and monthly for general service customers.

Billing services are performed on PowerStream's customized Customer Information System. The Billing Services area is scheduled to introduce an added customer convenience and environmentally friendly practice of e-billing in 2012. Once operational, the e-billing service will be available to those customers who wish to “turn off” paper billing, thus reducing costs related to paper stock, printing and mailing.

A forecast of PowerStream's bad debt expenses related to non-payment of distribution and commodity charges is included in the revenue requirement that PowerStream seeks to recover in this application. The forecast is based on historic experience and analysis of uncollectible amounts.

PowerStream manages its payment and collection activities internally through the Customer Credit Department. When a customer’s account is not paid by the due date, PowerStream follows a collections process which includes a number of steps as a reminder for the customer. These steps include a reminder letter, automated reminder telephone calls, hand delivered final notice, and a final verbal reminder and payment opportunity at time of disconnection by onsite staff. PowerStream also carries credit risk insurance on General Service accounts that have entered into bankruptcy or have been final billed and are not collected. This is a valuable tool in keeping the cost of bad debts as low as possible. This insurance has a dual purpose. It assists in the collection of accounts that are not collectable through our normal practices and that meet the insurance parameters; it also is a risk mitigation tool in the case of catastrophic events where large customers enter into bankruptcy.

Rates and Regulatory

The Rates and Regulatory Affairs department is responsible for helping to formulate PowerStream’s regulatory strategy, forecasting distribution revenue, rate applications, regulatory accounting and government relations. The rate application process is managed, including those submitted for cost of service, under incentive regulation or for special purposes such as MAADs or for the clearance of deferral accounts. The department works with OEB staff to help ensure that new policies and procedures are effectively implemented. Regulatory accounting is performed as well as ensuring compliance with reporting or other requirements. This includes items such as ensuring licence compliance, timely RRR reporting and fulfilling IESO filing requirements.

The Rates and Regulatory Affairs department works with a variety of industry stakeholders to provide input to policies or other changes that might affect the industry and PowerStream. The department also assists departments within PowerStream to help implement changes resulting from regulation.

Finance / Accounting

This area includes general accounting, corporate financial reporting, strategic decision support and managing insurance.

The General Accounting group is responsible for the day to day general accounting functions, which include payroll, accounts payable, miscellaneous accounts receivable, account reconciliations, fixed assets and work order accounting.

In the recent past projects to enhance the technology such as automated time entry and direct deposit employee expenses have improved efficiency in this department. The Accounting department is looking at additional functionality in 2012, such as further automating the accounts payable department.

The Corporate Financial Reporting function involves two departments: Financial Services and Corporate Reporting. The Financial Services department is responsible for monthly, quarterly and annual internal management reporting. This group interacts with the entire organization in order to develop the annual budgets and develop PowerStream's overall business plans and strategies. The Corporate Reporting group is also responsible for the implementation of the International Financial Reporting Standards ("IFRS") project and external reporting, including the annual audit.

The Strategic Decision Support group is responsible for providing financial modelling support to corporate wide initiatives such as treasury, financing and dividend strategies.

The finance area keeps up to date on accounting and regulatory changes and how these items affect PowerStream from an financial and reporting perspective. The mandated movement to IFRS has been a key focus area due to the system and reporting changes that are required.

Insurance is also managed in this area. Insurance expense includes property and liability insurance. Vehicle insurance is allocated to vehicle overhead accounts and applied to capital and operations activities through the overhead application process.

2. CORPORATE SERVICES

This function comprises Human Resources, Health, Safety and Environmental Services, Organizational Effectiveness, Information Services, Legal, Supply Chain Management, Corporate Communications, and Enterprise Risk and Internal Audit.

Human Resources

Human resources includes the planning, development and implementation of Human Resources ("HR") strategies and initiatives in support of the Corporate Plan, as well as activities and training associated with other key HR functions including: recruitment, compensation, performance management, attendance management, labour relations, training and development, employee relations, and employee engagement/culture.

Human Resources ensures that reasonable care is taken to achieve legal compliance in the areas of employment law, human rights, WSIB, privacy, and labour law. Further, Human Resources provides ongoing support and coaching to the organization on Human Resource functional areas. This includes creating and delivering annual programs identified on the Human Resource plan and on the Corporate Plan.

Human Resources is responsible for providing support to hiring managers for recruitment (includes job posting design, resume screening, development of interview guides, scheduling of interviews, conducting interviews, and preparing job offers). Human Resources determines organizational training needs and develops training solutions as well as develops the annual corporate headcount budget. This budget is reviewed monthly for significant variances and actions measures to control costs when required.

Health, Safety and Environmental Services

This area includes the planning and controlling of the Health, Safety and Environmental strategy and initiatives in support of the corporate vision, as well as activities and training associated with the health, safety and environmental responsibilities and liabilities in the workplace.

Health and Safety's mandate is to ensure that reasonable care is taken to achieve legal compliance, including the implementation of measures to protect workers and the environment.

Health, Safety and Environmental services are responsible for the day to day support and monitoring of health, safety and environmental issues that arise. This includes managing records, delivering training, promoting awareness, reporting and tracking of incidents, and development and implementation of annual initiatives.

The department provides technical advice and schedules appropriate employee training and skills development. The Health and Safety department co-ordinates the implementation of all Health and Safety programs, policies and procedures, safety training and WSIB. Health, Safety and Environmental ensure accident investigation, reporting and analysis of accidents to prevent recurrence. The Health Safety and Environmental Services department proactively works with management throughout the organization to promote health and safety and includes an Occupational Health Nurse. The Environmental Program develops and delivers specific environmental initiatives that are identified through corporate planning exercises or by the Health & Safety coordinator. In addition the coordinator develops, implements and maintains an ISO 14001 based Environmental Management System suitable for PowerStream's corporate and operational function. This Environmental Management System increases PowerStream's staffs' understanding of their environmental responsibilities through training and awareness and assists other departments in integrating environmental management into their business processes.

Organizational Effectiveness

This Department's purpose is to improve organizational effectiveness through the development of our strategic management processes and supporting implementation of programs that prioritize organizational efforts, initiatives and resources.

Developing measurement tools such as the Corporate Strategy Map, Balanced Scorecard and Operational Dashboards, are major activities for this department. Another key activity is participating on or leading corporate projects and initiatives with cross organizational impact. This unit also provides other services such as: business unit support; developing communication materials and key messages on corporate strategy and leading the continuous process improvement effort at PowerStream.

The Project Management Office ("PMO") is a new area with a focus on achieving efficiency in project management leading to more efficiently run projects. The primary objectives of the PMO at PowerStream are to: review and assess projects against corporate strategy, prioritize projects based on value to the Corporation, assess projects in consideration of conflicting demand for resources, implement consistent project management processes, tools and templates and apply project management best practices.

Information Services

The Information Services Department is responsible for the development of information services ("IS") strategies and the maintenance and operation of PowerStream's information technology infrastructure, software applications, telephone services and Customer Information System ("CIS").

IS Operations provides the installation, operation and support of "back-office" network infrastructure equipment such as servers, routers and phone system.

The IS Support Team provides technical support to over 500 staff. This group also handles the installation, support and maintenance of end-user equipment such as PC's, printers and mobile devices. Equipment is maintained at three facilities in addition to mobile computers located in field vehicles. Corporate wide delivery and support of mobile technology is also a function of this group.

The IS Strategic Planning and Administration Team is focused on both long and short term IS planning. Dedicated teams each support and operate the two core enterprise applications, JD Edwards Enterprise Resource Planning ("ERP") and the CIS (Billing) system. Application development and vendor management are key functions.

Information Security is administered by a dedicated specialist accountable directly to the VP of Information Services. This is an overarching centralized function which also provide consultancy to other business units.

Legal

Due to the increasing needs at PowerStream to review contracts, provide management with legal advice and deal with legal issues, PowerStream has created a legal department to deal with the various legal items that PowerStream now deals with, rather than seeking legal advice on a consultative basis. This has enabled PowerStream to be more proactive in reviewing and receiving legal advice. The legal department also deals with changes in the legislation and ensuring proper contract review.

The Legal Department is principally responsible for: (i) providing legal advice to staff at all levels on various matters; (ii) reviewing, drafting, and/or negotiating various contracts; (iii) reviewing and drafting various procurement related documents; and (iv) reviewing, drafting, and/or negotiating various easement transactions related to PowerStream's electrical assets including all easement registrations and all off-title and title searches related to PowerStream's electrical assets.

Supply Chain Management

Supply chain management is responsible for the areas of procurement, inventory management, fleet services and facility services.

Procurement's role is to ensure that the corporate Procurement policy is adhered to and that the flow of goods and services is maintained in a timely and fiscally responsible manner. New initiatives such as online requisitioning and the use of procurement cards will help achieve this. Other key Procurement responsibilities include:

- Process approximately 5,000 purchase requests per year.
- Administration of 2,200 vendors on JD Edwards system address book with approximately thirty new requests per month.

- Administration of competitive bidding process (i.e. RFP/tenders). The department processes about forty RFP's per year
- Inventory Management ensures the right amount of material is on hand at the right time to maintain distribution system reliability and help sustain system growth. This is achieved by actively managing the material requirements for emergency repair, preventative maintenance and capital work programs. PowerStream's growth has resulted in an opportunity to enhance the Inventory Supply Chain process by leveraging its increased buying potential and distributing some of the associated inventory costs throughout the supply chain (i.e. manufacturer and distributor). This has resulted in a greater focus being placed on inventory management and the introduction of new initiatives such as inventory forecasting, inventory variance reporting, bar coding for management of inventory and determination of field assets, and automated material requisitioning (i.e. online requests, mobile requests)

Fleet Services provides safe, reliable, economical and environmentally-sensible transportation and related services to support the utility's day to day operation. Fleet Services provides vehicles and mobile equipment to various business units requiring transportation. Fleet Services ensures all vehicles are operating effectively by implementing a cost effective preventative maintenance program supported by both an in house maintenance facility and external contractors. Fleet Services also oversees the corporate vehicle replacement program which is based on a life cycle analysis process and a vehicle utilization assessment.

Facilities Services is responsible for the safe, effective and environmentally friendly operation of PowerStream's facilities. This includes its corporate head office located at 161 Cityview Blvd in Vaughan, Ontario and its two operations centers located at 80 Addiscott Ct in Markham, Ontario and 55 Patterson Rd. in Barrie, Ontario. Facilities Services oversees a preventative maintenance program which is implemented by utilizing both in-house and external contractors. The department also assists in the evaluation of facility energy expenditures and proposes cost saving alternatives that reduce the organization's environmental impact. Facilities Services is responsible for the security of all facilities and assists in both Emergency Response and Business Continuity Planning.

Corporate Communications

The Corporate Communications department includes the development of corporate communications strategy, media and general public relations, customer communications, employee communications and corporate social responsibility.

Media and general public relations includes handling all media inquiries (24/7), development and distribution of materials for media and public relations activities including, but not limited to, news releases, media kits, presentations, speeches, annual reports and community events. Customer Communications refers to the activities associated with information distributed or made available to customers on a mass basis through corporate websites, customer newsletters, bill inserts, direct mail, advertising, e-blasts, telephone system and community events.

Employee Communications includes the activities associated with information which is made available to all employees through the corporate intranet site, company-wide broadcast e-mails, employee newsletters, posters/flyers and the internal telephone system.

Corporate social responsibility includes the activities associated with the administration and execution of obligations resulting from the company's support of staff, community organizations and events through its sponsorship and donations budgets including the administration of the Low-income Energy Assistance Program ("LEAP").

PowerStream's corporate charitable donations are managed in the communications area. PowerStream supports various other local initiatives in respect of which it does not seek recovery in this application.

Enterprise Risk and Internal Audit

The Enterprise Risk and Internal Audit function was created to improve processes and controls, and enhance good governance at PowerStream.

The Internal Audit area creates a three year audit plan, updated annually, that considers the risk inherent in PowerStream's operations and also reviews on a rotational basis key areas of the business. Many of the audits have a direct impact of making sure we safely secure customer information and that PowerStream has proper processes in place to safeguard the company's assets.

Enterprise Risk Management concentration has been in the area of discussion and rating of strategic risks and the communication of those risk and mitigation strategies to senior management and the Board of Directors. Formal Risk assessments are going to be introduced for key projects in our project management office through risk workshops, as well as formal operational risk assessments at a departmental level.

3. OPERATIONS AND ENGINEERING SUPPORT

Most of the Operating and Engineering expenses are directly charged or allocated to either capital or operations and maintenance. These areas also include expenses for metering and any smart grid expenses that are not included in the deferral accounts.

Operations & Construction

The main focus of the Operations & Construction function is to manage the construction and operations of PowerStream's facilities to ensure the safe and reliable delivery of power to the customers we serve. The Operations & Construction organization consists of Lines, System Control, Station Maintenance, and Protection & Control.

The Lines group constructs, operates and maintains all overhead and underground plant and assets. This includes activities such as pole line construction, system inspections, preventative maintenance, reactive maintenance, equipment repair, and trouble shooting and restoration activities related to power interruptions. Work is performed by a combination of in-house staff and contractors.

System Control operates 24 hours per day, seven days per week. Staff operate the distribution system remotely via the Supervisory Control and Data Acquisition ("SCADA") system. This includes monitoring and operating the eleven 230 kV:27.6 kV transformer stations as required by the Transmission System Code and IESO requirements. Control Room staff also monitor the distribution network, direct system operations and manage and direct power restoration activities. An outage management system ("OMS") was deployed in the System Control Centre in 2010 and 2011 as a tool to allow System Controllers to more effectively manage customer outage restoration. An IVR system was deployed in 2011 to provide customers with automated information on power outages that are currently being experienced.

Station Maintenance is responsible for ensuring the transformer stations and municipal substations are in good working order through comprehensive inspection and maintenance programs. This group maintains the large equipment in the stations, including power transformers, circuit breakers and reclosers, bus structures and switchgears and battery systems. In 2011 the group commenced development of a reliability-centred maintenance program to more effectively maintain the station assets.

Protection & Control maintains the instrumentation and communication systems necessary to monitor and operate the transformer stations, municipal substations and remotely operable switching devices deployed on the distribution system. This includes set up and calibration of protective relaying schemes in the stations, the SCADA system, fibre communications network, and digital radio systems. These are all key components of PowerStream's highly automated distribution network that allows for faster detection and isolation of system faults, ensuring power is restored to as many customers as possible in the shortest duration.

Engineering Services

The Engineering Services Division provides engineering services for the organization and manages the capital budget for the corporation. Engineering Services include: activities related to planning the distribution system; establishing the standards to which the distribution system will be built and maintained; designing distribution and transformer stations; completing distribution generation connection assessments; designing distribution line projects; facilitating the connection of new subdivisions and industrial, commercial and institutional customers; facilitating the upgrades of services for customers; providing inspection and locate services; managing the corporate Geographic Information System ("GIS"); ensuring availability of up-to-date records and maps on distribution system assets; and managing joint-use, street-light, and rail agreements.

The division is split into capital budgeting, engineering planning, and station design.

The Capital Budgeting team is responsible for providing oversight in the preparation and management of the capital budget for the entire organization. Activities include: setting policy as it relates to the management of the capital budget, compiling the corporate five year capital plan, gathering projects from the business units in the build of the yearly capital budget, managing the capital budget optimization process, providing reports to business units on their capital projects, assisting business unit members in the financial management of their capital projects, compiling the quarterly forecast of the expected year end capital spend, and preparing required capital reports for the organization including documentation for rate applications. The team works closely with the Accounting and Finance teams to ensure capital expenditures are reported accurately and align with appropriate fixed asset accounts.

The Engineering Planning team provides policy direction and guidance to the rest of the organization on appropriate construction activities to undertake on the distribution system, and ensures the records and agreements related to the distribution assets are kept up-to-date. The Engineering Planning team is divided into four groups: System Planning and Standards, Station Design and Construction, Administration, and GIS.

The System Planning and Standards group studies the distribution system to determine required changes on the system and construction projects necessary to ensure the system meets growth needs due to new customers or changing load requirements. The group is responsible for reviewing system reliability and asset condition, to prepare asset condition studies, and determine required maintenance or construction projects to ensure the distribution system operates efficiently and effectively, both in the near and long term. The group is responsible for creating and updating construction and material standards. This includes the investigation of more effective material to be used on the system and ensuring that the organization meets its obligations to Ontario Regulation 22/04.

The Station Design and Construction group provides engineering oversight of the distribution and transformer stations owned by PowerStream. These activities include: preparing asset condition studies for the major station components, studying and setting protection settings for breakers, and reclosers, and coordination guidelines for fuses on the distribution system. The group prepares designs for new stations and new or changed components within a station and oversees the projects as required. The team is responsible for design and oversight of

PowerStream's fibre system and WiMax system that are used for communication between offices, stations, and automated devices in the field and the associated cyber-security of North American Electricity Reliability Corporation ("NERC") critical cyber assets. Lastly, the team is responsible for distributed generation connections administering connection impact assessments and liaising with other parties on the generation connections as required.

The Administration group is responsible for managing joint-use agreements, street light agreements, and rail agreements. This includes oversight to ensure the organization is following the terms of these agreements and associated record keeping requirements. The group also provides assistance in tracking records for municipal site plan approvals and is responsible for coordinating required updates to PowerStream's Conditions of Service document.

The GIS group is responsible for the corporate GIS. This includes both the record keeping and management of the computer system and associated applications. Group members update system maps, complete as-built drawings, and ensure asset data is kept up-to-date.

The Distribution Design team provides design, inspection and locate services for the organization. The Distribution Design team is split into three groups: Capital Design, New Services, and Inspections and Locates.

The Capital Design group provides designs for all capital projects for the distribution system. This includes capital projects to replace assets or optimize the system, new construction to facilitate system growth, and relocation projects required by customers, road authorities or municipalities. The group completes the designs, obtains necessary approvals, prepares and issues drawings and work instructions, answers questions during construction, assesses changes during construction, reviews final as-built drawings, reconciles project costs, ensures appropriate billing occurs, and completes final project closing. Additionally, the group routinely provide estimates for other teams with respect to potential projects and provides the technical resources for joint-use installations.

The New Services group is responsible to liaise with customers to facilitate any new connections to the system. This includes facilitating new green field commercial and residential subdivisions, and facilitating the connection of industrial, commercial, and institutional customers. It also includes facilitating any upgrades to services required by customers, providing designs for connections to streetlight and traffic lights, and providing designs for temporary services. The group works directly with the customers and developers to review the customer site plans, prepares designs for PowerStream's required work, prepares estimates for customers, issues designs for construction, answers questions during construction, and finalizes project costs and billings as required.

The Inspections and Locates group provides two main functions. The first function is managing and ensuring completion of 60,000 plus locates per year. Two thirds of the locates are completed by a third party – the Locate Service Provider ("LSP"). PowerStream completes the remaining locates and performs quality control checks on the LSP, as well as those performed by other contractors under an Alternate Locate Agreement. The PowerStream locate group also investigates dig-ins that damage PowerStream assets. The second function is inspecting civil and underground work completed by PowerStream's in-house civil contractor or by the customer for new services. The inspectors provide the clearance for the construction crews to proceed to energize the facilities.

ADMINISTRATION EXPENSE – DETAILED VARIANCE ANALYSIS

Overview

The Administration program expenses comprise the activities of billing and collection, community relations, advertising and Administration and General ("A&G") activities.

The Billing and Collection function includes customer relations (call centre), meter reading, billing, payment and collections.

The Community Relations category includes communications activities with all external groups, such as media, shareholders and customers and are performed by the Corporate Communications Department.

A&G expenses include expenses related to the corporate, accounting and finance functions, senior management including the engineering and operations areas, insurance, bad debt and eligible charitable donations.

The Administrative Expense category also contains insurance expense which includes property and liability insurance. Table 1 that follows summarizes PowerStream's Administration Expense and related year-over-year variances for the period 2009-2013.

Table 1: Summary of Administration Expenses 2009–2013 ($000's)

	PowerStream South		PowerStream Combined					
	CGAAP					MIFRS		
	2009 Board Approved	2009 PS South Actual	2009 Combined Actual	2010 Actual	2011 Actual	2011 MIFRS Actual	2012 Bridge Year	2013 Test Year
Billing and Collection	**6,556**	**6,217**	**7,092**	**10,014**	**10,736**	**13871**	**12,530**	**13,630**
$ Increase		(339)	875	2,922	722	3,135	(1,341)	1,100
% Increase		-5%	14%	41%	7%	29%	-10%	9%
Community Relations / Advertising	**698**	**912**	**1,094**	**1,332**	**2168**	**2074**	**1,173**	**1,265**
$ Increase		214	182	238	836	(94)	(901)	92
% Increase		31%	20%	22%	63%	-4%	-43%	8%
Administrative and General Expenses	**16,695**	**21,257**	**23,773**	**21,624**	**22,625**	**29158**	**34,446**	**34,992**
$ Increase		4,562	2,516	(2,149)	1,001	6,533	5,288	546
% Increase		27%	12%	-9%	5%	29%	18%	2%
Insurance Expense	**982**	**914**	**1,174**	**1,239**	**1,618**	**1618**	**1,480**	**1,838**
$ Increase		(68)	260	65	379	0	(138)	358
% Increase		-7%	28%	6%	31%	0%	-9%	24%
Bad Debt Expense	**1,236**	**2,515**	**2,873**	**1,911**	**1,781**	**1781**	**2,085**	**2,127**
$ Increase		1,279	358	(962)	(130)	0	304	42
% Increase		103%	14%	-33%	-7%	0%	17%	2%
Charitable Contributions	**41**	**30**	**30**	**336**	**412**	**412**	**350**	**350**
$ Increase		(11)	0	306	76	0	(62)	0
% Increase		-27%	0%	1020%	23%	0%	-15%	0%
Other Distribution Expenses	**1,119**	**608**	**961**	**1,062**	**1,218**	**1,609**	**1,731**	**1,826**
$ Increase		(511)	353	101	156	391	122	95
% Increase		-46%	58%	11%	15%	32%	8%	5%
Sub Total	**27,327**	**32,453**	**36,997**	**37,518**	**40,558**	**50,523**	**53,795**	**56,028**
$ Increase		5,126	4,544	521	3,041	9,965	3,272	2,233
% Increase		19%	14%	1%	8%	25	6%	4%

Less-Shared Service cost incl. above	**0**	**0**	**0**	**0**	**0**	**(3568)**	**(2843)**	**(2928)**
TOTAL	**27,327**	**32,453**	**36,997**	**37,518**	**40,558**	**46,955**	**50,952**	**53,100**
$ Increase		**5,126**	**4,544**	**521**	**3,041**	**6,397**	**3,997**	**2,148**
% Increase		**19%**	**17%**	**1%**	**8%**	**16%**	**9%**	**4%**

2009 Actual Combined vs. 2009 Board Approved (PowerStream South)

Actual 2009 Administration Expenses for PowerStream Combined increased $9,670,000 or 35% from 2009 Board Approved amounts for PowerStream South (former PowerStream territory).

Out of this variance, the PowerStream North (former Barrie Hydro territory) portion is $4,544,000.

The remaining variance of $5,126,000 is attributable to PowerStream South. The main cost drivers for this variance are listed below.

- **Administration and General Expenses**

  Actual Administration and General Expenses in 2009 PowerStream South were $4,562,000 higher than the 2009 Board Approved amount. There are several major factors contributing to this variance, such as:

  - An amount of $2,691,000 related to merger transition costs in 2009 which was not included in 2009 Board Approved amount. This merger transition amount was largely related to payout packages of approximately $1,600,000. The remaining $1,091,000 was related to system integration, union negotiation, and legal and consulting costs to merge standards and procedures.
  - Based on the OEB's directive, the stranded meters that were written off and replaced by the smart meters were allowed to be amortized continuously over the remaining useful life. Accordingly, PowerStream used a separate general ledger corporate account to track the amortization of the stranded meters. This accounted for $893,000 of the increase in 2009 actual over the Board Approved amount.
  - There was a $1,061,000 increase associated with a one-time asset (mainly transformers) write-off in 2009. PowerStream recorded an impairment of major spare parts of $1,060,540 in the 2009 financial statements. This write- off was based on the estimate of slow moving items for major spare parts which were subsequently determined to be obsolete and therefore would no longer be used.

- **Bad Debt Expense**

Bad Debt Expense in 2009 PowerStream South was $2,515,000 compared to a 2009 Board Approved amount of $1,236,000. The increase of $1,279,000 is primarily due to a large amount of bad debt write offs with respect to large commercial customers and an increase of 2009 year-end bad debt provision due to the economic downturn.

- **Community Relations**

Community Relations expenses in 2009 PowerStream south were $214,000 higher than the 2009 Board Approved amount. This variance was driven by the following factors:

- $170,000 was associated with additional customer communication and media costs related to the smart meters program implementation.
- $44,000 resulted from additional advertising and publications cost related to communication to our customers on the Barrie Hydro Merger.

- **Other Distribution Expenses**

Other Distribution Expenses in 2009 PowerStream South amount to $608,000 compared with a Board Approved amount of $1,119,000. The decrease of $511,000 was largely because of the property taxes for the new head office buildings were lower than anticipated.

- **Billing and Collections**

Billing and Collections Expense in 2009 PowerStream South was $339,000 lower compared with 2009 Board Approved amount. This variance was mainly caused by the hiring lag in Customer Relations and Collection areas. The harmonization and integration process that went on at this period for the Barrie Hydro merger consolidation helped PowerStream delay the budgeted new hires.

2010 Actual vs. 2009 Actual

Actual 2010 Administration expenses increased by $521,000 or 1.0% compared to 2009 combined actual expenses. There were several major factors contributing to this variance.

- **Administrative and General Expenses**

  Actual A&G expenses in 2010 were $2,149,000 lower than 2009 actual amount. The principal drivers of this reduction are:

  - There was a $1,100,000 decrease in legal and consulting costs due to one-time merger transition costs that occurred in 2009 (i.e. system integration, union negotiation, and legal advice to merge standards and procedures). There was a $1,000,000 decrease in payroll costs which was related to the one-time payout package occurred during the merger transition in 2009.
  - In 2010, PowerStream began to report the Solar business as a separate business unit. A Services Level Agreement ("SLA") was established to cover the general administration costs incurred by PowerStream for the Solar business. As a result, $368,000 of general administration expenses related to the Solar business was transferred from PowerStream's core business to the Solar business unit.
  - There was a $1,061,000 decrease associated with a one-time asset write-off that occurred in 2009 as explained above.
  - On June 30, 2010, PowerStream signed a new three year collective agreement with the Power Workers Union ("PWU"). As a result of the new agreement, limited employee post-employment benefits were extended to all union employees and any union employees hired during the term of the collective bargaining agreement. An actuarial review was undertaken only for the additional employees added to the post-employment benefit plan. This review was for the period July 1, 2010 to December 31, 2010. In December 2010, PowerStream extended the post-employment benefit plan to management employees effective February 2011 on the same basis as noted above for the union employees. As a result, administration costs were increased by $1,205,000 for this coverage.

- **Billing and Collection Expenses**

Billing and Collection expenses in 2010 increased by $2,922,000 or 41% over 2009 actual expenses.

In December 2010, the OEB approved PowerStream's Smart Meter filing for costs associated with the smart meters installed in 2008 & 2009. The costs related to Smart Meters that were previously recorded under deferred accounts, were moved to the expense accounts as directed by OEB at the end of 2010, resulting in an increase of approximately $2,522,000 in the Billing and Collection expenses. This included, $2,113,000 related to contract advanced meter infrastructure, operating data storage, staffing training and process re-engineering. The rest of the expenses of $409,000 were largely related to call center, billing systems conversion and internal overheads cost in information system and customer services.

In 2010, collections costs were higher by $235,000 than 2009. This variance was largely due to additional services provided by Olameter who were contracted to PowerStream North and provided services which included disconnection, reconnection and fund collection. The purpose of this practice is to align and harmonize the collection process in PowerStream North with PowerStream South office.

Bad Debt Insurance cost was higher by $120,000 in 2010 compared with 2009. This variance was due to the increase of premiums as a result of the change in premium calculation base. The total of Distribution Revenue and Sales of Energy were used as the premium calculation base in 2010; however, only Distribution Revenue was used as the premium calculation base in 2009.

- **Bad Debt Expenses**

The Bad Debt expense in 2010 was $1,911,000 compared to a 2009 bad debt expense of $2,873,000. The reduction of $962,000 bad debt expenses is largely related to the unusually high bad debt expenses occurred in 2009.

- **Other Distribution Expenses**

  Other Distribution Expenses were $1,062,000 in 2010 compared to $961,000 in 2009. The increase of $101,000 was primarily related to the additional property taxes associated with the new operation center located at Markham.

- **Charitable Contributions**

  The 2010 contributions were $336,000 compared to $30,000 in 2009. The $306,000 increase was related to support provided to the Housing Help Center as part of the LEAP program, as well as the Georgian College Partnership. The new centre benefits students enrolled in the renowned utilities-focused Electrical Engineering Technology program and the Electrical Power Technician diploma program which will develop future skilled workforce for PowerStream.

2011 Actual vs. 2010 Actual

The actual 2011 Administration expenses increased by $3,041,000 or 8.0% over 2010 actual administration expense. There are several major factors contributing to this variance.

- **Billing and Collection**

  Billing and Collection expenses in 2011 increased by $722,000 or 7% compared to 2010. The principal drivers for this increase were:

  - Increase in payroll cost of $350,000 due to the 3% salary increase to cover the inflationary cost and the additions of two new headcounts in this group to cover OEB requirements as listed below.
  - OEB Low Income Emergency Assistance Program (“LEAP”) funding and low income code amendments require additional processes and interaction with customers. Many of these processes require additional activities such as the Arrears Management Program, application of deposits prior to disconnection, application of payments to electric first, interaction with social agencies regarding qualification and services to low income customers.

- OEB Code Amendment for move in/move out process required additional resources to track, schedule, perform and follow up on disconnect/reconnects between customers. This will also require additional internal resources to manage and verify the disconnect/reconnect process.

- An increase of $170,000 related to the third party call centre due to the increase of call volume under Customer Relations resulting from the OEB requirement stated above.

- An increase in Postage and Courier costs of $164,000 mainly attributable to the increase of postage costs and additional courier services.

Administrative and General Expenses

The Administration and General expenses in 2011 were $22,625,000, compared to $21,624,000 in 2010. The increase of $1,001,000 was primarily driven by the factors discussed below.

In 2011, as part of the ongoing strategic vision, a new business unit called “Organizational Effectiveness” was created. External consultants (approximately $200,000) were engaged to assist with the development of the strategic management system and supporting the implementation of strategies that prioritize organizational efforts, initiatives and resources that are critical to PowerStream’s productivity improvement.

The Information Technology group engaged external consultants in developing PowerStream technology strategy & Governance / Enterprise Model. This resulted in an increase in consulting cost of $290,000 and related JDE support cost of $193,000.

An increase in consulting costs related to 2013 PowerStream Cost of Service (“COS”) application accounted for approximately $175,000; and Human Resources (“HR”) consulting for Strategic Planning, Labour Relations and an Employee Survey accounted for approximately $217,000.

An increase of $343,000 related to smart meter implementation as approved by the OEB (EB-2010-0128); other increases were related to facilities maintenance of $154,000, telephone maintenance and mobile costs of $124,000, and work force development training programs in HR, Information Services and Legal areas of $169,000.

The increases in the above areas were offset by the reduction in the administration costs related to the one-time post-employee benefit adjustment of $1,200,000 in 2010.

- **Bad Debt Expense**

The Bad Debt expense in 2011 was $1,781,000 compared to a 2010 bad debt expense of $1,911,000. The reduction of $130,000 bad debt expenses was largely related to the decrease in bad debts allowance for miscellaneous account receivable mainly due to improved efficiency by PowerStream collection department.

- **Insurance Expense**

The Insurance expense in 2010 was $1,239,000 compared to 2011 Insurance expense of $1,618,000. The increase of $379,000 of insurance cost was mainly due to the premium increases in Property and Liability insurance.

- **Community Relations**

The Community Relations expenses in 2011 was $2,168,000 compared to $1,332,000 in 2010. The increase of $836,000 was driven by the followings factors:

Increase of $622,000 related to Smart Meter related costs for promoting the Smart Meter implementation, as approved by the OEB (EB-2010-0128).

Increase of $139,000 for printing costs related to Smart Meter Communications to customers.

In order to support the development and execution of external and internal digital communications programs and effectively manage various digital communication channels, the Communication team hired a Digital Communications Officer during the year. This resulted in an increase of approximately $75,000.

- **Charitable Contributions**

  The 2011 contributions were $412,000 compared to $336,000 in 2010. The $76,000 increase was related mainly to the establishment of the partnership with York University for supporting York University's Sustainable Energy Economics and Innovation Initiative.

- **Other Distribution Expenses**

  The 2011 other distribution expenses were $1,218,000 compared to $1,062,000 in 2010. The increase of $156,000 was mainly attributable to goods and services tax/harmonized sales tax audit in 2009 and 2010.

2011 Actual (MIFRS) vs. 2011 Actual (CGAAP)

Actual 2011 Administration expense under Modified International Reporting Standards ("MIFRS") increased by $6,397,000 or 16.0% over 2011 Actual Administration expense under the Canadian Generally Accepted Accounting Principles ("CGAAP") accounting methods. There are two major factors impacted this variance.

- MIFRS methods of accounting impacted an increase in Administration cost by $9,965,000 as a result of changes in the Burden Policy.
- Removal of the Shared Service cost of $3,568,000 from Administration cost. Before MIFRS, the Shared Services revenue and cost were both included in Administration expense. Under MIFRS, the Shared Service revenue was reclassified as Other Revenue. Accordingly, the Shared Service cost was removed from OM&A.

2012 Bridge Year Budget vs. 2011 Actual MIFRS

The 2012 Administration expenses increased $3,997,000 or 8.0% over 2011 Administration expense. The decrease of the Shared Service Cost, due to the loss of Barrie Water Services, accounted for $725,000 of the total variance. The remaining variances of $3,272,000 were illustrated below.

- **Billing and Collection**

The billing and collection cost in 2012 MIFRS budget is $1,341,000 lower than 2011 MIFRS actual.

- Approximately $340,000 of this variance is due to the decrease in conventional meter reading costs as PowerStream completed installation of smart meters in our service territories.
- An amount of $600,000 is as a result of transferring 2012 AMI operating costs and Operational Data Storage from Billing to Metering. The corresponding change has been reflected in the O&M costs.
- The remaining variance of $400,000 is primarily attributable to the 2011 approved smart meter costs, previously recorded in deferral accounts.

- **Community Relations**

Community Relations budgeted expenses in 2012 were $901,000 lower than the 2011 actual cost, which was abnormally high due to one-time transfer of smart meter communication and media costs from the deferred account to the administration cost.

- **Administrative and General Expenses**

The administrative and General Expenses in 2012 increased by $5,288,000 compared to the 2011 MIRFS Actual. The main factors affecting the variance are:

- Additional staff were added to the 2012 budget in support of work force succession planning, establishment of Project Management Office and Internal Audit functions and the implementation of IS Strategy. This has resulted in an increase of $635,000 in costs, based on the assumption that all new hires starts in July, 2012.
- Wage increases due to inflation in 2011 accounted for $1,035,000 of the total variance. Continued MIFRS adjustments resulted in an increase of $230,000 in the Administrative payroll cost.

- $532,000 increase in consulting/legal cost mainly due to the preparation of 2013 Cost of Service (“COS”) rate application to be submitted in 2012.
- The implementation of a five year IS Strategy (including the new CIS System), along with maintaining infrastructure and enhancements in support of National Quality Institute (“NQI”), now known as Excellence Canada, resulted in an increase of $856,000, of which, $500,000 is related to Oracle CIS license fee and the remaining variance is related to software and computer equipment maintenance.
- The 2012 forecasted Post Retirement Benefit are higher than 2011 Actual by $593,000 due to the changes in the policy affecting the decrease of 2011 Actual.
- Increases in property maintenance, general building repairs and building security resulted in an increase of $486,000 in OM&A costs.
- Trades training and other training increased by $465,000 in areas such as Health & Safety, IS, HR, Finance and Supply Chain.
- There was a $132,000 increase due to depreciation on stranded mechanical meters transferred from deferral accounts.

- **Bad Debt Expense**

The 2012 Bad Debt expense is forecasted to be $304,000 higher compared to 2011 Bad Debt expense. The 2012 forecast is based on the historical trend, factored in the current economic situation which causes $215,000 of the total increase; approximately $86,000 of the total increase is attributable to the reduction of miscellaneous Accounts Receivable Bad Debt provision in 2011.

- **Other Distribution Expense**

The 2012 Other Distribution Expense increases by $122,000 due mainly to the budgetary increase in property tax.

2013 Test Year vs. 2012 Bridge Year

The 2013 administration expense budget increases by $2,148,000 or 4% over 2012 budget.

- **Billing and Collection Expenses**

The 2013 Billing and Collection expense increases $1,100,000 or 9% over the 2012 . The increase is primarily driven by:

- Increase in cost of $655,000, as a result of additional headcount for a business analyst, and a supervisor position within the collections group. The business analyst position is required for performing credit risk, payment transition option, and joint service related fee analysis. The supervisor position is required for managing the increased volumes of walk in customers in the North office.
- Increases for Contract Labour of $210,000, which is primarily related to the increase for third party call centre costs due to increased call volumes related to Time of Use and Smart Meter related inquiries. This amount also includes increases in read/mailing services for conventional meter reading due to inflation; and increases in consulting fees related to customer service forum and energy audits.
- Increases in postage and envelopes of $138,000 due to inflation and customer growth; and the introduction of automated telephone and web based customer surveys system at PowerStream's contact centres resulted in an increase of $60,000.

- **Administrative and General Expenses**

The Administration and General expenses in 2013 is $546,000 higher than the 2012 budgeted amount. The principal drivers of this increase are:

- Asset Management group continues the strategic focus on succession planning. The full year salary of the new hire Project Engineer primarily supporting Lines in the development of programs, reporting and analysis assumed in July 2012 has been built into the 2013 budget, resulting in an increase of $109,000. An increase of $160,000 was related to Lines Apprentice training and development.
- The full year salary of the new additions in PMO and Internal Audit assumed in July 2012 is budgeted with full year costs in 2013. This resulted in a $298,000 increase in payroll costs. Consulting cost increased by $110,000 for Improvements in Process Management carried out by the PMO Office.

- Information Technology group has increased new hires as a result of the implementation of the five year IT strategy along with maintaining infrastructure and enhancements in support of NQI. This resulted in a $280,000 increase in payroll. An increase of $180,000 is mainly due to computer equipment maintenance, supplies and software maintenance agreements and licenses.
- The Supply Chain Management group plans to improve the inventory and facility management. This resulted in an increase of $74,000 related to the general facility office space allocation consultant and inventory planning consultant.
- These increases are offset by the forecasted reduction of $660,000 in legal and consulting fees associated with the 2013 COS rate application, which will primarily be incurred in 2012.

- **Insurance Expense**

The Insurance expense in 2013 is budgeted at $1,838,000 compared to a 2012 budgeted Insurance expense of $1,480,000. The increase of $358,000 is mainly driven by the premium increase in property and liability insurance, as well as the purchase of the new privacy & network security insurance policy.

- **Community Relations**

The Community Relations cost increases by $92,000 largely due to new addition budgeted for the Communication Officer and inflation increase in payroll cost.

- **Other Distribution Expense**

The 2013 budget increase of $95,000 is mainly due to the increase in property tax as a result of inflation.

DEPRECIATION AND AMORTIZATION

PowerStream amortizes its capital assets in accordance with the Canadian Institute of Chartered Accountants ("CICA") Handbook and the Board's Accounting Procedures Handbook for Electric Distribution Utilities. See Exhibit A3, Tab 1, Schedule 4 for PowerStream's capitalization and depreciation policy.

The capital assets are amortized on a straight-line basis. The "half-year rule" was applied for 2009 and 2012. The half-year rule results in applying one half of the annual amortization amount in the first year and the other half in the final year of an asset's useful life or in the year of disposition. The historical depreciation amounts for 2010 and 2011 reflect amortization calculated on a monthly basis once the assets are in service.

Note that for purposes of this application, PowerStream has included a full year of depreciation and amortization expense for 2013 additions. This has increased depreciation expense by $1,569,000 compared to the amount determined using the half-year rule.

PowerStream proposes that this is a more appropriate level of depreciation expense for the Incentive Regulation Mechanism ("IRM") period that follows this cost of service application. These additions will attract a full year of depreciation in the subsequent years of the IRM period. More adequate funding will be provided for capital additions.

PowerStream has compared the new depreciation expense on additions to the depreciation expense provided in rates from assets becoming fully depreciated. PowerStream has found that the new depreciation expense amount on additions significantly exceeds the amount of depreciation in rates provided by fully depreciated assets. This result is what would be expected in the situation. The bulk of PowerStream's assets are distribution assets with long lives, many 25 to 50 years. Assets purchased 25 to 50 years ago would have much lower costs than assets constructed at current costs, and thus the annual depreciation expense would be correspondingly lower. Continued growth also contributes to higher amounts of additions and related depreciation expense compared to fully depreciated assets and their annual depreciation expense that is no longer required.

For 2009 to 2011, under Canadian Generally Accepted Accounting Principles ("CGAAP"), PowerStream used the same amortization rates as approved in its 2009 rate application (EB-2008-0244).

Under International Financial Reporting Standards ("IFRS"), PowerStream is required to identify the useful lives of its assets. PowerStream engaged Kinectrics Inc. to conduct a depreciation study. The results of this study were used by PowerStream's Engineering department to set the useful lives used to amortize its assets under IFRS. In accordance with IFRS, PowerStream determined that a number of its asset classes would need to be split into subclasses to reflect the different useful lives for major components of certain assets, e.g., stations.

As per the Board's guidance on IFRS and modified IFRS ("MIFRS"), PowerStream has recorded the losses on derecognition of formerly pooled assets as a separate item under depreciation expense.

The OEB released an IFRS related depreciation document on July 8, 2010 based on a deprecation study for all of Ontario's electrical utilities conducted by Kinectrics Inc. PowerStream's IFRS useful lives and depreciation rates are aligned with the useful life ranges provided in the OEB document.

For more information on the impact of IFRS and the treatment of differences between CGAAP and IFRS, see Exhibit A3, Tab 1, Schedule 5.

Effective January 1, 2011, under IFRS, PowerStream adopted the useful lives for the amortization period of its assets as shown in Table 1 below

Table 1: Asset Useful Lives / Amortization Period

Current GL	Account name	Component	New G/L	CGAAP (yrs)	MIFRS (yrs)
1805	Land		**1805**	0	0
1806	Land Rights		**1806**	0	0
1808	Building and Fixtures- TS and MS	Building Structure	**1808**	50	40
1810	Major Spare Parts		**1810**	0	0
1815	Transformer Stations	Other	**1815**	40	40
		Power Transformer	**1816**	40	40
		Tap Changer	**1817**	40	25
		Winding	**1818**	40	40
		230 KV Bus including Supporting Steel Structure	**1819**	40	40
		Grounding System	**1821**	40	40
		Protection and Control System TS	**1822**	40	20
		SwitchGear and Relays	**1823**	40	30
		Capacitor Banks	**1824**	40	30
1820	Distribution Stations	Other	**1820**	30	30
		Power Transformer	**1826**	30	40
		Protection and Control System	**1827**	30	20
		SwitchGear and Relays	**1828**	30	30
1830	Poles, Towers & Fixtures		**1830**	25	45
1835	Overhead Cond.& Devices		**1835**	25	40
1840	Underground Conduit		**1840**	25	60
1845	Underground Conductor & Devices		**1845**	25	45
1849	Overhead\Transformers		**1849**	25	40
1850	Underground Transformers		**1850**	25	30
1855	Overhead Services		**1855**	25	40
1856	Underground Services		**1856**	25	25
1860	Meters		**1860**	25	25
1861	Interval Meters		**1861**	25	15
1862	Smart meters		**1862**	15	15
1875	Street Lighting		**1875**	25	25
1908	Building & Fixtures	Other	**1908**	50	50
		Building - Structure	**1912**	50	50
		Building - Windows	**1913**	50	30
		Barrie Hydro building- Structural	**1914**	60	60
		Barrie Hydro building- Other	**1916**	50	50
1910	Leasehold Improvements		**1910**	10	10
1915	Office Furniture & Equipment		**1915**	10	10
1920	Computer hardware	Other	**1920**	5	5
		Desktops/Laptops	**1921**	5	4
		Servers (including servers and SAN)	**1922**	5	5
		MFP's (including all printers)	**1923**	5	5
		Switches/Routers	**1924**	5	6
1925	Computer Software Application		**1925**	3	4
	Computer Software Operations		**1926**	3	3
1930/1931	Transportation		**NA**		
		Heavy Vehicles	**1931**	8	12
		Light Vehicles	**1930**	5	7
		Trailers	**1932**	5	22
1935	Stores Equipment		**1935**	10	10
1940	Tools, Shop & Garage		**1940**	10	10
1955	Communication Equipment		**1955**	10	6
1956	Wireless Communication Devices		**1956**	3	3
1961	Process Re-Engineering		**1961**	3	3
1980	System Supervisory Equip	Communication Equipment	**1980**	15	15
		Remote Terminal Units	**1981**	15	15
		Display Wall	**1982**	15	10
1985	Sentinel Light		**1985**	10	10
2005	Property Under Capital Lease		**2005**	25	25
2075	Non-Utility Property Owned Equipment		**2075**	0	0

Table 2 below provides a summary of depreciation and amortization expense for the period 2009 to 2013.

Table 2: Depreciation and Amortization Expense 2009 to 2013 ($000)

CCA Class	GL account	Detail Asset Class	Depreciation Rate (1)	Notes	2009 Actual CGAAP	2010 Actual CGAAP	2011 Actual CGAAP	2011 Actual MIFRS	2012 Foreacast MIFRS	2013 Foreacast MIFRS (4)
Distribution Assets										
47	1610	Hydro One TS - Contributed Capital	4.00%		0	0	29	29	32	32
n/a	1805	Land	0		0	0	0	0	0	0
CEC	1806	Land Rights	0		1	0	0	0	0	0
47	1808	Building & Fixtures	2.50%		853	136	143	191	196	196
47	1810	Major spare parts	0		0	0	440	0	0	0
47	1815	Transformer Stations	2.50%	2	2,393	2,622	3,071	4,970	4,299	4,179
47	1820	Distribution Stations	2.50%	2	342	1,106	1,094	2,079	1,165	1,279
47	1830	Poles, Towers & Fixtures	2.22%		4,290	4,906	5,370	2,331	2,637	3,038
47	1835	O/H Cond & Devices	2.50%		5,754	5,813	6,057	2,776	3,062	3,669
47	1840	U/G Conduit	1.67%		5,660	4,069	4,128	1,081	1,257	1,343
47	1845	U/G Cond & Devices	2.22%		11,459	12,163	12,080	5,021	5,547	6,570
47	1850	Line Transformers	2.85%	3	9,065	9,370	9,267	5,782	6,266	6,809
47	1855	Services (OH and UG)	2.86%	3	1,733	3,798	3,852	4,469	3,233	3,339
47	1860	Meters	5.00%	3	1,538	1,461	803	1,103	1,159	1,424
47	1860	Smart Meters	6.67%		1,629	3,116	3,754	3,735	3,417	3,481
		Subtotal Distribution Assets	n/a		44,719	48,561	50,088	33,566	32,270	35,359
General Plant Assets										
13	1870	Leased Property	2.50%		0	0	0	0	0	0
47	1908	Building & Fixtures - Head office	2.00%	2	560	919	481	919	939	958
13	1910	Leasehold Improvements	10.00%		310	89	0	0	0	0
8	1915	Office Equipment	10.00%		230	476	477	473	494	510
10	1920	Computer hardware	20.00%	2	1,834	1,791	1,520	1,568	1,679	2,114
12	1925	Computer Software	25.00%		2,704	2,383	4,055	2,137	2,626	2,737
10	1930	Transportation	8.33%	2	2,207	2,424	2,531	1,267	1,403	1,806
8	1935	Stores Equipment	10.00%		11	4	(0)	(0)	(0)	1
8	1940	Tools, Shop & Garage	10.00%		347	363	356	371	422	472
8	1955	Communication Equipment	22.22%	3	84	193	212	398	394	420
8	1960	Miscellaneous equipment	10.00%		0	0	0	0	0	0
47	1980	System Supervisory Equip	6.67%		913	1,034	1,022	1,452	963	975
47	1990	Other Tangible property	20.00%		0	0	0	0	0	0
12	1961	Process Re-engineering	33.33%		319	424	(991)	0	0	0
		Subtotal General Plant Assets	n/a		9,519	10,100	9,663	8,584	8,919	9,994
Other Capital										
47	2005	Prop. Under Capital Lease-Addiscott	4.00%		0	731	731	731	733	731
		Subtotal Other Capital Assets	n/a		0	731	731	731	733	731
		Total Assets Depreciation Before Contributed Capital	n/a		54,238	59,392	60,482	42,882	41,922	46,084
47	1995	Contributed Capital Amortization	varies		(9,819)	(10,630)	(11,839)	(7,383)	(8,004)	(8,763)
		NET DISTRIBUTION ASSETS DEPRECIATION	n/a		44,419	48,762	48,643	35,499	33,918	37,321

NOTES:
(1) The depreciation rates are based on PowerStream's depreciation study and implemented under MIFRS effective 2011
(2) This is the depreciation rate on the largest component within the asset class. Actual depreciation is calculated on the specific rate for each component within the class.
(3) This is the average depreciation rate of 2 subclass of assets within the asset group
(4) The additions for 2013 includes a full year depreciation on new 2013 additions

A comparison of the actual depreciation expense and the estimated depreciation expense using the OEB Appendix 2-M schedule has been included in Appendix 1, Schedule 21.

PURCHASED SERVICES AND PRODUCTS

PowerStream's procurement policy seeks to ensure that required services and products are purchased at fair and reasonable prices.

Purchases between $10,000 and $100,000 require written quotations from at least three approved vendors. Purchases over $100,000 require a competitive bidding process. Quotation requirements may be waived with the completion of Sole Source Justification Report , if the purchase is made from a qualified supplier which has previously proven to consistently offer competitive pricing and reliable service or if there are timing, technical or proprietary issues which require limiting the number of bidders or directing the order to a specific supplier.

Table 1, below, contains information on the purchases of non-affiliate services in respect of all procurement transactions above the materiality threshold, as well as a brief description of the service or product provided and the procurement method.

Table 1: Services and Products Purchased by PowerStream from Third Parties 2009 - 2011

Company	Service	Timeline	Procurement Method
Operations and Maintenance			
Trans Power U. C. Inc.	Underground line maintenance	Ongoing	RFP
K-line LTD	Overhead line maintenance	Ongoing	RFP
Utility Line Clearing & Maintenance	Tree trimming and insulator washing	Ongoing	RFP
McNamara PowerLine Consruct	Tree trimming	Ongoing	RFP
Ontario One Call Ltd.	Call centre for locates	Ongoing, started 2008	Sole source, as per agreement with LAC (“Locates Alliance Consortium”)

Company	Service	Timeline	Procurement Method
Progressive Management	Facility management for Barrie office	Until June 2010	Legacy contract – Barrie Hydro
Hapamp LTD	Underground civil construction - Barrie	Until April 2011	RFP from Barrie Hydro
Black and Macdonald Limited	Facility Management	Ongoing	RFQ
Cressman Tree Services	Tree trimming	Ongoing	RFP
Wickens Industrial Ltd.	Dry Ice cleaning of equipment	Ongoing	RFP
Protection Control/System Control			
Survalent	Maintenance Contract for all “Survalent” Software Platforms, Servers and WorkStations	Ongoing	Sole source software vendor (RFP in 2006)
TVD	“Avalanche” software – outage communications	Until 2012	RFQ
ESRI	Outage Management System (OMS) OMS Responder Mobile Outage Communication System	Ongoing	RFP in 2008 Sole Source for the additions to the OMS
Syntellect	IVR for the OMS	Ongoing	RFP
Metering			
Olameter Inc	Meter reading, bill printing, CDM, call centre	Completed in 2011	RFP
Rodan Energy and Metering Solution	Consulting re. Buttonville TS upgrade	Ongoing	Sole source specialized knowledge
Trilliant	Suite metering	Ongoing	RFP
Sensus Metering	Smart meter provider	Ongoing	RFP in 2006; contract extended for Phase 2 of the

Company	Service	Timeline	Procurement Method
	and network services		project.
Walwin Electric	Smart meter service changes	2011 and 2012	RFP
York Region Utility Services	Service connections and single phase services	Ongoing	RFP
Util-Assist	Project management for smart meters and AMI	Ongoing	Sole source (2006)
Engineering Services			
Kinetrics	Asset Condition Assessment and Report on Feeder Cable Ampacity	2006 2009-2010	RFP for Asset Condition Assessment Cable Ampacity – sole source (specialized knowledge, software vendor recommendation)
Canadian Locators Inc. (CLI)	Contract cable locates – Locates Alliance Consortium certified contractor	Ongoing	RFP with Locates Alliance Consortium
Barkley Technologies	Modelling, feeder, optimizization	Ongoing	Sole Source (specialized knowledge of the model, based on previous work with Barrie Hydro)
Corporate Services			
Gowlings Lafleur Henderson	Litigation, corporate advice	Ongoing	Sole source - specialized knowledge
Borden Ladner Gervais LLP	OPA-CDM agreements, corporate advice, M&A advice	Ongoing	Sole source - some aspects shared with CLD
Fraser Milner Casgrain LLP	Regulatory advice and applications	Until 2009	RFP in 2006
McCarthy Tetrault	PILs, Proceediing	2009-2011	Sole sources - some aspects shared with CLD

Company	Service	Timeline	Procurement Method
Deloitte and Touche LLP	Audit / tax advice	Ongoing	RFP
KPMG LLP	Strategic planning advice, IFRS advice	Ongoing	RFP
Mathews Dinsdale & Clark LLP	HR/ Labour Relations	Ongoing	Sole source - specialized knowledge
Regulatory Support Services	Rate Application Support	Ongoing	Sole source - specialized knowledge
IT Services			
Mid-Range Computer Group Inc.	Disaster recovery /website hosting	Ongoing	Service specific, RFQ for disaster recovery
Rondinone Management Service Inc.	PeopleSoft support	Ongoing	Sole source – Vendor involved with initial implementation (RFP in 1999) and has Intimate knowledge of system and business
T&W Info-Systems Ltd	IT support for CIS	Ongoing	Sole source – vendor can support PowerStream's Legacy CIS
Ideaca	IT consulting – Biztalk, Sharepoint	Ongoing	RFP
TEAMCAIN	OLOT – JDE enhancement	Ongoing,	Sole Source – to maintain momentum and continuity of resources (Vendor implemented Pilot)
RainBird Programming	CIS development and support	Ongoing	Sole Source (Legacy CIS)
Nellson IT Consulting	Project management and tech support – PowerStream IVR	Ongoing	RFQ
ESRI Canada LTD	GIS implementation and ongoing maintenance	Ongoing	RFP
Rogers Wireless	Mobile phones and	Ongoing	RFP

Company	Service	Timeline	Procurement Method
	service		
Savage Data Systems	EBT (Electronic Billing Transactions) and operational data store (ODS) hosting	ongoing	EBT - Sole Source due to tight integration to legacy CIS ODS - RFP
Utilismart (prev.ENERconnect)	IESO wholesale settlement services	Ongoing	RFQ
KPMG	IT advisory services	2011	RFQ

CORPORATE POLICY
SUBJECT: PowerStream Procurement Policy

Originator:	Rob Antenucci Director, Procurement, Materials & Fleet	Date:	15/05/08
Reviewed By:	Executive Management Team	Date:	06/11/08
Approved By:	Brian Bentz President & CEO	Date:	06/11/08
To Be Reviewed By:	Director, Purchasing & Fleet	Date:	06/11/09

1) Policy Statement

PowerStream is committed to establishing and maintaining a procurement system that is in compliance with all applicable laws and is consistent with PowerStream's environmental goals and objectives. In addition, PowerStream will endeavour to efficiently procure the most favourable prices through fair and equitable competition for PowerStream's suppliers and contractors.

2) Application

Except as otherwise authorized by the Board, the President/CEO or the Executive Vice-President of Corporate Services, all procurements made by PowerStream shall be administered by the Procurement and Materials Department and authorized by the Director of Procurement, Materials & Fleet or his/her authorized delegate and executed in accordance with this Procurement Policy. All Executives of PowerStream shall ensure compliance with this Procurement Policy within their respective business units and shall not authorize any Procurement outside of this policy.

This Procurement Policy shall be read and applied in accordance with PowerStream's Approval Levels Policy FCSA01.

Procurement Procedures supporting this Policy shall be adhered to accordingly.

3) Source of Supply

3.1 Inventory Material

All material to be purchased, stocked and issued by the Procurement and Materials Department, shall be evaluated, reviewed and approved by the Engineering Standards Department. Stock levels of inventory material are controlled by the Procurement and Materials Department, based on a review of re-order points / quantities, commitments for Lines and Engineering projects, lead time, and item cost.

The list of approved materials and corresponding suppliers will be maintained by the Procurement and Materials Department. Requisitions shall be entered, authorized through the embedded approval process within PeopleSoft and purchase orders shall be issued for all inventory items.

Material / Vendors may be added or removed through consultation with Engineering Standards.

3.2 Non-Inventory Material or Services

The Procurement and Materials Department shall maintain a list of approved Vendors /Contractors that have demonstrated their ability to satisfactorily provide goods/services to PowerStream. Purchase orders will only be issued to approved Vendors/Contractors.

The Procurement and Materials Department, through consultation with the using department(s) may remove a vendor for poor performance or non-performance. A written recommendation to remove a vendor from the approved list will come from the using department and will be filed by the Procurement Department. The vendor

will be removed from the database until all issues are resolved to the satisfaction of PowerStream and a written request is sent to the Procurement Department from the using department.
A Using Department may initiate a request to approve a new Vendor/Contractor to provide goods and/or services to PowerStream.

Information required for approval may include, but is not limited to:

1.) A letter from the potential vendor, listing references or present users; experience in manufacturing the particular product or providing the service, including years in business and financial position
2.) Recommendation of using department
3.) Formal vendor presentation to appropriate personnel
4.) Factory or field inspection including product test results as required
5.) Details regarding technical & financial capability, manpower capacity and service considerations
6.) Proof of ability to perform/deliver according to PowerStream's schedule
7.) Valid certificate for Workplace Safety & Insurance Board Certificate of Clearance (WSIB) or WSIB Independent Operator Status questionnaire
8.) Certification, guarantees conformance with our standards in writing
9.) PowerStream Environmental Survey (Appendix E)

If approved, the Vendor/Contractor will be added to the database of approved vendors and written notification of approval will be sent to the Vendor/Contractor as well as the Using Department.

PowerStream employees shall not have direct or indirect interest in any contract between a Vendor/Contractor for the supply of goods or services to PowerStream. Any conflict of interest must be disclosed in writing to the Director of Procurement, Materials & Fleet or Designate prior to award of any contract indicating the nature of the conflict. The conflict will be reviewed by Senior Management to determine if the contract should be voided due to the nature of the conflict.

4) <u>Obtaining Prices for Non-Inventory Material and Services</u>

The following guidelines apply for securing prices from approved Vendors/Contractors for Non-Inventory Material and Services:

Purchase Order Value	Procedure
$0 - $2,999	May be obtained using approved corporate procurement cards, credit cards, field purchase orders or petty cash procedures.
$3,000 - $9,999	No formal quote is necessary, however the normal process for requisitioning and the issuing of a purchase order is still required.
$10,000 - $100,000	The Procurement Department shall ensure that written quotations from at least three (3) approved vendors are obtained and will forward the results to the Using Department for review and selection.

With the approval of the Director of Procurement, Materials & Fleet or Designate, and the completion of the **Sole Source Justification Report** by the Using Department, the above mentioned quotation requirements may be waived if:

- The purchase is made from a qualified supplier which has previously proven to offer consistently competitive pricing, reliable service and delivery.
- There are timing, technical, or proprietary issues which necessitate the limiting of the number of bidders or directing the order to a specific supplier.

4.1 All Non-Inventory Acquisitions with a Value Less Than $3,000

Non-Inventory acquisitions with a total value of less than $3,000 may be obtained using approved corporate procurement cards, credit cards, field purchase orders or petty cash procedures. It is the responsibility of the users to obtain the highest quality of goods and/or services meeting their needs at the lowest possible price in accordance with this policy.

All contracts and purchase orders for work to be done on or off PowerStream's property will require Public Liability and Property Damage Insurance as well as proof of good standing with the Workplace Safety & Insurance Board.

4.2 All Non-Inventory Acquisitions with a Value Greater Than $3,000 (excluding tax)

Upon receipt of a properly authorized purchase requisition and required supporting documents, the Procurement Department will issue a purchase order to the supplier and maintain a copy in the Procurement Department's files. Material or Services may also be procured using approved corporate procurement cards or credit cards.

Purchase orders will only be issued after a supporting requisition has been entered and approved according to the levels established in the policy, FCSA01.

A requisition shall not be split or divided to avoid conformity with the approval levels established in the policy, FCSA01 and when fixed cost estimates are not available, maximum cost limits shall be used.

The requisition shall clearly define the required product or service including all details regarding price, required delivery, suggested supplier or contractor and correct account information. The originator of the requisition must also include the rationale supporting the selection of a suggested supplier or contractor.

4.3 Competitive Procurement Procedure for Contracts / Acquisitions Greater than $100,000

If the estimated amount of the requested product or service exceeds $100,000, the Procurement and Materials Department will develop a Request for Proposal document in collaboration with the requesting department using the Competitive Procurement Request Form.

The Procurement and Materials Department and the using department will evaluate and recommend a short list of acceptable bidders who will be invited to participate in the proposal process.
Vendors/Contractors must be pre-qualified where:

a) The work is such that the contract administration costs (work inspection, follow-up, extra fee negotiations) could result in substantial costs to PowerStream.

b) The material must meet national safety standards or where no standard exists, must demonstrate an acceptable level of performance.
c) The work involves complex, multi-disciplinary activities, specialized expertise, equipment, materials or financial requirements.

The proposals, when received will be date stamped and will be opened and evaluated in the presence of a representative from the requesting department and the Director of Procurement, Materials & Fleet or Designate. A summary of proposals and a recommendation will be forwarded to the appropriate level of management for approval.

The following is a list of exceptions of purchases that do not require a purchase order:

- CDM rebates
- Corporate procurement/credit card purchases
- Corporate sponsorships/donations
- Customer refunds
- Developer rebates and construction deposit refunds
- DRC payments
- Employee expense/mileage forms and employee clothing/footwear purchases
- Facility lease/rent payments
- IESO and Hydro One power bills
- Insurance, taxes and PIL's payments
- Payments to shareholders
- Payroll payments such as OMERS, WSIB, EHT, benefits and payroll deductions
- Professional memberships, conferences, seminars and training courses
- Regulatory payments
- Utilities such as hydro, water and phone

5.) Contracts and Long Term Agreements

Contracts are required to further set out the mutual obligations not normally covered in a purchase order. The contract shall reference specifications, drawings and any other related documentation in addition to the terms of payment including details regarding progress payments as required. The contract shall also be written to guarantee the performance of the vendor and/or contractor for the duration of the contract

All multi-year contracts require the approvals as specified in FCSA01.

All requests for contract extensions must be supported by the original contract documents containing the right of extension and a completed Contract Extension Justification Report completed and signed by the using department.

6.) Blanket Orders

Blanket orders are issued for a period not to exceed (12) twelve months. The quantity and pricing may not be known until the order is completed at the end of the period, but is based on forecasts from the using department. The Department that uses this type of order is responsible for all charges against the order and a new purchase order will be issued at the beginning of a period for each Department. The Using Department will furnish all information to the Procurement Department necessary to complete the order at the end of the period.

7) Disposal of Scrap, Surplus, Obsolete Material & Equipment

Any equipment, tools, furnishings or material identified as obsolete or surplus by the Manager of the using Department shall notify the Director of Procurement, Materials & Fleet or Designate in writing so that the articles can be properly disposed of to the benefit of PowerStream.

-Appendix A-

COMPETITIVE PROCUREMENT REQUEST FORM

Project Details

Project Name:		
Estimate $:	Requested Issue Date:	Requested Close Date:
Term of Proposed Contract	Start Date:	End Date:

Required Information

Required Item	**Notes (attached, N/A, details…etc.)**
Suggested Vendor List	
Construction / Delivery Schedule	
Drawings	
Specifications	
Required Pricing Schedule	
Suggested Evaluation Criteria	

Submitted By: **(name / signature)**	**Date:**
Business Unit Authorization as per FCSA01 **(name / signature)**	**Date:**

Forward completed form to: Director of Procurement, Materials & Fleet or Designate

For Procurement Use Only		
RFP Number		
Title		
Date Received:	Issue Date:	Closing Date:

-Appendix B-

CONTRACT EXTENSION JUSTIFICATION REPORT

Contract Details

Contract Name:		
Original Contract Value: ($)		Date of Original Issue:
Term of Original Contract	Start Date:	End Date:

Extension Information

Extension Terms:		**Start Date:**		**End Date:**
Extension Price:	**Price:**	**PST:**	**GST:**	**Total:**
Please attach additional documentation as required to support the information above.				

Approval

The undersigned recommend and authorize the Director of Procurement, Materials & Fleet or Designate to extend the above noted contract as per the terms above and the attached documentation.	
Recommended By: (name / signature)	**Date:**
Approved by: Business Unit Authorization as per FCSA01 (name / signature)	**Date:**
Approved By: Director of Procurement, Materials & Fleet or Designate (name / signature)	**Date:**
Approved By: EVP Corporate Services (name / signature)	**Date:**

-Appendix C-

SOLE SOURCE JUSTIFICATION REPORT

Sole Source Details

After a review of project requirements, timing, costs and available service providers, it is recommended that the following Goods / Services be sourced through the vendor shown below:				
Description of Goods / Services Required:				
Vendor Name:				
Contract Price:	**Price:**	**PST:**	**GST:**	**Total:**
Contract Terms:		**Start Date:**		**End Date:**
Please attach additional documentation justifying sole source recommendation.				

Approval

The undersigned recommend and authorize the Director of Procurement, Materials & Fleet or Designate to award the above noted contract as per the terms above and the attached documentation.	
Recommended By: **(name / signature)**	**Date:**
Approved by: **Business Unit Authorization as per FCSA01** **(name / signature)**	**Date:**
Approved By: **Director of Procurement, Materials & Fleet or Designate** **(name / signature)**	**Date:**

VENDORS NAME :	_____	**DATE REQUESTED:** _____
MAILING ADDRESS:	_____ __________	**DATE REQUIRED:** _____
TELEPHONE:	_____ - _____ - _____	**JOB NUMBER: (i.e.C08XXX) C0**_____ **SHIP TO LOCATION:** _____
FAX:	_____ - _____ - __________	**JDE(SYSTEM) RECEIPT:** ☐ **YES** ☐ **NO**
CONTACT:	_____	**FOB: VENDOR** ☐ **POWERSTREAM** ☐

Line No.	Job Cost #	Qty	UOM	Item Number / Description	Unit Cost	Account Number	Work order	Hold Back or Percentage	Deposit Amount $	GST Y/N	PST Y/N
1						. .				☐	☐
2						. .				☐	☐
3						. .				☐	☐
4						. .				☐	☐
5						. .				☐	☐
6						. .				☐	☐

Requested by: **(Print Name First, Last)** **Signature & Job Title** **Date: mm/dd/yy** ____________________ **Send to Vendor** ☐ Yes ☐ No Other _____	**Approved by:** **(Print Name First, Last)** **Signature & Job Title** ____________________ **Date: mm/dd/yy** ____________________

-Appendix D-

Power Stream

-Appendix E-

POWERSTREAM ENVIRONMENTAL SURVEY

Details

Company Name:
Company Address:
Type of Company:

Questionnaire Completed By:

Name:
Position:
Date:
Signature: ________________

1. Does your company have an environmental policy, if yes, please enclose.

2. Does your company produce an environmental report, if yes, please provide a copy?

3. Please provide details of the name and position of the person responsible for your company's environmental policy.

4. Are you currently operating or planning to implement an environmental management system? If yes, please provide details.

5. What are the environmental impacts of the goods, works and services you intend to supply include an assessment of:
    a. Use of raw materials and natural resources
    b. Emissions to air
    c. Energy and water consumption
    d. Packaging
    e. Waste management and recycling programs

6. What steps are you taking to minimize the environmental impacts described above.

7. Do you have measuring and monitoring systems in place to assess actual performance against the company's environmental objectives and targets? If yes, please provide examples.

8. How do you ensure your suppliers have addressed their environmental impacts?

9. Outline any environmental initiatives, corporate environmental sponsorships awards, or community projects in which you are participating.

10. What measures do you have in place to raise awareness of environmental issues amongst your staff?

REGULATORY COSTS

Appendix 2-H that follows, has been completed in accordance with the Board's Filing Requirements. Legal and consulting costs are higher in 2012 than in 2013 mainly due to the cost of service review for 2013 rates.

File Number:	EB-2012-0161
Exhibit:	D1
Tab:	5
Schedule:	2
Page:	
Date:	May 4, 2012

Appendix 2-H
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	Account Balance	Ongoing or One-time Cost? 2	2009	2010	2011	Bridge Year 2012	Annual % Change	Test Year 2013	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655.4565		On-Going	$ 992,906	$ 1,001,353	$ 1,010,494	$ 1,102,500	9.11%	$ 1,157,625	5.00%
2	OEB Hearing Assessments (applicant-originated)	5665-1265		One-Time	$ 203,925	$ 3,960	$ 5,115	$ 170,000	3223.56%	$ 110,000	-35.29%
3	OEB Section 30 Costs (OEB-initiated)	5665-1265		On-Going	$ 50,303	$ 31,954	$ 45,713	$ 80,000	75.00%	$ 50,000	-37.50%
4	Expert Witness costs for regulatory matters			One-Time	$ -	$ -	$ -	$ -	0.00%	$ -	0.00%
5	Legal costs for regulatory matters (2)	5630-1262		One-Time	$ 722,072	$ 39,251	$ 59,420	$ 610,000	926.58%	$ 110,000	-81.97%
6	Consultants' costs for regulatory matters (2)	5630-1261		One-Time	$ 125,346	$ 81,241	$ 86,403	$ 150,000	73.61%	$ 50,000	-66.67%
7	Operating expenses associated with staff resources allocated to regulatory matters	5610-xxxx 5655-xxxx		On-Going	$ 608,738	$ 558,275	$ 681,661	$ 688,557	1.01%	$ 769,377	11.74%
8	Operating expenses associated with other resources allocated to regulatory matters [1]			On-Going							
9	Other regulatory agency fees or assessments (ESA)	9083		On-Going	$ 104,282	$ 134,543	$ 136,989	$ 139,000	1.47%	$ 141,000	1.44%
10	Any other costs for regulatory matters (please define)										
11	Intervenor costs										
12	Sub-total - Ongoing Costs [3]		$ -		$ 1,756,230	$ 1,726,125	$ 1,874,857	$ 2,010,057	7.21%	$ 2,118,002	5.37%
13	Sub-total - One-time Costs [4]		$ -		$ 1,051,343	$ 124,452	$ 150,938	$ 930,000	516.15%	$ 270,000	-70.97%
14	Total		$ -		$ 2,807,573	$ 1,850,578	$ 2,025,795	$ 2,940,057	45.13%	$ 2,388,002	-18.78%

DONATIONS

The top section of Table 1 below shows the amounts paid in donations. These amounts have been excluded for the purposes of setting rates. PowerStream confirms that no political donations have been included for recovery.

PowerStream has formed strategic partnerships with both Georgian College and York University and these amounts are included for recovery. These partnerships will help develop technical staff needed by PowerStream. PowerStream has, and will continue to get ready access to these in-demand, skilled workers for entry level positions. The rate recoverable amounts are shown in the lower section of Table 1.

Table 1: Donations

(In Dollars) **Donations**	**2009 Actual**	**2010 Actual**	**2011 Actual**	**2012 Forecast**	**2013 Forecast**
Not Included for Rate Recovery					
United Way	89,304	31,818	40,926	57,000	57,000
Other	11,379	11,955	6,899	13,000	13,000
Total Excluded From Rate Application	100,683	43,773	47,825	70,000	70,000
Included for Rate Recovery					
LEAP		186,289	187,009	200,000	200,000
Winter Warmth	30,000				
Georgian College		150,000	150,000	150,000	150,000
York University			75,000	213,750	213,750
Total Included in Rate Application	30,000	336,289	412,009	563,750	563,750
Total Donations	**130,683**	**380,062**	**459,834**	**633,750**	**633,750**

EMPLOYEE HEADCOUNT, COMPENSATION AND BENEFITS

INTRODUCTION

Establishing headcount and wages is part of PowerStream's business planning process. As such there is a thorough review and approval process. The starting assumption is that current staffing levels are sufficient and any increases need to be justified.

Headcount initially declined as part of the merger - recognizing expected synergies.

Since 2009, there has been upward pressure on headcount and therefore, wages, largely driven by: the need to support the apprentice programs (metering, lines, station maintenance and Protection and Control), establishment of the Project Management office, implementation of the IS Strategy, and establishment of a Legal and Internal Audit department.

Even with increases from 2009 to 2013 PowerStream's full time head count is projected to be slightly lower in 2013 than the pre-merger full time headcount.

DEFINITIONS

Several defined terms are used within this Exhibit. Those terms, and their definitions, as follows:

Headcount - The total number of Permanent positions budgeted for.

Full Time Equivalent ("FTE") - The total number of full time, part time, co-op and summer students, temporary and contract employees and the Board of Directors. In calculating FTEs staff working part time or part of the year are prorated.

Total Compensation – This includes base salary, incentive, overtime and non financial benefits. These are the gross amounts paid to employees including both capital and OM&A labour.

Core Business – This means the Distribution business only and does not include Conservation and Demand Management or Solar business activities.

PowerStream notes that additional information related to its headcount requirements can be found at Exhibit D1, Tab 1, Schedule 1.

HEADCOUNT

Prior to the merger of PowerStream and Barrie Hydro Distribution Inc. in January 2009, the two distributors had a combined headcount of 519 in the core business. PowerStream set a merger target to reduce this to 475 positions by December 2010 and achieved 463.6 core business positions (excluding new position requirements).

Headcount planning starts by each business unit reviewing PowerStream's Strategy Map, 2015 critical success factors and the 2012 and 2013 supporting objectives which are described in Exhibit A3 Tab 1 Schedule 1. Each business unit then identifies the headcount required with consideration of the requirements for delivering the team's commitment to PowerStream's strategy. Staff are required to perform important functions to meet PowerStream's strategic objectives and provide value added services to PowerStream's customers.

PowerStream continues to experience increases in customer growth, while continuing to operate in an environment of increasing regulatory, technical and other requirements, imposed by third parties all of which have caused PowerStream's workload to increase with a corresponding increase in the number of staff that is required to carry out that work.

Senior management are required to justify the need for all new staff positions to the Executive Management Team ("EMT"). The EMT recommends the changes to the Audit and Finance Committee of the Board of Directors, and to the Board of Directors, as a whole, as part of the overall budget.

The 2012 budget process led to the approval of 23 new staff positions and 1 additional position approved in the later part of 2011, and 1 headcount transferred from CDM. Only 50% of these 23 positions were budgeted in 2012 or 11.5 Headcount positions and the remaining 11.5 were included in 2013. An additional 17 positions were approved in 2013 with 50% of these positions budgeted in 2013 or 8.5 Headcount which will minimize costs to the customers in this submission.

Table 1 is a year-over-year comparison of budgeted staff positions for the period 2009 to 2013 and the corresponding growth in PowerStream's customer base over the same period.

Table 1: Budgeted Staffing Level (permanent Headcount positions)

Budgeted Staff Positions	Predecessor LDC's 2009	2010	2011	2012	2013
Starting level	519.1	519.1	473.4	481.8	495.3
New requirements		3	11	10.5	16.5
Increases due to growth		7	2	2	3.5
Positions eliminated		-54.5	-3	-	
Positions assigned to/from Solar/CDM in 2012		-1.2	-1.6	1	
Budgeted Staff level	**519.1**	**473.4**	**481.8**	**495.3**	**515.3**
Staff increase (decrease)		**-45.7**	**8.4**	**13.5**	**20**
% change		**-8.8%**	**1.8%**	**2.8%**	**4%**

PowerStream's 2013 budgeted number of staff positions (i.e., "headcount") is 515.3 for core business. This represents an increase of 51.7 positions over the post-merger level of 463.6. The additional 51.7 positions comprise 37.2 (41 additional staff and 3.8 reductions) positions to handle new or increased regulatory and other requirements and 14.5 additional staff positions due to growth.

Even with increases from 2009 to 2013 PowerStream's over-all full time head count is projected to be lower in 2013 vs. pre-merger.

Forty-one FTEs of co-op and summer students and 13 Board of Directors bring PowerStream's total 2013 complement to 569.5 (515.3 + 41.2 +13). The use of co-op and summer students permits PowerStream to operate with a lower number of permanent staff positions and provides a degree of flexibility.

PowerStream hires contract and temporary staff to bridge short-term gaps created by approved leaves or vacant positions. Temporary staff may also be hired from time to time to assist with special projects where a specialized skill set is required for a limited period of time.

Table 2 summarizes the year-over-year totals in FTEs for the period 2009 to 2013 in six separate categories. In calculating FTEs, staff working part-time or part of the year are prorated.

Table 2: Full Time Equivalents

	2009 PS EDR	2009 Actual	2010 Actual	2011 Actual	2012 Budget	2013 Forecast
Senior Management	18	27.7	27.5	28.5	28.2	28.2
Management	66	80.2	82.7	75.9	86	89
Non-Union	54.1	43.5	47.5	49.3	53.5	61
Unionized	262.6	305.7	314.2	315.4	327.6	337.1
Sub-total	**400.7**	**457.1**	**471.9**	**469.1**	**495.3**	**515.3**
Board Of Directors	10	13	13	13	13	13
Temp & Students	23	45.5	42.6	47	40.8	41.2
Total	**433.7**	**515.6**	**527.5**	**529.1**	**549.1**	**569.5**

Senior Management Team

PowerStream's Senior Management Team includes the President and CEO, Vice-Presidents and Directors. The Director-level employees are responsible for a number of departments and/or have cross-department responsibilities.

Management

The Management category consists of Managers and Supervisors. Additional staff is needed to better support the operations of the business.

Non-Union

The Non-Union category consists of engineers, finance professionals, some information technology staff, human resources staff and administrative and executive assistants. Additional staff is required in key support areas in order to meet business objectives and priorities and support the operations of the business.

Unionized Positions

The unionized workforce at PowerStream is represented by the Power Workers Union ("PWU"), Local 1000. Unionized staff consists of the various trade positions, commonly referred to as "outside" workers and administrative and clerical staff, commonly referred to as "inside" workers. Both inside and outside workers are covered under a single Collective Agreement.

The increase in unionized positions in the period 2009-2013 is due mainly to the hiring of additional staff for the apprenticeship program in anticipation of future retirements. Additional staff is also required to accommodate the workload from customer and distribution system growth but primarily to ensure fully competent staff are available to serve customers in a safe and effective manner.

The last round of collective bargaining was in 2010 and the next is expected to start January 2013 for an agreement end date of March 31, 2013. The current collective agreement provides for annual salary adjustments of 3% in 2010-2011 and 2.9% in 2012.

PowerStream has determined that the average age of its outside staff is 43.5 years of age. Workforce demographics for these staff are shown in Table 3, below.

Table 3: Demographics – Outside Staff

Age by Category	Lines		Control Room		Protection & Control		Station Maintenance		Metering		Engineering Design		Total	
	No.	%	No.	%	No.	%	No.	%	No.	%	No.	%	No.	%
50 and Above	30	34%	6	31%	3	38%	5	50%	6	43%	6	29%	56	35%
40-49	27	31%	3	16%	1	12%	3	30%	5	36%	5	23%	44	28%
30-39	10	11%	4	21%	3	38%	0	0%	3	21%	4	19%	24	15%
Less than 30	21	24%	6	31%	1	12%	2	20%	0	0%	6	29%	36	23%
Total	88		19		8		10		14		21		160	
Years to Retirement	Lines		Control Room		Protection & Control		Station Maintenance		Metering		Engineering Design		Total	
	No.	%	No.	%	No.	%	No.	%	No.	%	No.	%	No.	%
6 or less	24	31%	5	26%	1	14%	5	50%	5	36%	5	31%	45	28%
7-10	23	29%	3	16%	1	14%	0	0%	1	7%	3	19%	31	19%
Total (<=10)	47	60%	8	42%	2	28%	5	50%	6	43%	8	50%	76	48%

Table 3 shows that 63% percent of the outside work force is over 40 years of age. Based on age and years of service, 28% percent are expected to retire within the next six years and an additional 19% percent are expected to retire over the following ten years. PowerStream must ensure that it maintains the level of technical staffing required to serve its customers in a safe and effective manner. It takes nearly five years to achieve “journeyman” status (i.e., fully qualified) and then a further two years to reach full proficiency. In order to address this demographic reality in the face of continued growth, in the period 2009 to 2013, PowerStream will have hired a total of 32 apprentices, 19 of whom are being hired to fill existing vacancies and 13 of whom will be replacing future retirements. The 13 apprentice positions include 8 linepersons, 2 station maintenance, 2 metering and 1 P&C technician.

TOTAL COMPENSATION

Table 4 summarizes the year-over-year changes in total compensation of the employees in each of six categories, for the period 2009-2013.

Table 4: Total Compensation by Group ($) (including Benefit)

	2009 PS EDR	2009	2010	2011	2012	2013
Board of Directors	320,826	283,428	281,952	305,878	411,640	423,990
Senior Management	4,390,958	5,191,038	6,457,442	6,914,994	7,024,404	7,330,328
Management	8,486,313	9,712,179	11,444,739	11,004,428	13,181,412	14,130,866
Non-Union	6,405,884	4,307,946	5,244,785	5,745,024	6,146,389	7,333,607
Unionized	24,139,242	27,970,885	30,981,592	32,190,699	32,711,217	34,877,584
Temp & Students	0	1,809,169	1,580,245	1,617,627	1,735,871	1,785,980
Total	**43,743,224**	**49,274,646**	**55,990,754**	**57,778,650**	**61,210,932**	**65,882,355**

Total Compensation includes base salary, incentive, overtime and non financial benefits.

In the period 2009-2013, Total Compensation increased by a total of $22.1 million or 50.5%. This figure does not relay the total picture, however, because the $43.7 million “2009 EDR” amount does not include $10.8 million of the former Barrie Hydro. If the value of Barrie is added to the 2009 EDR total, the total increases to $54.5 million and the increase over the period 2009 to 2013 becomes $11.3 million or 20.7% percent or 5.2 % per year.

The increase in Total Compensation in the period 2009-2013 is due to a number of factors. These factors are set out in Table 5 and explained below.

Table 5: Changes in Total Compensation 2009 to 2013 ($000)

2008 EDR amount (Barrie)		$10,877
2009 EDR amount (PS)		$43,743
Decreases due to merger savings, hiring lags, other		$-5,345
Contract and inflationary increases	12%	$4,945
Increase in number of staff	9%	$4,553
Increase in benefits	10%	$4,968
Other changes	4%	$2,141
2013 Total Compensation (include Benefit)		$65,882

The 2009 EDR amount is based on a 2008 Historical Test Year and represents compensation at 2008 levels. In the period 2009 to 2013, the annual inflation adjustment under the Collective Agreement was 3% for 2009 to 2010 and 2.9% for 2011 and 2.9% is included for 2012 and 2013. Wages of the management and non-union staff were adjusted by the 1.5% in 2009, 3% in 2010, 2.9% in 2011(2012 to 2013 budget 3%). These annual increases result in a 12 percent increase in adjusted total compensation over the period 2009 to 2013. In the same period, PowerStream's staffing complement increased by 53 FTE’s or 10.3%.

The contract/inflationary wage increases, the increase in the number of staff, and increases in benefits are the principal drivers of changes in Total Compensation in the period 2009-2013.

Average Yearly Base Wages

Table 6 is a summary of the year-over-year average base wages, by category, in the period 2009 to 2013.

Table 6: Compensation - Average Yearly Base Wages ($)

	2009 PS Board Approved	2009	2010	2011	2012	2013
Board of Directors	30,077	20,396	19,977	22,027	29,593	30,481
Senior Management	174,309	161,578	163,889	172,504	173,809	180,611
Management	98,487	95,493	97,868	105,054	106,877	111,090
Non-union	62,059	81,868	83,457	88,191	85,815	89,613
Unionized	64,500	65,314	68,383	70,088	72,108	74,548
Temp & Students	0	36,189	32,180	31,047	37,165	37,985

- **Senior Management/Management/Non-union salaries**

In 2009, following the merger of PowerStream and Barrie Hydro, an independent consultant was retained to review the compensation structure for management employees. The consultant conducted salary surveys of comparable companies in terms of size, both within and outside of the utility sector. On the basis of the results of this review, PowerStream adopted a new salary total compensation structure for Management level positions.

- **Unionized salaries**

In 2010, PowerStream negotiated a three-year Collective Agreement with the PWU. Under the terms of this agreement, all bargaining unit employees were entitled to an annual 3% wage increase in the first two years with 2.9% in the final year. The Collective Agreement remained in effect until March 31, 2013.

Average Yearly Overtime

Table 7 summarizes the year-over-year changes in average annual overtime payments in the period 2009-2013, for each of six categories of employees.

Table 7: Compensation – Average Yearly Overtime ($)

	2009 PS Board Approved	2009	2010	2011	2012	2013
Board of Directors	0	0	0	0	0	0
Senior Management	0	0	0	0	0	0
Management	0	2,368	1,132	1,261	306	306
Non-Union	0	408	268	158	0	0
Unionized	5,296	8,715	11,430	12,888	7,682	7,813
Temp & Students	0	143	63	133	0	0

Overtime is budgeted, annually, based on historical data. Due to the nature of PowerStream's work, however, certain unforeseen situations may arise in any given year. The increase in overtime in 2010/2011 was primarily due to scheduled capital overtime in lines and the installation of smart meters to accommodate commercial customers.

Average Yearly Incentive Pay

Average Yearly Incentive Pay is commonly referred to at PowerStream as the Performance Incentive Program ("PIP"). Senior Management, Management and all permanent Non-union employees are eligible to participate annually in this program.

In the PIP, employees are rewarded for the achievement of goals specifically related to their job, and for the achievement of overall corporate goals. The corporate goals are identified and tracked in a "balanced scorecard" and are reported regularly to the Board of Directors.

Senior management have a greater weighting of corporate goals in their PIP reflecting their greater influence on overall corporate achievement.

As part of the PIP calculation, employees are incented upon the successful achievement of targets related to a number of customer-focused metrics (e.g. Customer Service, Reliability and Smart Grid). These metrics are key to ensuring that the organization continues to focus on its customers and provides a level of service and reliability consistent with the needs of the customer.

PIPs span a calendar year and the assessments are done after year-end, when results are known. Executive PIP payments are reviewed and approved by the Human Resources, Compensation & Governance Committee or the Board of Directors. All other payments are approved by the Executive and Vice Presidents.

Table 8 summarizes the average annual incentive per employee in each of the four categories.

Table 8: Compensation – Average Yearly Incentive ($)

	2009 PS EDR	2009	2010	2011	2012	2013
Board of Directors	0	0	0	0	0	0
Senior Management	32,969	0	37,325	33,918	33,914	35,154
Management	4,958	0	5,815	6,964	6,817	7,075
Non-union	2,244	0	5,413	5,338	4,291	4,481
Temp & Students	0	0	0	0	0	0

Benefits

In order to attract and retain staff at all levels, PowerStream offers a comprehensive employee benefits package. These benefits include medical and dental coverage, long term disability and life insurance, various forms of leaves and a company-sponsored defined retirement plan (OMERS). These benefits are also designed to ensure and address the health and overall wellness needs of staff.

Benefits also include the company cost of Canada Pension Plan contributions, Employment Insurance, Employer Health Tax and Workers Safety Insurance premiums.

For unionized staff, benefits are a negotiated item. Changes to the plan may only be achieved through the collective bargaining process.

Table 9 sets out the year-over-year changes in the annual cost of providing employee benefits. Increases over the 2009-2013 period reflect both inflationary expenses and the current demographic profile of PowerStream's employees.

Table 9: Average Actual Cost of Employee Benefits ($)

	2009 PS EDR	2009	2010	2011	2012	2013
Board of Directors	2,006	1,406	1,712	1,502	2,072	2,134
Senior Management	36,664	25,629	33,626	36,366	41,370	44,175
Management	25,136	17,629	22,341	24,004	29,647	30,723
Non-Union	18,783	16,734	21,272	22,825	24,780	26,129
Unionized	22,128	15,800	15,463	16,945	17,211	18,250
Temp & Students	0	3,453	4,871	3,293	5,339	5,396

Pension Expenses

PowerStream contributes to an employee pension benefit as provided through the Ontario Municipal Employees Retirements Savings Plan ("OMERS"). Pension contributions increase proportionally to increases in base earnings and are allowed on incentive pay but not on overtime earnings.

Table 10 summarizes the year-over-year changes in the annual cost of employee pension benefits.

Table 10: Pension Premiums ($)

	2009 PS EDR	2009	2010	2011	2012	2013
Pension Premiums	2,327,849	2,701,270	3,081,122	3,597,028	4,390,407	5,127,685

Post-Retirement Benefits

PowerStream provides post-retirement benefits to its employees in limited situations. For union staff all existing employees and all new employees hired during the term of the collective agreement (until March 31, 2013) are eligible for post retirement benefits. The 2009 actual amount reflects the addition of former Barrie Hydro employees.

Table 11 summarizes the year-over-year changes in the annual cost of post-retirement benefits. The changes from 2009 compared to 2010 reflect the integration of this benefit as a result of the merger. Additional staff are now eligible for post retirement benefits.

Table 11: Post Retirement Benefits Costs ($)

	2009 PS EDR	2009	2010	2011	2012	2013
Post Retirement Benefits Costs	1,080,000	964,494	1,970,844	1,257,730	1,761,730	1,814,582

TAXES - OVERVIEW

PowerStream is required to make payments in lieu of income taxes ("taxes") based on its taxable income. Previously PowerStream paid taxes on its taxable capital but no longer does. The Large Corporations Tax ended effective January 1, 2006 and the Ontario Capital Tax ended July 1, 2010.

PowerStream has used the OEB Tax Work Form model to calculate the amount of taxes for inclusion in its 2013 rates. This model is included at Exhibit D2, Tab 1, Schedule 3.

Table 1 below summarizes PowerStream's taxes as for the 2011 Historical Year, 2012 Bridge Year and 2013 Test Year. PowerStream has included $2,449,646 for taxes in its revenue requirement for 2013.

Table 1: Summary of Taxes ($000)

	2011 Historical Year	2012 Bridge Year	2013 Test Year
Net Income before Taxes (NIBT)	$ 38,123	$ 28,984	$ 30,587
Taxable Income	$ 25,008	$ 9,342	$ 9,766
Taxes	$ 6,303	$ 2,417	$ 2,450
Effective Rate	25.20%	25.87%	25.09%

Note: 2012 and 2013 NIBT represent Target Net Income and does not include grossed up PILs, 2012 and 2013 taxes are grossed up for comparison purposes.
Above amounts are for distribution only.

Table 2 shows the legislated tax rates used in calculating the tax amounts:

Table 2: Legislated Tax Rates

Federal income tax	**2011 Historical Year**	**2012 Bridge Year**	**2013 Test Year**
General corporate rate	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%
Rate reduction	-11.50%	-13.00%	-13.00%
	16.50%	15.00%	15.00%
Ontario income tax	11.75%	11.25%	10.50%
Combined federal and Ontario	28.25%	26.25%	25.50%

The effective rate is lower than the legislated rates due to the Ontario Small Business credit and other tax credits. Tax calculations are discussed further in Exhibit D2, Tab 1, Schedule 2.

PowerStream notes that the 2012 Ontario Budget indicated the reduction in the Ontario income tax rates in 2012 and 2013 shown above is no longer going to take place. PowerStream will update with the legislated tax rates in effect when it prepares the draft rate order.

TAX CALCULATIONS

Tax calculations are done using the OEB PILs / Income Taxes Work Form ("Tax Model"), which is included as Exhibit D2, Tab 1, Schedule 3.

Table 1 below summarizes the Tax Credits entered into the tax calculations in the Tax Model.

Table 1: Summary of Tax Credits

	2011 Historical Year	2012 Bridge Year	2013 Test Year
Investment Tax Credits	$ 540,638	$ 420,700	$ 420,700
Miscellaneous Tax Credits	$ 221,478	$ 207,000	$ 207,000
Total Tax Credits	**$ 762,116**	**$ 627,700**	**$ 627,700**

Investment Tax Credits consists of the Scientific Research and Experimental Development ("SR&ED") investment tax credit. These credits vary considerably from year to year. The amount of credit is determined by outside consultants that come in after the year end and review projects to determine what may qualify. The amounts shown above for 2012 and 2013 represent a six year average of actual SR&ED credits.

Miscellaneous Tax Credits mainly consist of the Ontario Apprenticeship Training Tax Credit and the Ontario Co-operative Education Tax Credit., as shown in Table 2 below.

Table 2: Miscellaneous Tax Credits

	2011 Historical Year	2012 Bridge Year	2013 Test Year
Apprenticeship Credits	**$ 112,986**	**$ 120,000**	**$ 120,000**
Co-op Credits	**$ 92,926**	**$ 70,000**	**$ 70,000**
Other Miscellaneous Credits	**$ 15,566**	**$ 17,000**	**$ 17,000**
Total Tax Credits	**$ 221,478**	**$ 207,000**	**$ 207,000**

The Apprenticeship and Co-op credits are dependent on the number of hires in a particular year, and are separately tracked by Human Resources when filing the annual PILs return. The amounts shown above for 2012 and 2013 are based on the estimated co-operative and apprentice staff eligible for these credits in the respective years.

V1.2

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Choose Your Utility:

Peterborough Distribution Incorporated
PowerStream Inc. - Barrie
PowerStream Inc. - South
PUC Distribution Inc.

Application Contact Information

Name:	Tom Barrett
Title:	Manager, Rates & Applications
Phone Number:	905-532-4640
Email Address:	tom.barrett@powerstream.ca

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While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

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Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Data Input Sheet - Applicant's Rate Base

Rate Base			**$ 838,472,596**	

Return on Rate Base

Deemed ShortTerm Debt %	4.00%	T	$ 33,538,904	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$ 469,544,654	*X = S * U*
Deemed Equity %	40.00%	V	$ 335,389,038	*Y = S * V*
Short Term Interest Rate	2.08%	Z	$ 697,609	*AC = W * Z*
Long Term Interest	4.96%	AA	$ 23,269,763	*AD = X * AA*
Return on Equity (Regulatory Income)	9.12%	AB	**$ 30,587,480**	*AE = Y * AB*
Return on Rate Base			**$ 54,554,853**	*AF = AC + AD + AE*

Questions that must be answered

	Historic	Bridge	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	Yes	Yes
2. Does the applicant have any SRED Expenditures?	Yes	Yes	Yes
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	Yes	Yes	Yes
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	Yes	Yes	Yes
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Tax Rates & Exemptions

Tax Rates **Federal & Provincial** **As of March 22, 2011**	**Effective** #################	**Effective** #################	**Effective** #################	**Effective** #################	
Federal income tax					
General corporate rate	38.00%	38.00%	38.00%	38.00%	
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%	
	16.50%	15.00%	15.00%	15.00%	(refer to Note 1)
Ontario income tax	11.75%	11.25%	10.50%	10.00%	
Combined federal and Ontario	28.25%	26.25%	25.50%	25.00%	
Federal & Ontario Small Business					
Federal small business threshold	500,000	500,000	500,000	500,000	
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	
Federal small business rate	11.00%	11.00%	11.00%	11.00%	
Ontario small business rate	4.50%	4.50%	4.50%	4.50%	

NOTES:

1. Federal Budgets of March 22, 2011 and June 6, 2011 reaffirmed the corporate tax rate reductions to 16.5% in 2011 and 15% in 2012.

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Regulated Historic Year
1	Distribution System - post 1987	426,160,498		426,160,498
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election			0
2	Distribution System - pre 1988	57,651,854		57,651,854
8	General Office/Stores Equip	53,818,809	3,026	53,815,783
10	Computer Hardware/ Vehicles	6,581,291		6,581,291
10.1	Certain Automobiles			0
12	Computer Software	2,152,756	4,005	2,148,751
13_1	Lease # 1	34,415		34,415
13_2	Lease #2	125,622		125,622
13_3	Lease # 3	580,822		580,822
13_4	Lease # 4	1,051,143		1,051,143
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	469,387		469,387
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment	4,887,250	4,887,250	0
45	Computers & Systems Software acq'd post Mar 22/04	218,218		218,218
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			0
47	Distribution System - post February 2005	226,321,315		226,321,315
50	Data Network Infrastructure Equipment - post Mar 2007	1,009,282		1,009,282
52	Computer Hardware and system software			0
95	CWIP	31,844,046	1,333,735	30,510,311
				0
				0
				0
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	**812,906,708**	**6,228,016**	**806,678,692**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				**7,117,982**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	29,950			
Other Adjustments	0			
Subtotal	29,950	**x 3/4 =**	22,462	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			22,462	**22,462**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**7,140,444**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**7,140,444**
Current Year Deduction		**7,140,444**	**x 7% =**	**499,831**
Cumulative Eligible Capital - Closing Balance				**6,640,613**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)	201,841		201,841
General reserve for bad debts	1,471,237		1,471,237
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits	15,264,856		15,264,856
Provision for Environmental Costs	399,275		399,275
Restructuring Costs	223,819		223,819
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**17,561,028**	**0**	**17,561,028**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Schedule 7-1 Loss Carry Forward - Histroic

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic	0		0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic	0		0

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Adjusted Taxable Income - Historic Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	35,525,958	-2,596,830	38,122,788
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	45,937,615	81,617	45,855,998
Amortization of intangible assets	106	3,084,541		3,084,541
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112	518,271		518,271
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120	41,228		41,228
Non-deductible meals and entertainment expense	121	108,686	5,937	102,749
Non-deductible automobile expenses	122	7,387		7,387
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126	17,561,028		17,561,028
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208	724,238		724,238
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290	1,170,824		1,170,824
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
	294			0
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received		540,638		540,638
Co-op tax credit		92,926		92,926
Apprentice tax credit		112,986		112,986
ORDTC		25,968		25,968
Smart meter OM&A already deducted for tax		888,704		888,704
IFRS revenue deferred		744,996		744,996
Depreciation on stranded meters		1,200,704		1,200,704
Smart meter revenue collected		475,494		475,494
				0
				0
				0
Total Additions		**73,236,234**	**87,554**	**73,148,680**

Deductions:				
Gain on disposal of assets per financial statements	401	253,974		253,974
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	60,184,952	1,633,424	58,551,528
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	499,831		499,831
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413	17,233,493		17,233,493
Reserves from financial statements - balance at beginning of year	414			0
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390	536,625		536,625
Capital Lease Payments	391	1,429,911		1,429,911
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
Canadian Renewable & Conservation Expenses (CRCE)		67,023	67,023	0
OM&A in regulatory asset for smart meters & smart grid		257,318		257,318
Smart meter revenue already considered in tax return		5,284,535		5,284,535
Smart meter revenue refunded to customers		455,805		455,805
Equipment rental charges capitalized for accounting		1,018	1,018	0
Deduction of debt issue expense (amortized over 5 years)		195,636	2,366	193,270
IFRS, smart grid, and renewable generation costs deferred		1,048,871		1,048,871
Total Deductions		**87,448,992**	**1,703,831**	**85,745,161**
Net Income for Tax Purposes		**21,313,200**	**-4,213,107**	**25,526,307**
Charitable donations from Schedule 2	311	518,271		518,271
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**20,794,929**	**-4,213,107**	**25,008,036**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

PILs Tax Provision - Historical Year

Wires Only

Note: Input the actual information from the tax returns for the historical year.

Regulatory Taxable Income						$ 25,008,036	A
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.75%	B	$ 2,938,444	C = A * B		
Small business credit	Ontario Small Business Threshold		D				
	Rate reduction (negative)		E	$ -	F = D * E		
Ontario Income tax						$ 2,938,444	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.75%	K = J / A		
	Federal tax rate			16.50%	L		
	Combined tax rate					28.25%	M = L + L
Total Income Taxes						**$ 7,064,770**	N = A * M
Investment Tax Credits						$ 540,638	O
Miscellaneous Tax Credits						$ 221,478	P
Total Tax Credits						**$ 762,116**	Q = O + P
Corporate PILs/Income Tax Provision for Bridge Year						**$ 6,302,654**	R = N - Q

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 426,160,498	$ 1,519,000		$ 427,679,498	$ 759,500	$ 426,919,998	4%	$ 17,076,800	$ 410,602,698
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election				$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 57,651,854			$ 57,651,854	$ -	$ 57,651,854	6%	$ 3,459,111	$ 54,192,743
8	General Office/Stores Equip	$ 53,815,783	$ 2,772,000		$ 56,587,783	$ 1,386,000	$ 55,201,783	20%	$ 11,040,357	$ 45,547,426
10	Computer Hardware/ Vehicles	$ 6,581,291	$ 1,958,000		$ 8,539,291	$ 979,000	$ 7,560,291	30%	$ 2,268,087	$ 6,271,204
10.1	Certain Automobiles				$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 2,148,751	$ 1,243,000		$ 3,391,751	$ 621,500	$ 2,770,251	100%	$ 2,770,251	$ 621,500
13 1	Lease # 1	$ 34,415			$ 34,415	$ -	$ 34,415	1.0	$ 34,415	$ -
13 2	Lease #2	$ 125,622			$ 125,622	$ -	$ 125,622	0.7	$ 89,359	$ 36,263
13 3	Lease # 3	$ 580,822			$ 580,822	$ -	$ 580,822	0.1	$ 31,395	$ 549,427
13 4	Lease # 4	$ 1,051,143			$ 1,051,143	$ -	$ 1,051,143	0.0	$ 36,882	$ 1,014,261
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 469,387			$ 469,387	$ -	$ 469,387	8%	$ 37,551	$ 431,836
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 218,218			$ 218,218	$ -	$ 218,218	45%	$ 98,198	$ 120,020
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 226,321,315	$ 57,816,620	-$ 700,000	$ 283,437,935	$ 28,558,310	$ 254,879,625	8%	$ 20,390,370	$ 263,047,565
50	Data Network Infrastructure Equipment - post Mar 2007	$ 1,009,282	$ 3,758,000		$ 4,767,282	$ 1,879,000	$ 2,888,282	55%	$ 1,588,555	$ 3,178,727
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 30,510,311			$ 30,510,311	$ -	$ 30,510,311		$ -	$ 30,510,311
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 806,678,692	$ 69,066,620	-$ 700,000	$ 875,045,312	$ 34,183,310	$ 840,862,002		$ 58,921,331	$ 816,123,981

Ontario Energy Board

PILS / INCOME TAXES
WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				**6,640,613**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	39,000			
Other Adjustments	0			
Subtotal	39,000	**x 3/4 =**	29,250	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			29,250	**29,250**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**6,669,863**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**6,669,863**
Current Year Deduction		**6,669,863**	**x 7% =**	**466,890**
Cumulative Eligible Capital - Closing Balance				**6,202,973**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments		Balance for Bridge Year	Change During the Year	Disallowed Expenses
				Additions	Disposals			
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	201,841		201,841	313,000	201,841	313,000	111,159	
General reserve for bad debts	1,471,237		1,471,237	2,078,000	1,471,237	2,078,000	606,763	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	15,264,856		15,264,856	17,638,000	15,264,856	17,638,000	2,373,144	
Provision for Environmental Costs	399,275		399,275	0	399,275	0	-399,275	
Restructuring Costs	223,819		223,819	291,000	223,819	291,000	67,181	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**17,561,028**	**0**	**17,561,028**	**20,320,000**	**17,561,028**	**20,320,000**	**2,758,972**	**0**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Schedule 7-1 Loss Carry Forward - Bridge Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Total**
Actual Historical	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	**Total**
Actual Historical	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Income before PILs/Taxes	**A**	28,984,232

Additions:		
Interest and penalties on taxes	103	7,000
Amortization of tangible assets	104	31,959,000
Amortization of intangible assets	106	3,359,000
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	633,750
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	1,000
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	330,000
Non-deductible club dues and fees	120	34,000
Non-deductible meals and entertainment expense	121	97,000
Non-deductible automobile expenses	122	9,000
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	0
Reserves from financial statements- balance at end of year	126	20,320,000
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions		
Interest Expensed on Capital Leases	290	1,153,000
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		420,700
Co-op tax credit		70,000
Apprentice tax credit		120,000
Depreciation on stranded meters		1,300,000
IFRS revenue deferred		745,000
Total Additions		**60,558,450**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Adjusted Taxable Income - Bridge Year

Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	58,921,331
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	466,890
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	0
Reserves from financial statements - balance at beginning of year	414	17,561,028
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	330,000
Capital Lease Payments	391	1,430,000
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Smart meter revenue already considered in tax return		
Deduction of debt issue expense (amortized over 5 years)		
SR&ED capital expenditures deducted for tax purposes		857,380
Total Deductions		**79,566,630**
Net Income for Tax Purposes		**9,976,052**
Charitable donations from Schedule 2	311	633,750
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**9,342,302**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

PILs Tax Provision - Bridge Year

Wires Only

Regulatory Taxable Income						$ 9,342,302	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	11.25%	**B**	$ 1,051,009	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction	-6.75%	**E**	-$ 33,750	**F = D * E**		
Ontario Income tax						$ 1,017,259	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			10.89%	**K = J / A**		
	Federal tax rate			15.00%	**L**		
	Combined tax rate					25.89%	**M = L + L**
Total Income Taxes						**$ 2,418,604**	**N = A * M**
Investment Tax Credits						$ 420,700	**O**
Miscellaneous Tax Credits						$ 207,000	**P**
Total Tax Credits						**$ 627,700**	**Q = O + P**
Corporate PILs/Income Tax Provision for Bridge Year						**$ 1,790,904**	**R = N - Q**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 410,602,698	299,000		$ 410,901,698	$ 149,500	$ 410,752,198	4%	$ 16,430,088	$ 394,471,610
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 54,192,743			$ 54,192,743	$ -	$ 54,192,743	6%	$ 3,251,565	$ 50,941,178
8	General Office/Stores Equip	$ 45,547,426	1,973,000		$ 47,520,426	$ 986,500	$ 46,533,926	20%	$ 9,306,785	$ 38,213,641
10	Computer Hardware/ Vehicles	$ 6,271,204	2,893,000		$ 9,164,204	$ 1,446,500	$ 7,717,704	30%	$ 2,315,311	$ 6,848,893
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 621,500	4,405,000		$ 5,026,500	$ 2,202,500	$ 2,824,000	100%	$ 2,824,000	$ 2,202,500
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ 36,263			$ 36,263	$ -	$ 36,263	1.0	$ 36,263	$ -
13 3	Lease # 3	$ 549,427			$ 549,427	$ -	$ 549,427	0.1	$ 31,395	$ 518,032
13 4	Lease # 4	$ 1,014,261			$ 1,014,261	$ -	$ 1,014,261	0.0	$ 36,882	$ 977,379
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bld	$ 431,836			$ 431,836	$ -	$ 431,836	8%	$ 34,547	$ 397,289
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 120,020			$ 120,020	$ -	$ 120,020	45%	$ 54,009	$ 66,011
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 263,047,565	70,902,620	-700,000	$ 333,250,185	$ 35,101,310	$ 298,148,875	8%	$ 23,851,910	$ 309,398,275
50	Data Network Infrastructure Equipment - post Mar 2007	$ 3,178,727	2,014,000		$ 5,192,727	$ 1,007,000	$ 4,185,727	55%	$ 2,302,150	$ 2,890,577
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 30,510,311			$ 30,510,311	$ -	$ 30,510,311	0%	$ -	$ 30,510,311
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 816,123,981	$ 82,486,620	-$ 700,000	$ 897,910,601	$ 40,893,310	$ 857,017,291		$ 60,474,905	$ 837,435,696

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Schedule 10 CEC - Test Year

Cumulative Eligible Capital					6,202,973
Additions					
Cost of Eligible Capital Property Acquired during Test Year		41,000			
Other Adjustments		0			
	Subtotal	41,000	**x 3/4 =**	30,750	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002		0	**x 1/2 =**	0	
				30,750	**30,750**
Amount transferred on amalgamation or wind-up of subsidiary		0			**0**
	Subtotal				6,233,723
Deductions					
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year		0			
Other Adjustments		0			
	Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance					**6,233,723**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")			**6,233,723**	**x 7% =**	**436,361**
Cumulative Eligible Capital - Closing Balance					**5,797,362**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	313,000		313,000	313,000	313,000	313,000	0	
General reserve for bad debts	2,078,000		2,078,000	2,078,000	2,078,000	2,078,000	0	
Accrued Employee Future Benefits:	0		0			0	0	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	17,638,000		17,638,000	19,402,000	17,638,000	19,402,000	1,764,000	
Provision for Environmental Costs	0		0			0	0	
Restructuring Costs	291,000		291,000	291,000	291,000	291,000	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	**20,320,000**	**0**	**20,320,000**	**22,084,000**	**20,320,000**	**22,084,000**	**1,764,000**	**0**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion**	**Utility Balance**
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

Taxable Income - Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		30,587,480
Additions:		
Interest and penalties on taxes	103	7,000
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	35,253,000
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	3,468,000
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	633,750
Taxable Capital Gains	113	1,000
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	1,317,000
Non-deductible club dues and fees	120	34,000
Non-deductible meals and entertainment expense	121	97,000
Non-deductible automobile expenses	122	9,000
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	22,084,000
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	1,133,000
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		420,700
Co-op tax credit		70,000

Apprentice tax credit		120,000
Total Additions		**64,647,450**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	60,474,905
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	436,361
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	20,320,000
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	1,317,000
Capital Lease Payments	391	1,430,000
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Deduction of debt issue expense (amortized over 5 years)		
SR&ED capital expenditures deducted for tax purposes		857,380
Total Deductions		**84,835,645**
NET INCOME FOR TAX PURPOSES		**10,399,285**
Charitable donations	311	633,750
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**9,765,535**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

PowerStream Inc. - South

PILs Tax Provision - Test Year

Wires Only

Regulatory Taxable Income							$ 9,765,535	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	10.50%	**B**	$	1,025,381	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**					
	Rate reduction	-6.00%	**E**	-$	30,000	**F = D * E**		
Ontario Income tax							$ 995,381	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate				10.19%	**K = J / A**		
	Federal tax rate				15.00%	**L**		
	Combined tax rate						25.19%	**M = K + L**
Total Income Taxes							**$ 2,460,211**	N = A * M
Investment Tax Credits							$ 420,700	**O**
Miscellaneous Tax Credits							$ 207,000	**P**
Total Tax Credits							**$ 627,700**	Q = O + P
Corporate PILs/Income Tax Provision for Test Year							**$ 1,832,511**	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]					74.81%	**S = 1 - M**	**$ 617,134**	T = R / S - N
Income Tax (grossed-up)							**$ 2,449,646**	U = R + T

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

POWERSTREAM SOLAR

On May 14, 2009, the *Green Energy Act, 2009* ("GEA") received Royal Assent. On September 9, 2009, the relevant sections were proclaimed into force and the GEA amended the OEB Act to address, among other things, distributor-owned generation facilities.

The GEA amended s. 71 of the OEB Act by adding the following:

> *(3) Despite subsection (1), a distributor may own and operate,*
>
> *(a) a renewable energy generation facility that does not exceed 10 megawatts or such other capacity as may be prescribed by regulation and meets the criteria prescribed by regulation;*
>
> *(b) a generation facility that uses technology that produces power and thermal energy from a single source that meets the criteria prescribed by regulation; or*
>
> *(c) an energy storage facility that meets the criteria prescribed by regulation.*

In response to the changes brought on by the GEA and the resulting opportunities, PowerStream started a Solar PV (Photo Voltaic) business in 2009 (referred to below as "PowerStream Solar"). This business has been focused on projects with the following attributes:

- Solar panels are installed on the rooftops of commercial, industrial and institutional buildings; the rooftops are leased by PowerStream;
- The generation activities are based on 20 year Feed-in-Tariff ("FIT") contracts from the Ontario Power Authority ("OPA");
- Approximately 250kW of generation capacity per installation; and
- While PowerStream Solar's generation projects will be installed on a variety of buildings, emphasis is on buildings belonging to its three Shareholders – the City of Vaughan, the Town of Markham and the City of Barrie.

Table 1, below shows the projects in operation at the end of 2011.

Table 1: PowerStream Solar – Projects in Operation at the End of 2011

Building Owner	Location	kW AC	Commercial Operation
PowerStream	55 Patterson, Barrie	210	Apr 2011
BMNPHC	Barrie (5 microFIT Sites)	50	
BMNPHC	Timbercrest (Essa Rd)	60	Sep 2011
BMNPHC	Northfields (Kozlov St)	40	
BMNPHC	Berczy Glen (Berczy St)	30	
BMNPHC	Barrie (5 microFIT Sites)	50	Oct 2011
BMNPHC	186 Grove St., Barrie	10	Nov 2011
Town of Markham	Thornhill (Bayview Ave)	350	Dec 2011 (Declared)
Town of Markham	Angus Glen (Major Mackenzie Ave.)	250	Dec 2011 (Declared)
Total	**17 Projects**	**1,050**	

Note: BMNPHC is the Barrie Municipal Not-for-Profit Housing Corporation

It is expected that projects will operate at a loss until the installation costs are recouped. The business has a 60:40 debt to equity ratio with debt being arranged through Infrastructure Ontario and equity being provided by PowerStream's three Shareholders. Table 2 below, shows the unaudited income statement for 2011. Sales, expenses, amortization and interest are all below budget due to delay in obtaining FIT contracts from the OPA.

Table 2: Power Stream Solar 2011 Unaudited Income Statement

('000's)	2011 Actual	2011 Budget	Variance (Fav/Unfav)
Revenue – Sale of Energy	151	2,790	(2,639)
Expenses	2587	3,510	923
EBITDA	(2,436)	(720)	(1,716)
Amortization	82	748	666
Interest	13	512	498
EBT	(2,531)	(1,979)	(552)
PILS	(684)	(559)	125
Net Earnings	(1,847)	(1,420)	(427)

In keeping with the statutory framework, PowerStream does not contemplate including the renewable generation assets in rate base, nor including any costs or revenues in rates.

The Board's Guideline for *Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities (G-2009-0300)*, issued September 15, 2009 (the "Guideline") presented two ownership scenarios for generation ownership: through an affiliate; or by a distributor and non-rate regulated. PowerStream selected the second option since it was simpler and there would be no costs to establish an affiliate company. PowerStream has been further guided by Board Staff's Compliance Bulletin dated July 7, 2010 on *Distributor-owned Generation: Application of Section 71(3) of the Ontario Energy Board Act, 1998*.

PowerStream Solar has been organized such that:

- Ratepayers in no way subsidize PowerStream Solar and also do not receive any of the initial losses (or future gains);
- Costs are booked to accounts in accordance with the Guideline;
- PowerStream Solar purchases services from the regulated LDC business in a manner similar to the relationship between a distributor and an affiliate. The provision of services is based on a Service Level Agreement ("SLA") that has been developed in accordance with the Guideline and using fully allocated costs with the appropriate cost drivers. The services include corporate services, finance, information services, facilities and procurement and communications; and,
- PowerStream Solar's financial reporting is separate from that of the regulated LDC business.

PowerStream Solar has not had an adverse impact on the credit rating for PowerStream and has therefore not impacted borrowing costs for the distribution business. The financial and business risks for PowerStream Solar are managed within this business and also do not affect distribution activities.

On December 15, 2010, PowerStream filed with the Board a Notice under Section 80 of the OEB Act advising of its plans to develop rooftop solar renewable generation projects. On

January 25, 2011 the Board wrote to PowerStream indicating that it did not intend to issue a notice of review of the proposal.

COST OF CAPITAL, COST OF EQUITY, DEBT FINANCING AND DIVIDEND POLICY

Overview

PowerStream has followed the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities,* December 11, 2009 in determining the cost of capital.

In calculating the cost of capital, PowerStream has used the deemed capital structure of 56% long-term debt, 4% short-term debt, and 40% equity, and the Cost of Capital parameters in the OEB letter of March 2, 2012, for the allowed return on equity and where appropriate for debt.

PowerStream's cost of capital for 2013 has been calculated as 6.51%, as shown in Table 1, below.

Table 1: PowerStream - Weighted Average Cost of Capital

		2009 Board Approved		2013 Test Year	
	Deemed Capital Structure	**Rate**	**Weighted Average Cost of Capital (WACC)**	**Rate**	**Weighted Average Cost of Capital (WACC)**
Long-term debt	56%	5.89%	3.30%	4.96%	2.78%
Short-term debt	4%	1.33%	0.05%	2.08%	0.08%
Equity	40%	8.01%	3.21%	9.12%	3.65%
Total	**100%**		**6.56%**		**6.51%**

The 2013 Weighted Average Cost of Capital ("WACC") of 6.51% is slightly lower than the PowerStream 2009 Board Approved WACC of 6.56%.

In calculating the weighted average cost of capital, the return on equity and portions of debt have been calculated using the Cost of Capital parameters from the OEB letter dated March 2, 2012 for rates effective May 1, 2012. This calculation may require updating when the Board releases the Cost of Capital parameters for rates effective January 1, 2013 later this year.

Capital Structure

PowerStream's actual capital structure since 2009 is presented below in Table 2.

Table 2: PowerStream Actual and Forecast Capitalization Structure, %

	2009 Actual	2010 Actual	2011 Actual	2012 Estimate	2013 Forecast
Total debt	59.7	59.2	56.7	58.2	59.1
Equity	40.3	40.8	43.3	41.8	40.9

The actual debt to equity ratios vary from the deemed debt to equity ratios mainly due to borrowing patterns, for example, due to the lack of short-term debt in 2009. PowerStream attempts to maintain its capital structure in line with the OEB deemed structure. As noted above, PowerStream has used the Board's deemed capital structure in calculating its cost of capital.

As directed in Chapter 2 of the *Filing Requirements for Transmission and Distribution Applications*, dated June 22, 2011, PowerStream has completed the Board's Appendix 2-N, which is included at the end of this exhibit.

Cost of Equity

For the purposes of this 2013 rate application, PowerStream used a Return on Equity ("ROE") of 9.12%, as per the OEB's letter of March 2, 2012. This value is "placeholder" and will be updated as per the methodology specified in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities,* when the updated data becomes available.

Cost of Debt

Table 3 below compares PowerStream's actual and projected weighted average cost of long term debt with the Board's deemed Long Term ("LT") debt rates.

Table 3: PowerStream Cost of Debt

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Estimate	2013 Forecast
Long-term debt						
OEB Deemed LT Debt rate	6.10%	7.62%	5.87%	5.32%	4.41%	4.41%
Actual & Forecast Weighted Average LT debt rate	5.89%	6.06%	6.01%	6.01%	5.02%	4.96%

Note: Deemed LT debt rates for 2013 are assumed to be the same as 2012.

For rate setting purposes, the total cost of debt is calculated based on a weighting of 56% long-term debt and 4% short-term debt. As per 2009 Board Report on Cost of Capital, the deemed short-term debt rate is used for the weighted Cost of Capital calculations.

The calculation of weighted average long-term debt rate for rate setting purposes is performed in compliance with the policies documented in 2009 Board Report on the Cost of Capital. The detailed calculations are presented in the appendix at the end of this exhibit.

The variances between the actual and forecast long-term debt rates and the deemed LT Debt rates are attributable to the following:

- the lower than deemed interest rate in 2008 and 2009 on the term bank loan;
- the higher than deemed interest rate in 2010 and 2011 on the Electricity Distributors Finance Corporation (“EDFIN”) debentures issued in 2002 at an effective rate of 7.01%;

EDFIN debentures will be refinanced in August 2012 at a rate lower than the current one; and

The 2011 to 2013 deemed LT rate is lower than the actual rate on the shareholders’ promissory notes. The actual rate on the shareholder notes was lower than the deemed LT rates at the time of issuance.

The 2013 forecast cost of long-term debt has decreased from the 2009 Board-Approved level of 5.89% to 5.24%. This decrease is the result of new debt at lower rates, primarily the fixed rate bank loan of $50.0 million and new debt, which is forecast to also have a lower interest rate.

PowerStream has been working with its financial advisors, Bank of Montreal – Nesbitt Burns in preparation for refinancing the $125.0 million EDFIN debenture which comes due in August, 2012. The interest rate in August 2012 for the new debt is uncertain. The deemed LT rate of 4.41% has been used as the forecasted rate for this and other new debt in the calculation of weighted average long-term debt rate for 2012 and 2013.

Financing Plan

PowerStream has established a Financing Plan, which has been approved by its Board of Directors on January 25, 2012, and updates this plan annually.

There are two primary goals of the Financing Plan:

- to ensure that PowerStream has adequate funding available for Operating and Capital requirements; and
- to ensure that PowerStream maintains its debt equity structure in line with the Board's guidelines.

In order to ensure that these goals are achieved, Corporate Finance staff use annual financial forecasts combined with historical financial data to determine what (if any) level of borrowing is appropriate for PowerStream. Table 4 below summarizes PowerStream's debt position.

Table 4: PowerStream's Debt Position

Debt holder	Particulars	As of Dec.31, 2010	As of Dec.31, 2011
City of Vaughan	Shareholder Note	$ 78,236,285	$ 78,236,285
City of Vaughan	Deferred Interest	$ 8,743,130	$ 8,743,130
Town of Markham	Shareholder Note	$ 67,866,202	$ 67,866,202
Town of Markham	Deferred Interest	$ 7,584,243	$ 7,584,243
City of Barrie	Shareholder Note	$ 20,000,000	$ 20,000,000
EDFIN Debenture (at face value)	Debenture	$125,000,000	$125,000,000
TD Commercial	Debenture	$ 50,000,000	$ 50,000,000
Total Long-term debt		**$357,429,860**	**$357,429,860**
TD Commercial	Short Term Bank Debt	$ 40,000,000	$ 40,000,000
Total		**$397,429,860**	**$397,429,860**

PowerStream's long-term debt comprises the following:

- Senior unsecured debentures totalling $125.0 million issued through the EDFIN at an interest rate of 6.45% per annum, maturing August 15, 2012; and
- Promissory notes issued to shareholders totalling $166.1 million, $78.2 million held by the Corporation of the City of Vaughan, $67.9 million held by the Corporation of the Town of Markham and $20.0 million held by the Corporation of the City of Barrie, at an interest rate of 5.58% per annum with a maturity date of May 31, 2024. These promissory notes are repayable 90 days following demand by the City or the Town. However, these promissory notes are subordinate to both the EDFIN debentures and bank loan. The loan agreement specifies the shareholders postponement agreements as "bank security." In PowerStream's financial statements these promissory notes are classified as long-term debt since the shareholders have provided letters confirming their intent to not demand repayment within the next year. The interest on these promissory notes (for Markham and Vaughan) was deferred for eight quarters commencing October 1, 2006 for five years.
- Deferred interest due to shareholders totalling $16.3 million, $8.7 million held by the Corporation of the City of Vaughan and $7.6 million held by the Corporation of the Town

of Markham, at an interest rate of 5.58% per annum and a maturity date of October 31, 2013.

- An unsecured $50 million bank loan at an interest rate of 5.08% per annum maturing February 26, 2013.

PowerStream also has the following short-term facilities:

- The $75 million Line of Credit at TD Commercial Banking will renew automatically each year (subject to a brief review). $15 million of this line of credit has been used as short term loan, leaving $60 million available for future use.
- PowerStream has access to an unsecured $25 million revolving demand facility. This facility is renewable annually and has been used as short term loan.

PowerStream has a $15 million Letter of Guarantee facility, of which $12.5 million has been used to provide the Independent Electricity System Operator ("IESO") with a letter of credit for Prudential.

Dividend Policy

PowerStream established a dividend policy which was approved by its Board of Directors on December 14, 2005, and updated on September 17, 2008. The dividend policy is in place to provide shareholders with a steady income stream while providing the Corporation with an appropriate capital structure.

The key criteria for the determination of dividends:

- Cash position at the beginning of the year;
- Working capital requirements for the current year; and
- Net capital expenditures required for the current year.

PowerStream's dividend policy is to pay a minimum of 50% of net income, excluding the Permitted Generation Business income with consideration given to the following:

- All financial covenants on any debt issued by the Corporation

- Qualifications to meet external bond rating services to maintain an “A” rating
- Cash requirements of the Corporation to meet working capital requirements and short-term (five year) plans of capital expenditures

The amounts to be paid to each Shareholder are based on their respective ownership.

Appendix 2-N – Capitalization Ratios

Cost of Capital / Capitalization Ratio

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
	2009 Approved (PowerStream South)					
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.0%		$325,249	5.89%	$19,166
2	Short-term Debt	4.0%	(1)	$23,232	1.33%	$309
3	**Total Debt**	60.0%		$348,481	5.59%	$19,475
	Equity					
4	Common Equity	40.0%		$232,321	8.01%	$18,609
5	Preferred Shares	0.0%		$ -		$ -
6	**Total Equity**	40.0%		$232,321	8.01%	$18,609
7	**Total**	100.0%		$580,802	6.56%	$38,084

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
	2009 Actual (PowerStream Combined)					
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	53.7%		$357,430	6.06%	$21,666
2	Short-term Debt	6.0%	(1)	$40,000	1.33%	$532
3	**Total Debt**	59.7%		$397,430	5.59%	$22,198
	Equity					
4	Common Equity	40.3%		$268,248	8.01%	$21,487
5	Preferred Shares	0.0%		$ -		$ -
6	**Total Equity**	40.3%		$268,248	8.01%	$21,487
7	**Total**	100.0%		$665,678	6.56%	$43,685
				-		

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	2010 Actual (PowerStream Combined)				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	52.3%	$357,430	6.01%	$21,482
2	Short-term Debt	5.9% (1)	$40,000	2.07%	$828
3	**Total Debt**	58.2%	$397,430	5.61%	$22,310
	Equity				
4	Common Equity	41.8%	$285,429	9.85%	$28,115
5	Preferred Shares	0.0%	$ -		$ -
6	**Total Equity**	41.8%	$285,429	9.85%	$28,115
7	**Total**	100.0%	$682,859	7.38%	$50,425
			-		

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	2011 Actual (PowerStream Combined)				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	51.0%	$357,430	6.01%	$21,482
2	Short-term Debt	5.7% (1)	$40,000	2.46%	$984
3	**Total Debt**	56.7%	$397,430	5.65%	$22,466
	Equity				
4	Common Equity	43.3%	$303,746	9.58%	$29,099
5	Preferred Shares	0.0%	$ -		$ -
6	**Total Equity**	43.3%	$303,746	9.58%	$29,099
7	**Total**	100.0%	$701,176	7.35%	$51,565
			-		

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
	2012 Bridge Year (PowerStream Combined)					
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	54.8%		$407,430	5.02%	$20,437
2	Short-term Debt	3.4%	(1)	$25,000	2.08%	$520
3	**Total Debt**	58.2%		$432,430	4.85%	$20,957
	Equity					
4	Common Equity	41.8%		$310,535	9.12%	$28,321
5	Preferred Shares	0.0%		$ -		$ -
6	**Total Equity**	41.8%		$310,535	9.12%	$28,321
7	**Total**	100.0%		$742,965	6.63%	$49,278
				-		

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
	2013 Test Year (PowerStream Combined)					
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.0%		$452,430	4.96%	$22,422
2	Short-term Debt	3.1%	(1)	$25,000	2.08%	$520
3	**Total Debt**	59.1%		$477,430	4.81%	$22,942
	Equity					
4	Common Equity	40.9%		$330,619	9.12%	$30,152
5	Preferred Shares	0.0%		$ -		$ -
6	**Total Equity**	40.9%		$330,619	9.12%	$30,152
7	**Total**	100.0%		$808,049	6.57%	$53,094
				-		

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Calculation of the long-term debt cost

LONG -TERM DEBT
WEIGHTED DEBT COST - 2010 Actual

No.	Description	Debt Holder	Is the Debt Holder Affiliated with the LDC? (Y/N)	Date of Issuance of Debt (Date)	Principal ($)	Term (Years)	Actual Rate (%)	Debt Rate Used for Weighted Debt Rate Cost
1	Promissory Note	City of Vaughan	Y	1-Jun-2004	$ 78,236,285	20	5.58%	5.58%
2	Promissory Note	Town of Markham	Y	1-Jun-2004	$ 67,866,202	20	5.58%	5.58%
3	EDFIN Debenture	EDFIN	N	15-Aug-2002	$ 100,000,000	10	7.01%	7.01%
4	Deferred interest	Markham	Y	1-Oct-2006	$ 954,515	7	5.58%	5.58%
5	Deferred interest	Vaughan	Y	1-Oct-2006	$ 1,100,367	7	5.58%	5.58%
6	Deferred interest	Markham	Y	1-Jan-2007	$ 3,786,934	6	5.58%	5.58%
7	Deferred interest	Vaughan	Y	1-Jan-2007	$ 4,365,585	6	5.58%	5.58%
8	Deferred interest	Markham	Y	1-Jan-2008	$ 2,842,794	5	5.58%	5.58%
9	Deferred interest	Vaughan	Y	1-Jan-2008	$ 3,277,179	5	5.58%	5.58%
10	New debt	TD	N	26-Feb-2008	$ 50,000,000	5	5.08%	5.08%
11	Promissory Note	City of Barrie	Y	1-Jan-2009	$ 20,000,000	16	5.58%	5.58%
12	EDFIN Debenture	EDFIN	N	15-Aug-2002	$ 25,000,000	10	7.01%	7.01%
	Total				**$ 357,429,860**			
	Weighted Average Debt Cost - 2010						**6.01%**	**6.01%**

LONG -TERM DEBT
WEIGHTED DEBT COST - 2011 Actual

No.	Description	Debt Holder	Is the Debt Holder Affiliated with the LDC? (Y/N)	Date of Issuance of Debt (Date)	Principal ($)	Term (Years)	Actual Rate (%)	Debt Rate Used for Weighted Debt Rate Cost
1	Promissory Note	City of Vaughan	Y	1-Jun-2004	$ 78,236,285	85	5.58%	5.58%
2	Promissory Note	Town of Markham	Y	1-Jun-2004	$ 67,866,202	20	5.58%	5.58%
3	EDFIN Debenture	EDFIN	N	15-Aug-2002	$ 100,000,000	10	7.01%	7.01%
4	Deferred interest	Markham	Y	1-Oct-2006	$ 954,515	7	5.58%	5.58%
5	Deferred interest	Vaughan	Y	1-Oct-2006	$ 1,100,367	7	5.58%	5.58%
6	Deferred interest	Markham	Y	1-Jan-2007	$ 3,786,934	6	5.58%	5.58%
7	Deferred interest	Vaughan	Y	1-Jan-2007	$ 4,365,585	6	5.58%	5.58%
8	Deferred interest	Markham	Y	1-Jan-2008	$ 2,842,794	5	5.58%	5.58%
9	Deferred interest	Vaughan	Y	1-Jan-2008	$ 3,277,179	5	5.58%	5.58%
10	Bank loan	TD	N	26-Feb-2008	$ 50,000,000	5	5.08%	5.08%
11	Promissory Note	City of Barrie	Y	1-Jan-2009	$ 20,000,000	16	5.58%	5.58%
12	EDFIN Debenture	EDFIN	N	15-Aug-2002	$ 25,000,000	10	7.01%	7.01%
		Total			$ 357,429,860			
	Weighted Average Debt Cost - 2011						**6.01%**	**6.01%**

LONG -TERM DEBT
WEIGHTED DEBT COST - Bridge Year 2012

No.	Description	Debt Holder	Is the Debt Holder Affiliated with the LDC? (Y/N)	Date of Issuance of Debt (Date)	Principal ($)	Term (Years)	Actual /Forecasted Rate (%)	Debt Rate Used for Weighted Debt Rate Cost
1	Promissory Note	City of Vaughan	Y	1-Jun-2004	$ 78,236,285	20	5.58%	5.58%
2	Promissory Note	Town of Markham	Y	1-Jun-2004	$ 67,866,202	20	5.58%	5.58%
3	EDFIN Debenture/new debt	EDFIN	N	15-Aug-2012	$ 100,000,000	20	6.09%	4.41%
4	Deferred interest	Markham	Y	1-Oct-2006	$ 954,515	7	5.58%	5.58%
5	Deferred interest	Vaughan	Y	1-Oct-2006	$ 1,100,367	7	5.58%	5.58%
6	Deferred interest	Markham	Y	1-Jan-2007	$ 3,786,934	6	5.58%	5.58%
7	Deferred interest	Vaughan	Y	1-Jan-2007	$ 4,365,585	6	5.58%	5.58%
8	Deferred interest	Markham	Y	1-Jan-2008	$ 2,842,794	5	5.58%	5.58%
9	Deferred interest	Vaughan	Y	1-Jan-2008	$ 3,277,179	5	5.58%	5.58%
10	Bank loan	TD	N	26-Feb-2008	$ 50,000,000	5	5.08%	5.08%
11	Promissory Note	City of Barrie	Y	1-Jan-2009	$ 20,000,000	16	5.58%	5.58%
12	EDFIN Debenture/new debt	EDFIN	N	15-Aug-2012	$ 25,000,000	20	6.09%	4.41%
13	New Debt	TBD	N	15-Aug-2012	$ 50,000,000	5	4.41%	4.41%
		Total			$ 407,429,860			
Weighted Average Debt Cost - 2012							**5.53%**	**5.02%**

LONG -TERM DEBT
WEIGHTED DEBT COST - Test Year 2013

No.	Description	Debt Holder	Is the Debt Holder Affiliated with the LDC? (Y/N)	Date of Issuance of Debt (Date)	Principal ($)	Term (Years)	Actual /Forecasted Rate (%)	Debt Rate Used for Weighted Debt Rate Cost
1	Promissory Note	City of Vaughan	Y	1-Jun-2004	$ 78,236,285	20	5.58%	5.58%
2	Promissory Note	Town of Markham	Y	1-Jun-2004	$ 67,866,202	20	5.58%	5.58%
3	EDFIN Debenture/new debt	EDFIN	N	15-Aug-2012	$ 100,000,000	20	4.41%	4.41%
4	Deferred interest	Markham	Y	1-Oct-2006	$ 954,515	7	5.58%	5.58%
5	Deferred interest	Vaughan	Y	1-Oct-2006	$ 1,100,367	7	5.58%	5.58%
6	Deferred interest	Markham	Y	1-Jan-2007	$ 3,786,934	6	5.58%	5.58%
7	Deferred interest	Vaughan	Y	1-Jan-2007	$ 4,365,585	6	5.58%	5.58%
8	Deferred interest	Markham	Y	1-Jan-2008	$ 2,842,794	5	5.58%	5.58%
9	Deferred interest	Vaughan	Y	1-Jan-2008	$ 3,277,179	5	5.58%	5.58%
10	Bank loan	TD	N	26-Feb-2008	$ 50,000,000	5	5.08%	5.08%
11	New debt	TBD	N	1-Aug-2012	$ 50,000,000	5	4.41%	4.41%
12	Promissory Note	City of Barrie	Y	1-Jan-2009	$ 20,000,000	16	5.58%	5.58%
13	EDFIN Debenture/new debt	EDFIN	N	15-Aug-2012	$ 25,000,000	20	4.41%	4.41%
14	New debt	TBD	N	1-Sep-2013	$ 45,000,000	5	4.41%	4.41%
					$ 452,429,860			
Weighted Average Debt Cost - 2013							**4.96%**	**4.96%**

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CALCULATION OF REVENUE DEFICIENCY OR SURPLUS - OVERVIEW

PowerStream requires an increase in its distribution rates to continue providing safe and reliable service to its customers in an efficient manner. PowerStream earns the bulk of its revenue through distribution charges. PowerStream also earns ”Other Revenues" which reduce the revenue that PowerStream needs to collect through distribution rates.

The calculation of the revenue deficiency does not include the recovery of Regulatory Assets (Exhibit I) and Low Voltage Charges (Exhibit H, Tab 3, Schedule 1). In accordance with the Board's Filing Requirements, costs and revenues related to the Cost of Power are segregated from the calculation of the revenue sufficiency/deficiency.

The calculation of the revenue deficiency/surplus for 2013 is based on the following information:

- The 2012 approved rates (Exhibit H, Tab 6, Schedule 1)
- The 2013 load forecast and customer count forecast (Exhibit C1,Tab 1, Schedules 1 to 4)
- The 2013 Base Revenue Requirement (Exhibit F, Tab 1 Schedule 2).

Since the distribution rates for PowerStream rate zones are not yet harmonized, revenue at current rates is calculated separately for each rate zone, using the approved 2012 Barrie and South distribution rates and 2013 forecasted load, consumption and customer count by rate zones. These amounts are added to derive the total revenue at current rates, which is then compared to the combined PowerStream revenue requirement, to calculate the revenue deficiency.

In the 2013 test year, the Base Revenue Requirement is calculated to be $169.5 million. The 2013 distribution revenue at current rates would be $162.0 million, including revenue from the already approved Smart Meter Incremental Revenue Requirement (“SMIRR”) rate riders.

PowerStream proposes to recover the revenue deficiency of $7.5 million (4.6%) through an increase in distribution rates.

PowerStream's rate base, allowed net income and allowed total return are summarized in Table 1.

Table 1: PowerStream Rate Base, Allowed Net Income and Total Return ($000's)

	Board Approved		**Actual**				**Bridge**	**Test Year**
	2008 Barrie	**2009 PS**	**2009**	**2010**	**2011**	**2011**	**2012**	**2013**
	CGAAP					**MIFRS**		
Rate Base	149,854	526,814	639,482	688,546	754,564	760,328	794,524	838,473
Net Income Before Interest	10,942	34,543	42,537	50,873	55,054	55,474	51,964	54,555
Targeted Net Income	5,458	16,879	20,489	27,129	28,915	29,136	28,984	30,587
Rate of Return on Rate Base	7.3%	6.6%	6.7%	7.4%	7.3%	7.3%	6.5%	6.5%

REVENUE REQUIREMENT

PowerStream's Service Revenue Requirement is comprised of distribution expenses, return on rate base and PILS.

The distribution expenses are described in Exhibit D1, and the PILS calculation is explained in Exhibit D2. The calculation of the rate of return on rate base, which is derived from a deemed capital structure and the cost of capital, is described in Exhibit E.

Revenue offsets, discussed in Exhibit C2, are deducted to arrive at the Base Revenue Requirement.

PowerStream's Revenue Requirement is summarized in Table 1, below.

Table 1: Base Revenue Requirement ($ Millions)

	OEB Approved		Actual				Bridge	Test
	2008 Barrie	2009 PowerStream	2009	2010	2011	2011	2012	2013
	CGAAP					MIFRS		
OM&A Expenses	10.0	43.2	59.7	56.8	62.1	73.9	81.6	85.7
Depreciation	10.2	36.2	41.9	46.0	45.8	33.9	32.1	35.8
Target Net Income	5.5	16.9	20.5	27.1	28.9	29.1	29.0	30.6
Interest	5.5	17.7	22.0	23.7	26.1	26.3	23.0	24.0
Taxes	2.9	7.1	9.9	10.8	6.3	0.1	1.8	2.5
Service Revenue Requirement	34.1	**121.1**	**154.0**	**164.4**	**169.2**	**163.3**	**167.5**	**178.6**
Revenue offsets	2.6	6.6	10.1	8.9	9.2	9.9	8.8	9.1
Base Revenue Requirement	31.5	**114.5**	**143.9**	**155.5**	**160.0**	**153.4**	**158.7**	**169.4**

The details of the Base Revenue Requirement calculation are shown in Exhibit F, Tab 1, Schedule 4.

REVENUE DEFICIENCY/SURPLUS

Any Revenue Deficiency or Sufficiency for a test year is the difference between the revenue that PowerStream would earn in the test year using current rates and the Base Revenue Requirement for the test year.

The 2013 revenue at current rates is based on the distribution rates effective as of May 1, 2012 and the customer count and load forecast for 2013. The methodology for and the assumptions underpinning the load forecast are explained in Exhibit C1.

In 2013, PowerStream's will have the revenue deficiency shown in Table 1.

Table 3: PowerStream Revenue Deficiency ($ Millions)

Revenue at Current Rates	2013 Base Revenue Requirement	Revenue Deficiency
162.045	169.488	7,443

The "drivers" of the revenue deficiency are enumerated in Table 2.

Table 2: Summary of the Components of Revenue Deficiency

Driver	Impact on Revenue Deficiency ($ millions)	Evidentiary Reference
Return on Rate Base	9.1	Exhibit B
OM&A Expenses	32.5	Exhibit D1
Amortization Expense	(10.5)	Exhibit D1
PILs	(7.6)	Exhibit D2
Load Growth and IRM Increases	(8.8)	Exhibit C1
SMIRR[1]	(7.2)	Exhibit C1
2013 Revenue Deficiency	**7.5**	

1. Smart Meter Incremental Revenue Requirement

The revenue deficiency arises from the following major factors:

- The increase in the Return on Rate Base is the result of continued investment in the distribution infrastructure and resulting increase in Net Fixed Assets from 2009 to 2013. The forecasted value of rate base in 2013 is $839.0 million; this represents a $161.0 million increase compared to the Board-Approved Rate Base. The increase in Net Fixed Assets is offset in part by the projected decrease in the rate of return on rate base to 6.51% for 2013.
- The reduction in the Working Capital Allowance from the default 15% to 13.0% offset partially the increase in the Net Fixed Assets and contributed to 0.9 million decrease in revenue deficiency.
- The $32.5 million increase in OM&A expense is largely due to the impact International Financial Reporting Standards ("IFRS") implementation and increases in cost of labour.

The revenue deficiency would be higher than it is, however, but for the following factors:

- The decrease in amortization expense as a result of IFRS implementation leading to using longer useful lives for assets.
- The decrease in PILs, primarily due to the lower tax rates, decreases the revenue deficiency by $7.6 million.
- The revenue from approved SMIRR rate adders amounts to $7.2 million in 2013, thus decreasing the revenue deficiency.
- The forecast load growth adds $8.8 million to revenue, thus decreasing the deficiency.

REVENUE DEFICIENCY/SURPLUS – SUPPORTING CALCULATIONS

Table 1: Base Revenue Requirement Calculation

	PS North	PS South	PowerStream Combined					
	Board Approved	Board Approved	Historic Actual				Bridge Year	Test Year
	2008	2009	2009	2010	2011	2011 MIFRS	2012	2013
								$
Rate Base	149,853,574	526,814,171	639,481,783	688,545,545	754,564,401	760,328,010	794,523,911	840,585,346
Adjust rate base for PP&E deferral account								(2,575,585)
Adjust rate base for GEA deferral account								462,834
Adjusted Rate Base								**838,472,595**
x Cost of Capital	7.30%	6.56%	6.65%	7.39%	7.30%	7.30%	6.54%	6.51%
Return on Ratebase	**10,941,592**	**34,543,472**	**42,536,502**	**50,873,094**	**55,053,671**	**55,474,189**	**51,963,577**	**54,554,853**
Operations, Maintenance and Administration	10,047,532	43,216,300	59,677,127	56,837,729	62,086,731	73,885,361	81,595,680	85,701,101
Depreciation and Amortization	10,150,089	36,242,684	41,855,013	45,970,569	45,756,070	33,860,519	32,093,830	35,042,637
Distribution Expenses	**20,197,621**	**79,458,984**	**101,532,141**	**102,808,298**	**107,842,801**	**107,745,881**	**113,689,510**	**120,743,738**
Depreciation Adjustment for PP&E Deferral amortized over 4 years								(643,896)
Depreciation Adjustment: Derecgnition Expense								1,400,000
Depreciation Adjustment for GEA Deferral amortization								45,463
Distribution Expenses with Depreciation adjusted	**20,197,621**	**79,458,984**	**101,532,141**	**102,808,298**	**107,842,801**	**107,745,881**	**113,689,510**	**121,545,305**
Revenue Requirement Before Income Taxes	**31,139,213**	**114,002,455**	**144,068,643**	**153,681,392**	**162,896,472**	**163,220,069**	**165,653,087**	**176,100,158**
Income Taxes	2,890,210	**7,128,578**	**9,932,216**	**10,806,922**	**6,302,654**	**144,687**	**1,790,904**	**2,449,646**
SERVICE REVENUE REQUIREMENT	**34,029,423**	**121,131,033**	**154,000,859**	**164,488,314**	**169,199,126**	**163,364,756**	**167,443,991**	**178,549,804**
	(0)	(0)						
LESS:								
Revenue Offsets:								
Board Approved Charges								
Specific Service Charges	951,255	2,291,675	4,445,387	4,162,933	3,906,959	3,908,690	3,270,000	3,385,000
Late Payment Charges	642,288	1,834,000	2,294,927	2,458,215	2,187,137	2,187,137	2,400,000	2,500,000
Other Distribution Revenue	554,531	1,284,499	1,931,984	1,937,434	1,986,413	1,986,413	2,008,000	2,032,000
Other Income & Deductions	408,000	1,157,873	1,382,995	386,384	1,086,634	1,808,839	1,120,800	1,145,000
TOTAL REVENUE OFFSETS	2,556,074	6,568,047	10,055,292	8,944,966	9,167,142	9,891,078	8,798,800	9,062,000
Base Revenue Requirement	**31,473,349**	**114,562,986**	**143,945,567**	**155,543,348**	**160,031,984**	**153,473,678**	**158,645,191**	**169,487,804**

1 **Table 2: Target Net Income Calculation**

	PS North	PS South	PowerStream Combined					
	Board Approved	Board Approved	Historic Actual				Bridge Year	Test Year
	2008	2009	2009	2010	2011	2011 MIFRS	2012	2013
Revenue Requirement	31,139,213	114,002,455	144,068,643	153,681,392	162,896,472	163,220,069	165,653,087	176,100,158
Distribution Expenses other than PILS and interest	20,197,621	79,458,984	101,532,141	102,808,298	107,842,801	107,745,881	113,689,510	121,545,305
Net income before Interest	10,941,592	34,543,472	42,536,502	50,873,094	55,053,671	55,474,189	51,963,577	54,554,853
Calculated Interest (as below)	5,483,550	17,664,346	22,047,506	23,744,400	26,138,763	26,338,419	22,979,344	23,967,373
Target Net Income before consideration of PILS	**5,458,042**	**16,879,126**	**20,488,996**	**27,128,694**	**28,914,908**	**29,135,769**	**28,984,232**	**30,587,480**
Interest calculation								
Rate base	149,853,574	526,814,171	639,481,783	688,545,545	754,564,401	760,328,010	794,523,911	838,472,595
x Long-term debt component	*53.50%*	*56.00%*	*56.00%*	*56.00%*	*56.00%*	*56.00%*	*56.00%*	*56.00%*
x Long-term Debt Rate reflected in Revenue Requirement	*6.51%*	*5.89%*	*6.06%*	*6.01%*	*6.01%*	*6.01%*	*5.02%*	*4.96%*
	5,215,612	17,384,080	21,707,302	23,174,284	25,396,272	25,590,257	22,318,300	23,269,764
x Short-term debt component	*4.00%*	*4.00%*	*4.00%*	*4.00%*	*4.00%*	*4.00%*	*4.00%*	*4.00%*
x Short-term Debt Rate reflected in Revenue Requirement	*4.47%*	*1.33%*	*1.33%*	*2.07%*	*2.46%*	*2.46%*	*2.08%*	*2.08%*
	267,938	280,265	340,204	570,116	742,491	748,163	661,044	697,609
2 *Total calculated interest*	5,483,550	17,664,346	22,047,506	23,744,400	26,138,763	26,338,419	22,979,344	23,967,373

Table 3: Revenue Deficiency / Sufficiency Calculation

	PS North	PS South	PowerStream Combined					
	Board Approved	Board Approved	Historic Actual				Bridge Year	Test Year
	2008	2009	2009	2010	2011	2011 MIFRS	2012	2013
Rate Base	149,853,574	526,814,171	639,481,783	688,545,545	754,564,401	760,328,010	794,523,911	838,472,595
Target Net Income before PILS	5,458,042	16,879,126	20,488,996	27,128,694	28,914,908	29,135,769	28,984,232	30,587,480
Net Income at Existing Rates								25,019,376
Distribution revenue at current rates								162,044,558
Distribution Revenue requirement								169,487,804
Revenue Deficiency in test year								**(7,443,246)**
Equity Portion of Rate Base								335,389,038
Income /(Equity Portion of Rate Base)								7.46%
Target Return - Equity on Rate Base								9.12%
Deficiency/Sufficiency in Return on Equity								-1.7%
Indicated Rate of Return								5.84%
Requested Rate of Return on Rate Base								6.51%
Deficiency/Sufficiency in Rate of Return								**-0.66%**
Net Deficiency, $								(5,568,104)
Gross Revenue Deficiency, $								**(7,443,273)**

COST ALLOCATION - OVERVIEW

This cost allocation study ("CAS") reflects the first time that combined results for PowerStream and Barrie are presented. PowerStream has followed the guidance in the *"Report of the Board: Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) dated March 31, 2011"* and used the OEB's Cost Allocation model.

Prior to this application, separate applications had been made by PowerStream and Barrie Hydro.

Both PowerStream and Barrie Hydro submitted a CAS informational filings with the Board in January 2007. The filings comprised a "Manager's Summary" and related material that were prepared in accordance with the following:

- Board Directions on Cost Allocations Methodology for Electricity Distributors dated September 29, 2006 (EB-2005-0317, Cost Allocation Review); and
- Cost Allocation Informational Filing Guidelines for Electricity Distributors dated November 15, 2006.

PowerStream filed an application with the Board on March 7, 2007 to harmonize its rates across the four municipalities that constitute its service area. The harmonization process included the following steps:

- an allocation of the 2006 revenue requirement to the rate classes, using the Board-developed cost allocation model applicable at the time, and a comparison of the allocated costs to the revenues from the 2006 rates to determine the difference between the rates and the allocated costs; and
- a re-alignment of the 2006 rates by closing the differences by 25% between the allocated costs and the rates for each rate class.

The Board approved the harmonized rates in its Decision and Order dated July 26, 2007 (EB-2007-0074). The harmonized rates became effective on November 1, 2007.

PowerStream prepared a CAS for its 2009 Cost of Service application (EB-2008-0244) in accordance with the Board's cost allocation directions and guidelines valid at the time of the application. PowerStream 2009 CAS model was underpinned by revenues at rates calculated based on the then proposed revenue requirement and existing rate class revenue allocation, forecast customer numbers, forecast kWh consumption, forecast demand and updated load.

In its 2008 Rate Application (EB-2007-0746) Barrie Hydro used the results of its 2006 cost allocation informational filings. The resulting cost/revenue ratios were further updated for revised treatment of transformer allowance.

PowerStream has used the OEB 2013 cost allocation model to adjust rates calculated at the current revenue allocation so that the proposed rates for January 1, 2013 result in revenue-to-cost ratios that fall within the ranges established by the *Report of the Board: Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) dated March 31, 2011*.

A revenue adjustment was required to bring the Large User class within the required range. This was offset against the Street Lighting class, which had the largest revenue to cost ratio. See Exhibit G, Tab 1, Schedule 2 for more information on the cost allocation results and adjustments.

PowerStream has used the Monthly Service Charge ("MSC") ceiling calculated in the 2013 model in determining the proposed MSC for each rate class as follows. Where the current 2012 MSC is at or above the 2013 ceiling, the proposed MSC has been capped at the 2012 MSC. Otherwise the proposed MSC has been determined as the lower of the 2013 MSC (calculated at the current fixed-variable revenue split) and the 2013 ceiling. For some customer classes (Large User, Unmetered Scattered Load and Sentinel Lighting) some adjustments were made to bring the Fixed/Variable revenue ratios closer to the average ratio for other classes; where MSC has been adjusted upwards (Large User and Sentinel Lighting), the proposed rates are below the effective Cost Allocation ceiling (calculated as higher of 2012 MSC and OEB 2013 ceiling).

UPDATED COST ALLOCATION STUDY RESULTS

The Board's policy on revenue-to-cost ratios is set out in the following *Report of the Board: Application of Cost Allocation for Electricity Distributors dated November 27, 2007 (EB-2007-0667)*. This report established "ranges of tolerance around revenue-to cost ratios of one" (p. 4) for each customer class. The ranges were updated in the following *Report of the Board: Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) dated March 31, 2011*. This report also sets a number of revisions to Board's electricity distributors Cost Allocation Policy that are to be implemented by distributors starting with 2012 applications.

The 2007 report stated that the Monthly Service Charge ("MSC") – the fixed rate component of the distribution rates – would be examined in the Board's consultation process on rate design for recovery of electricity costs (EB-2007-0031). Accordingly, in the meantime, the Board does not expect any distributor to make any changes that would raise its MSC above the ceiling nor, for any distributor with an MSC currently above the ceiling, any changes to reduce its MSC to or below the ceiling (pp. 12-13).

PowerStream has prepared a Cost Allocation Study for 2013 ("2013 CAS"), based on an allocation of the 2013 test year costs (i.e., the 2013 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc. PowerStream engaged the services of Elenchus Research Associates Inc. to assist with updating of load profiles for the test year load forecast and to review the 2013 CAS.

Per the Filing Requirements for Transmission and Distribution Applications dated June 22, 2011, PowerStream has completed OEB Appendix 2-O with the results of the 2013 cost allocation study and proposed adjustments. This is included as Appendix 1, Schedule 21, OEB Appendix 2-O,

Table 1 below provides the revenue-to-cost ratios for 2008 for Barrie and 2009 for PowerStream from the last cost allocation filings in two separate columns. The fourth column is based on the calculated rates, before any cost allocation adjustment. As can be seen, for the Large User customer class the ratio does not fall within the Board-approved revenue-to-cost ratio range.

The fifth column is based on the proposed rates; that is, the rates that do reflect those ranges for all customer classes.

Table 1: PowerStream Revenue-to-Cost Ratios

Customer Class	Board Approved Range	Barrie 2008 Approved	PowerStream 2009 Approved	2013 CAS Ratios	2013 Proposed Ratios
Residential	85% - 115%	113.5	92.9	101.2	101.2
GS<50 kW	80% - 120%	97.5	116.7	98.8	98.8
GS>50 kW	80% - 120%	86.3	106.5	98.1	98.1
Large Use	85% - 115%	N/A	115.0	43.7	100.2
USL	80% - 120%	98.6	119.9	100.6	100.6
Sentinel Lighting	80% - 120%	N/A	75.4	92.4	92.4
Street Lighting	70% - 120%	25	74.5	118.9	109.2

A revenue allocation adjustment was required for the Large Use customer class, to increase the revenues and bring the revenue-to-cost ratios within the Board-approved range. The net adjustment to the Large Use class left a revenue sufficiency of $220,000. Since the Street Light customer class has the highest revenue to cost ratio, the sufficiency has been credited to this customer class because doing so would move its revenue-to-cost ratio closer to 1.00 (i.e., fully allocated costs).

There has been a change in the revenue cost ratio for the Large Use class from the 2009 CAS to the 2013 CAS. PowerStream now has two large use customers, one of which uses the primary distribution system while the other uses dedicated feeder lines from a transformer station. Previously, PowerStream had only one customer in the Large Use class, making very limited use of the local distribution system. Now primary asset costs, in addition to the cost of the dedicated assets and the >50kV assets, are allocated to this class.

The 2013 Revenue-to-Cost ratio for Street Lighting increased to 119.05% from previously approved for PowerStream South ratio of 74.5%. This increase is due to a correction to the average number of street lights per connection to PowerStream's system with respect to the Barrie street lights. Table 2 summarize the results and adjustments.

Table 2: Cost Allocation Summary and Adjustments

	2009 EDR Final Approved 2009	2013 EDR CA model at "status quo" rates 2013	OEB PROPOSED RANGE Low	 High	Proposed per Application 2013
Revenue /Expenses Ratio					
Residential	92.9%	101.2%	85%	115%	**101.2%**
GS Less Than 50 kW	116.7%	98.8%	80%	120%	**98.8%**
GS 50 to 4,999 kW	106.5%	98.1%	80%	120%	**98.1%**
GS 50 to 4,999 kW Legacy					
Large Use	115.0%	41.7%	85%	115%	**100.2%**
Unmetered Scattered Load	119.9%	100.6%	80%	120%	**100.6%**
Sentinel Lighting	75.4%	92.4%	80%	120%	**92.4%**
Street Lighting	74.5%	118.9%	70%	120%	**109.2%**

Costs Allocated (line 35, CA model)	2009 EDR Final Approved 2009	2013 EDR CA model at "status quo" rates 2013	Proposed per Application 2013
Residential	$66,551,755	95,291,157	95,291,157
GS Less Than 50 kW	$16,174,114	27,734,368	27,734,368
GS 50 to 4,999 kW	$36,202,283	52,348,687	52,348,687
GS 50 to 4,999 kW Legacy	$0		-
Large Use	$54,552	376,565	376,565
Unmetered Scattered Load	$431,330	509,050	509,050
Sentinel Lighting	$26,725	18,117	18,117
Street Lighting	$1,690,275	2,271,860	2,271,860
	$121,131,034	$178,549,804	$178,549,804

Total Revenue requirement *should match tab O1, line 20*	2009 EDR Final Approved 2009	2013 EDR CA model at "status quo" rates 2013	Proposed per Application 2013
Residential	$61,853,512	$96,392,161	$96,392,161
GS Less Than 50 kW	$18,876,898	$27,408,811	$27,408,811
GS 50 to 4,999 kW	$38,541,454	$51,360,723	$51,360,723
GS 50 to 4,999 kW Legacy	$0	$0	$0
Large Use	$62,735	$157,180	$377,180
Unmetered Scattered Load	$517,171	$512,345	$512,345
Sentinel Lighting	$20,148	$16,742	$16,742
Street Lighting	$1,259,116	$2,701,841	$2,481,841
	$121,131,033	$178,549,804	$178,549,804

Miscellanious revenue *tab O1, line 19*	2009	2013	2013
Residential	$3,627,310	5,123,849	5,123,849
GS Less Than 50 kW	$1,588,671	1,397,719	1,397,719
GS 50 to 4,999 kW	$1,248,751	2,392,812	2,392,812
GS 50 to 4,999 kW Legacy	$0	-	-
Large Use	$904	7,830	7,830
Unmetered Scattered Load	$86,559	38,094	38,094
Sentinel Lighting	$545	839	839
Street Lighting	$15,306	100,858	100,858
	$6,568,047	$9,062,000	$9,062,000

Distribution Revenue Requirement *tab O1, line 18*	2009 EDR Final Approved 2009	2013 EDR CA model at "status quo" rates 2013	Distribution revenue re-allocation 2012	Proposed per Application 2013
Residential	$58,226,202	$91,268,313		$91,268,313
GS Less Than 50 kW	$17,288,227	$26,011,092		$26,011,092
GS 50 to 4,999 kW	$37,292,703	$48,967,911		$48,967,911
GS 50 to 4,999 kW Legacy				$0
Large Use	$61,830	$149,350	220,000	$369,350
Unmetered Scattered Load	$430,612	$474,251		$474,251
Sentinel Lighting	$19,603	$15,904		$15,904
Street Lighting	$1,243,810	$2,600,983	(220,000)	$2,380,983
Total	$114,562,987	$169,487,804	-	$169,487,804

Table 3 compares the 2012, the 2013 calculated (before application of the ceiling) and the 2013 proposed monthly fixed service charge ("MSC") to values in the 2013 CAS.

Table 3: PowerStream Monthly Fixed Service Charges ($)

Customer Class	2013 CAS		2012 Charge		2013 Calculated Charge	2013 Proposed Charge
	Floor	Ceiling	South	North		
Residential	3.81	15.21	11.99	15.34	13.57	13.57
GS<50 kW	13.54	30.60	28.64	16.11	27.91	27.91
GS>50 kW	31.65	104.67	84.45	395.68	148.18	148.18
Large User	267.75	499.49	2,173.63	9,690.24	2,317.47	6,017.47
USL	3.14	12.35	14.32	7.95	13.69	8.08
Sentinel Lighting	0.93	7.26	2.00	n/a	2.13	3.51
Street Lighting	0.66	1.26	0.84	3.02	1.34	1.34

Note: the "effective Cost Allocation ceiling" is highlighted in the table; it is defined as the higher of current 2012 rates and the 2013 CAS ceiling.

The 2013 Calculated Charges were determined using the current fixed/variable revenue split for each customer class. Where the current 2012 MSC is at or above the ceiling calculated in the 2013 CAS, no change is proposed (e.g., GS>50 kW Class). If the 2012 MSC is below the ceiling, then the proposed MSC is the lower of the 2013 calculated MSC and the ceiling (e.g., GS<50 Class). For the classes where fixed/variable revenues ratios are adjusted, the proposed MSC is below the "effective ceiling", i.e. the proposed MSC for Large Use class is below the current 2012 MSC in Barrie rate zone, and the proposed MSC for Sentinel customer class is below the 2013 CAS ceiling. The proposed MSC for Unmetered Scattered Load is adjusted down, below the calculated rate but within the range defined by 2013 CAS.

Once the MSC for each class is determined, the fixed distribution revenue from the MSC is calculated and subtracted from the total class revenue allocation. The remainder is the variable distribution revenue for the class. This variable distribution revenue value is then used to determine the variable charge.

PowerStream has maintained the current transformer ownership allowance of $0.60 per kW, pending the results of further cost allocation refinements by the OEB.

The cost of the transformer allowance was excluded from the Cost Allocation Study. In rate design the amount of transformer ownership allowance has been allocated only to the classes that receive it. .

PowerStream has used ten year weather normalization in preparing the load forecast which in turn has been used to create the load profiles used in the Cost Allocation Study. See Exhibit C1 Tab 1 Schedule 2 for more information on the Load Forecast and its use of weather normalization. PowerStream's Load Profiles used in the cost allocation update were based on load forecasts as of January 2012

The final forecast increased 713,881 kWhs or 0.01% from the preliminary forecast used for the load profiles. The main reason for the increase was updating to more current parameters such as the forecasted Real GDP Index. The effect of these changes on the relative consumption by customer class was plus or minus 0.3% or less in all cases.

2013 COST ALLOCATION
PowerStream
EB-2012-0161
Friday, May 04, 2012
Sheet I2 Class Selection - Edit description in Sheet I2, cell C

Instructions:
Step 1: Please input your existing classes
Step 2: If this is your first run, select "First Run" in the drop-down menu below
Step 3: After all classes have been entered, Click the "Update" button in row E41

Please Provide a summary of this Run
Edit description in Sheet I2, cell C17

		Utility's Class Definition	Current
1	Residential		YES
2	GS <50		YES
3	GS>50-Regular	GS>50	YES
4	GS> 50-TOU		NO
5	GS >50-Intermediate		NO
6	Large Use >5MW	Large Use	YES
7	Street Light		YES
8	Sentinel		YES
9	Unmetered Scattered Load		YES
10	Embedded Distributor		NO
11	Back-up/Standby Power		YES
12	Rate Class 1		NO
13	Rate class 2		NO
14	Rate class 3		NO
15	Rate class 4		NO
16	Rate class 5		NO
17	Rate class 6		NO
18	Rate class 7		NO
19	Rate class 8		NO
20	Rate class 9		NO

2013 COST ALLOCATION

PowerStream

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Friday, May 04, 2012

Sheet I4 Break Out Worksheet - Edit description in Sheet I2, cell C17

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G14	$715,820,090

RATE BASE AND DISTRIBUTION ASSETS

Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	BALANCE SHEET ITEMS Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	EXPENSE ITEMS 5705 Amortization Expense - Property, Plant, and Equipment	5710 Amortization of Limited Term Electric Plant	5715 Amortization of Intangibles and Other Electric Plant	5720 Amortization of Electric Plant Acquisition Adjustments
1565	Conservation and Demand Management	$0		-	-					-				
1805	Land	$10,967,832		($10,967,832)	-									
1805-1	Land Station >50 kV		95.00%	$10,419,440	10,419,440					10,419,440				
1805-2	Land Station <50 kV		5.00%	$548,392	548,392					548,392				
1806	Land Rights	$1,434,694		($1,434,694)	-									
1806-1	Land Rights Station >50 kV		54.00%	$774,735	774,735					774,735			$32,000	
1806-2	Land Rights Station <50 kV		46.00%	$659,959	659,959					659,959				
1808	Buildings and Fixtures	$6,133,572		($6,133,572)	-									
1808-1	Buildings and Fixtures > 50 kV		99.00%	$6,072,236	6,072,236			($479,880)		5,592,356	$194,226			
1808-2	Buildings and Fixtures < 50 KV		1.00%	$61,336	61,336			($4,847)		56,488	$1,962			
1810	Leasehold Improvements	$9,183,889		($9,183,889)	-									
1810-1	Leasehold Improvements >50 kV		0.00%	$0	-					-				
1810-2	Leasehold Improvements <50 kV		100.00%	$9,183,889	9,183,889					9,183,889				
1815	Transformer Station Equipment - Normally Primary above 50 kV	$97,047,115		$0	97,047,115	($20,394,500)	$1,410,969	($11,339,064)		66,724,520	$3,589,858			
1820	Distribution Station Equipment - Normally Primary below 50 kV	$23,835,202		($23,835,202)	-					-				
1820-	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		0.00%	$0	-					-				
1820-	Distribution Station Equipment - Normally Primary below 50 kV Primary)		80.00%	$19,068,162	19,068,162	($876,000)	$48,558	($3,107,219)		15,133,500	$989,847			
1820-	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		20.00%	$4,767,040	4,767,040	($219,000)	$12,139	($776,805)		3,783,375	$247,462			
1825	Storage Battery Equipment	$0		$0	-									
1825-	Storage Battery Equipment > 50 kV			$0	-					-				
1825-	Storage Battery Equipment <50 kV		100.00%	$0	-					-				
1830	Poles, Towers and Fixtures	$116,836,140		($116,836,140)	-									
1830-	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		0.00%	$0	-					-				
1830-	Poles, Towers and Fixtures - Primary		98.00%	$114,499,418	114,499,418	($14,333,892)	$705,526	($6,353,993)		94,517,059	$2,591,732			
1830-	Poles, Towers and Fixtures - Secondary		2.00%	$2,336,723	2,336,723	($292,528)	$14,398	($129,673)		1,928,920	$52,892			
1835	Overhead Conductors and Devices	$115,134,532		($115,134,532)	-									
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		0.00%	$0	-					-				
1835-4	Overhead Conductors and Devices - Primary		91.00%	$104,772,424	104,772,424	($29,918,319)	$2,006,316	($6,803,226)		70,057,195	$2,437,290			
1835-5	Overhead Conductors and Devices - Secondary		9.00%	$10,362,108	10,362,108	($2,958,955)	$198,427	($672,847)		6,928,734	$241,051			
1840	Underground Conduit	$68,971,830		($68,971,830)	-									
1840-3	Underground Conduit - Bulk Delivery		0.00%	$0	-					-				
1840-4	Underground Conduit - Primary		100.00%	$68,971,830	68,971,830	($20,285,418)	$887,228	($3,008,852)		46,564,789	$930,673			
1840-5	Underground Conduit - Secondary		0.00%	$0	-					-				
1845	Underground Conductors and Devices	$227,783,862		($227,783,862)	-									
1845-3	Underground Conductors and Devices - Bulk Delivery		0.00%	$0	-					-				
1845-4	Underground Conductors and Devices - Primary		100.00%	$227,783,862	227,783,862	($87,029,932)	$6,157,032	($13,966,453)		132,944,509	$4,181,266			
1845-5	Underground Conductors and Devices - Secondary		0.00%	$0	-					-				
1850	Line Transformers	$150,354,721		$0	150,354,721	($62,072,605)	$5,914,056	($15,152,441)		79,043,731	$4,314,367			
1855	Services	$59,524,600		$0	59,524,600	($21,439,876)	$2,473,986	($9,371,233)		31,187,478	$2,318,075			
1860	Meters	$71,657,895		$0	71,657,895	($7,244,251)	$979,794	($11,864,649)		53,528,790	$4,468,241			
1880	IFRS Placeholder Account	($2,112,751)		$0	- 2,112,751					- 2,112,751				
	Total	**$956,753,133**		**$0**	**$956,753,133**	**($267,065,274)**	**$20,808,430**	**($83,031,181)**	**$0**	**627,465,108**	**$26,558,942**	**$0**	**$32,000**	**$0**
	SUB TOTAL from I3	**$958,865,884**												

General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset	5705 Amortization Expense - Property, Plant, and Equipment	5710 Amortization of Limited Term Electric Plant	5715 Amortization of Intangibles and Other Electric Plant	5720 Amortization of Electric Plant Acquisition Adjustments
1905	Land	$0			-					$ -				
1906	Land Rights	$0			-					$ -				
1908	Buildings and Fixtures	$41,539,455			41,539,455			($2,336,872)		$ 39,202,584	$957,840			
1910	Leasehold Improvements	$0			-			$0		$ -				
1915	Office Furniture and Equipment	$4,046,346			4,046,346			($1,211,518)		$ 2,834,829	509,850			
1920	Computer Equipment - Hardware	$9,865,027			9,865,027			($4,304,238)		$ 5,560,789	2,114,360			
1925	Computer Software	$12,195,850			12,195,850				($6,147,616)	$ 6,048,234			$2,737,000	
1930	Transportation Equipment	$12,865,799			12,865,799			($3,469,113)		$ 9,396,686	-			
1935	Stores Equipment	$3,417			3,417			$1,826		$ 5,243	642			
1940	Tools, Shop and Garage Equipment	$3,509,018			3,509,018			($1,035,463)		$ 2,473,556	-			

2013 COST ALLOCATION

PowerStream

EB-2012-0161

Friday, May 04, 2012

Sheet I4 Break Out Worksheet - Edit description in Sheet I2, cell C17

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G14	$715,820,090

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1945	Measurement and Testing Equipment	$0			-					$ -				
1950	Power Operated Equipment	$0			-					$ -				
1955	Communication Equipment	$1,986,938			1,986,938			($1,002,597)		$ 984,341	420,417			
1960	Miscellaneous Equipment	$0			-					$ -				
1970	Load Management Controls - Customer Premises	$0			-					$ -				
1975	Load Management Controls - Utility Premises	$0			-					$ -				
1980	System Supervisory Equipment	$8,977,752			8,977,752			($2,928,316)		$ 6,049,436	975,417			
1990	Other Tangible Property	$0			-					$ -	801,567			
2005	Property Under Capital Leases	$17,549,082			17,549,082			($1,829,211)		$ 15,719,871	$731,000			
2010	Electric Plant Purchased or Sold	$0			-					$ -	-			
	Total	$112,538,686		$0	$112,538,686	$0	$0	($18,115,503)	($6,147,616)	$88,275,567	$6,511,093	$0	$2,737,000	$0
	SUB TOTAL from I3	$112,538,686												
	I3 Directly Allocated	$79,414												
	Grand Total	$1,069,371,233		$0	$1,069,291,819	($267,065,274)	$20,808,430	($101,146,683)	($6,147,616)	$715,740,675	$33,070,035	$0	$2,769,000	$0

To be Prorated

1995	Contributed Capital - 1995	($267,065,274)	$267,065,274	Balanced
2105	Accumulated Depreciation - 2105	($80,338,253)	$0 / $80,338,253	Balanced
2120	Accumulated Depreciation - 2120	($6,147,616)	$0 / $6,147,616	Balanced
	Total	($353,551,143)		
	Net Assets	$715,820,090	Net Fixed Assets Match	($0)

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	$33,070,035	($33,070,035)	Balanced
5710	Amortization of Limited Term Electric Plant	$0	$0 / $0	Balanced
5715	Amortization of Intangibles and Other Electric Plant	$2,769,000	($2,769,000)	Balanced
5720	Amortization of Electric Plant Acquisition Adjustments	$0	$0	Balanced
	Total Amortization Expense	$35,839,035		

2013 COST ALLOCATION
PowerStream
EB-2012-0161
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Sheet O1 Revenue to Cost Summary Worksheet - Edit description in Sheet I2, cell C17

Ontario

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50	6 Large Use	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	11 Back-up/Standby Power
crev	Distribution Revenue at Existing Rates	$154,832,425	$83,376,466	$23,761,948	$44,733,723	$136,436	$2,376,080	$14,528	$433,243	$0
mi	Miscellaneous Revenue (mi)	$9,062,000	$5,123,849	$1,397,719	$2,392,812	$7,830	$100,858	$839	$38,094	$0
		Miscellaneous Revenue Input equals Output								
	Total Revenue at Existing Rates	$163,894,425	$88,500,315	$25,159,667	$47,126,535	$144,266	$2,476,938	$15,367	$471,337	$0
	~~Factor required to recover deficiency (1 + D)~~	~~1.0947~~								
	Distribution Revenue at Status Quo Rates	$169,487,804	$91,268,313	$26,011,092	$48,967,911	$149,350	$2,600,983	$15,904	$474,251	$0
	Miscellaneous Revenue (mi)	$9,062,000	$5,123,849	$1,397,719	$2,392,812	$7,830	$100,858	$839	$38,094	$0
	Total Revenue at Status Quo Rates	$178,549,804	$96,392,161	$27,408,811	$51,360,723	$157,180	$2,701,841	$16,742	$512,345	$0
	Expenses									
di	Distribution Costs (di)	$26,255,944	$12,989,547	$3,584,418	$9,149,845	$68,959	$405,639	$3,137	$54,399	$0
cu	Customer Related Costs (cu)	$19,172,923	$12,355,540	$3,832,030	$2,711,815	$2,891	$143,450	$1,463	$125,734	$0
ad	General and Administration (ad)	$40,271,884	$22,368,831	$6,544,756	$10,642,647	$65,534	$490,028	$4,087	$156,001	$0
dep	Depreciation and Amortization (dep)	$35,839,035	$18,880,054	$5,395,229	$10,974,821	$81,174	$442,326	$3,384	$62,048	$0
INPUT	PILs (INPUT)	$2,449,443	$1,233,200	$360,024	$810,879	$6,350	$33,967	$260	$4,764	$0
INT	Interest	$23,965,388	$12,065,647	$3,522,478	$7,933,650	$62,128	$332,329	$2,542	$46,614	$0
	Total Expenses	$147,954,617	$79,892,818	$23,238,935	$42,223,657	$287,036	$1,847,738	$14,873	$449,561	$0
	Direct Allocation	$10,240	$0	$0	$0	$10,240	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$30,584,947	$15,398,339	$4,495,433	$10,125,030	$79,289	$424,122	$3,245	$59,489	$0
	Revenue Requirement (includes NI)	$178,549,804	$95,291,157	$27,734,368	$52,348,687	$376,565	$2,271,860	$18,117	$509,050	$0
	($0)	Revenue Requirement Input equals Output								
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$956,753,133	$491,620,028	$137,802,856	$309,246,510	$2,331,181	$13,733,076	$104,817	$1,914,666	$0
gp	General Plant - Gross	$112,538,686	$57,508,222	$16,180,536	$36,686,344	$277,600	$1,644,323	$12,549	$229,112	$0
accum dep	Accumulated Depreciation	($86,485,869)	($45,892,222)	($12,902,103)	($26,350,275)	($198,961)	($994,278)	($7,614)	($140,416)	$0
co	Capital Contribution	($267,065,274)	($142,222,034)	($36,163,241)	($83,085,812)	($565,419)	($4,392,231)	($33,342)	($603,194)	$0
	Total Net Plant	$715,740,675	$361,013,993	$104,918,047	$236,496,767	$1,844,400	$9,990,889	$76,410	$1,400,169	$0
	Directly Allocated Net Fixed Assets	$79,414	$0	$0	$0	$79,414	$0	$0	$0	$0
COP	Cost of Power (COP)	$857,779,706	$276,329,000	$106,349,703	$461,255,432	$6,385,069	$6,103,894	$47,994	$1,308,614	$0
	OM&A Expenses	$85,700,751	$47,713,918	$13,961,205	$22,504,307	$137,384	$1,039,117	$8,687	$336,135	$0
	Directly Allocated Expenses	$350	$0	$0	$0	$350	$0	$0	$0	$0
	Subtotal	*$943,480,807*	*$324,042,918*	*$120,310,907*	*$483,759,739*	*$6,522,803*	*$7,143,011*	*$56,681*	*$1,644,748*	*$0*
	Working Capital	$122,652,505	$42,125,579	$15,640,418	$62,888,766	$847,964	$928,591	$7,368	$213,817	$0
	Total Rate Base	$838,472,594	$403,139,573	$120,558,465	$299,385,533	$2,771,779	$10,919,481	$83,778	$1,613,986	$0
	$1	Rate Base Input equals Output								
	Equity Component of Rate Base	$335,389,038	$161,255,829	$48,223,386	$119,754,213	$1,108,711	$4,367,792	$33,511	$645,594	$0
	Net Income on Allocated Assets	$30,584,947	$16,499,343	$4,169,876	$9,137,066	($140,096)	$854,103	$1,870	$62,784	$0
	Net Income on Direct Allocation Assets	$2,533	$0	$0	$0	$2,533	$0	$0	$0	$0
	Net Income	$30,587,480	$16,499,343	$4,169,876	$9,137,066	($137,562)	$854,103	$1,870	$62,784	$0
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES STATUS QUO%	100.00%	101.16%	98.83%	98.11%	41.74%	118.93%	92.41%	100.65%	0.00%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($14,655,379)	($6,790,842)	($2,574,700)	($5,222,152)	($232,299)	$205,077	($2,750)	($37,713)	$0
	$1	Deficiency Input equals Output								
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$1,101,005	($325,557)	($987,964)	($219,384)	$429,981	($1,375)	$3,295	$0
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.12%	10.23%	8.65%	7.63%	-12.41%	19.55%	5.58%	9.73%	0.00%

2013 COST ALLOCATION

PowerStream

EB-2012-0161

Friday, May 04, 2012

Sheet O3.6 MicroFIT Charge Worksheet - Edit descr

ALLOCATION BY RATE CLASSIFICATION

Description	**Residential**	**Monthly Unit Cost**
Customer Premises - Operations Labour (5070)	$ 1,210,951.97	$ 0.33
Customer Premises - Materials and Expenses (5075)	$ 1,291,985.02	$ 0.35
Meter Expenses (5065)	$ 2,022,761.68	$ 0.55
Maintenance of Meters (5175)	$ -	$ -
Meter Reading Expenses (5310)	$ 841,997.25	$ 0.23
Customer Billing (5315)	$ 2,544,665.59	$ 0.69
Amortization Expense - General Plant Assigned to Meters	$ 476,813.95	$ 0.13
Admin and General Expenses allocated to O&M expenses for meters	$ 2,144,257.87	$ 0.58
Allocated PILS (general plant assigned to meters)	$ 15,501.33	$ 0.00
Interest Expense	$ 151,665.27	$ 0.04
Income Expenses	$ 193,557.24	$ 0.05
Total Cost	$ 10,894,157.16	$ 2.94
Number of Residential Customers	308309	

POWERSTREAM

2013 EDR Model

Revenue to Cost Ratios by Customer Class

	2009 EDR Final Approved	2013 EDR CA model at "status quo" rates	OEB PROPOSED RANGE		Proposed per Application
	2009	2013	Low	High	2013
Revenue /Expenses Ratio					
Residential	92.9%	101.2%	85%	115%	**101.2%**
GS Less Than 50 kW	116.7%	98.8%	80%	120%	**98.8%**
GS 50 to 4,999 kW	106.5%	98.1%	80%	120%	**98.1%**
GS 50 to 4,999 kW Legacy					
Large Use	115.0%	41.7%	85%	115%	**100.2%**
Unmetered Scattered Load	119.9%	100.6%	80%	120%	**100.6%**
Sentinel Lighting	75.4%	92.4%	80%	120%	**92.4%**
Street Lighting	74.5%	118.9%	70%	120%	**109.2%**

	2009 EDR Final Approved	2013 EDR CA model at "status quo" rates	Proposed per Application
Costs Allocated (line 35, CA model)	2009	2013	2013
Residential	$66,551,755	95,291,157	95,291,157
GS Less Than 50 kW	$16,174,114	27,734,368	27,734,368
GS 50 to 4,999 kW	$36,202,283	52,348,687	52,348,687
GS 50 to 4,999 kW Legacy	$0		-
Large Use	$54,552	376,565	376,565
Unmetered Scattered Load	$431,330	509,050	509,050
Sentinel Lighting	$26,725	18,117	18,117
Street Lighting	$1,690,275	2,271,860	2,271,860
	$121,131,034	$178,549,804	$178,549,804

	2009 EDR Final Approved	2013 EDR CA model at "status quo" rates	Proposed per Application
Total Revenue requirement	2009	2013	2013
should match tab O1, line 20			
Residential	$61,853,512	$96,392,161	$96,392,161
GS Less Than 50 kW	$18,876,898	$27,408,811	$27,408,811
GS 50 to 4,999 kW	$38,541,454	$51,360,723	$51,360,723
GS 50 to 4,999 kW Legacy	$0	$0	$0
Large Use	$62,735	$157,180	$377,180
Unmetered Scattered Load	$517,171	$512,345	$512,345
Sentinel Lighting	$20,148	$16,742	$16,742
Street Lighting	$1,259,116	$2,701,841	$2,481,841
	$121,131,033	$178,549,804	$178,549,804

Miscellanious revenue			
tab O1, line 19			
Residential	$3,627,310	5,123,849	5,123,849
GS Less Than 50 kW	$1,588,671	1,397,719	1,397,719
GS 50 to 4,999 kW	$1,248,751	2,392,812	2,392,812
GS 50 to 4,999 kW Legacy	$0	-	-
Large Use	$904	7,830	7,830
Unmetered Scattered Load	$86,559	38,094	38,094
Sentinel Lighting	$545	839	839
Street Lighting	$15,306	100,858	100,858
	$6,568,047	$9,062,000	$9,062,000

	2009 EDR Final Approved	2013 EDR CA model at "status quo" rates	Distribution revenue re-allocation	Proposed per Application
Distribution Revenue Requirement	2009	2013	2012	2012
tab O1, line 18				
Residential	$58,226,202	$91,268,313		$91,268,313
GS Less Than 50 kW	$17,288,227	$26,011,092		$26,011,092
GS 50 to 4,999 kW	$37,292,703	$48,967,911		$48,967,911
GS 50 to 4,999 kW Legacy				$0
Large Use	$61,830	$149,350	220,000	$369,350
Unmetered Scattered Load	$430,612	$474,251		$474,251
Sentinel Lighting	$19,603	$15,904		$15,904
Street Lighting	$1,243,810	$2,600,983	(220,000)	$2,380,983
Total	$114,562,987	$169,487,804	-	$169,487,804

RATE DESIGN OVERVIEW

This Exhibit explains how PowerStream designed its proposed rates in order to collect its revenue requirement for 2013; that is, the Base Revenue Requirement plus the Transformer Allowance and Low Voltage Costs. The existing Tariffs of Rates and Charges for PowerStream rate zones (May 1, 2012) are provided in Exhibit H, Tab 6, Schedule 1. The proposed Tariff of Rates and Charges (January 1, 2013) is provided in Exhibit H, Tab 6, Schedule 2. The bill impacts for typical customers are provided in Exhibit H, Tab 6, Schedule 3.

For the 2009 Rate Application, PowerStream developed its own rates model by modifying the Board's 2006 EDR model. For this 2013 Rate Application, this model was further modified to accommodate data input for separate rate zones, rate harmonization and changes in the cost allocation model, as per the Report of the Board: Review of Electricity Distribution Cost Allocation Policy issued on March 31, 2011 and corresponding Cost Allocation Model.

The following steps were taken in the rate design process:

1. The basis for allocating revenue to customer classes (“Allocation Base”) was calculated separately for each rate zone (PowerStream South and North). The Allocation Base was derived by using current rates for each rate zone, customer count for the 2013 test year and the average consumption/load per customer for 2009 to 2013. The same methodology was used in the OEB 2006 EDR model. The resulting amounts for each rate zone were added to calculate the combined basis for revenue allocation. More detail is provided in Exhibit H, Tab 2, Schedule 1.
2. The combined Base Revenue Requirement ("BRR") for 2013 was allocated to the customer classes using the combined percentages calculated in step 1.
3. Low voltage charges and the transformer allowance were allocated to the customer classes separately using, for this purpose, the methodology approved in the PowerStream 2009 Rate Application. More detail is provided in Exhibit H, Tab 3, Schedules 1 and 2.
4. The 2013 costs and 2013 Revenue at Current Rates and Revenue Deficiency were used as an input for the 2013 Cost Allocation Study (“2013 CAS”), as described in Exhibit G, Tab 1, Schedule 1.

5. PowerStream then adjusted the allocation of BRR to the customer classes so that the proposed rates for 2013 result in revenue-to-cost ratios that would fall within the ranges established in the following Report of the Board: *Application of Cost Allocation for Electricity Distributors dated November 28, 2007* (EB-2007-0667).

The revenue allocation by customer class is presented in Table 1 below. More detail on the 2013 revenue-to-cost ratios is provided in Exhibit H, Tab 1, Schedule 2.

Table 1: Revenue Allocation

	As per 2013 CAS		Proposed Per Application	
	$	%	$	%
Residential	$91,268,313	53.8%	$91,268,313	53.8%
GS<50	$26,011,092	15.3%	$26,011,092	15.3%
GS>50	$48,967,911	28.9%	$48,967,911	28.9%
Large Use	$149,350	0.1%	$369,350	0.2%
USL	$474,251	0.3%	$474,251	0.3%
Sentinel Lighting	$15,904	0.0%	$15,904	0.0%
Street Lighting	$2,600,983	1.5%	$2,380,983	1.4%
Total	**$169,487,804**	**100.0%**	**$169,487,804**	**100.0%**

6. The “floor” and “ceiling values” for the monthly fixed service charges, as calculated in the 2013 CAS, were used to determine the monthly fixed charge for each customer class. An additional fixed rate mitigation adjustment was required for the Large Use, Unmetered Scattered Load and Sentinel classes to bring the fixed/variable revenues ratio for those classes closer to the average ratio for the remaining customer classes.

7. The variable distribution rates were determined based on the distribution revenue allocated to each customer class and forecasted (kW) load and consumption (kWh) for 2013.

8. The proposed distribution rates for 2013 are presented in Table 2 below.

Table 2: Proposed Distribution Rates

	Distribution Charges				Final Rates	
	Variable	Fixed	Low Volatge	Transformer Allowance	Variable	Fixed
Residential	0.0151	13.57	0.0003		0.0154	13.57
GS<50	0.0148	27.91	0.0003		0.0151	27.91
GS>50	3.3534	148.18	0.1191	0.1915	3.664	148.18
Large Use	1.1969	6,017.47	0.1439	0.60	1.9408	6,017.47
USL	0.0156	8.06	0.0003		0.0159	8.06
Sentinel Lighting	8.7473	3.51	0.1033		8.8506	3.51
Street Lighting	5.885	1.34	0.0918		5.9768	1.34

The derivation of the Low Voltage and Transformer Allowance Charges is described in Exhibit H, Tab 3, Schedules 1 and 2.

SUMMARY OF RECOMMENDATIONS

The following is a summary of PowerStream's rate design proposals:

- PowerStream proposes a Base Revenue Requirement of $169,487,804 (Exhibit F), transformer ownership allowances of $2,435,656 (Exhibit H, Tab 3, Schedule 2), and low voltage charges of $2,731,456 (Exhibit H, Tab 3, Schedule 1).
- PowerStream proposes to harmonize rates for the current Barrie and South rate zones. This is discussed in Exhibit H, Tab 2, Schedule 1.
- PowerStream proposes to collect this total revenue requirement from the customer classes in proportions that are similar to the current proportions but, nevertheless, adjusted for some customer classes based on the results of the 2013 Cost Allocation Study (revenue-to-cost ratios). The affected customer classes are: Large Use and Street Lighting. Cost Allocation adjustments are discussed in Exhibit G, Tab 1, Schedule 3. The Rate Design issues are discussed in detail in Exhibit H, Tab 1, Schedule 1.
- PowerStream proposes disposition of deferral and variance account balances as at December 31, 2011, the most recent audited balances, along with accrued interest up to December 31, 2012 based on the proposed January 1, 2013 effective date for the rate riders. In the case of International Financial Reporting Standards ("IFRS") Transitional Costs and savings arising from the Harmonized Sales Tax ("HST"), PowerStream is proposing to include the projected balances as at December 31, 2012. PowerStream is seeking disposition of the remaining stranded meter costs resulting from the smart meter program. These matters are discussed in detail in Exhibit I, Tab 1, Schedules 1 to 12.
- PowerStream is proposing a funding rate adder of $0.20 per customer per month for the planned Green Energy Act ("GEA") spending over the years 2012 to 2016. The details on GEA rate adder calculation are presented in Exhibit I, Tab 1, Schedule 11.
- PowerStream requests that the OEB approve a charge to customers to recover the cost of the Meter Data Management and Repository ("MDM/R") system as proposed by the Independent Electricity System Operator ("IESO"). This charge is $0.81 per RPP eligible customer per month or as determined by the Board.

- PowerStream is proposing to harmonize Standby Power monthly charges by applying the current Standby charge of $2.6854 per kW, approved on an interim basis for Barrie rate zone, for both South and Barrie rate zones.

RATE HARMONIZATION

On January 1, 2009 PowerStream Inc. (“PowerStream”) merged with Barrie Hydro Distribution Inc. (“Barrie Hydro”).

In the PowerStream - Barrie Hydro MAADs application (EB-2008-0335) proposed ”*to harmonize distribution rates within 3 to 5 years from the date of closing the Proposed Transaction; before the time of MergeCo’s rate rebasing.”*

PowerStream currently has two rate zones, one for the former PowerStream service territory and one for the former Barrie Hydro service territory.

In this Application, PowerStream seeks to harmonize rates for the two zones into a single rate. There will continue to be separate deferral and variance disposition rate riders for each rate zone, until the individual rate zone balances are cleared.

To harmonize rates, PowerStream used the method similar to the one approved by the Board in PowerStream’s Application EB-2007-0074 to harmonize the rates for the four former rates zones of Richmond Hill, Aurora, Markham and Vaughan. Specifically, the combined Base Revenue Requirement ("BRR") for the test year was allocated to the customer classes across four rate zones.

The resulting distribution rates for two rates zones are shown in Table 1 below.

Table 1: Summary of Current and Proposed Rates

Customer Class	*Billing Determinant*	Current 2012 Rates				Proposed 2013 Rates	
		PowerStream South		PowerStream North		PowerStream	
		Fixed	Variable	Fixed	Variable	Fixed	Variable
Residential	*kWh*	11.99	0.0135	15.34	0.0137	13.57	0.0154
GS<50 kW	*kWh*	28.64	0.0116	16.11	0.0164	27.91	0.0151
GS>50 kW	*kW*	84.45	3.5036	395.68	1.8393	148.18	3.664
Large Use	*kW*	2,173.63	1.0484	9,690.24	0.5918	6,017.47	1.9408
Unmetered Scattered Load	*kWh*	14.32	0.0087	7.95	0.0161	8.06	0.0159
Sentinel Lights	*kW*	2.00	9.3917	-	-	3.51	8.8506
Street Lighting	*kW*	0.84	4.8616	3.02	11.2961	1.34	5.9768

Note: Excludes the proposed Deferral and Variance disposition rate riders.

Due to the different starting points prior to harmonization, bill impacts will differ by rate zone and are provided in Exhibit H, Tab 6, Schedule 3.

LOW VOLTAGE ("LV") CHARGES

In compliance with *Accounting Procedures Handbook* ("APH"), Article 220, PowerStream uses Account 4750 to record amounts paid to Hydro One for Low Voltage services and Account 4075 to record the amounts billed to its customers for low voltage services. Account 1550 is used to record the variances between Accounts 4750 and 4075.

LV charges are excluded from PowerStream's Base Revenue Requirement. PowerStream treats Hydro One's LV charges as a "pass-through," as prescribed by APH, Article 220.

PROPOSED LV CHARGES

PowerStream is supplied from Hydro One's sub-transmission/distribution facilities that are connected to its transmission system. PowerStream is considered by Hydro One as a Sub-Transmission ("ST") customer, because PowerStream has some embedded supply points; that is PowerStream receives supply via Hydro One distribution assets. Hydro One commenced charging new transmission rates for these situations effective January 1, 2011 (EB-2009-0096).

PowerStream's proposed LV charges are based on the 2013 forecast of LV costs of $2,371,456. The forecast was developed in two steps:

- the historical ratio between actual LV related kW volumes and the system kW billed by Hydro One, applied to estimated system kW, was used to derive 2013 LV volumes; and
- the 2013 LV cost forecast was developed by applying current Hydro One LV rates to estimated 2013 LV volumes.

The LV forecast for 2013 has been allocated to the customer classes based on the methodology previously approved in PowerStream's 2009 Rate Model, which is based on the OEB's 2006 EDR Model. The basis for the allocation is transmission connection amounts. For each rate zone, these amounts are allocated based on PowerStream's forecast load (kW) and consumption (kWh) for 2013 and PowerStream transmission connection approved rates for 2012 (EB-2011-0005). For the consumption-billed customer classes, the forecast 2013 consumption (kWh) was adjusted by the loss factor. The allocated amounts for each rate zone were added to derive the combined LV forecast allocated by customer classes. The calculation is presented in Table 1 below.

Table 1: LV Charge Allocation to Rate Classes

		PowerStream South					PowerStream Combined		
		2012 Transmission Connection Rate	Loss Factor	Basis for Allocation			Basis for Allocation		Allocated LV charges
		$ per kwh / kw		kwh	kw	$	$	%	$
Residential	$/kWh	$ 0.0027	1.0299	2,220,752,100	0	$5,996,031	$ 7,385,044	33.8%	$921,975
GS<50	$/kWh	$ 0.0024	1.0299	865,278,152	0	$2,076,668	$ 2,541,962	11.6%	$317,348
GS>50	$/kW	$ 0.9755		0	10,195,076	$9,945,296	$ 11,569,499	52.9%	$1,444,378
Large Use	$/kW	$ 1.1529		0	187,932	$216,667	$ 216,667	1.0%	$27,049
USL	$/kWh	$ 0.0027	1.0299	9,989,018	0	$26,970	$ 34,794	0.2%	$4,344
Sentinel Lighting	$/kW	$ 0.8272	1.0299	487,962	1,240	$1,026	$ 1,026	0.0%	$128
Street Lighting	$/kW	$ 0.7584	1.0299	49,165,524	138,665	$105,164	$ 130,035	0.6%	$16,234
Total				3,145,672,757	10,522,913	$18,367,822	$ 21,879,027	100.0%	**$2,731,456**

		PowerStream North				
		Transmission Connection Rate	Loss Factor	Basis for Allocation		
		$ per kwh / kw		kwh	kw	$
Residential	$/kWh	$ 0.0023	1.0565	603,919,026	0	$1,389,014
GS<50	$/kWh	$ 0.0021	1.0565	221,568,993	0	$465,295
GS>50	$/kW	$ 0.8391		0	1,935,649	$1,624,203
USL	$/kWh	$ 0.0023	1.0565	3,401,434	0	$7,823
Street Lighting	$/kW	$ 0.6524	1.0565	13,226,420	38,122	$24,871
Total				842,115,873	1,973,771	$3,511,206

The calculation of PowerStream's proposed harmonized LV rates for each customer class is presented in Table 2, below.

Table 2: LV Rates Calculation

		2013			LV Wheeling Rates	
		LV charge allocated, $	kwh	kw	$/kwh	$/kw
Residential	*$/kWh*	$ 921,975	2,727,901,711	-	0.0003	
GS<50	*$/kWh*	$ 317,348	1,049,877,268	-	0.0003	
GS>50	*$/kW*	$ 1,444,378	4,553,483,283	12,130,724		0.1191
Large Use	*$/kW*	$ 27,049	63,032,980	187,932		0.1439
USL	*$/kWh*	$ 4,344	12,918,549	-	0.0003	
Sentinel Lighting	*$/kW*	$ 128	473,795	1,240		0.1033
Street Lighting	*$/kW*	$ 16,234	60,257,245	176,787		0.0918
Total		**$ 2,731,456**	**8,467,944,830**	**12,496,684**		

TRANSFORMER OWNERSHIP ALLOWANCE

There are circumstances under which PowerStream does not supply customers with transformation equipment, but rather the customer provides its own equipment. This typically occurs when the customer has unique consumption characteristics that require the use of special equipment or the level of consumption is above a certain threshold (i.e. greater than 3,000 KVA at 600/347V or greater than 5,000 KVA at 4,160V). The distribution rates are derived assuming that PowerStream provides transformation to customers. Customers that provide their own transformation are entitled to receive a credit equivalent to the costs of transformation included in Base Distribution Rates.

PowerStream is proposing to maintain the current Transformer Ownership Allowance Credit of $0.60 per kW of demand per month. Table 1 below summarizes the Transformer Ownership Allowance for 2009 to 2013.

Table 1: Transformer Ownership Allowance

	Actual 2009		Actual 2010		Actual 2011		Bridge Year /Budget 2012		Test Year 2013	
	kw	$	kw	$	kw	$	kw	$	kw	$
GS Less Than 50 kW		$ -	4,570	$ (2,742)	0	$ -	0	$ -	0	$ -
GS 50 to 4,999 kW	3,920,692	$(2,352,415)	3,702,703	$(2,221,622)	3,644,494	$(2,186,696)	3,889,932	$(2,333,959)	3,871,495	$(2,322,897)
GS 50 to 4,999 kW Legacy	56,804	$ (34,083)		$ -		$ -		$ -		$ -
Large Use	83,090	$ (49,854)	80,806	$ (48,484)	80,298	$ (48,179)	83,894	$ (50,336)	187,932	$ (112,759)
TOTALS	**4,060,587**	**$(2,436,352)**	**3,788,079**	**$(2,272,847)**	**3,724,792**	**$(2,234,875)**	**3,973,826**	**$(2,384,296)**	**4,059,427**	**$(2,435,656)**

This amount is then allocated to the General Service > 50kW and Large Use classes based on the total demand of these classes in order to derive the distribution revenue related to this allowance.

In allocating the transformer allowance to customer classes, PowerStream used the same methodology as approved by the OEB in PowerStream's 2009 Rate Application. The transformer allowance amounts are excluded from the Base Revenue Requirement calculation and separately allocated to the customer classes. Similarly, PowerStream has not entered the transformer ownership allowance amount into the cost allocation model to prevent the model from allocating this cost to rate classes that do not receive this allowance. The amount of transformer ownership allowance has been allocated only to the classes that receive it, as shown in Table 2 below.

Table 2 Transformer Ownership Allowance - Allocation by Classes

		Transformer Credit, $	kW	Rate - $/kW
GS>50	*$/kW*	$ 2,322,897	12,130,724	0.1915
Large Use	*$/kW*	$ 112,759	187,932	0.6000
Total		**$ 2,435,656**	**12,318,657**	

MICROFIT GENERATOR RATE

In its Rate Order of March 17, 2010, OEB approved a single province-wide fixed monthly charge of $5.25, related to the MicroFIt generator rate class, to be used by all licenced electricity distributors. Currently, PowerStream applies this rate to all MicroFIT generation accounts.

In accordance with the minimum filing requirements, PowerStream did not include MicroFIT as a separate class in its 2013 Cost Allocation Model. The unit costs to be used to update the provincial uniform rate at a future date are calculated in the 2013 Cost Allocation Model (Tab O3.6) and are presented in the Table 1 below.

Table 1

Description	**Residential**	**Monthly Unit Cost**
Customer Premises - Operations Labour (5070)	$ 1,210,952	$ 0.33
Customer Premises - Materials and Expenses (5075)	$ 1,291,985	$ 0.35
Meter Expenses (5065)	$ 2,022,762	$ 0.55
Maintenance of Meters (5175)	$ -	$ -
Meter Reading Expenses (5310)	$ 841,997	$ 0.23
Customer Billing (5315)	$ 2,544,666	$ 0.69
Amortization Expense - General Plant Assigned to Meters	$ 476,814	$ 0.13
Admin and General Expenses allocated to O&M expenses for meters	$ 2,144,258	$ 0.58
Allocated PILS (general plant assigned to meters)	$ 15,501	$ 0.00
Interest Expense	$ 151,665	$ 0.04
Income Expenses	$ 193,557	$ 0.05
Total Cost	$ 10,894,157	$ 2.94
Number of Residential Customers	308,309	

TRANSMISSION RATES

On June 22, 2011, the Ontario Energy Board ("OEB") issued Revision 3.0 to Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates, October 22, 2008, which provided instructions on the evidence needed, and the methodology to be used to adjust retail transmission service rates ("RTSRs") to reflect changes in the Ontario Uniform Transmission Rates ("UTRs"). Subsequently, the OEB also provided a filing module to assist the distributors in calculating the distributor's class specific RTSRs. The OEB's model and guidance has been followed in calculating the harmonized 2013 RTSRs.

Current RTSRs

PowerStream's current RTSRs are set as per OEB's Final Rate Order EB-2011-0005, issued on April 20, 2012. These rates are shown below in Table 1.

Table 1: Current Retail Transmission Service Rates, Effective May 1, 2012

		PS South		PS Barrie	
Rate Class	**Unit**	**Network**	**Connection**	**Network**	**Connection**
Residential	**kWh**	$ 0.0073	$ 0.0027	$ 0.0069	$ 0.0054
General Service Less Than 50 kW	**kWh**	$ 0.0066	$ 0.0024	$ 0.0063	$ 0.0048
General Service 50 to 4,999 kW	**kW**	$ 2.6667	$ 0.9755	$ 2.4796	$ 1.8993
General Service 50 to 4,999 kW - Time of Use	**kW**	$ -	$ -	$ 3.2918	$ 2.5212
Large Use	**kW**	$ 3.1285	$ 1.1529	$ 3.1192	$ 2.5775
Unmetered Scattered Load	**kWh**	$ 0.0066	$ 0.0027	$ 0.0063	$ 0.0048
Sentinel Lighting	**kW**	$ 2.0378	$ 0.8272	$ -	$ -
Street Lighting	**kW**	$ 2.0174	$ 0.7584	$ 1.9589	$ 1.5002

Harmonized 2013 RTSRs

The proposed harmonized RTSRs are shown in Table 2 below.

Table 2: Proposed Retail Transmission Service Rates, Effective January 1, 2013

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0071	$ 0.0032
General Service Less Than 50 kW	kWh	$ 0.0065	$ 0.0028
General Service 50 to 4,999 kW	kW	$ 2.6030	$ 1.0984
General Service 50 to 4,999 kW - Time of Use	kW	$ 2.7288	$ 1.1884
Large Use	kW	$ 3.0886	$ 1.1266
Unmetered Scattered Load	kWh	$ 0.0064	$ 0.0031
Sentinel Lighting	kW	$ 2.0118	$ 0.8084
Street Lighting	kW	$ 1.9798	$ 0.8901

PowerStream is proposing to harmonize its Retail Transmission Service Rates across the existing PowerStream South and Barrie rate zones. PowerStream has used the OEB's RTSR filing module for the purpose of 2013 transmission rate design with the following adjustments:

1. As the retail transmission service rates are not yet harmonized, revenue at current rates is calculated separately for each rate zone, using the approved 2012 Barrie and South retail transmission rates (OEB's Decision EB-2011-0005) and the actual 2011 billing determinants by rate zone and rate class.

2. These revenue amounts are added to derive the total revenue by customer class used to allocate the projected wholesale transmission cost. The wholesale costs for each rate class are then divided by its 2011 billing determinants to arrive at the harmonized retail transmission services rates.

In determining the RTSR, PowerStream has estimated the wholesale transmission costs using the current 2012 approved rates. It is likely that the UTR and Hydro One Network Inc. sub-transmission rates will change for 2013. If this information is available prior to the approval of PowerStream's 2013 rates, the calculated RTSRs may need to be updated.

For the purpose of the 2013 Test Year cost of power calculations, the 2012 approved wholesale transmission rates are applied to projected volumes 'til the end of the 2013 Test year period.

Appendix A

To Final Rate Order

Final Tariff of Rates and Charges

Board File No: EB-2011-0005

DATED: April 20, 2012

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0005

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall be classified as general service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	11.99
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	$	1.28
Rate Rider for Smart Meter Incremental Revenue Requirement (2011) – in effect until the effective date of the next cost of service application	$	0.14
Distribution Volumetric Rate	$/kWh	0.0135
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – Effective until April 30, 2013	$/kWh	(0.0004)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0073
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0027

MONTHLY RATES AND CHARGES – Regulatory Component

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

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0005

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	28.64
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	$	1.01
Rate Rider for Smart Meter Incremental Revenue Requirement (2011) – in effect until the effective date of the next cost of service application	$	3.37
Distribution Volumetric Rate	$/kWh	0.0116
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0066
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0024

MONTHLY RATES AND CHARGES – Regulatory Component

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

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0005

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	84.45
Distribution Volumetric Rate	$/kW	3.5036
Low Voltage Service Rate	$/kW	0.0472
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.0501)
Retail Transmission Rate – Network Service Rate	$/kW	2.6667
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9755

MONTHLY RATES AND CHARGES – Regulatory Component

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

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0005

LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	2,173.63
Distribution Volumetric Rate	$/kW	1.0484
Low Voltage Service Rate	$/kW	0.0558
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.0175)
Retail Transmission Rate – Network Service Rate	$/kW	3.1285
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1529

MONTHLY RATES AND CHARGES – Regulatory Component

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

PowerStream Inc.
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EB-2011-0005

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	14.32
Distribution Volumetric Rate	$/kWh	0.0087
Low Voltage Service Rate	$/kWh	0.0001
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kWh	(0.0007)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0066
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0027

MONTHLY RATES AND CHARGES – Regulatory Component

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

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EB-2011-0005

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.00
Distribution Volumetric Rate	$/kW	9.3917
Low Voltage Service Rate	$/kW	0.0401
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.1458)
Retail Transmission Rate – Network Service Rate	$/kW	2.0378
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.8272

MONTHLY RATES AND CHARGES – Regulatory Component

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

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EB-2011-0005

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

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

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.84
Distribution Volumetric Rate	$/kW	4.8616
Low Voltage Service Rate	$/kW	0.0367
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.1276)
Retail Transmission Rate – Network Service Rate	$/kW	2.0174
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7584

MONTHLY RATES AND CHARGES – Regulatory Component

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

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0005

microFIT GENERATOR SERVICE CLASSIFICATION

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

APPLICATION

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0005

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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Customer Administration		
Arrears certificate	$	15.00
Statement of Account	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for Other Billing Information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Account History	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Legal Letter Charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter Dispute Charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Temporary Service install and remove – overhead – no transformer	$	500.00

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0005

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

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

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

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0299
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0197
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to residential customers residing in detached, semi detached, townhouse (freehold or condominium) dwelling units duplexes or triplexes. Supply will be limited up to a maximum of 200 amp @ 240/120 volt. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	15.34
Rate Rider for Smart Meter Incremental Revenue Requirement (2011) – in effect until the effective date of the next cost of service application	$	1.78
Distribution Volumetric Rate	$/kWh	0.0137
Low Voltage Service Rate	$/kWh	0.0008
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kWh	(0.0006)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – Effective until April 30, 2013	$/kWh	0.0004
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective Until April 30, 2013	$/kWh	(0.0006)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0069
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0054

MONTHLY RATES AND CHARGES – Regulatory Component

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

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly peak demand is less than or expected to be less than 50 kW. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	16.11
Rate Rider for Smart Meter Incremental Revenue Requirement (2011) – in effect until the effective date of the next cost of service application	$	4.73
Distribution Volumetric Rate	$/kWh	0.0164
Low Voltage Service Rate	$/kWh	0.0007
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kWh	(0.0004)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – Effective until April 30, 2013	$/kWh	0.0007
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective Until April 30, 2013	$/kWh	(0.0004)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0063
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES – Regulatory Component

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

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than 50 kW but less than 5000 kW. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	395.68
Distribution Volumetric Rate	$/kW	1.8393
Low Voltage Service Rate	$/kW	0.2913
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.0650)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – Effective until April 30, 2013	$/kW	0.0012
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective Until April 30, 2013	$/kW	(0.0705)
Retail Transmission Rate – Network Service Rate	$/kW	2.4796
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8993

MONTHLY RATES AND CHARGES – Regulatory Component

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

PowerStream Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

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

EB-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

GENERAL SERVICE 50 to 4,999 kW TOU SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is expected to be equal to or greater than 50 kW but less than 5000 kW and who has an electrical service of at least 600 amps at 600/347 volts or 1600 amps at 208/120 volts. If the customer meets these criteria then an interval meter is required. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	395.68
Distribution Volumetric Rate	$/kW	1.8393
Low Voltage Service Rate	$/kW	0.2913
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.0650)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – Effective until April 30, 2013	$/kW	0.0012
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective Until April 30, 2013	$/kW	(0.0705)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	3.2918
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.5212

MONTHLY RATES AND CHARGES – Regulatory Component

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

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than or is expected to be equal to or greater than 5000 kW. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	9,690.24
Distribution Volumetric Rate	$/kW	0.5918
Low Voltage Service Rate	$/kW	0.3886
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.0764)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	3.1192
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.5775

MONTHLY RATES AND CHARGES – Regulatory Component

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

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 240/120 or 120 volts whose monthly peak demand is less than or expected to be less than 50 kW. As determined by Barrie Hydro Distribution Inc. because of the type of connection or location a meter is not feasible in these situations. A detailed calculation of the load will be calculated for billing purposes. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	7.95
Distribution Volumetric Rate	$/kWh	0.0161
Low Voltage Service Rate	$/kWh	0.0007
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kWh	(0.0005)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective Until April 30, 2013	$/kWh	(0.0009)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0063
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES – Regulatory Component

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

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – APPROVED ON AN INTERIM BASIS

Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).	$/kW	2.6854

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts concerning roadway lighting for a Municipality, Regional Municipality, and/or the Ministry of Transportation. This lighting will be controlled by photocells. The consumption for these customers will be based on the calculated connected load times as established in the approved OEB Street Lighting Load Shape Template. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	3.02
Distribution Volumetric Rate	$/kW	11.2961
Low Voltage Service Rate	$/kW	0.2301
Rate Rider for Tax Change – Effective Until April 30, 2013	$/kW	(0.4780)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective Until April 30, 2013	$/kW	(0.1545)
Retail Transmission Rate – Network Service Rate	$/kW	1.9589
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5002

MONTHLY RATES AND CHARGES – Regulatory Component

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

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

microFIT GENERATOR SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears Certificate	$	15.00
Easement Letter	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of Account Charge – no disconnection	$	15.00
Disconnect/Reconnect at Meter - during Regular Hours	$	30.00
Disconnect/Reconnect at Meter - after Regular Hours	$	185.00
Disconnect/Reconnect at Pole - during Regular Hours	$	185.00
Disconnect/Reconnect at Pole - after Regular Hours	$	415.00
Service Call – customer owned equipment – charge based on time and materials		
Service Call – after regular hours – charge based on time and materials		
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

PowerStream Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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

EB-2011-0005

Former Barrie Hydro Distribution Inc. Service Area

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

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

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

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0565
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0462
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

PowerStream Inc.

PROPOSED TARIFF OF RATES AND CHARGES
Effective January 1st, 2013

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

EB-2012-0161

SERVICE CLASSIFICATIONS

Residential

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.
Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall be classified as general service.Further servicing details are available in the distributor's Conditions of Service.

General Service Less Than 50 kW

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

General Service 50 to 4,999 kW

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW, both regular and interval metered.
Further servicing details are available in the distributor's Conditions of Service.

Large Use

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

Unmetered Scattered Load

This classification refers to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

Sentinel Lighting

This classification refers to an unmetered lighting load supplied to a sentinel light.
Further servicing details are available in the distributor's Conditions of Service.

Street Lighting

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.Further servicing details are available in the distributor's Conditions of Service.

Stand By Power - Approved on an Interim Basis

This classification refers to an account that has Load Displacement generation and requires the distributor to provide back-up service. Further servicing details are available in the utility's Conditions of Service.

microFIT Generator

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

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MONTHLY RATES AND CHARGES

Residential

Service Charge	**$**	13.57
Distribution Volumetric Rate	**$/kWh**	0.0151
Low Voltage Charge	**$/kWh**	0.0003
GEA Rate Adder	**$/kWh**	0.2000
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0071
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0032
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0011
Regulated Price Plan – Administration Charge	**$**	0.25

General Service Less Than 50 kW

Service Charge	**$**	27.91
Distribution Volumetric Rate	**$/kWh**	0.0148
Low Voltage Charge	**$/kWh**	0.0003
GEA Rate Adder	**$/kWh**	0.2000
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0065
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0028
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0011
Regulated Price Plan – Administration Charge	**$**	0.25

General Service 50 to 4,999 kW

Service Charge	**$**	148.18
Distribution Volumetric Rate	**$/kW**	3.5449
Low Voltage Charge	**$/kW**	0.1191
GEA Rate Adder	**$/kW**	0.2000
Retail Transmission Rate – Network Service Rate	**$/kW**	2.6030
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	1.0984
Retail Transmission Rate – Network Service Rate - Interval Metered	**$/kW**	2.7288
Retail Transmission Rate – Line and Transformation Connection Service Rate - Interval metered	**$/kW**	1.1884
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0011
Regulated Price Plan – Administration Charge	**$**	0.25

Large Use

Service Charge	**$**	6,017.47
Distribution Volumetric Rate	**$/kW**	1.7969
Low Voltage Charge	**$/kW**	0.1439
GEA Rate Adder	**$/kW**	0.2000
Retail Transmission Rate – Network Service Rate	**$/kW**	3.0886
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	1.1266
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0011
Regulated Price Plan – Administration Charge	**$**	0.25

Unmetered Scattered Load

Service Charge	**$**	8.06
Distribution Volumetric Rate	**$/kWh**	0.0156
Low Voltage Charge	**$/kWh**	0.0003
GEA Rate Adder	**$/kWh**	0.2000
Retail Transmission Rate – Network Service Rate	**$/kWh**	0.0064
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kWh**	0.0031
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0011
Regulated Price Plan – Administration Charge	**$**	0.25

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Sentinel Lighting		
Service Charge (per connection)	**$**	3.51
Distribution Volumetric Rate	**$/kW**	8.7473
Low Voltage Charge	**$/kW**	0.1033
GEA Rate Adder	**$/kW**	0.2000
Retail Transmission Rate – Network Service Rate	**$/kW**	2.0118
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.8084
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0011
Regulated Price Plan – Administration Charge	**$**	0.25

Street Lighting		
Service Charge (per connection)	**$**	1.34
Distribution Volumetric Rate	**$/kW**	5.8850
Low Voltage Charge	**$/kW**	0.0918
Retail Transmission Rate – Network Service Rate	**$/kW**	1.9798
Retail Transmission Rate – Line and Transformation Connection Service Rate	**$/kW**	0.8901
Wholesale Market Service Rate	**$/kWh**	0.0052
Rural Rate Protection Charge	**$/kWh**	0.0011
Regulated Price Plan – Administration Charge	**$**	0.25

Stand By Power - Approved On An Interim Basis		
Distribution Volumetric Rate	**$/kW**	2.6854

microFIT Generator		
Service Charge	**$**	5.25

Deferral and Variance Account Disposition Rate Riders by rate zone are shown separately.

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RATE RIDERS FOR REGULATORY ASSET RECOVERY

POWERSTREAM SOUTH

Residential		
Rate Rider for Deferral/Variance Account disposition -- Effective until Dec.31, 2014	$/kWh	0.0000
Rate Rider for Global Adjustment sub-Account disposition (Applicable only for non-RPP customers) - Effective until Dec.31, 2014	$/kWh	0.0017
General Service Less Than 50 kW		
Rate Rider for Deferral/Variance Account disposition -- Effective until Dec.31, 2014	$/kWh	(0.0012)
Rate Rider for Global Adjustment sub-Account disposition (Applicable only for non-RPP customers) - Effective until Dec.31, 2014	$/kWh	0.0017
General Service 50 to 4,999 kW		
Rate Rider for Deferral/Variance Account disposition -- Effective until Dec.31, 2014	$/kW	(0.5397)
Rate Rider for Global Adjustment sub-Account disposition (Applicable only for non-RPP customers) - Effective until Dec.31, 2014	$/kWh	0.0017
Large Use		
Rate Rider for Deferral/Variance Account disposition -- Effective until Dec.31, 2014	$/kW	(0.1895)
Rate Rider for Global Adjustment sub-Account disposition (Applicable only for non-RPP customers) - Effective until Dec.31, 2014	$/kWh	0.0017
Unmetered Scattered Load		
Rate Rider for Deferral/Variance Account disposition -- Effective until Dec.31, 2014	$/kWh	(0.0022)
Rate Rider for Global Adjustment sub-Account disposition (Applicable only for non-RPP customers) - Effective until Dec.31, 2014	$/kWh	0.0017
Sentinel Lighting		
Rate Rider for Deferral/Variance Account disposition -- Effective until Dec.31, 2014	$/kW	(0.7433)
Rate Rider for Global Adjustment sub-Account disposition (Applicable only for non-RPP customers) - Effective until Dec.31, 2014	$/kWh	0.0017
Street Lighting		
Rate Rider for Deferral/Variance Account disposition -- Effective until Dec.31, 2014	$/kW	(0.6372)
Rate Rider for Global Adjustment sub-Account disposition (Applicable only for non-RPP customers) - Effective until Dec.31, 2014	$/kWh	0.0017

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POWERSTREAM BARRIE

Residential		
Rate Rider for LRAM Recovery (2012) - Effective until April 30,2013	**$/kWh**	0.0004
Rate Rider for Deferral/Variance Account disposition (2012) - effective Until April 2013	**$/kWh**	(0.0006)
Rate Rider for Deferral/Variance Account disposition -- Effective until Dec.31, 2014	**$/kWh**	0.0008
Rate Rider for Global Adjustment sub-Account disposition (Applicable only for non-RPP customers) - Effective until Dec.31, 2014	**$/kWh**	0.0030
General Service Less Than 50 kW		
Rate Rider for LRAM Recovery (2012) - Effective until April 30,2013	**$/kWh**	0.0007
Rate Rider for Deferral/Variance Account disposition (2012) - effective Until April 2013	**$/kWh**	(0.0004)
Rate Rider for Deferral/Variance Account disposition -- Effective until Dec.31, 2014	**$/kWh**	(0.0009)
Rate Rider for Global Adjustment sub-Account disposition (Applicable only for non-RPP customers) - Effective until Dec.31, 2014	**$/kWh**	0.0030
General Service 50 to 4,999 kW		
Rate Rider for LRAM Recovery (2012) - Effective until April 30,2013	**$/kW**	0.0012
Rate Rider for Deferral/Variance Account disposition (2012) - effective Until April 2013	**$/kW**	(0.0705)
Rate Rider for Deferral/Variance Account disposition -- Effective until Dec.31, 2014	**$/kW**	(0.5536)
Rate Rider for Global Adjustment sub-Account disposition (Applicable only for non-RPP customers) - Effective until Dec.31, 2014	**$/kWh**	0.0030
Large Use		
Rate Rider for Deferral/Variance Account disposition -- Effective until Dec.31, 2014	**$/kW**	(0.0829)
Rate Rider for Global Adjustment sub-Account disposition (Applicable only for non-RPP customers) - Effective until Dec.31, 2014	**$/kWh**	0.0001
Unmetered Scattered Load		
Rate Rider for Deferral/Variance Account disposition (2012) - effective Until April 2013	**$/kWh**	(0.0009)
Rate Rider for Deferral/Variance Account disposition -- Effective until Dec.31, 2014	**$/kWh**	(0.0014)
Rate Rider for Global Adjustment sub-Account disposition (Applicable only for non-RPP customers) - Effective until Dec.31, 2014	**$/kWh**	0.0030
Street Lighting		
Rate Rider for Deferral/Variance Account disposition (2012) - effective Until April 2013	**$/kW**	(0.1545)
Rate Rider for Deferral/Variance Account disposition -- Effective until Dec.31, 2014	**$/kW**	(0.4548)
Rate Rider for Global Adjustment sub-Account disposition (Applicable only for non-RPP customers) - Effective until Dec.31, 2014	**$/kWh**	0.0001

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Specific Service Charges

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Disconnect/Reconnect at meter - during regular hours (for non-payment)	$	65.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Install/Remove load control device - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours (for non-payment)	$	185.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Install/Remove load control device - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00

Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Temporary service install & remove - overhead - no transformer	$	500.00

Allowances

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

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0345
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0243
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

SUMMARY OF BILL IMPACTS BY CUSTOMER CLASS

Bill impacts for typical customers have been calculated using the proposed rates, including revised Low Voltage ("LV") charges, the proposed regulatory assets recovery rate riders, and the Green Energy Act ("GEA") funding rate adder. The revised Retail Transmission Service ("RTS") rates are also included. For customers on the Regulated Price Plan (RPP), bill impacts have been calculated using the commodity prices effective May 1, 2012:

- 7.5¢/kWh – for the consumption below the threshold; and
- 8.8¢/kWh – for the consumption above the threshold.

The threshold for the residential customers on RPP has been annualized at 800 kWh/month. The threshold for non-residential customers on RPP is 750 kWh/month.

For non-RPP customers the bill impacts were calculated using a commodity price of 8.2¢/kWh for all levels of consumption.

For bill impact calculation purposes, the commodity prices and regulatory charges are assumed to be constant.

The monthly total bill impacts for typical customers are presented in Table 1. The monthly bill impacts on the delivery portion of the bill are presented in Table 2. The monthly impacts on the distribution portion of the bill are presented in Table 3.

Table 1: Summary of Monthly Bill Impacts for a Typical Customer – Total Bill

Customer Class	Billing Determinant	Consumption per customer	Load per customer	Total Monthly Bill Impact			
				PowerStream South		PowerStream Barrie	
		kwh	kW	$	%	$	%
Residential	kWh	800	-	$ 2.80	2.6%	$ (5.13)	(4.4%)
GS<50 kW	kWh	2,000	-	$ 1.69	0.6%	$ (6.20)	(2.2%)
GS>50 kW	kW	80,000	250	$ 173.03	1.6%	$ (80.10)	(0.7%)
Large Use	kW	2,800,000	7,350	$ 14,692.57	4.2%	$ (8,215.58)	(2.2%)
Unmetered Scattered Load	kWh	150	-	$ (5.79)	(16.6%)	$ (0.58)	(2.0%)
Sentinel Lights	kW	180	1	$ 0.62	1.8%		
Street Lighting	kW	280	1	$ 1.43	3.7%	$ (9.38)	(19.0%)

All total bill impacts for typical customers are less than 10%, with the exception of Street Lighting in North Rate zone (19.0% decrease) and Unmetered Scattered Load in South Rate Zone (16.6% decrease).

Table 2: Summary of Monthly Bill Impacts for a Typical Customer – Delivery Charge

Customer Class	Billing Determinant	Consumption per customer	Load per customer	Monthly Delivery Charge Impact			
				PowerStream South		PowerStream Barrie	
		kwh	kW	$	%	$	%
Residential	kWh	800	-	$ 2.41	7.5%	$ (3.38)	(8.8%)
GS<50 kW	kWh	2,000	-	$ 0.79	1.1%	$ (1.94)	(2.5%)
GS>50 kW	kW	80,000	250	$ 120.63	6.5%	$ 84.53	4.2%
Large Use	kW	2,800,000	7,350	$ 13,002.28	31.2%	$ (7,270.43)	(12.5%)
Unmetered Scattered Load	kWh	150	-	$ (5.18)	(30.5%)	$ (0.24)	(2.0%)
Sentinel Lights	kW	180	1	$ 0.49	3.4%		
Street Lighting	kW	280	1	$ 1.16	13.9%	$ (7.80)	(44.9%)

Table 3: Summary of Monthly Bill Impacts for a Typical Customer – Distribution Portion

Customer Class	Billing Determinant	Consumption per customer	Load per customer	Monthly Distribution Charge Impact			
				PowerStream South		PowerStream Barrie	
		kwh	kW	$	%	$	%
Residential	kWh	800		$ 2.12	8.8%	$ (1.51)	(5.4%)
GS<50 kW	kWh	2,000		$ 0.09	0.2%	$ 2.27	4.1%
GS>50 kW	kW	80,000	250	$ 105.83	11.0%	$ 253.90	28.4%
Large Use	kW	2,800,000	7,350	$ 13,488.85	132.8%	$ 3,618.60	22.2%
Unmetered Scattered Load	kWh	150		$ (5.22)	(33.6%)	$ 0.04	0.4%
Sentinel Lights	kW	180	1	$ 0.53	4.7%		
Street Lighting	kW	280	1	$ 1.07	19.1%	$ (7.21)	(51.8%)

In the PowerStream South rate zone, a typical residential customer using 800 kWh per month would experience a $2.12 increase on the distribution portion of the bill (8.8%) and $2.8 increase in the total bill (2.6%). In PowerStream North rate zone, a typical residential customer using 800 kWh per month would experience a $1.51 decrease on the distribution portion of the bill (5.4%) and $5.13 decrease in the total bill (4.4%).

In the PowerStream South rate zone, the typical GS<50 kw customer using 2,000 kWh per month would experience a $0.09 increase on the distribution portion of the bill (0.2%) and $1.69 increase in the total bill (0.6%). In PowerStream North rate zone, a typical GS<50 kW customer using 2,000 kWh per month would experience a $2.27 increase on the distribution portion of the bill (4.1%) and $6.20 decrease in the total bill (2.2%).

Due to the impact of harmonization of distribution and transmission rates, all customer classes in PowerStream North rate zone would have slight decreases in their total bills.

The calculation of Bill impacts is presented in OEB Appendix 2-V (Appendix 1, Schedule 21).

The Total Bill Impacts for different ranges of load and consumption by customer class and rate zone are shown in tables 4 and 5 below.

Table 4: Summary of Total Bill Impacts – PowerStream South

Class	Consumption kWh	Load kW	Current	New	Difference $	Bill Impact %	High	Low
Residential	100		25.51	26.17	$ 0.66	2.6%	2.6%	2.4%
	250		$ 42.94	$ 44.05	1.11	2.6%		
	500		$ 71.98	$ 73.84	1.86	2.6%		
	800		$ 107.81	$ 110.61	2.80	2.6%		
	1,000		$ 133.77	$ 137.17	3.40	2.5%		
	1,500		$ 198.66	$ 203.59	4.93	2.5%		
	2,000		$ 263.56	$ 270.00	6.44	2.4%		
General Service Less Than 50 kW	1,000		150.83	149.17	(1.66)	-1.1%	2.3%	-1.1%
	2,000		277.74	279.43	1.69	0.6%		
	2,500		341.20	344.56	3.36	1.0%		
	5,000		658.47	670.18	11.71	1.8%		
	10,000		1,293.02	1,321.44	28.42	2.2%		
	12,500		1,610.30	1,647.07	36.77	2.3%		
General Service 50 to 4,999 kW	15,000	60	2,240.09	2,326.52	86.43	3.9%	3.9%	0.9%
	40,000	100	5,329.75	5,461.35	131.60	2.5%		
	80,000	250	10,967.37	11,140.40	173.03	1.6%		
	100,000	500	15,198.69	15,329.71	131.02	0.9%		
	400,000	1,000	52,436.14	53,101.94	665.80	1.3%		
	1,000,000	3,000	134,982.53	136,359.45	1,376.92	1.0%		
Large Use	2,800,000	7,350	352,621.47	367,314.04	14,692.57	4.2%	4.2%	2.7%
	5,000,000	10,000	608,794.99	629,505.68	20,710.69	3.4%		
	8,000,000	15,000	966,532.14	996,386.79	29,854.65	3.1%		
	10,000,000	17,500	1,199,968.62	1,235,355.74	35,387.12	2.9%		
	12,000,000	20,000	1,433,405.09	1,474,324.70	40,919.61	2.9%		
	15,000,000	22,000	1,772,944.38	1,820,979.37	48,034.99	2.7%		
Unmetered Scattered Load	150		34.84	29.05	(5.79)	-16.6%	1.8%	-16.6%
	250		47.09	42.00	(5.09)	-10.8%		
	500		77.72	74.38	(3.34)	-4.3%		
	750		108.67	107.15	(1.52)	-1.4%		
	1,000		143.08	143.33	0.25	0.2%		
	1,500		211.89	215.70	3.81	1.8%		
Sentinel Lighting		0.30					4.7%	1.3%
	180	0.50	27.86	29.18	1.32	4.7%		
	270	0.75	40.52	41.53	1.01	2.5%		
	350	1.00	52.16	52.85	0.69	1.3%		
Street Lighting	73	0.20	$ 10.42	$ 11.17	$ 0.75	7.2%	7.2%	3.7%
	110	0.30	$ 15.07	$ 15.90	$ 0.83	5.5%		
	146	0.40	$ 19.61	$ 20.54	$ 0.93	4.7%		
	183	0.50	$ 24.26	$ 25.28	$ 1.02	4.2%		
	280	1.00	$ 38.47	$ 39.90	$ 1.43	3.7%		

Table 5: Summary of Total Bill Impacts – PowerStream Barrie

Class	Consumption kWh	Load kW	Current	Proposed	Difference $	Bill Impact %	Max	Min
Residential	100		$ 29.83	$ 26.23	$ (3.60)	-12.1%	-2.8%	-12.1%
	250		48.07	44.20	(3.87)	-8.1%		
	500		78.48	74.14	(4.34)	-5.5%		
	800		115.56	110.43	(5.13)	-4.4%		
	1,000		142.68	137.12	(5.56)	-3.9%		
	1,500		210.47	203.84	(6.63)	-3.2%		
	2,000		278.27	270.56	(7.71)	-2.8%		
General Service Less Than 50 kW	1,000		149.19	149.79	0.60	0.4%	0.4%	-4.5%
	2,000		286.85	280.65	(6.20)	-2.2%		
	2,500		355.67	346.08	(9.59)	-2.7%		
	5,000		699.81	673.24	(26.57)	-3.8%		
	10,000		1,388.10	1,327.54	(60.56)	-4.4%		
	12,500		1,732.23	1,654.69	(77.54)	-4.5%		
General Service 50 to 4,999 kW	15,000	60	2,579.54	2,342.91	(236.63)	-9.2%	1.6%	-9.2%
	40,000	100	5,700.86	5,510.71	(190.15)	-3.3%		
	80,000	250	11,314.52	11,234.42	(80.10)	-0.7%		
	100,000	500	15,382.04	15,429.60	47.56	0.3%		
	400,000	1,000	52,981.98	53,595.53	613.55	1.2%		
	1,000,000	3,000	135,385.84	137,546.40	2,160.56	1.6%		
Large Use	2,800,000	7,350	371,352.59	363,137.01	(8,215.58)	-2.2%	-0.9%	-2.2%
	5,000,000	10,000	631,217.14	621,670.26	(9,546.88)	-1.5%		
	8,000,000	15,000	995,918.48	983,729.66	(12,188.82)	-1.2%		
	10,000,000	17,500	1,232,837.05	1,219,383.76	(13,453.29)	-1.1%		
	12,000,000	20,000	1,469,755.62	1,455,037.86	(14,717.76)	-1.0%		
	15,000,000	22,000	1,812,080.59	1,796,509.45	(15,571.14)	-0.9%		
Unmetered Scattered Load	150		29.61	29.03	(0.58)	-2.0%	-2.0%	-4.2%
	250		43.17	41.97	(1.20)	-2.8%		
	500		77.08	74.33	(2.75)	-3.6%		
	750		111.61	107.06	(4.55)	-4.1%		
	1,000		149.39	143.22	(6.17)	-4.1%		
	1,500		224.96	215.53	(9.43)	-4.2%		
Street Lighting	73	0.20	$ 14.60	$ 11.17	$ (3.43)	-23.5%	-18.4%	-23.5%
	110	0.30	$ 20.11	$ 15.91	$ (4.20)	-20.9%		
	146	0.40	$ 25.51	$ 20.55	$ (4.96)	-19.4%		
	183	0.50	$ 31.01	$ 25.29	$ (5.72)	-18.4%		
	280	1.00	$ 49.31	$ 39.93	$ (9.38)	-19.0%		

REVENUE TO COST RATIOS BY CUSTOMER CLASS

The revenue to cost (“R/C”) ratios by customer class are presented in table 1 below.

Table 1 PowerStream R/C Ratios

Class	Previously Approved Ratios		Status Quo Ratios	Proposed Ratios	Policy Range
	PowerStream North	PowerStream South	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	2011*	2009			
	%	%	%	%	%
Residential	111.9	92.9	101.2	101.2	85 - 115
GS < 50 kW	100.0	116.7	98.8	98.8	80 - 120
GS > 50 kW	81.0	106.5	98.1	98.1	80 - 120
Large User	86.0	115.0	41.7	100.2	85 - 115
Street Lighting	70.0	74.5	118.9	109.2	70 - 120
Sentinel Lighting		75.4	92.4	92.4	80 - 120
Unmetered Scattered Load (USL)	99.0	119.9	100.6	100.6	80 - 120

Please refer to Exhibit G, Tab 1, Schedules 2 and 3 for more details on Cost Allocation. As per the Board’s Filing Requirements, PowerStream has also filed the OEB Appendix 2-O “Cost Allocation”, as part of Appendix 1, Supporting Schedule 21.

RATE MITIGATION

All bill impacts with the exception noted below are less than 10% and, as a result, PowerStream has not proposed any rate mitigation measures. The exceptions are the decreases in total bill for the Street Lighting class in the Barrie rate zone and for Unmetered Scattered Load in South Rate zone.

Since this impact is mainly result of rate harmonization between the two rate zones and the customers will experience a decrease (not an increase) in the total bill, rate mitigation measures are not considered necessary.

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Appendix 2-U
Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Service Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	305,233	311,385	308,309	2,727,901,711		$ 13.57	$ 0.0154		$ 92,214,724	$ 92,190,288		$ 92,190,288	-$ 24,436
GS < 50 kW	Customers	30,966	31,432	31,199	1,049,877,268		$ 27.91	$ 0.0151		$ 26,302,316	$ 26,328,439		$ 26,328,439	$ 26,123
GS > 50 to 4,999 kW	Customers	4,647	4,676	4,662		12,130,724	$ 148.18		$ 3.6640	$ 52,735,867	$ 50,412,289	$ 2,322,897	$ 52,735,186	-$ 680
Large Use	Customers	2	2	2		187,932	$ 6,017.47		$ 1.9408	$ 509,158	$ 396,400	$ 112,759	$ 509,159	$ 1
Streetlighting	Connections	82,656	84,084	83,370		176,787	$ 1.34		$ 5.9768	$ 2,397,212	$ 2,397,217		$ 2,397,217	$ 5
Sentinel Lighting	Connections	120	120	120		1,240	$ 3.51		$ 8.8506	$ 16,032	$ 16,032		$ 16,032	-$ 0
Unmetered Scattered Load	Connections	2,804	2,824	2,814	12,918,549		$ 8.06	$ 0.0159		$ 477,575	$ 478,595		$ 478,595	$ 1,020
				-						$ -			$ -	$ -
Total										$ 174,652,883	$ 172,219,260	$ 2,435,656	$ 174,654,916	$ 2,033

LOSS ADJUSTMENT FACTORS

Overview

As electricity travels along wires and through transformers and other devices, resistance in the conductor causes some electricity to be converted to heat energy and lost. As a result when electricity comes from the provincial grid and flows to customers, more electricity is required from the grid than actually reaches the customers. This fact of physics is usually referred to as "line losses" or simply "losses". Losses can also result from the theft of power and meter reading or billing errors.

The loss adjustment factors are applied to customers' metered consumption for billing purposes. It is designed to result in billed consumption that reflects the amount of electricity PowerStream has to purchase in order to meet customers requirements taking into account the distribution losses.

PowerStream's proposed loss factors are well below the Board's threshold of 5% cited in section 2.11.7 of the *Filing Requirements for Transmission and Distribution Applications*, as updated June 22, 2011 ("Filing Requirements").

In its 2008 Cost of Service proceeding, the Board directed the former Barrie Hydro Distribution Inc. ("Barrie Hydro"), now part of PowerStream, to file a loss study and this study was filed. Please refer to Exhibit H, Tab 7, Schedule 2 for further discussion of distribution system losses and the Barrie Hydro loss study.

PowerStream has calculated the billing loss adjustment factors as per the Filing Requirements, using Appendix 2-P. PowerStream's proposed loss adjustment factors are based on the average of the three most recent complete years from 2009 to 2011. In this Application, PowerStream is proposing to harmonize rates for its two current rate zones including loss factors. It is proposed to base the harmonized loss factors on the weighted average of the three most recent years for the former PowerStream ("South") and former Barrie Hydro.

The proposed loss factors are shown in Table 1 below, together with, for comparative purposes, the current approved South and Barrie Hydro loss adjustment factors and a weighted average of the two current approved loss factors.

Table 1: PowerStream Current Approved and Proposed Loss Adjustment Factors

Billing Loss Factors	PowerStream South Approved	Barrie Hydro Approved	Weighted Average of Approved	Proposed January 1, 2013 (3 Yr. Avg.)
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0299	1.0565	1.0348	**1.0346**
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0145	1.0145	1.0145	**1.0145**
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0197	1.0462	1.0246	**1.0243**
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0045	1.0045	1.0045	**1.0045**

A comparison of the proposed loss factors based on the most recent three year average to the weighted average of the current approved loss factors shows that there has been a very slight decrease in the loss factors for customers with demand less than 5,000 kW since the last approval. The weighted average uses the three year average split for energy sales between PowerStream South (81.7%) and Barrie Hydro (18.3%).

Note that several different “total loss factors” are derived to be used as the loss adjustment factor for billing in different situations as described in the following section.

LOSS ADJUSTMENT FACTOR CALCULATIONS

PowerStream has calculated loss factors based on the Board’s Appendix 2-P, Loss Factors, in the Filing Requirements. This is included as an appendix to this exhibit.

PowerStream receives most of its electricity through IESO-controlled grid points. PowerStream proposes to use the current Board approved Supply Facility Loss Factor (“SFLF”) of 1.0045. The SFLF is to account for losses that occur from the point that power is taken from the transmission grid to the point where it enters PowerStream’s distribution lines. Losses occur mainly from the transformation of the power from the transmission grid voltage to the distribution system voltage.

The Distribution Loss Factor (“DLF”) represents losses in the Distributor’s system as calculated using the Board’s Appendix 2-P. PowerStream calculated an average DLF of 1.0299 over the last three years.

As seen in Table 1 above, there are several different loss factors depending on whether or not the customer is a large use customer with average monthly peak demand over 5,000 kW and how the customer is metered.

The Total Loss Factor ("TLF") to be used as the billing loss factor adjustment is calculated as the SFLF multiplied by DLF. The same SFLF of 1.0045 is used for all customers.

PowerStream proposes to use the current approved loss adjustment factor for primary metered large use (>5000 kW demand) customers of 1.0045, which represents the SFLF. For secondary metered large use (>5000 kW demand) customers PowerStream proposes to use the current Board approved loss adjustment factor of 1.0145, which represents the SFLF and the secondary metered loss factor of 1.0100 described in the next paragraph.

PowerStream proposes to use the current Board approved secondary metered loss factor of 1.0100. This secondary metered loss factor is a default value (2006 EDR Handbook, Schedule 10-5) representing the losses that occur in the line transformer where the voltage is stepped down from the distribution voltage (typically 27.6kV) to the customer's service voltage (typically 600V for commercial and 120/240V for residential). Where the customer is metered before the line transformer this is referred to as "primary metered". If the customer is metered after the line transformer, this is referred to as "secondary metered".

Table 2 below shows the DLF for each type of customer and resulting TLF when the SFLF of 1.0045 is applied. The DLF and TLF determined in Appendix 2-P applies to Secondary Metered Customers <5,000 kW demand, as stated on the form (rows "G" and "I"). The primary metered customer DLF is determined by applying the Board approved secondary metered loss factor of 1.0100.

Table 2: PowerStream Loss Adjustment Factors - Detailed Calculation

Billing Loss Factors	**PowerStream South Approved**	**PowerStream - Barrie Approved**	**Weight Average of Approved**	**Proposed January 1, 2013**
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0299	1.0565	1.0348	**1.0345**
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0145	1.0145	1.0145	**1.0145**
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0197	1.0462	1.0246	**1.0243**
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0045	1.0045	1.0045	**1.0045**
Supply Facilities Loss Factor - all customers				**1.0045**
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW				**1.0299**
Distribution Loss Factor - Secondary Metered Customer > 5,000 kW				**1.0100**
Distribution Loss Factor - Primary Metered Customer < 5,000 kW				**1.0197**
Distribution Loss Factor - Primary Metered Customer > 5,000 kW				**1.0000**

Appendix 2-P
Loss Factors

		Historical Years			3-Year Average
		2009	**2010**	**2011**	
	Losses Within Distributor's System				
A(1)	"Wholesale" kWh delivered to distributor (higher value)	Not available	Not available	Not available	0
A(2)	"Wholesale" kWh delivered to distributor (lower value)	8,238,568,148	8,611,402,381	8,658,416,020	8,502,795,516
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	27,205,480	27,609,737	27,116,405	27,310,541
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	8,211,362,668	8,583,792,644	8,631,299,615	8,475,484,976
D	"Retail" kWh delivered by distributor	8,039,883,040	8,334,777,460	8,394,821,657	8,256,494,052
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	27,205,480	27,609,737	27,116,405	27,310,541
F	Net "Retail" kWh delivered by distributor = **D - E**	8,012,677,560	8,307,167,723	8,367,705,252	8,229,183,512
G	Loss Factor in Distributor's system = **C / F**	1.0248	1.0333	1.0315	1.0299
	Losses Upstream of Distributor's System				
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045
	Total Losses				
I	Total Loss Factor = **G x H**	1.0294	1.0379	1.0361	1.0345

Notes

A(1) If directly connected to the IESO-controlled grid, kWh pertains to the virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the higher of the two values provided by MV-WEB.

If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

A(2) If directly connected to the IESO-controlled grid, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the lower of the two kWh values provided by MV-WEB.

If fully embedded with the host distributor, kWh pertains to an actual or virtual meter at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

Additionally, kWh pertaining to distributed generation directly connected to the distributor's own distribution network should be included in **A(2)**.

B If a Large Use Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1% (i.e., **B** = 1.01 X **E**).

D kWh corresponding to **D** should equal “total billed energy sales in kWhs for each rate class” in item 1 of Section 2.1.3 of the “Electricity Reporting and Record-keeping Requirements” dated May 1, 2010 or in any successor document.

G and **I** These loss factors pertain to secondary-metered customers with demand less than 5,000 kW.

H If directly connected to the IESO-controlled grid, SFLF = 1.0045.

If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface X loss factor re losses in host distributor’s system. If the host distributor is Hydro One Networks Inc., SFLF = 1.0060 X 1.0278 = 1.0340. If partially embedded, SFLF should be calculated as the weighted average of above.

Distributors that wish to propose a different SFLF should provide appropriate justification for any such proposal including supporting calculations and any other relevant material.

DISTRIBUTION SYSTEM LOSSES

PowerStream's service territory consists of the former Barrie Hydro Distribution Inc. ("Barrie Hydro") and the former PowerStream Inc. ("PowerStream"), service territories, as a result of the merger on January 1, 2009.

As shown in Appendix 2-P (Exhibit H, Tab 7, Schedule 1), the three year average total loss factor ("TLF") for 2009 to 2011 is 3.46%, made up of a supply facility loss factor ("SFLF") of 1.0045 and distribution loss factor ("DLF") of 2.99%. Both the TLF of 3.46% and the DLF of 2.99% are well below the Ontario Energy Board ("OEB") threshold of 5% for distribution losses.

PowerStream takes proactive steps to manage distribution system losses. PowerStream has seen continued growth in load and much of the new load is situated further away from its supply points. The longer distances that the electricity has to travel to supply these new customer loads leads to increased losses. PowerStream has managed to mitigate the losses from new load further from the supply point with the measures described below under "Technical Losses and Mitigation".

In its 2008 cost of service filing, Barrie Hydro was directed to file a loss study. This was filed with the OEB in December 2008 and is discussed below under the title "Barrie Hydro 2008 Loss Study".

OVERVIEW

Distribution system losses for any period are the difference between, collectively, the electricity measured at the points of purchase and the electricity measured at the points of sale. There are two types of losses: non-technical and technical.

Technical losses include power or energy used in the components of the system that deliver electricity to the customer's meter. This can occur through:

- Power transformers
- Distribution transformers
- Overhead and underground lines

- Secondary overhead and underground lines

Non-technical losses includes all unaccounted for energy other than technical losses. This can occur through:

- Theft
- Meter reading errors
- Meter inaccuracies
- Billing errors
- Unmetered loads

Non-technical losses are mitigated through a number of checks in PowerStream's procedures. Supply point data and related losses charged are reviewed to ensure that the amounts are reasonable and the losses charged are in accordance with the approved loss factors. Load transfers are recorded and accounted for in determining overall losses. PowerStream uses exception reports from its Customer Information System ("CIS") to identify metering or meter-reading errors. PowerStream does calculations to accurately capture the impact of significant unmetered loads such as street lighting and cable television amplifiers. PowerStream's Line staff watch for evidence of fraud to the extent possible and report such instances.

TECHNICAL LOSSES AND MITIGATION

Feeders are the main power lines that distribute power from municipal substations ("MS") connected to Hydro One's 44kV sub-transmission lines and from transformer stations ("TS") connected to Hydro One's 230kV transmission lines to supply the areas where customers are located. Feeders are a component of the distribution system that offer good opportunities for loss reduction. Heavily loaded or long feeders tend to have higher line losses.

Reductions to distribution system losses are frequently the result of initiatives that involve reductions in load or a reduction in feeder lengths (system reconfiguration).

PowerStream performs an annual review of feeder and station peak loading to identify feeders and stations that are loaded above PowerStream's planning guidelines. These stations and feeders are then prioritized based on the severity of the overloading and studied to determine where existing switches should be opened or closed and where additional switches should be installed to reduce loading by reconfiguring the system. On occasion new feeders are installed in order to reduce the load on existing feeders, and thereby reduce line losses.

PowerStream also works to reduce losses with respect to transformation. Transformers are purchased with the lowest economically viable losses. Transformers have losses based on the load they deliver (load losses) and also have losses without delivering load (no load losses). Manufacturers vary their designs based on what is specified between these two loss components, and the initial cost for a utility to purchase the units reflects the requirements. An industry standard formula has typically been used that weights the ratio of the no load and load losses along with the initial purchase price. Purchasing using this calculation ensures that over the life of the transformer, that total losses are economically compared. PowerStream uses this methodology when procuring transformers.

PowerStream works with commercial customers with dedicated transformers to make sure that these are “right sized” for the customer’s load. Transformers supplied to customers that have a large capacity relative to the actual load will typically have higher losses than transformers where the load and capacity are more closely matched.

Management of system losses is an on-going consideration in the planning, design, operation, purchase, upgrading and replacement of distribution facilities and equipment. There are a number of initiatives that PowerStream is conducting on regular basis to address reduction of losses. These initiatives include:

1. Conductor Size Study

The larger the conductor, the lower the losses. As part of the annual capital program, PowerStream reviews its distribution system for those areas where smaller conductor sizes and high loads occur. Economic analysis is normally carried out as part of the annual capital budget planning process and the installation larger conductors can sometimes be justified by the loss savings.

2. Feeder Phase Balancing

Balanced three phase circuits have lower losses than unbalanced three phase circuits. PowerStream reviews its distribution system feeder peaks for those feeders where the unbalanced loads exceeds industry standards, typically 15%. The feeders are then prioritized based on the worst phase imbalance and studies are carried out to balance the phases by changing existing open points and in some cases adding new switches to establish new open points.

3. Feeder Balancing

An annual review is carried out of all distribution feeder peak loadings. Feeders loaded beyond PowerStream's approved loading guideline are prioritized based on the severity of the overloading. A study is carried out to identify new open points and load is transferred among neighbouring feeders. Existing switches are used to reconfigure the system. In some cases new switches are installed to achieve the appropriate feeder balance. In some instances where feeder balance is not achievable because of excessive feeder peak loadings, new feeders are specified and installed.

4. Load Balancing of Station Transformers

An annual peak loading review is carried out for all TS and MS transformers. Transformers that have peak loading above PowerStream's approved loading guidelines are prioritized based on the degree of overloading. A study is carried out and load is transferred from the overloaded transformer to neighboring station transformers, when possible.

It is becoming increasingly difficult to locate stations near customer loads. due land availability, environmental issues and the availability of transmission capacity in urban areas. Stations are being located appreciable distances from customer loads. This will result in long feeders and consequently higher line losses.

BARRIE HYDRO 2008 LOSS STUDY

In its 2008 Cost of Service proceeding, the OEB directed Barrie Hydro, now part of PowerStream, to file a loss study. The loss study was filed in December 2008.

The study showed that the total Barrie Hydro losses consisted of an aggregate of lower losses in urban areas (City of Barrie) and higher losses in the less urban areas (Bradford, Penetanguishene and New Tecumseth). The City of Barrie had 3.29% loss factor while the other areas had much higher losses. The higher losses in the other areas were due to the fact that these areas were supplied by long 44 kV feeders and their embedded supply points had default Hydro One losses of 3.4% added before the losses in Barrie Hydro's system.

Since 2009, Hydro One and PowerStream have worked together to improve supply to these areas. Following are some of the improvements that have been implemented:

New Tecumseth: the number of 44 kV feeders has increased from two to three. The resulting reduction in feeder peak loading has decreased losses.

Bradford: the number of 44 kV feeders increased from two to three. The resulting reduction in feeder peak loading has decreased losses.

Penetanguishene: Currently there are two shared, Hydro One Networks Inc. ("HONI") and PowerStream), 44 kV feeders supplying Penetanguishene's load. There are no plans for additional feeders as the peak load does not justify additional feeders. HONI, however, has replaced sections of small conductors with larger conductors. PowerStream has plans to replace approximately five kilometers of small conductor with larger conductors. The replacement of smaller conductors with larger conductors will result in reduced losses. PowerStream is continuing to explore initiatives that involve reductions in load and feeder lengths through system reconfiguration while managing loads within PowerStream's Planning Guidelines. These initiatives will result in reduced line losses.

DEFERRAL AND VARIANCE ACCOUNTS - OVERVIEW

PowerStream has followed the Board's guidance in the *Accounting Procedures Handbook* and *FAQs* ("APH") for recording amounts in the deferral and variance ("D&V") accounts, and in the *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)* (EB-2008-0046, July 31, 2009) for the disposition. PowerStream has completed and included the Board's "2013_EDDVAR_Continuity_Schedule-CoS" spreadsheet.

Carrying charges have been calculated at the Board's prescribed rates, on monthly opening principal balances, in accordance with the APH and the Board's letter, *Approval of Accounting Interest Rates Methodology for Regulatory Accounts Board File No. EB-2006-0117,* dated November 28, 2006.

PowerStream has two separate rate zones at the time of filing: the former Barrie Hydro Distribution Inc. ("Barrie") rate zone and the former PowerStream Inc. ("South") rate zone. Due to the differing situations for each rate zone, PowerStream has calculated separate D&V account balances for most D&V accounts and associated rate riders for each rate zone. In some cases, the D&V balances are not specific to a rate zone. These balances have been included in a "Shared" continuity schedule and allocated to customers of both rate zones and associated rate riders calculated that apply to both rate zones. PowerStream proposes to harmonize rates in this Application. However it will be necessary to continue to have different deferral and variance account rate riders for the two rate zones until these balances are cleared.

The detailed continuity schedules are provided for the South, Barrie and "Shared" rate zones in Exhibit I, Tab 1, Schedules 4 to 6. PowerStream updated the Board's regulatory asset model from PowerStream's 2009 Cost of Service application and used this to allocate amounts to rate classes and calculate the resulting rate riders. The results and the models are included in Exhibit I, Tab 1, Schedule 3.

PowerStream's current approved rates, for both the Barrie and the South rate zones, contain smart meter incremental revenue requirement rate riders related to approved final disposition of smart meter amounts, which expire upon rebasing. The Barrie rate zone also has Deferral/Variance Account Disposition rate riders effective until April 30, 2013 for disposition of the account 1562 Deferred PILs balance approved in its 2012 IRM rate application. Accordingly the Barrie account 1562 balance has been excluded from this disposition.

In this Application, PowerStream is seeking disposition of D&V account balances as at December 31, 2011, the most recent audited balances, along with accrued interest up to December 31, 2012 based on the proposed January 1, 2013 effective date for the rate riders. PowerStream has also projected the balances of *account 1508 - Deferred IFRS Transition costs* (including amounts in rates), *account 1592 PILs and Tax Variance for 2006 and Subsequent Years – HST/OVAT*, and *account 1592 PILs and Tax Variance for 2006 and Subsequent Years – HST/OVAT Contra* to December 31, 2012. The corresponding 50% of account 1592 PILs and Tax Variance for 2006 and Subsequent Years – HST/OVAT to be refunded to customers recorded in account 2425 has also been projected to December 31, 2012. See Exhibit I, Tab 1, Schedules 10 and 12 for more information.

PowerStream is seeking disposition of the remaining stranded meter costs resulting from the smart meter program. See Exhibit I, Tab 1, Schedule 8 for more information. Due to the rate impact on certain classes, PowerStream proposes to recover the D&V balances which include stranded meter costs over a period of two years from January 1, 2013 to December 31, 2014. The balance has been projected to December 31, 2012 by deducting 2012 depreciation.

PowerStream proposes to refund a balance of $5.3 million, excluding Global Adjustment, to customers in the South rate zone over a period of two years, from January 1, 2013 to December 31, 2014, by means of the customer class specific rate riders shown in Table 1 below.

Table 1: Proposed Regulatory Asset Recovery Rate Riders – South Rate Zone

Class	*Charge (Credit)*	*Per*
Residential	$ 0.0006	kWh
GS < 50 kW	$ (0.0006)	kWh
GS > 50 kW	$ (0.3248)	kW
Large Users	$ (0.1066)	kW
Unmetered Scattered Load	$ (0.0016)	kWh
Sentinel Lighting	$ (0.5298)	kW
Street Lighting	$ (0.4051)	kW

PowerStream proposes to recover a balance of $12.7 million in account 1588 RSVA Power – Global Adjustment in the South rate zone, from non-RPP customers only, over a period of two years, from January 1, 2013 to December 31, 2014 by means of a charge of $0.0016 per kWh.

PowerStream proposes to recover a balance of $0.2 million from customers in the Barrie rate zone over a period of two years, from January 1, 2013 to December 31, 2014, by means of the customer class specific rate riders shown in Table 2 below.

Table 2: Proposed Regulatory Asset Recovery Rate Riders – Barrie Rate Zone

Class	*Charge (Credit)*	*Per*
Residential	$ 0.0014	kWh
GS < 50 kW	$ (0.0003)	kWh
GS > 50 kW	$ (0.3387)	kW
Large Users	$ -	kW
Unmetered Scattered Load	$ (0.0009)	kWh
Sentinel Lighting	$ -	kW
Street Lighting	$ (0.2228)	kW

PowerStream proposes to recover a balance of $4.6 million in account 1588 RSVA Power – Global Adjustment in the Barrie rate zone, from non-RPP customers only, over a period of two years, from January 1, 2013 to December 31, 2014 by means of a charge of $0.0029 per kWh.

PowerStream proposes to refund a balance of $9.8 million to customers in both rate zones over a period of two years, from January 1, 2013 to December 31, 2014, by means of the customer class specific rate riders shown in Table 3 below.

Table 3: Proposed Regulatory Asset Recovery Rate Riders – Both Rate Zones

Class	***Charge (Credit)***	***Per***
Residential	$ (0.0006)	kWh
GS < 50 kW	$ (0.0006)	kWh
GS > 50 kW	$ (0.2148)	kW
Large Users	$ (0.0829)	kW
Unmetered Scattered Load	$ (0.0006)	kWh
Sentinel Lighting	$ (0.2135)	kW
Street Lighting	$ (0.2320)	kW

PowerStream proposes to recover a balance of $1.2 million in account 1588 RSVA Power – Global Adjustment, from non-RPP customers only, in both rate zones over a period of two years, from January 1, 2013 to December 31, 2014 by means of a charge of $0.0001 per kWh.

STATUS OF DEFERRAL AND VARIANCE ACCOUNTS

The balances of PowerStream's deferral and variance ("D&V") accounts at December 31, 2011 are summarized in Table 1 below.

Table 1: Deferral and Variance Accounts at December 31, 2011 ($000)

Description	Amount
Retail Settlement Variance Accounts	$ (3,400)
Smart Meter costs	$ 13,030
PILs Variances (Accounts 1562 and 1592)	$ (5,521)
Regulatory Asset recoveries/ repayments	$ 292
IFRS Transitional Cost Variance	$ (62)
Renewable Energy Enabling Deferral	$ 671
Smart Grid Deferral	$ 949
Other Regulatory Liabilities	$ (322)
Other Variance and Deferral Accounts	$ 35
Total for disposition	**$ 5,671**

Positive or debit amounts are assets and represent amounts to be recovered from customers. Negative or credit amounts, shown in parenthesis "()", are liabilities and represent amounts to be refunded to customers. Each of these D&V balances are described below, following the reconciliation to the December 31, 2011 audited financial statements.

These amounts have been entered into the OEB Deferral and Variance Account Work Form - Continuity Schedule ("Continuity Schedule"). There are three schedules, one for each rate zone (South, Barrie) and one for balances that pertain to both rate zones.

Table 2 summarizes the total balances at December 31, 2011 for disposition and reconciles this with the three Continuity Schedules and to the December 31, 2011 2.1.7 RRR trial balance filing. As can be seen there are a few small differences between the details schedules and the RRR amount. These very small and in total are less than $500.

Table 2: Reconciliation of Continuity Schedules to 2.1.7 RRR Filing

Account Descriptions	Account Number	Barrie	South	Shard	Total	2.1.7 RRR
		Total Claim	Total Claim	Total Claim		As of Dec-31-11
LV Variance Account	1550	(154,314)	(514,439)	(37,328)	(706,081)	(706,080)
RSVA - Wholesale Market Service Charge	1580	(273,551)	(5,113,437)	(17,227,313)	(22,614,301)	(22,614,301)
RSVA - Retail Transmission Network Charge	1584	291,995	(3,006,921)	5,271,815	2,556,888	2,556,889
RSVA - Retail Transmission Connection Charge	1586	(106,584)	(2,977,347)	(300,905)	(3,384,836)	(3,384,838)
RSVA - Power (excluding Global Adjustment)	1588	(3,142,798)	2,868,224	2,776,930	20,697,522	20,697,611
RSVA - Power - Sub-account - Global Adjustment	1588	4,542,172	12,482,601	1,170,392		
Recovery of Regulatory Asset Balances	1590	(28)	6,569	(4,360)	2,181	2,180
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	0	0	0	289,442	289,777
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	416,743	(22,779,083)	0		
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	(409,702)	23,061,484	0		
Disposition and Recovery of Regulatory Balances[7]	1595	0	0	0		
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		**1,163,933**	**4,027,650**	**(8,350,768)**	**(3,159,185)**	**(3,158,761)**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	0	(2,671)	2,576	5,077	5,078
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	0	(6,649)	6,558		
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	427,648	(489,693)	0		
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0	0	67,307		
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	0	0	0		
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0	0	0		
Other Regulatory Assets - Sub-Account - Other [4]	1508	0	0	0		
Retail Cost Variance Account - Retail	1518	59,587	14,723	(63,658)	10,651	10,651
Misc. Deferred Debits	1525	0	0	0	0	0
Renewable Generation Connection Capital Deferral Account	1531	0	0	527,538	527,538	527,538
Renewable Generation Connection OM&A Deferral Account	1532	0	0	143,129	143,129	143,129
Renewable Generation Connection Funding Adder Deferral Account	1533	0	0	0	0	
Smart Grid Capital Deferral Account	1534	0	0	493,319	493,319	493,319
Smart Grid OM&A Deferral Account	1535	0	0	455,182	455,182	455,182
Smart Grid Funding Adder Deferral Account	1536	0	0	0	0	
Retail Cost Variance Account - STR	1548	(27,087)	0	(1,927)	(29,014)	(29,014)

Board-Approved CDM Variance Account	1567	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0	0	0	0	0
RSVA - One-time	1582	97,560	(170)	(46,277)	51,113	51,113
Other Deferred Credits	2425	0	9,312	(331,569)	(322,257)	(322,256)
Group 2 Sub-Total		**557,708**	**(475,149)**	**1,252,178**	**1,334,738**	**1,334,739**
Deferred Payments in Lieu of Taxes	1562	(562,943)	(4,028,681)	0	(4,591,624)	(4,591,624)
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	(61,394)	(711,953)	(156,346)		
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0	0	(636,840)	(929,693)	(929,679)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	0	0	636,840		
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		1,097,305	(1,188,133)	(7,254,936)	(7,345,764)	(7,345,326)
Special Purpose Charge Assessment Variance Account[9] (Entered manually - Model error)	1521	0	0	(13,976)	(13,976)	(13,976)
Total including Account 1521		**1,097,305**	**(1,188,133)**	**(7,268,912)**	**(7,359,740)**	**(7,359,302)**
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	0	0	0		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	0	0	0	12,788,784	12,788,784
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	3,045,590	9,743,194	0		
Smart Meter OM&A Variance[11]	1556	152,168	88,639	0	240,807	240,807
The following is not included in the total claim but are included on a memo basis:						
Deferred PILs Contra Account [5]	1563	0	0	0	0	0
IFRS-CGAAP Transition PP&E Amounts[10]	1575	0	0	0	0	0

Grand Total		4,295,063	8,643,700	(7,268,912)	5,669,851	5,670,289

Several adjustments to the December 31, 2011 balances as listed above were necessary to arrive at the appropriate balances for disposition at this time.

Table 3 summarizes the actual amounts proposed for disposition.

Table 3: Summary of Disposition Amounts

	South	Barrie	Shared	Total
Claim before GA	$ (5,278,816)	$ 182,345	$ (9,798,429)	$(14,894,900)
Global Adjustment (GA)	$ 12,657,774	$ 4,607,383	$ 1,188,351	$ 18,453,508
Total	**$ 7,378,958**	**$ 4,789,728**	**$ (8,610,078)**	**$ 3,558,608**

The actual net claim for recovery of $3.6 million, per Table 3, is lower by $2.1 million than the actual balances of the accounts for disposition of $5.7 million, per Table 1 and 2. This is due to a number of adjustments, as shown in table 4.

Table 4: Summary of Adjustments – Total Claim vs. December 31, 2011 Amounts

	South	Barrie	Shared	Total	Note
Principal - Dec 31/11	$ 10,114,662	$ 4,475,784	$ (7,182,078)	$ 7,408,368	1
Interest - Dec 31/11	$ (1,470,962)	$ (180,721)	$ (86,835)	$ (1,738,518)	1
Balance - Dec 31/11	**$ 8,643,700**	**$ 4,295,063**	**$ (7,268,913)**	**$ 5,669,850**	1
Adjustments					
Interest Jan 1-Dec 31/12	$ 5,476	$ 31,713	$ (120,442)	$ (83,253)	2
1521 SPC	$ -	$ -	$ 13,976	$ 13,976	
1555 Stranded meters	$ (988,860)	$ (251,140)	$ -	$ (1,240,000)	3
1508 IFRS 2012 forecast	$ (281,358)	$ 131,150	$ -	$ (150,208)	4
1562 PILs	$ -	$ 562,944	$ -	$ 562,944	5
2425 HST/OVAT 2012			$ (213,842)	$ (213,842)	6
1531/1534 GEA Capital	$ -	$ -	$ (1,020,857)	$ (1,020,857)	7
Total claim	**$ 7,378,958**	**$ 4,769,730**	**$ (8,610,078)**	**$ 3,538,610**	

Notes:

1. Totals from Continuity Schedules as at December 31, 2011, agreed to 2.1.7 RRR filing.
2. Add interest for January 1, 2012 to December 31, 2012 based on January 1, 2013 date for rate riders.
3. Record 2012 “depreciation” on stranded meters.
4. Add forecast of 2012 IFRS expenses and amount collected b.
5. Remove Barrie 1562 PILs approved in 2012 IRM, refunded by rate riders from May 1/12 to Apr 30/13.
6. .Add an additional year of HST/PST savings in 2012, prior to rebasing.
7. Remove GEA capital as this is included in rate base.

Reconciliation to Financial Statements:

Table 5 reconciles the amount in Table 1 with the amount shown in the Canadian Generally Accepted Accounting Principles ("CGAAP") audited financial statements at December 31, 2011.

Table 5: Reconciliation of Disposition Amounts to Financial Statements ($000)

Description	Amount
Total for disposition above	$ 5,670
Future Income Taxes	$ (49,533)
Provision for regulatory assets and liabilities	$ (792)
Total regulatory assets and liabilities	**$ (44,655)**
Per Financial Statements:	
Regulatory Assets	$ 14,591
Regulatory Liabilities	$ (59,246)
Net total per financials	**$ (44,655)**

The regulatory asset and liability amounts in the financial statements contain amounts for financial statement purposes that are not part of the OEB EDDVAR balances. The difference is made up mainly of the liability for Future Income Taxes. This is an offset to the Future Income Tax asset that is recorded, rather than an adjustment to the income tax expense insofar as it relates to the distribution business. This reflects the fact that distribution rates are set based on taxes payable and the future tax benefits will translate into lower distribution rates when realized, rather than a benefit to the utility.

PowerStream has tracked the balance of D&V accounts separately for each rate zone where necessary due to the different circumstances of each zone. There are some accounts where this separation was not possible or necessary. Tracking by rate zone is discussed further below under the individual deferral and variance accounts.

.As a consequence, there are three continuity schedules, one for PowerStream South, another for PowerStream Barrie, and one for the combined balances, "PowerStream – Shared". The "Shared" balances are allocated to all customers. These continuity schedules are included as Exhibit I, Tab 1, Schedule 5, 6 and 7.

Retail Settlement Variance Accounts ("RSVA"):

This amount consists of accounts: 1550 Low Voltage, 1580 RSVA Wholesale Market Services, 1582 RSVA Wholesale Market Services – One Time Charges, 1584 RSVA Retail Transmission Network, 1586 RSVA Retail Transmission Connection, and 1580 RSVA Power. RSVA power related to Global Adjustment is tracked separately within account 1588. These accounts are discussed further below.

- Low Voltage or “LV” is the difference between the amounts included in rates and billed to customers and the cost to PowerStream of Hydro One's charges for using its LV lines to transmit electricity from its transformer stations to PowerStream’s distribution system.

- “RSVA - Wholesale Market Service Charge” is the difference between the cost to PowerStream of the IESO's charges for operating the IESO-administered markets and the IESO-controlled grid – Wholesale Market Services ("WMS") – and the amounts that Power Stream billed to customers. Customers have been billed the Board-approved WMS. In recent years the costs charged by the IESO have been lower resulting in a liability.

- “RSVA - One-time Wholesale Market Service” is the difference between the amount of the IESO's charges that are not already incorporated in the WMS rate, as specified by the Board, and the amount that PowerStream billed to customers for the same services using the Board-approved WMS rate. As there has been no Board-approved billing for the one-time WMS, this asset represents the amount of one-time WMS charges from the IESO.

- “RSVA - Retail Transmission Network Charge” is the difference between the amount of the wholesale charges for transmission network services and the amount that PowerStream billed to customers using the network service component of its Board-approved rates for retail transmission service (“RTS”).

- “RSVA - Retail Transmission Connection Charge” is the difference between the wholesale charges for transmission connection services and the amount that PowerStream billed to customers using the connection service component of its Board-approved RTS rates.

- "RSVA - Power (excluding Global Adjustment)" is the difference between the amount that that PowerStream billed to customers for electricity and the amount that the IESO billed to PowerStream for electricity excluding from the latter, for this purpose, the amount of the Global Adjustment.

- "RSVA - Power (Global Adjustment)" is the difference between the amount that that PowerStream billed to customers for the Global Adjustment, at the rates prescribed by the OEB, and the amount that the IESO billed to PowerStream for Global Adjustment.

As of January 1, 2010, PowerStream was receiving a single IESO invoice and no longer separated the Retail Settlement Variances ("RSVA") between rate zones. As a result the RSVA account balances are tracked separately by rate zone until December 31, 2009, and on a combined basis thereafter.

Smart Meter Costs (accounts 1555 and 1556):

This amount consists mainly of the net book value of stranded meters, less proceeds received on disposition. Stranded meters are the conventional meters that were retired prematurely as a result of the requirement to replace them with a smart meter. There is also a much smaller amount of costs related to customer premise costs to allow installation of a smart meter after the April 30, 2011 cutoff used in PowerStream's final smart meter cost recovery application (EB-2011-0128). These amounts are tracked separately by rate zone.

See Exhibit I, Tab 1, Schedule 8 for more details regarding the remaining costs related to smart meter implementation for which PowerStream is seeking disposition

PILs Variances (accounts 1562 and 1592):

This amount consists mainly of the account 1562 Deferred PILs liability for the South related to differences between tax rates used to set rates and actual tax rates for the 2001 to 2005 rate years. The account 1592 liability relates to both rate zones and contains the amount of Federal Large Corporations Tax ("LCT") that remained in rates until the 2007 rate year after the removal of LCT in 2006. These amounts are tracked separately by rate zone.

See Exhibit I, Tab 1, Schedule 9 for more details regarding the balance in account 1562 for which PowerStream is seeking disposition for the South rate zone. PowerStream sought and obtained approval for disposition of the 1562 balance for the Barrie rate zone as part of its 2012 IRM rate application (EB-2011-0005).

Regulatory Asset Recoveries/ Repayments (accounts 1590 and 1595):

This amount is the net difference between the amounts that PowerStream has charged or credited to customers by means of its Board-approved rate riders for the recovery of regulatory assets and the Board-approved amounts transferred to the recovery accounts. These amounts are tracked separately by rate zone. To date there has been no recovery of combined D&V amounts, other than account 1521 for the Special Purpose Charge ("SPC") which is discussed below under "Other Variance and Deferral Accounts".

IFRS Transitional Cost Variance (account 1508 sub-account):

This amount represents the difference between the one-time non-capital costs, to switch to International Financial Reporting Standards ("IFRS") financial accounting and reporting, and the amounts collected in rates. An amount of $2.98 million was submitted in PowerStream South's 2009 COS application to be collected at the rate of $745,000. This amount was included in the approved 2009 revenue requirement and has been recorded in this sub-account as an offset to the costs incurred.

These costs are common to both rate zones and cannot be specifically identified with a rate zone. For purposes of disposition, PowerStream has allocated the costs between rate zones based on the number of customers in each rate zone. The amounts recovered are all from the South rate zone and have been allocated accordingly.

See Exhibit I, Tab 1, Schedule 10 for more details on the IFRS transitional costs, revenue collected and allocation to rate zones.

Renewal Energy Enabling Deferral (accounts 1531 and 1532):

See Exhibit I, Tab 1, Schedule 11 for more details on the proposed disposition of the Green Energy Act Deferral accounts and the requested funding adder. This amount is not tracked separately by rate zone.

Smart Grid Deferral (accounts 1534 and 1535):

See Exhibit I, Tab 1, Schedule 11 for more details on the proposed disposition of the Green Energy Act Deferral accounts and the requested funding adder. This amount is not tracked separately by rate zone.

Other Regulatory Liabilities (account 2425):

This amount consists mainly of the 50% of savings attributed to the replacement of Provincial Sales Tax ("PST") by the Harmonized Sales Tax ("HST") effective July 1, 2010. This amount is not tracked separately by rate zone.

See Exhibit I, Tab 1, Schedule 12 for further discussion on determination of the amounts recorded in account 1592 PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits ("ITCs") and the 50% to be refunded to rate payers that PowerStream has recorded in account 2425.

Other Variance and Deferral Accounts:

A summary of "Other variance and deferral accounts" at December 31, 2011 is shown in Table 6 below.

Table 6: Other Variance and Deferral Accounts at December 31, 2011:

Account	Amount
1508 Other Regulatory Assets (excluding IFRS sub-accounts)	$ 67,122
1518 RCVA $_{Retail}$	$ 10,661
1521 Special Purpose Charge (SPC) Assessment Variance Account	$ (14,007)
1548 RCVA $_{STR}$	$ (29,014)
Total	**$ 34,762**

The balance in account 1508 consists of regulatory rate rider charges from Hydro One and accrued interest.

The balance in account 1521 is a small variance between the special purpose charge assessment paid and the amount billed to customers. The Special Purpose Charge variance amount of $14,007 credit was approved for disposition in PowerStream's 2012 IRM rate application. Due to the small balance, which resulted in $0.0000 rate riders for some classes, no disposition rate riders were approved. The Board directed the amount to be transferred to account 1595, for inclusion in calculating future disposition rate riders. As approval occurred in 2012, this does not appear in the account 1595 balance as at December 31, 2011. For purposes of this disposition, the balance will be ignored due to the size of the amount and the fact that unlike the existing balance of account 1595, this amount is not separated by rate zone. As a practical matter it should be cleared as part of the combined balances in the future.

There is a small variance in the retail cost variance accounts (1518 and 1548) that has developed over several years between costs to service retailers and charges to retailers. No change is proposed to retail service charges.

Summary of V&D Dispositions

The status of D&V account disposition for each rate zone is discussed below.

PowerStream Barrie

In its 2008 Cost of Service ("COS") application, Barrie Hydro sought approval to dispose of its D&V account balances as at December 31, 2006. The Board approved disposition of accounts 1508 and 1550 only, over a period of three years, from May 1, 2008 to April 30, 2011. The Board deferred approval of most D&V accounts pending the outcome of the Board's Deferral and Variance Account initiative which resulted in the EDDVAR report in 2009. Similarly, disposition of account 1562 Deferred PILs was not approved as the Board determined that this should be dealt with in separate combined proceeding.

In its 2010 IRM application, PowerStream – Barrie received approval to dispose of Group 1 account balances as of December 31, 2008.

In the Combined Proceeding on Account 1562 Deferred PILs (EB-2011-0381), the Board selected Barrie Hydro as one of the three applicants. In 2011, the Board approved the amount in account 1562 to be disposed and directed PowerStream Barrie to include this in its 2012 IRM rate application (EB-2011-0005) where disposition over one year, May 1, 2012 to April 30, 2013 was approved.

PowerStream applied in 2011 and obtained approval to recover the costs of smart meters installed in the Barrie rate zone up to April 30, 2011. The cost of stranded meters was not considered for disposition at this time. PowerStream proposed that the cost of stranded meters be dealt with at the next COS filing and the Board accepted this proposal. PowerStream was directed to track in account 1556 the actual costs related to customer premises to remedy situations where there were issues preventing installation of a smart meter.

PowerStream South

In its 2009 COS application, PowerStream South obtained approval to clear most of the D&V account balances as at December 31, 2007, including recovery of smart meter costs. The PILs variance accounts 1562 and 1592 were not included.

In 2010, PowerStream filed a smart meter cost recovery application and received approval to recover the costs of smart meters installed in the South in 2008 and 2009.

In 2011, PowerStream applied and obtained approval to recover the costs of smart meters installed in the South rate zone in 2010 and up to April 30, 2011. The cost of stranded meters was not considered for disposition at this time. PowerStream proposed that cost of stranded meters be dealt with at the next COS filing and the Board accepted this proposal. PowerStream was directed to track in account 1556 the actual costs related to customer premises to remedy situations where there were issues preventing installation of a smart meter.

PowerStream Combined:

Both the separate and combined Group 1 balances were considered in PowerStream’s 2012 IRM application. The total fell below the threshold amount and there was no disposition. Only accounts 1521 (discussed above under “Other variance and deferral accounts) and 1562 (Barrie - discussed above under PILs variances) were approved

RATE RIDER CALCULATION

PowerStream has followed the same methodology it used in its 2009 EDR Application to calculate rate riders, as follows:

- The amount to be recovered or refunded is based on the most recent audited year-end balances (i.e., December 31, 2011), plus
- Interest on this amount is accrued up to the effective date of the proposed rate riders (i.e., January 1, 2013), and
- Adjustments were made to some balances as explained in Exhibit I, Tab 1, Schedule 2 to arrive at the appropriate balances for disposition

Due to the magnitude of the amount to be recovered, PowerStream is proposing a two-year refund period to minimize changes in rates from year to year. Rate riders are calculated as volumetric charges.

For the Global Adjustment rate rider this has been calculated as a charge per kWh for all classes, based on non-RPP kWhs and to be charged only to non-RPP customers.

PowerStream adapted the OEB model used in PowerStream's 2009 Cost of Service application to allocate the disposition amounts to rate classes and calculate the rate riders. There are three models included in this schedule:

- PowerStream South rate zone
- PowerStream Barrie rate zone
- Shared balances for both rate zones

For each one of these schedules, there is a corresponding OEB Continuity Schedule with details of the December 31, 2011 amounts. These are included as Exhibit I, Tab 1, Schedules 5 to 7.

Each model consists of 5 sheets:

- Sheet 1 shows the claim amount by account, allocators used, allocation to classes and calculation of rate riders using 2013 billing determinants.
- Sheet 2 shows the balances from the continuity schedules, adjustments to remove any amounts not to be included in this disposition then further adjustments as explained in Exhibit I, Tab 1, Schedule 2.
- Sheet 3 calculates interest on the principal balances as at December 31, 2011 from January 1, 2012 to December 31, 2012, based on an effective date of January 1, 2013 for the disposition rate riders.
- Sheet 4 shows the details for the allocators used to allocate amounts to rate classes.
- Sheet 5 shows the Global Adjustment amount for recovery, the non-RPP kWhs allocation to rate classes and the calculation of the per non-RPP kWh rate rider.

Sheet 1 - Rate Riders Calculation

Name of Distributor:	**PowerStream Inc. - South**	**Licence Number**	**ED-2004-0520**
Contact Name:	Tom Barrett, Manager, Rate Applications	**Case Number**	EB-2012-0161
Contact e-mail	Tom.Barrett@PowerStream.ca	**Date Filed**	May 4, 2012
Phone #:	905-532-4640		

Regulatory Asset Accounts:	**Amount**	**ALLOCATOR**	**Residential**	**GS < 50 KW**	**GS > 50**	**Large Users**	**Unmetered Scattered Load**	**Sentinel Lighting**	**Street Lighting**	**Total**	Check
LV - Account 1550	$ (521,788)	kWh	$ (164,443)	$ (62,938)	$ (288,033)	$ (2,056)	$ (718)	$ (33)	$ (3,569)	$ (521,788)	-
WMSC - Account 1580	$ (5,185,293)	kWh	$ (1,634,156)	$ (625,447)	$ (2,862,340)	$ (20,430)	$ (7,132)	$ (323)	$ (35,464)	$ (5,185,293)	-
Network - Account 1584	$ (3,048,228)	kWh	$ (960,656)	$ (367,675)	$ (1,682,656)	$ (12,010)	$ (4,193)	$ (190)	$ (20,848)	$ (3,048,228)	-
Connection - Account 1586	$ (3,018,929)	kWh	$ (951,422)	$ (364,141)	$ (1,666,483)	$ (11,894)	$ (4,152)	$ (188)	$ (20,648)	$ (3,018,929)	-
Power - Account 1588 (excluding GA)	$ 2,904,508	kWh	$ 915,362	$ 350,340	$ 1,603,321	$ 11,444	$ 3,995	$ 181	$ 19,865	$ 2,904,508	-
Subtotal - RSVA excl. GA	**$ (8,869,730)**		**$ (2,795,314)**	**$ (1,069,861)**	**$ (4,896,191)**	**$ (34,946)**	**$ (12,200)**	**$ (553)**	**$ (60,663)**	**$ (8,869,730)**	
Non-RSVA Accounts:											
Other Regulatory Assets - Account 1508	$ (787,571)	kWh	$ (248,205)	$ (94,996)	$ (434,748)	$ (3,103)	$ (1,083)	$ (49)	$ (5,386)	$ (787,571)	-
Retail Cost Variance Account - Acct 1518	$ 14,905	# of Customers	$ 10,549	$ 1,112	$ 173	$ 0	$ 97	$ 5	$ 2,968	$ 14,905	-
Misc. Deferred Debits Acct 1525	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Renewable Generation Connection Capital Deferral Account Acct 1531	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Renewable Generation Connection OM&A Deferral Account Acct 1532	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Renewable Generation Connection Funding Adder Deferral Account Acct 1533	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Smart Grid Capital Deferral Account Acct 1534	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Smart Grid OM&A Deferral Account Acct 1535	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Smart Grid Funding Adder Deferral Account Acct 1536	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Retail Cost Variance Account - STR Acct 1548	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Board-Approved CDM Variance Account Acct 1567	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Extra-Ordinary Event Costs Acct 1572	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Deferred Rate Impact Amounts Acct 1574	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
RSVA - One-time Acct 1582	$ (170)	kWh	$ (54)	$ (21)	$ (94)	$ (1)	$ (0)	$ (0)	$ (1)	$ (170)	-
Other Deferred Credits Acct 2425	$ 9,312	kWh	$ 2,935	$ 1,123	$ 5,140	$ 37	$ 13	$ 1	$ 64	$ 9,312	-
Subtotal - Non RSVA	**$ (763,525)**		**$ (234,775)**	**$ (92,782)**	**$ (429,529)**	**$ (3,067)**	**$ (974)**	**$ (43)**	**$ (2,356)**	**$ (763,525)**	
Deferred Payments in Lieu of Taxes Acct 1562	$ (4,084,566)	Dist. Revenue	$ (2,042,708)	$ (605,682)	$ (1,372,791)	$ (4,022)	$ (15,083)	$ (687)	$ (43,593)	$ (4,084,566)	-
PILs and Tax Variance for 2006 and Subsequent Years Acct 1592	$ (721,298)	Dist. Revenue	$ (360,724)	$ (106,958)	$ (242,423)	$ (710)	$ (2,664)	$ (121)	$ (7,698)	$ (721,298)	-
Smart Meter Capital and Recovery Offset Variance Acct 1555	$ 8,754,334	Metered Customers	$ 7,803,817	$ 822,703	$ 127,781	$ 34	$ -	$ -	$ -	$ 8,754,334	-
Smart Meter OM&A Variance Acct 1556	$ 89,946	Metered Customers	$ 80,180	$ 8,453	$ 1,313	$ 0	$ -	$ -	$ -	$ 89,946	-
	$ 4,038,416		**$ 5,480,565**	**$ 118,515**	**$ (1,486,120)**	**$ (4,698)**	**$ (17,747)**	**$ (808)**	**$ (51,291)**	**$ 4,038,416**	-
Subt-total before Recoveries	**$ (5,594,839)**		**$ 2,450,476**	**$ (1,044,127)**	**$ (6,811,841)**	**$ (42,711)**	**$ (30,921)**	**$ (1,405)**	**$ (114,310)**	**$ (5,594,839)**	-
Recoveries Amounts											
Recoveries - Acct 1590	$ 6,617	Prev. Allocation	$ 1,831	$ 737	$ 3,947	$ 56	$ 4	$ 2	$ 41	$ 6,617	-
Recoveries - Acct 1595	$ 309,406	Prev. Allocation	$ 85,607	$ 34,450	$ 184,561	$ 2,599	$ 185	$ 89	$ 1,915	$ 309,406	-
Sub-total Recoveries Amounts	**$ 316,023**		$ 87,438	$ 35,187	$ 188,508	$ 2,654	$ 189	$ 91	$ 1,956	$ 316,023	-
Total to be Recovered (Refunded)	**$ (5,278,816)**		**$ 2,537,914**	**$ (1,008,940)**	**$ (6,623,332)**	**$ (40,057)**	**$ (30,732)**	**$ (1,314)**	**$ (112,354)**	**$ (5,278,816)**	
Number of years to be collected or refunded:	**2**										
Balance to be collected or refunded per year	$ (2,639,408)		$ 1,268,957	$ (504,470)	$ (3,311,666)	$ (20,028)	$ (15,366)	$ (657)	$ (56,177)	$ (2,639,408)	

Class	**Residential**	**GS < 50 KW**	**GS > 50**	**Large Users**	**Scattered Load**	**Sentinel Lighting**	**Street Lighting**
Billing Determinants	kWh	kWh	kW	kW	kWh	kW	kW
Billing Determinants - quantity (**2013 Test Year**)	**2,156,279,348**	**840,157,445**	**10,195,076**	**187,932**	**9,699,018**	**1,240**	**138,665**
Regulatory Asset Rate Riders	$ 0.0006	$ (0.0006)	$ (0.3248)	$ (0.1066)	$ (0.0016)	$ (0.5298)	$ (0.4051)

Notes:

1. See Sheet 5 for 1588 Global Adjustment Allocation and Rate Rider.

Sheet 2 - December 31, 2011 Regulatory Assets

Name of Distributor: **PowerStream Inc. - South**

Licence Number ED-2004-0520
Case Number EB-2012-0161
Date Filed May 4, 2012

Account Description	Account Number	Principal Amounts as of Dec-31 2011	Adjustment	Revised Principal Amounts as of Dec-31 2011	Interest to Dec31 2011	Adjustment	Revised Interest to Dec31 2011	Interest Jan1-12 to Dec 31-12	Adjustment	Total Claim
LV Variance Account	1550	$ (498,528)		$ (498,528)	$ (15,911)		$ (15,911)	$ (7,348)		$ (521,788)
RSVA - Wholesale Market Service Charge	1580	$ (4,874,780)		$ (4,874,780)	$ (238,657)		$ (238,657)	$ (71,856)		$ (5,185,293)
RSVA - Retail Transmission Network Charge	1584	$ (2,802,278)		$ (2,802,278)	$ (204,643)		$ (204,643)	$ (41,306)		$ (3,048,228)
RSVA - Retail Transmission Connection Charge	1586	$ (2,820,954)		$ (2,820,954)	$ (156,393)		$ (156,393)	$ (41,582)		$ (3,018,929)
RSVA - Power (excluding Global Adjustment)	1588	$ 2,461,511		$ 2,461,511	$ 406,713		$ 406,713	$ 36,283		$ 2,904,508
RSVA - Power - Sub-account - Global Adjustment	1588	$ 11,883,945		$ 11,883,945	$ 598,656		$ 598,656	$ 175,173		$ 12,657,774
Recovery of Regulatory Asset Balances	1590	$ 3,257		$ 3,257	$ 3,312		$ 3,312	$ 48		$ 6,617
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	$ -		$ -	$ -		$ -	$ -		$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	$ (21,314,022)		$ (21,314,022)	$ (1,465,061)		$ (1,465,061)	$ (314,175)		$ (23,093,257)
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	$ 23,146,078		$ 23,146,078	$ (84,594)		$ (84,594)	$ 341,180		$ 23,402,664
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		**$ 5,184,229**	**$ -**	**$ 5,184,229**	**$ (1,156,579)**	**$ -**	**$ (1,156,579)**	**$ 76,417**	**$ -**	**$ 4,104,067**
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		**$ (6,699,716)**	**$ -**	**$ (6,699,716)**	**$ (1,755,235)**	**$ -**	**$ (1,755,235)**	**$ (98,756)**	**$ -**	**$ (8,553,706)**
Non-RSVA										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -		$ -	$ (2,671)		$ (2,671)	$ -		$ (2,671)
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -		$ -	$ (6,649)		$ (6,649)	$ -		$ (6,649)
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ (488,477)		$ (488,477)	$ (1,216)		$ (1,216)	$ (7,200)	$ (281,358)	$ (778,252)
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -		$ -	$ -		$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	$ -		$ -	$ -		$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -		$ -	$ -		$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other	1508	$ -		$ -	$ -		$ -	$ -		$ -
Retail Cost Variance Account - Retail	1518	$ 12,361		$ 12,361	$ 2,362		$ 2,362	$ 182		$ 14,905
Misc. Deferred Debits	1525	$ -		$ -	$ -		$ -	$ -		$ -
Renewable Generation Connection Capital Deferral Account	1531	$ -		$ -	$ -		$ -	$ -		$ -
Renewable Generation Connection OM&A Deferral Account	1532	$ -		$ -	$ -		$ -	$ -		$ -
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -		$ -	$ -		$ -	$ -		$ -
Smart Grid Capital Deferral Account	1534	$ -		$ -	$ -		$ -	$ -		$ -
Smart Grid OM&A Deferral Account	1535	$ -		$ -	$ -		$ -	$ -		$ -
Smart Grid Funding Adder Deferral Account	1536	$ -		$ -	$ -		$ -	$ -		$ -
Retail Cost Variance Account - STR	1548	$ -		$ -	$ -		$ -	$ -		$ -
Board-Approved CDM Variance Account	1567	$ -		$ -	$ -		$ -	$ -		$ -
Extra-Ordinary Event Costs	1572	$ -		$ -	$ -		$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -		$ -	$ -		$ -	$ -		$ -
RSVA - One-time	1582	$ (0)		$ (0)	$ (170)		$ (170)	$ -		$ (170)
Other Deferred Credits	2425	$ (0)		$ (0)	$ 9,312		$ 9,312	$ -		$ 9,312
Sub-Totals		**$ (476,117)**	**$ -**	**$ (476,117)**	**$ 969**	**$ -**	**$ 969**	**$ (7,018)**	**$ (281,358)**	**$ (763,525)**
Deferred Payments in Lieu of Taxes	1562	$ (3,791,314)		$ (3,791,314)	$ (237,367)		$ (237,367)	$ (55,885)		$ (4,084,566)
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ (633,969)		$ (633,969)	$ (77,984)		$ (77,984)	$ (9,345)		$ (721,298)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -		$ -	$ -		$ -	$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -		$ -	$ -		$ -	$ -		$ -
Sub-Totals		**$ (4,425,283)**	**$ -**	**$ (4,425,283)**	**$ (315,351)**	**$ -**	**$ (315,351)**	**$ (65,230)**	**$ -**	**$ (4,805,864)**
Total for Group 1 , group 2 and accounts 1562 ,1592		**$ 282,829**	**$ -**	**$ 282,829**	**$ (1,470,962)**	**$ -**	**$ (1,470,962)**	**$ 4,169**	**$ (281,358)**	**$ (1,465,322)**
Special Purpose Charge Assessment Variance Account	**1521**						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital11	**1555**	$ -		$ -	$ -		$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries11	**1555**	$ -		$ -	$ -		$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs11	**1555**	$ 9,743,194		$ 9,743,194	$ -		$ -	$ -	**$ (988,860)**	$ 8,754,334
Smart Meter OM&A Variance11	**1556**	$ 88,639		$ 88,639	$ -		$ -	$ 1,307		$ 89,946
Sub-Totals - Smart Meters		**$ 9,831,833**	**$ -**	**$ 9,831,833**	**$ -**	**$ -**	**$ -**	**$ 1,307**	**$ (988,860)**	**$ 8,844,280**
Total		**$ 10,114,662**	**$ -**	**$ 10,114,662**	**$ (1,470,962)**	**$ -**	**$ (1,470,962)**	**$ 5,476**	**$ (1,270,218)**	**$ 7,378,958**

SHEET 3 - Interest on Reg. Assets Balance as of Dec. 31, 2011

PowerStream Inc. - South
EB-2012-0161

	Balance as of Dec. 31, 2011	Interest Jan 2012 to Dec 2012
1550 LV Variance Account	$ (498,528)	$ (7,348)
1580 RSVA - Wholesale Market Service Charge	$ (4,874,780)	$ (71,856)
1584 RSVA - Retail Transmission Network Charge	$ (2,802,278)	$ (41,306)
1586 RSVA - Retail Transmission Connection Charge	$ (2,820,954)	$ (41,582)
1588 RSVA - Power (excluding Global Adjustment)	$ 2,461,511	$ 36,283
1588 RSVA - Power - Sub-account - Global Adjustment	$ 11,883,945	$ 175,173
1590 Recovery of Regulatory Asset Balances	$ 3,257	$ 48
1595 Disposition and Recovery/Refund of Regulatory Balances (2008)	$ -	$ -
1595 Disposition and Recovery/Refund of Regulatory Balances (2009)	$ (21,314,022)	$ (314,175)
1595 Disposition and Recovery/Refund of Regulatory Balances (2010)	$ 23,146,078	$ 341,180
1508 Other Regulatory Assets - Sub-Account - OEB Cost Assessments	$ -	$ -
1508 Other Regulatory Assets - Sub-Account - Pension Contributions	$ -	$ -
1508 Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	$ (488,477)	$ (7,200)
1508 Other Regulatory Assets - Sub-Account - Incremental Capital Charges	$ -	$ -
1508 Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	$ -	$ -
1508 Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	$ -	$ -
1508 Other Regulatory Assets - Sub-Account - Other	$ -	$ -
1518 Retail Cost Variance Account - Retail	$ 12,361	$ 182
1525 Misc. Deferred Debits	$ -	$ -
1531 Renewable Generation Connection Capital Deferral Account	$ -	$ -
1532 Renewable Generation Connection OM&A Deferral Account	$ -	$ -
1533 Renewable Generation Connection Funding Adder Deferral Account	$ -	$ -
1534 Smart Grid Capital Deferral Account	$ -	$ -
1535 Smart Grid OM&A Deferral Account	$ -	$ -
1536 Smart Grid Funding Adder Deferral Account	$ -	$ -
1548 Retail Cost Variance Account - STR	$ -	$ -
1567 Board-Approved CDM Variance Account	$ -	$ -
1572 Extra-Ordinary Event Costs	$ -	$ -
1574 Deferred Rate Impact Amounts	$ -	$ -
1582 RSVA - One-time	$ (0)	$ -
2425 Other Deferred Credits	$ (0)	$ -
1562 Deferred Payments in Lieu of Taxes	$ (3,791,314)	$ (55,885)
1592 PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	$ (633,969)	$ (9,345)
1592 PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	$ -	$ -
1592 PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	$ -	$ -
1521 Special Purpose Charge Assessment Variance Account	$ -	$ -
1555 Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital11	$ -	$ -
1555 Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries11	$ -	$ -
1555 Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs11	$ 9,743,194	$ -
1556 Smart Meter OM&A Variance11	$ 88,639	$ 1,307
	10,114,662	**$ 5,476**

SHEET 3 - Interest on Reg. Assets Balance as of Dec. 31, 2011

Interest Calculation

	Date	Jan 2012	Feb 2012	Mar 2012	Apr 2012	May 2012	Jun 2012	Jul 2012	Aug 2012	Sep 2012	Oct 2012	Nov 2012	Dec 2012	Total Interest
	days	31	29	31	30	31	30	31	31	30	31	30	31	
	interest	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	
1550	$ (498,528)	$ (622)	$ (582)	$ (622)	$ (602)	$ (622)	$ (602)	$ (622)	$ (622)	$ (602)	$ (622)	$ (602)	$ (622)	$ (7,348)
1580	$ (4,874,780)	$ (6,086)	$ (5,693)	$ (6,086)	$ (5,890)	$ (6,086)	$ (5,890)	$ (6,086)	$ (6,086)	$ (5,890)	$ (6,086)	$ (5,890)	$ (6,086)	$ (71,856)
1584	$ (2,802,278)	$ (3,499)	$ (3,273)	$ (3,499)	$ (3,386)	$ (3,499)	$ (3,386)	$ (3,499)	$ (3,499)	$ (3,386)	$ (3,499)	$ (3,386)	$ (3,499)	$ (41,306)
1586	$ (2,820,954)	$ (3,522)	$ (3,295)	$ (3,522)	$ (3,408)	$ (3,522)	$ (3,408)	$ (3,522)	$ (3,522)	$ (3,408)	$ (3,522)	$ (3,408)	$ (3,522)	$ (41,582)
1588	$ 2,461,511	$ 3,073	$ 2,875	$ 3,073	$ 2,974	$ 3,073	$ 2,974	$ 3,073	$ 3,073	$ 2,974	$ 3,073	$ 2,974	$ 3,073	$ 36,283
1588	$ 11,883,945	$ 14,837	$ 13,880	$ 14,837	$ 14,358	$ 14,837	$ 14,358	$ 14,837	$ 14,837	$ 14,358	$ 14,837	$ 14,358	$ 14,837	$ 175,173
1590	$ 3,257	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 48
1595	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1595	$ (21,314,022)	$ (26,610)	$ (24,894)	$ (26,610)	$ (25,752)	$ (26,610)	$ (25,752)	$ (26,610)	$ (26,610)	$ (25,752)	$ (26,610)	$ (25,752)	$ (26,610)	$ (314,175)
1595	$ 23,146,078	$ 28,898	$ 27,033	$ 28,898	$ 27,966	$ 28,898	$ 27,966	$ 28,898	$ 28,898	$ 27,966	$ 28,898	$ 27,966	$ 28,898	$ 341,180
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ (488,477)	$ (610)	$ (571)	$ (610)	$ (590)	$ (610)	$ (590)	$ (610)	$ (610)	$ (590)	$ (610)	$ (590)	$ (610)	$ (7,200)
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1518	$ 12,361	$ 15	$ 14	$ 15	$ 15	$ 15	$ 15	$ 15	$ 15	$ 15	$ 15	$ 15	$ 15	$ 182
1525	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1531	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1532	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1533	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1534	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1535	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1536	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1548	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1567	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1572	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1574	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1582	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2425	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1562	$ (3,791,314)	$ (4,733)	$ (4,428)	$ (4,733)	$ (4,581)	$ (4,733)	$ (4,581)	$ (4,733)	$ (4,733)	$ (4,581)	$ (4,733)	$ (4,581)	$ (4,733)	$ (55,885)
1592	$ (633,969)	$ (792)	$ (740)	$ (792)	$ (766)	$ (792)	$ (766)	$ (792)	$ (792)	$ (766)	$ (792)	$ (766)	$ (792)	$ (9,345)
1592	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1592	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1521	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1555	$ 9,743,194													$ -
1556	$ 88,639	$ 111	$ 104	$ 111	$ 107	$ 111	$ 107	$ 111	$ 111	$ 107	$ 111	$ 107	$ 111	$ 1,307
	$ 10,114,662													**$ 5,476**

Sheet 4 - Allocators PowerStream Inc. - South **EB-2012-0161**

2011 Data By Class	kW	kWhs	Cust. Num.'s	Dx Revenue (Last COS)	Non-RPP kWhs	Previous recoveries	Metered Customers
RESIDENTIAL CLASS		2,169,017,329	231,951	58,283,564	234,827,010	7,781,013	231,951
GENERAL SERVICE <50 KW CLASS		830,156,008	24,453	17,281,631	172,847,431	3,131,270	24,453
GENERAL SERVICE >50 KW NON TIME OF USE	10,146,413	3,799,187,396	3,798	39,169,171	3,580,103,689	16,775,113	3,798
GENERAL SERVICE >50 KW TIME OF USE			0			0	0
LARGE USER CLASS	80,298	27,116,405	1	114,752	82,754,178	236,189	1
UNMETERED SCATTERED LOADS	0	9,466,519	2,130	430,370	1,027,236	16,805	
SENTINEL LIGHTS	1,113	429,377	120	19,603	9,328,045	8,093	
STREET LIGHTING	131,120	47,071,564	65,268	1,243,816	71,218	174,025	
Totals	10,358,945	6,882,444,600	327,721	$ 116,542,907	4,080,958,807	28,122,508	260,203

Allocators	kW	kWhs	Cust. Num.'s	Dx Revenue (Last COS)	Non-RPP kWhs	Previous recoveries	Metered Customers
RESIDENTIAL CLASS	0.0%	31.5%	70.8%	50.0%	5.8%	27.7%	89.1%
GENERAL SERVICE <50 KW CLASS	0.0%	12.1%	7.5%	14.8%	4.2%	11.1%	9.4%
GENERAL SERVICE >50 KW NON TIME OF USE	97.9%	55.2%	1.2%	33.6%	87.7%	59.7%	1.5%
GENERAL SERVICE >50 KW TIME OF USE	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LARGE USER CLASS	0.8%	0.4%	0.0%	0.1%	2.0%	0.8%	0.0%
UNMETERED SCATTERED LOADS	0.0%	0.1%	0.6%	0.4%	0.0%	0.1%	0.0%
SENTINEL LIGHTS	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%
STREET LIGHTING	1.3%	0.7%	19.9%	1.1%	0.0%	0.6%	0.0%
Totals	100%	100%	100%	100%	100%	100%	100%

Sheet 5 **PowerStream Inc. - South** **EB-2012-0161**

RSVA - GLOBAL ADJUSTMENT ALLOCATION

Balance to allocate $ 12,657,774 Years 2

Customer Class	Allocator (Non-RPP kwh)	RSVA- GA Allocated	billing determinant	Rate Rider
Residential Class	5.75%	$ 728,355.09	234,827,010	$ 0.0016
General Service <50 Kw Class	4.24%	$ 536,115.10	172,847,431	$ 0.0016
General Service >50 Kw Non Time Of Use	87.73%	$ 11,104,287.99	3,580,103,689	$ 0.0016
General Service >50 Kw Time Of Use	0.00%	$ -	0	
Large User Class	2.03%	$ 256,675.87	82,754,178	$ 0.0016
Unmetered Scattered Loads	0.03%	$ 3,186.14	1,027,236	$ 0.0016
Sentinel Lights	0.23%	$ 28,932.48	9,328,045	$ 0.0016
Street Lighting	0.00%	$ 220.89	71,218	$ 0.0016
Total	100.00%	$ 12,657,773.57	4,080,958,807	
		$ -		

Sheet 1 - Rate Riders Calculation

Name of Distributor:	**PowerStream Inc. - Barrie**	**Licence Number**	**ED-2004-0520**
Contact Name:	Tom Barrett, Manager, Rate Applications	**Case Number**	EB-2012-0161
Contact e-mail	Tom.Barrett@PowerStream.ca	**Date Filed**	May 4, 2012
Phone #:	905-532-4640		

Regulatory Asset Accounts:	**Amount**	**ALLOCATOR**	**Residential**	**GS < 50 KW**	**GS > 50**	**Large Users**	**Unmetered Scattered Load**	**Sentinel Lighting**	**Street Lighting**	**Total**	Check
LV - Account 1550	$ (156,537)	kWh	$ (57,813)	$ (21,698)	$ (75,462)	$ -	$ (308)	$ -	$ (1,255)	$ (156,537)	-
WMSC - Account 1580	$ (277,488)	kWh	$ (102,484)	$ (38,464)	$ (133,769)	$ -	$ (547)	$ -	$ (2,225)	$ (277,488)	-
Network - Account 1584	$ 296,214	kWh	$ 109,400	$ 41,060	$ 142,796	$ -	$ 584	$ -	$ 2,375	$ 296,214	-
Connection - Account 1586	$ (108,107)	kWh	$ (39,927)	$ (14,985)	$ (52,115)	$ -	$ (213)	$ -	$ (867)	$ (108,107)	-
Power - Account 1588 (excluding GA)	$ (3,187,933)	kWh	$ (1,177,392)	$ (441,894)	$ (1,536,808)	$ -	$ (6,281)	$ -	$ (25,557)	$ (3,187,933)	-
Subtotal - RSVA excl. GA	**$ (3,433,851)**		**$ (1,268,217)**	**$ (475,982)**	**$ (1,655,358)**	**$ -**	**$ (6,766)**	**$ -**	**$ (27,529)**	**$ (3,433,851)**	
Non-RSVA Accounts:											
Other Regulatory Assets - Account 1508	$ 564,978	kWh	$ 208,662	$ 78,314	$ 272,359	$ -	$ 1,113	$ -	$ 4,529	$ 564,978	-
Retail Cost Variance Account - Acct 1518	$ 60,327	# of Customers	$ 44,674	$ 4,036	$ 552	$ -	$ 439	$ -	$ 10,626	$ 60,327	-
Misc. Deferred Debits Acct 1525	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Renewable Generation Connection Capital Deferral Account Acct 1531	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Renewable Generation Connection OM&A Deferral Account Acct 1532	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Renewable Generation Connection Funding Adder Deferral Account Acct 1533	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Smart Grid Capital Deferral Account Acct 1534	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Smart Grid OM&A Deferral Account Acct 1535	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Smart Grid Funding Adder Deferral Account Acct 1536	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Retail Cost Variance Account - STR Acct 1548	$ (27,444)	# of Customers	$ (20,323)	$ (1,836)	$ (251)	$ -	$ (200)	$ -	$ (4,834)	$ (27,444)	-
Board-Approved CDM Variance Account Acct 1567	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Extra-Ordinary Event Costs Acct 1572	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Deferred Rate Impact Amounts Acct 1574	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
RSVA - One-time Acct 1582	$ 98,748	kWh	$ 36,470	$ 13,688	$ 47,604	$ -	$ 195	$ -	$ 792	$ 98,748	-
Other Deferred Credits Acct 2425	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Subtotal - Non RSVA	**$ 696,609**		**$ 269,483**	**$ 94,202**	**$ 320,264**	**$ -**	**$ 1,547**	**$ -**	**$ 11,113**	**$ 696,609**	
Deferred Payments in Lieu of Taxes Acct 1562	$ -	Dist. Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
PILs and Tax Variance for 2006 and Subsequent Years Acct 1592	$ (62,199)	Dist. Revenue	$ (38,157)	$ (8,181)	$ (14,714)	$ (254)	$ (324)	$ -	$ (569)	$ (62,199)	-
Smart Meter Capital and Recovery Offset Variance Acct 1555	$ 2,794,450	Metered Customers	$ 2,534,200	$ 228,923	$ 31,327	$ -	$ -	$ -	$ -	$ 2,794,450	-
Smart Meter OM&A Variance Acct 1556	$ 154,411	Metered Customers	$ 140,031	$ 12,649	$ 1,731	$ -	$ -	$ -	$ -	$ 154,411	-
	$ 2,886,662		**$ 2,636,074**	**$ 233,391**	**$ 18,344**	**$ (254)**	**$ (324)**	**$ -**	**$ (569)**	**$ 2,886,662**	-
Subt-total before Recoveries	**$ 149,420**		**$ 1,637,341**	**$ (148,389)**	**$ (1,316,751)**	**$ (254)**	**$ (5,543)**	**$ -**	**$ (16,985)**	**$ 149,420**	(0.00)
Recoveries Amounts											
Recoveries - Acct 1590	$ (28)	Prev. Allocation	$ (13)	$ (3)	$ (12)	$ -	$ (0)	$ (0)	$ -	$ (28)	-
Recoveries - Acct 1595	$ 12,953	Prev. Allocation	$ 5,786	$ 1,610	$ 5,472	$ -	$ 28	$ 56	$ -	$ 12,953	-
Sub-total Recoveries Amounts	**$ 12,925**		$ 5,774	$ 1,607	$ 5,461	$ -	$ 28	$ 56	$ -	$ 12,925	-
Total to be Recovered (Refunded)	**$ 162,345**		**$ 1,643,114**	**$ (146,782)**	**$ (1,311,290)**	**$ (254)**	**$ (5,514)**	**$ 56**	**$ (16,985)**	**$ 162,345**	
Number of years to be collected or refunded:	**2**										
Balance to be collected or refunded per year	$ 81,172		$ 821,557	$ (73,391)	$ (655,645)	$ (127)	$ (2,757)	$ 28	$ (8,493)	$ 81,172	

Class	**Residential**	**GS < 50 KW**	**GS > 50**	**Large Users**	**Scattered Load**	**Sentinel Lighting**	**Street Lighting**
Billing Determinants	kWh	kWh	kW	kW	kWh	kW	kW
Billing Determinants - quantity (**2013 Test Year**)	**571,622,363**	**209,719,823**	**1,935,649**	**0**	**3,219,531**	**0**	**38,122**
Regulatory Asset Rate Riders	$ 0.0014	$ (0.0003)	$ (0.3387)		$ (0.0009)		$ (0.2228)

Notes:

1. See Sheet 5 for 1588 Global Adjustment Allocation

Sheet 2 - December 31, 2011 Regulatory Assets

Name of Distributor: **PowerStream Inc. - Barrie**

Licence Number **ED-2004-0520**
Case Number **EB-2012-0161**
Date Filed **May 4, 2012**

Account Description	Account Number	Principal Amounts as of Dec-31 2011	Adjustment	Revised Principal Amounts as of Dec-31 2011	Interest to Dec31 2011	Adjustment	Revised Interest to Dec31 2011	Interest Jan1-12 to Dec 31-12	Adjustment	Total Claim
LV Variance Account	1550	$ (150,811)		$ (150,811)	$ (3,503)		$ (3,503)	$ (2,223)		$ (156,537)
RSVA - Wholesale Market Service Charge	1580	$ (267,069)		$ (267,069)	$ (6,482)		$ (6,482)	$ (3,937)		$ (277,488)
RSVA - Retail Transmission Network Charge	1584	$ 286,232		$ 286,232	$ 5,763		$ 5,763	$ 4,219		$ 296,214
RSVA - Retail Transmission Connection Charge	1586	$ (103,340)		$ (103,340)	$ (3,244)		$ (3,244)	$ (1,523)		$ (108,107)
RSVA - Power (excluding Global Adjustment)	1588	$ (3,062,075)		$ (3,062,075)	$ (80,723)		$ (80,723)	$ (45,136)		$ (3,187,933)
RSVA - Power - Sub-account - Global Adjustment	1588	$ 4,424,023		$ 4,424,023	$ 118,149		$ 118,149	$ 65,211		$ 4,607,383
Recovery of Regulatory Asset Balances	1590	$ -		$ -	$ (28)		$ (28)	$ -		$ (28)
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	$ -		$ -	$ -		$ -	$ -		$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	$ 296,228		$ 296,228	$ 120,515		$ 120,515	$ 4,367		$ 421,110
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	$ 104,848		$ 104,848	$ (514,550)		$ (514,550)	$ 1,545		$ (408,157)
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		**$ 1,528,036**	**$ -**	**$ 1,528,036**	**$ (364,103)**	**$ -**	**$ (364,103)**	**$ 22,524**	**$ -**	**$ 1,186,457**
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		**$ (2,895,987)**	**$ -**	**$ (2,895,987)**	**$ (482,252)**	**$ -**	**$ (482,252)**	**$ (42,688)**	**$ -**	**$ (3,420,926)**
Non-RSVA										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -		$ -	$ -		$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -		$ -	$ -		$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ 419,213		$ 419,213	$ 8,435		$ 8,435	$ 6,179	$ 131,150	$ 564,978
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -		$ -	$ -		$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	$ -		$ -	$ -		$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -		$ -	$ -		$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other	1508	$ -		$ -	$ -		$ -	$ -		$ -
Retail Cost Variance Account - Retail	1518	$ 50,237		$ 50,237	$ 9,350		$ 9,350	$ 741		$ 60,327
Misc. Deferred Debits	1525	$ -		$ -	$ -		$ -	$ -		$ -
Renewable Generation Connection Capital Deferral Account	1531	$ -		$ -	$ -		$ -	$ -		$ -
Renewable Generation Connection OM&A Deferral Account	1532	$ -		$ -	$ -		$ -	$ -		$ -
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -		$ -	$ -		$ -	$ -		$ -
Smart Grid Capital Deferral Account	1534	$ -		$ -	$ -		$ -	$ -		$ -
Smart Grid OM&A Deferral Account	1535	$ -		$ -	$ -		$ -	$ -		$ -
Smart Grid Funding Adder Deferral Account	1536	$ -		$ -	$ -		$ -	$ -		$ -
Retail Cost Variance Account - STR	1548	$ (24,249)		$ (24,249)	$ (2,838)		$ (2,838)	$ (357)		$ (27,444)
Board-Approved CDM Variance Account	1567	$ -		$ -	$ -		$ -	$ -		$ -
Extra-Ordinary Event Costs	1572	$ -		$ -	$ -		$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -		$ -	$ -		$ -	$ -		$ -
RSVA - One-time	1582	$ 80,600		$ 80,600	$ 16,960		$ 16,960	$ 1,188		$ 98,748
Other Deferred Credits	2425	$ -		$ -	$ -		$ -	$ -		$ -
Sub-Totals		**$ 525,801**	**$ -**	**$ 525,801**	**$ 31,907**	**$ -**	**$ 31,907**	**$ 7,751**	**$ 131,150**	**$ 696,609**
Deferred Payments in Lieu of Taxes	1562	$ (721,235)	$ 721,235	$ -	$ 158,292	$ (158,292)	$ -	$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ (54,576)		$ (54,576)	$ (6,818)		$ (6,818)	$ (804)		$ (62,199)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -		$ -	$ -		$ -	$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -		$ -	$ -		$ -	$ -		$ -
Sub-Totals		**$ (775,811)**	**$ 721,235**	**$ (54,576)**	**$ 151,474**	**$ (158,292)**	**$ (6,818)**	**$ (804)**	**$ -**	**$ (62,199)**
Total for Group 1 , group 2 and accounts 1562 ,1592		**$ 1,278,026**	**$ 721,235**	**$ 1,999,261**	**$ (180,721)**	**$ (158,292)**	**$ (339,013)**	**$ 29,470**	**$ 131,150**	**$ 1,820,867**
Special Purpose Charge Assessment Variance Account	**1521**						$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital11	**1555**	$ -		$ -	$ -		$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries11	**1555**	$ -		$ -	$ -		$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs11	**1555**	$ 3,045,590		$ 3,045,590	$ -		$ -	$ -	**$ (251,140)**	$ 2,794,450
Smart Meter OM&A Variance11	**1556**	$ 152,168		$ 152,168	$ -		$ -	$ 2,243		$ 154,411
Sub-Totals - Smart Meters		**$ 3,197,758**	**$ -**	**$ 3,197,758**	**$ -**	**$ -**	**$ -**	**$ 2,243**	**$ (251,140)**	**$ 2,948,861**
Total		**$ 4,475,784**	**$ 721,235**	**$ 5,197,019**	**$ (180,721)**	**$ (158,292)**	**$ (339,013)**	**$ 31,713**	**$ (119,990)**	**$ 4,769,728**

SHEET 3 - Interest on Reg. Assets Balance as of Dec. 31, 2011

PowerStream Inc. - Barrie
EB-2012-0161

		Balance as of Dec. 31, 2011	Interest Jan 2012 to Dec 2012
1550	LV Variance Account	$ (150,811)	$ (2,223)
1580	RSVA - Wholesale Market Service Charge	$ (267,069)	$ (3,937)
1584	RSVA - Retail Transmission Network Charge	$ 286,232	$ 4,219
1586	RSVA - Retail Transmission Connection Charge	$ (103,340)	$ (1,523)
1588	RSVA - Power (excluding Global Adjustment)	$ (3,062,075)	$ (45,136)
1588	RSVA - Power - Sub-account - Global Adjustment	$ 4,424,023	$ 65,211
1590	Recovery of Regulatory Asset Balances	$ -	$ -
1595	Disposition and Recovery/Refund of Regulatory Balances (2008)	$ -	$ -
1595	Disposition and Recovery/Refund of Regulatory Balances (2009)	$ 296,228	$ 4,367
1595	Disposition and Recovery/Refund of Regulatory Balances (2010)	$ 104,848	$ 1,545
1508	Other Regulatory Assets - Sub-Account - OEB Cost Assessments	$ -	$ -
1508	Other Regulatory Assets - Sub-Account - Pension Contributions	$ -	$ -
1508	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	$ 419,213	$ 6,179
1508	Other Regulatory Assets - Sub-Account - Incremental Capital Charges	$ -	$ -
1508	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	$ -	$ -
1508	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	$ -	$ -
1508	Other Regulatory Assets - Sub-Account - Other	$ -	$ -
1518	Retail Cost Variance Account - Retail	$ 50,237	$ 741
1525	Misc. Deferred Debits	$ -	$ -
1531	Renewable Generation Connection Capital Deferral Account	$ -	$ -
1532	Renewable Generation Connection OM&A Deferral Account	$ -	$ -
1533	Renewable Generation Connection Funding Adder Deferral Account	$ -	$ -
1534	Smart Grid Capital Deferral Account	$ -	$ -
1535	Smart Grid OM&A Deferral Account	$ -	$ -
1536	Smart Grid Funding Adder Deferral Account	$ -	$ -
1548	Retail Cost Variance Account - STR	$ (24,249)	$ (357)
1567	Board-Approved CDM Variance Account	$ -	$ -
1572	Extra-Ordinary Event Costs	$ -	$ -
1574	Deferred Rate Impact Amounts	$ -	$ -
1582	RSVA - One-time	$ 80,600	$ 1,188
2425	Other Deferred Credits	$ -	$ -
1562	Deferred Payments in Lieu of Taxes	$ -	$ -
1592	PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	$ (54,576)	$ (804)
1592	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	$ -	$ -
1592	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	$ -	$ -
1521	Special Purpose Charge Assessment Variance Account	$ -	$ -
1555	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital11	$ -	$ -
1555	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries11	$ -	$ -
1555	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs11	$ 3,045,590	
1556	Smart Meter OM&A Variance11	$ 152,168	$ 2,243
		5,197,019	**$ 31,713**

SHEET 3 - Interest on Reg. Assets Balance as of Dec. 31, 2011

PowerStream Inc. - Barrie

Interest Calculation

	Date	Jan 2012	Feb 2012	Mar 2012	Apr 2012	May 2012	Jun 2012	Jul 2012	Aug 2012	Sep 2012	Oct 2012	Nov 2012	Dec 2012	
	days	31	29	31	30	31	30	31	31	30	31	30	31	Total Interest
	interest	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	
1550	$ (150,811)	$ (188)	$ (176)	$ (188)	$ (182)	$ (188)	$ (182)	$ (188)	$ (188)	$ (182)	$ (188)	$ (182)	$ (188)	$ (2,223)
1580	$ (267,069)	$ (333)	$ (312)	$ (333)	$ (323)	$ (333)	$ (323)	$ (333)	$ (333)	$ (323)	$ (333)	$ (323)	$ (333)	$ (3,937)
1584	$ 286,232	$ 357	$ 334	$ 357	$ 346	$ 357	$ 346	$ 357	$ 357	$ 346	$ 357	$ 346	$ 357	$ 4,219
1586	$ (103,340)	$ (129)	$ (121)	$ (129)	$ (125)	$ (129)	$ (125)	$ (129)	$ (129)	$ (125)	$ (129)	$ (125)	$ (129)	$ (1,523)
1588	$ (3,062,075)	$ (3,823)	$ (3,576)	$ (3,823)	$ (3,700)	$ (3,823)	$ (3,700)	$ (3,823)	$ (3,823)	$ (3,700)	$ (3,823)	$ (3,700)	$ (3,823)	$ (45,136)
1588	$ 4,424,023	$ 5,523	$ 5,167	$ 5,523	$ 5,345	$ 5,523	$ 5,345	$ 5,523	$ 5,523	$ 5,345	$ 5,523	$ 5,345	$ 5,523	$ 65,211
1590	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1595	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1595	$ 296,228	$ 370	$ 346	$ 370	$ 358	$ 370	$ 358	$ 370	$ 370	$ 358	$ 370	$ 358	$ 370	$ 4,367
1595	$ 104,848	$ 131	$ 122	$ 131	$ 127	$ 131	$ 127	$ 131	$ 131	$ 127	$ 131	$ 127	$ 131	$ 1,545
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ 419,213	$ 523	$ 490	$ 523	$ 507	$ 523	$ 507	$ 523	$ 523	$ 507	$ 523	$ 507	$ 523	$ 6,179
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1518	$ 50,237	$ 63	$ 59	$ 63	$ 61	$ 63	$ 61	$ 63	$ 63	$ 61	$ 63	$ 61	$ 63	$ 741
1525	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1531	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1532	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1533	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1534	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1535	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1536	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1548	$ (24,249)	$ (30)	$ (28)	$ (30)	$ (29)	$ (30)	$ (29)	$ (30)	$ (30)	$ (29)	$ (30)	$ (29)	$ (30)	$ (357)
1567	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1572	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1574	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1582	$ 80,600	$ 101	$ 94	$ 101	$ 97	$ 101	$ 97	$ 101	$ 101	$ 97	$ 101	$ 97	$ 101	$ 1,188
2425	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1562	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1592	$ (54,576)	$ (68)	$ (64)	$ (68)	$ (66)	$ (68)	$ (66)	$ (68)	$ (68)	$ (66)	$ (68)	$ (66)	$ (68)	$ (804)
1592	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1592	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1521	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1555	$ 3,045,590													$ -
1556	$ 152,168	$ 190	$ 178	$ 190	$ 184	$ 190	$ 184	$ 190	$ 190	$ 184	$ 190	$ 184	$ 190	$ 2,243
	$ 5,197,019													**$ 31,713**

Sheet 4 - Allocators

PowerStream Inc. - Barrie
EB-2012-0161

2011 Data By Class	kW	kWhs	Cust. Num.'s	Dx Revenue (Last COS)	Non-RPP kWhs	Previous recoveries	Metered Customers
RESIDENTIAL CLASS		558,562,896	66,011	19,705,477	59,538,086	250,054	66,011
GENERAL SERVICE <50 KW CLASS		209,637,437	5,963	4,225,125	8,714,391	69,585	5,963
GENERAL SERVICE >50 KW NON TIME OF USE	1,910,483	729,072,254	816	7,598,682	662,363,985	236,488	816
GENERAL SERVICE >50 KW TIME OF USE		0	0				0
LARGE USER CLASS	0	0	0	130,952	0	0	0
UNMETERED SCATTERED LOADS	0	2,979,955	649	167,256	4,712	1,220	
SENTINEL LIGHTS	0	0	0	0	51,390,266	2,415	
STREET LIGHTING	33,926	12,124,515	15,701	293,992	0		
Totals	1,944,409	1,512,377,057	89,140	$ 32,121,483	782,011,440	559,762	72,790

Allocators	kW	kWhs	Cust. Num.'s	Dx Revenue (Last COS)	Non-RPP kWhs	Previous recoveries	Metered Customers
RESIDENTIAL CLASS	0.0%	36.9%	74.1%	61.3%	7.6%	44.7%	90.7%
GENERAL SERVICE <50 KW CLASS	0.0%	13.9%	6.7%	13.2%	1.1%	12.4%	8.2%
GENERAL SERVICE >50 KW NON TIME OF USE	98.3%	48.2%	0.9%	23.7%	84.7%	42.2%	1.1%
GENERAL SERVICE >50 KW TIME OF USE	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LARGE USER CLASS	0.0%	0.0%	0.0%	0.4%	0.0%	0.0%	0.0%
UNMETERED SCATTERED LOADS	0.0%	0.2%	0.7%	0.5%	0.0%	0.2%	0.0%
SENTINEL LIGHTS	0.0%	0.0%	0.0%	0.0%	6.6%	0.4%	0.0%
STREET LIGHTING	1.7%	0.8%	17.6%	0.9%	0.0%	0.0%	0.0%
Totals	100%	100%	100%	100%	100%	100%	100%

Sheet 5
RSVA - GLOBAL ADJUSTMENT ALLOCATION

PowerStream Inc. - Barrie

EB-2012-0161

Balance to allocate	$ 4,607,383	Years	2

Customer Class	Allocator (Non-RPP kwh)	RSVA- GA Allocated	billing determinant	Rate Rider
Residential Class	7.61%	$ 350,781.05	59,538,086	$ 0.0029
General Service <50 Kw Class	1.11%	$ 51,342.65	8,714,391	$ 0.0029
General Service >50 Kw Non Time Of Use	84.70%	$ 3,902,455.51	662,363,985	$ 0.0029
General Service >50 Kw Time Of Use	0.00%	$ -	0	
Large User Class	0.00%	$ -	0	
Unmetered Scattered Loads	0.00%	$ 27.76	4,712	$ 0.0029
Sentinel Lights	6.57%	$ 302,776.47	51,390,266	$ 0.0029
Street Lighting	0.00%	$ -	0	
Total	100.00%	$ 4,607,383.44	782,011,440	
		$ -		

Sheet 1 - Rate Riders Calculation

Name of Distributor:	**PowerStream Inc. - Shared**	**Licence Number**	**ED-2004-0520**
Contact Name:	Tom Barrett, Manager, Rate Applications	**Case Number**	EB-2012-0161
Contact e-mail	Tom.Barrett@PowerStream.ca	**Date Filed**	May 4, 2012
Phone #:	905-532-4640		

Regulatory Asset Accounts:	**Amount**	**ALLOCATOR**	**Residential**	**GS < 50 KW**	**GS > 50**	**Large Users**	**Unmetered Scattered Load**	**Sentinel Lighting**	**Street Lighting**	**Total**	Check
LV - Account 1550	$ (37,792)	kWh	$ (12,279)	$ (4,681)	$ (20,385)	$ (122)	$ (56)	$ (2)	$ (266)	$ (37,792)	-
WMSC - Account 1580	$ (17,478,175)	kWh	$ (5,678,873)	$ (2,164,869)	$ (9,427,921)	$ (56,457)	$ (25,914)	$ (894)	$ (123,247)	$(17,478,175)	-
Network - Account 1584	$ 5,348,307	kWh	$ 1,737,730	$ 662,448	$ 2,884,936	$ 17,276	$ 7,930	$ 274	$ 37,714	$ 5,348,307	-
Connection - Account 1586	$ (305,380)	kWh	$ (99,222)	$ (37,825)	$ (164,725)	$ (986)	$ (453)	$ (16)	$ (2,153)	$ (305,380)	-
Power - Account 1588 (excluding GA)	$ 2,816,771	kWh	$ 915,203	$ 348,889	$ 1,519,398	$ 9,099	$ 4,176	$ 144	$ 19,862	$ 2,816,771	-
Subtotal - RSVA excl. GA	**$ (9,656,268)**		**$ (3,137,440)**	**$ (1,196,038)**	**$ (5,208,698)**	**$ (31,191)**	**$ (14,317)**	**$ (494)**	**$ (68,091)**	**$ (9,656,268)**	
Non-RSVA Accounts:											
Other Regulatory Assets - Account 1508	$ 77,411	kWh	$ 25,152	$ 9,588	$ 41,757	$ 250	$ 115	$ 4	$ 546	$ 77,411	-
Retail Cost Variance Account - Acct 1518	$ (64,590)	# of Customers	$ (46,168)	$ (4,713)	$ (715)	$ (0)	$ (431)	$ (19)	$ (12,546)	$ (64,590)	-
Misc. Deferred Debits Acct 1525	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Renewable Generation Connection Capital Deferral Account Acct 1531	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Renewable Generation Connection OM&A Deferral Account Acct 1532	$ 145,230	kWh	$ 47,187	$ 17,988	$ 78,339	$ 469	$ 215	$ 7	$ 1,024	$ 145,230	-
Renewable Generation Connection Funding Adder Deferral Account Acct 1533	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Smart Grid Capital Deferral Account Acct 1534	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Smart Grid OM&A Deferral Account Acct 1535	$ 461,817	kWh	$ 150,050	$ 57,201	$ 249,109	$ 1,492	$ 685	$ 24	$ 3,256	$ 461,817	-
Smart Grid Funding Adder Deferral Account Acct 1536	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Retail Cost Variance Account - STR Acct 1548	$ (1,955)	# of Customers	$ (1,397)	$ (143)	$ (22)	$ (0)	$ (13)	$ (1)	$ (380)	$ (1,955)	-
Board-Approved CDM Variance Account Acct 1567	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Extra-Ordinary Event Costs Acct 1572	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Deferred Rate Impact Amounts Acct 1574	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
RSVA - One-time Acct 1582	$ (46,950)	kWh	$ (15,254)	$ (5,815)	$ (25,325)	$ (152)	$ (70)	$ (2)	$ (331)	$ (46,950)	-
Other Deferred Credits Acct 2425	$ (550,105)	kWh	$ (178,736)	$ (68,137)	$ (296,732)	$ (1,777)	$ (816)	$ (28)	$ (3,879)	$ (550,105)	-
Subtotal - Non RSVA	**$ 20,859**		**$ (19,166)**	**$ 5,971**	**$ 46,410**	**$ 282**	**$ (314)**	**$ (15)**	**$ (12,309)**	**$ 20,859**	
Deferred Payments in Lieu of Taxes Acct 1562	$ -	Dist. Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
PILs and Tax Variance for 2006 and Subsequent Years Acct 1592	$ (158,596)	Dist. Revenue	$ (83,199)	$ (22,944)	$ (49,892)	$ (262)	$ (638)	$ (21)	$ (1,641)	$ (158,596)	-
Smart Meter Capital and Recovery Offset Variance Acct 1555	$ -	Metered Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Smart Meter OM&A Variance Acct 1556	$ -	Metered Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
	$ (158,596)		**$ (83,199)**	**$ (22,944)**	**$ (49,892)**	**$ (262)**	**$ (638)**	**$ (21)**	**$ (1,641)**	**$ (158,596)**	-
Subt-total before Recoveries	**$ (9,794,005)**		**$ (3,239,805)**	**$ (1,213,011)**	**$ (5,212,180)**	**$ (31,171)**	**$ (15,268)**	**$ (529)**	**$ (82,041)**	**$ (9,794,005)**	-
Recoveries Amounts											
Recoveries - Acct 1590	$ (4,423)	Prev. Allocation								$ -	4,423.25
Recoveries - Acct 1595	$ -	Prev. Allocation								$ -	-
Sub-total Recoveries Amounts	**$ (4,423)**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	4,423.25
Total to be Recovered (Refunded)	**$ (9,798,429)**		**$ (3,239,805)**	**$ (1,213,011)**	**$ (5,212,180)**	**$ (31,171)**	**$ (15,268)**	**$ (529)**	**$ (82,041)**	**$ (9,794,005)**	
Number of years to be collected or refunded:	**2**										
Balance to be collected or refunded per year	$ (4,899,214)		$ (1,619,903)	$ (606,505)	$ (2,606,090)	$ (15,585)	$ (7,634)	$ (265)	$ (41,020)	$ (4,897,003)	

Class	**Residential**	**GS < 50 KW**	**GS > 50**	**Large Users**	**Scattered Load**	**Sentinel Lighting**	**Street Lighting**
Billing Determinants	kWh	kWh	kW	kW	kWh	kW	kW
Billing Determinants - quantity (**2013 Test Year**)	**2,727,901,711**	**1,049,877,268**	**12,130,724**	**187,932**	**12,918,549**	**1,240**	**176,787**
Regulatory Asset Rate Riders	$ (0.0006)	$ (0.0006)	$ (0.2148)	$ (0.0829)	$ (0.0006)	$ (0.2135)	$ (0.2320)

Notes:

1. See Sheet 5 for 1588 Global Adjustment Allocation and Rate Rider.

Sheet 2 - December 31, 2011 Regulatory Assets

Name of Distributor: **PowerStream Inc. - Shared**

Licence Number ED-2004-0520
Case Number EB-2012-0161
Date Filed May 4, 2012

Account Description	Account Number	Principal Amounts as of Dec-31 2011	Adjustment	Revised Principal Amounts as of Dec-31 2011	Interest to Dec31 2011	Adjustment	Revised Interest to Dec31 2011	Interest Jan1-12 to Dec 31-12	Adjustment	Total Claim
LV Variance Account	1550	$ (31,468)		$ (31,468)	$ (5,860)		$ (5,860)	$ (464)		$ (37,792)
RSVA - Wholesale Market Service Charge	1580	$ (17,018,860)		$ (17,018,860)	$ (208,453)		$ (208,453)	$ (250,863)		$ (17,478,175)
RSVA - Retail Transmission Network Charge	1584	$ 5,189,342		$ 5,189,342	$ 82,473		$ 82,473	$ 76,492		$ 5,348,307
RSVA - Retail Transmission Connection Charge	1586	$ (303,590)		$ (303,590)	$ 2,685		$ 2,685	$ (4,475)		$ (305,380)
RSVA - Power (excluding Global Adjustment)	1588	$ 2,702,866		$ 2,702,866	$ 74,064		$ 74,064	$ 39,841		$ 2,816,771
RSVA - Power - Sub-account - Global Adjustment	1588	$ 1,218,396		$ 1,218,396	$ (48,004)		$ (48,004)	$ 17,960		$ 1,188,351
Recovery of Regulatory Asset Balances	1590	$ (4,299)		$ (4,299)	$ (61)		$ (61)	$ (63)		$ (4,423)
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	$ -		$ -	$ -		$ -	$ -		$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	$ -		$ -	$ -		$ -	$ -		$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	$ -		$ -	$ -		$ -	$ -		$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		**$ (8,247,613)**	**$ -**	**$ (8,247,613)**	**$ (103,155)**	**$ -**	**$ (103,155)**	**$ (121,572)**	**$ -**	**$ (8,472,340)**
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		**$ (9,466,009)**	**$ -**	**$ (9,466,009)**	**$ (55,151)**	**$ -**	**$ (55,151)**	**$ (139,532)**	**$ -**	**$ (9,660,692)**
Non-RSVA										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -		$ -	$ 2,576		$ 2,576	$ -		$ 2,576
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -		$ -	$ 6,558		$ 6,558	$ -		$ 6,558
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -		$ -	$ -		$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ 65,840		$ 65,840	$ 1,467		$ 1,467	$ 971		$ 68,278
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	$ -		$ -	$ -		$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -		$ -	$ -		$ -	$ -		$ -
Other Regulatory Assets - Sub-Account - Other	1508	$ -		$ -	$ -		$ -	$ -		$ -
Retail Cost Variance Account - Retail	1518	$ (63,272)		$ (63,272)	$ (386)		$ (386)	$ (933)		$ (64,590)
Misc. Deferred Debits	1525	$ -		$ -	$ -		$ -	$ -		$ -
Renewable Generation Connection Capital Deferral Account	1531	$ 524,817	$ (524,817)	$ -	$ 2,721	$ (2,721)	$ -	$ -		$ -
Renewable Generation Connection OM&A Deferral Account	1532	$ 142,559		$ 142,559	$ 570		$ 570	$ 2,101		$ 145,230
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -		$ -	$ -		$ -	$ -		$ -
Smart Grid Capital Deferral Account	1534	$ 488,921	$ (488,921)	$ -	$ 4,398	$ (4,398)	$ -	$ -		$ -
Smart Grid OM&A Deferral Account	1535	$ 450,104		$ 450,104	$ 5,078		$ 5,078	$ 6,635		$ 461,817
Smart Grid Funding Adder Deferral Account	1536	$ -		$ -	$ -		$ -	$ -		$ -
Retail Cost Variance Account - STR	1548	$ (1,880)		$ (1,880)	$ (47)		$ (47)	$ (28)		$ (1,955)
Board-Approved CDM Variance Account	1567	$ -		$ -	$ -		$ -	$ -		$ -
Extra-Ordinary Event Costs	1572	$ -		$ -	$ -		$ -	$ -		$ -
Deferred Rate Impact Amounts	1574	$ -		$ -	$ -		$ -	$ -		$ -
RSVA - One-time	1582	$ (45,640)		$ (45,640)	$ (637)		$ (637)	$ (673)		$ (46,950)
Other Deferred Credits	2425	$ (318,422)		$ (318,422)	$ (13,147)		$ (13,147)	$ (4,694)	$ (213,842)	$ (550,105)
Sub-Totals		**$ 1,243,027**	**$ (1,013,738)**	**$ 229,289**	**$ 9,151**	**$ (7,119)**	**$ 2,032**	**$ 3,380**	**$ (213,842)**	**$ 20,859**
Deferred Payments in Lieu of Taxes	1562	$ -		$ -	$ -		$ -	$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ (152,637)		$ (152,637)	$ (3,709)		$ (3,709)	$ (2,250)		$ (158,596)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ (636,840)		$ (636,840)	$ -		$ -	$ (9,387)	$ (427,684)	$ (1,073,911)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ 636,840		$ 636,840	$ -		$ -	$ 9,387	$ 427,684	$ 1,073,911
Sub-Totals		**$ (152,637)**	**$ -**	**$ (152,637)**	**$ (3,709)**	**$ -**	**$ (3,709)**	**$ (2,250)**	**$ -**	**$ (158,596)**
Total for Group 1 , group 2 and accounts 1562 ,1592		**$ (7,157,223)**	**$ (1,013,738)**	**$ (8,170,961)**	**$ (97,714)**	**$ (7,119)**	**$ (104,833)**	**$ (120,442)**	**$ (213,842)**	**$ (8,610,077)**
Special Purpose Charge Assessment Variance Account	1521	$ (24,855)	**$ 24,855**	$ -	$ 10,879	**$ (10,879)**	$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital11	**1555**	$ -		$ -	$ -		$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries11	**1555**	$ -		$ -	$ -		$ -	$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs11	**1555**	$ -		$ -	$ -		$ -	$ -		$ -
Smart Meter OM&A Variance11	**1556**	$ -		$ -	$ -		$ -	$ -		$ -
Sub-Totals - Smart Meters		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total		**$ (7,182,078)**	**$ (988,883)**	**$ (8,170,961)**	**$ (86,835)**	**$ (17,998)**	**$ (104,833)**	**$ (120,442)**	**$ (213,842)**	**$ (8,610,077)**

Notes

Remove Green Energy capital balances as these are added to rate base.
Remove 1521 Special Purpose Charge cleared in 2012 IRM

SHEET 3 - Interest on Reg. Assets Balance as of Dec. 31, 2011

PowerStream Inc. - Shared
EB-2012-0161

	Balance as of Dec. 31, 2011	Interest Jan 2012 to Dec 2012
1550 LV Variance Account	$ (31,468)	$ (464)
1580 RSVA - Wholesale Market Service Charge	$ (17,018,860)	$ (250,863)
1584 RSVA - Retail Transmission Network Charge	$ 5,189,342	$ 76,492
1586 RSVA - Retail Transmission Connection Charge	$ (303,590)	$ (4,475)
1588 RSVA - Power (excluding Global Adjustment)	$ 2,702,866	$ 39,841
1588 RSVA - Power - Sub-account - Global Adjustment	$ 1,218,396	$ 17,960
1590 Recovery of Regulatory Asset Balances	$ (4,299)	$ (63)
1595 Disposition and Recovery/Refund of Regulatory Balances (2008)	$ -	$ -
1595 Disposition and Recovery/Refund of Regulatory Balances (2009)	$ -	$ -
1595 Disposition and Recovery/Refund of Regulatory Balances (2010)	$ -	$ -
1508 Other Regulatory Assets - Sub-Account - OEB Cost Assessments	$ -	$ -
1508 Other Regulatory Assets - Sub-Account - Pension Contributions	$ -	$ -
1508 Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	$ -	$ -
1508 Other Regulatory Assets - Sub-Account - Incremental Capital Charges	$ 65,840	$ 971
1508 Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	$ -	$ -
1508 Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	$ -	$ -
1508 Other Regulatory Assets - Sub-Account - Other	$ -	$ -
1518 Retail Cost Variance Account - Retail	$ (63,272)	$ (933)
1525 Misc. Deferred Debits	$ -	$ -
1531 Renewable Generation Connection Capital Deferral Account	$ -	$ -
1532 Renewable Generation Connection OM&A Deferral Account	$ 142,559	$ 2,101
1533 Renewable Generation Connection Funding Adder Deferral Account	$ -	$ -
1534 Smart Grid Capital Deferral Account	$ -	$ -
1535 Smart Grid OM&A Deferral Account	$ 450,104	$ 6,635
1536 Smart Grid Funding Adder Deferral Account	$ -	$ -
1548 Retail Cost Variance Account - STR	$ (1,880)	$ (28)
1567 Board-Approved CDM Variance Account	$ -	$ -
1572 Extra-Ordinary Event Costs	$ -	$ -
1574 Deferred Rate Impact Amounts	$ -	$ -
1582 RSVA - One-time	$ (45,640)	$ (673)
2425 Other Deferred Credits	$ (318,422)	$ (4,694)
1562 Deferred Payments in Lieu of Taxes	$ -	$ -
1592 PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	$ (152,637)	$ (2,250)
1592 PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	$ (636,840)	$ (9,387)
1592 PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	$ 636,840	$ 9,387
1521 Special Purpose Charge Assessment Variance Account	$ -	$ -
1555 Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital11	$ -	$ -
1555 Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries11	$ -	$ -
1555 Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs11	$ -	$ -
1556 Smart Meter OM&A Variance11	$ -	$ -
	(8,170,961)	**$ (120,442)**

SHEET 3 - Interest on Reg. Assets Balance as of Dec. 31, 2011

Interest Calculation

	Date	Jan 2012	Feb 2012	Mar 2012	Apr 2012	May 2012	Jun 2012	Jul 2012	Aug 2012	Sep 2012	Oct 2012	Nov 2012	Dec 2012	Total Interest
	days	31	29	31	30	31	30	31	31	30	31	30	31	
	interest	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	1.47%	
1550	$ (31,468)	$ (39)	$ (37)	$ (39)	$ (38)	$ (39)	$ (38)	$ (39)	$ (39)	$ (38)	$ (39)	$ (38)	$ (39)	$ (464)
1580	$ (17,018,860)	$ (21,248)	$ (19,877)	$ (21,248)	$ (20,563)	$ (21,248)	$ (20,563)	$ (21,248)	$ (21,248)	$ (20,563)	$ (21,248)	$ (20,563)	$ (21,248)	$ (250,863)
1584	$ 5,189,342	$ 6,479	$ 6,061	$ 6,479	$ 6,270	$ 6,479	$ 6,270	$ 6,479	$ 6,479	$ 6,270	$ 6,479	$ 6,270	$ 6,479	$ 76,492
1586	$ (303,590)	$ (379)	$ (355)	$ (379)	$ (367)	$ (379)	$ (367)	$ (379)	$ (379)	$ (367)	$ (379)	$ (367)	$ (379)	$ (4,475)
1588	$ 2,702,866	$ 3,375	$ 3,157	$ 3,375	$ 3,266	$ 3,375	$ 3,266	$ 3,375	$ 3,375	$ 3,266	$ 3,375	$ 3,266	$ 3,375	$ 39,841
1588	$ 1,218,396	$ 1,521	$ 1,423	$ 1,521	$ 1,472	$ 1,521	$ 1,472	$ 1,521	$ 1,521	$ 1,472	$ 1,521	$ 1,472	$ 1,521	$ 17,960
1590	$ (4,299)	$ (5)	$ (5)	$ (5)	$ (5)	$ (5)	$ (5)	$ (5)	$ (5)	$ (5)	$ (5)	$ (5)	$ (5)	$ (63)
1595	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1595	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1595	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ 65,840	$ 82	$ 77	$ 82	$ 80	$ 82	$ 80	$ 82	$ 82	$ 80	$ 82	$ 80	$ 82	$ 971
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1518	$ (63,272)	$ (79)	$ (74)	$ (79)	$ (76)	$ (79)	$ (76)	$ (79)	$ (79)	$ (76)	$ (79)	$ (76)	$ (79)	$ (933)
1525	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1531	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1532	$ 142,559	$ 178	$ 167	$ 178	$ 172	$ 178	$ 172	$ 178	$ 178	$ 172	$ 178	$ 172	$ 178	$ 2,101
1533	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1534	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1535	$ 450,104	$ 562	$ 526	$ 562	$ 544	$ 562	$ 544	$ 562	$ 562	$ 544	$ 562	$ 544	$ 562	$ 6,635
1536	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1548	$ (1,880)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (28)
1567	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1572	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1574	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1582	$ (45,640)	$ (57)	$ (53)	$ (57)	$ (55)	$ (57)	$ (55)	$ (57)	$ (57)	$ (55)	$ (57)	$ (55)	$ (57)	$ (673)
2425	$ (318,422)	$ (398)	$ (372)	$ (398)	$ (385)	$ (398)	$ (385)	$ (398)	$ (398)	$ (385)	$ (398)	$ (385)	$ (398)	$ (4,694)
1562	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1592	$ (152,637)	$ (191)	$ (178)	$ (191)	$ (184)	$ (191)	$ (184)	$ (191)	$ (191)	$ (184)	$ (191)	$ (184)	$ (191)	$ (2,250)
1592	$ (636,840)	$ (795)	$ (744)	$ (795)	$ (769)	$ (795)	$ (769)	$ (795)	$ (795)	$ (769)	$ (795)	$ (769)	$ (795)	$ (9,387)
1592	$ 636,840	$ 795	$ 744	$ 795	$ 769	$ 795	$ 769	$ 795	$ 795	$ 769	$ 795	$ 769	$ 795	$ 9,387
1521	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ (8,170,961)													**$ (120,442)**

Sheet 4 - Allocators

PowerStream Inc. - Shared
EB-2012-0161

2011 Data By Class	kW	kWhs	Cust. Num.'s	Dx Revenue (Last COS)	Non-RPP kWhs	Previous recoveries	Metered Customers
RESIDENTIAL CLASS	0	2,727,580,225	297,962	77,989,041	294,365,097		297,962
GENERAL SERVICE <50 KW CLASS	0	1,039,793,445	30,416	21,506,756	181,561,821		30,416
GENERAL SERVICE >50 KW NON TIME OF USE	12,056,896	4,528,259,650	4,614	46,767,853	4,242,467,674		4,614
GENERAL SERVICE >50 KW TIME OF USE	0	0	0	0			0
LARGE USER CLASS	80,298	27,116,405	1	245,704	82,754,178		1
UNMETERED SCATTERED LOADS	0	12,446,475	2,779	597,625	1,031,949		
SENTINEL LIGHTS	1,113	429,377	120	19,603	60,718,311		
STREET LIGHTING	165,046	59,196,079	80,969	1,537,807	71,218		
Totals	12,303,354	8,394,821,657	416,861	$ 148,664,390	4,862,970,248	-	332,993

Allocators	kW	kWhs	Cust. Num.'s	Dx Revenue (Last COS)	Non-RPP kWhs	Previous recoveries	Metered Customers
RESIDENTIAL CLASS	0.0%	32.5%	71.5%	52.5%	6.1%		89.5%
GENERAL SERVICE <50 KW CLASS	0.0%	12.4%	7.3%	14.5%	3.7%		9.1%
GENERAL SERVICE >50 KW NON TIME OF USE	98.0%	53.9%	1.1%	31.5%	87.2%		1.4%
GENERAL SERVICE >50 KW TIME OF USE	0.0%	0.0%	0.0%	0.0%	0.0%		0.0%
LARGE USER CLASS	0.7%	0.3%	0.0%	0.2%	1.7%		0.0%
UNMETERED SCATTERED LOADS	0.0%	0.1%	0.7%	0.4%	0.0%		0.0%
SENTINEL LIGHTS	0.0%	0.0%	0.0%	0.0%	1.2%		0.0%
STREET LIGHTING	1.3%	0.7%	19.4%	1.0%	0.0%		0.0%
Totals	100%	100%	100%	100%	100%	0%	100%

Sheet 5
RSVA - GLOBAL ADJUSTMENT ALLOCATION

PowerStream Inc. - Shared

EB-2012-0161

Balance to allocate $ 1,188,351 Years 2

Customer Class	Allocator (Non-RPP kwh)	RSVA- GA Allocated	billing determinant	Rate Rider
Residential Class	6.05%	$ 71,933.23	294,365,097	$ 0.0001
General Service <50 Kw Class	3.73%	$ 44,367.79	181,561,821	$ 0.0001
General Service >50 Kw Non Time Of Use	87.24%	$ 1,036,720.77	4,242,467,674	$ 0.0001
General Service >50 Kw Time Of Use	0.00%	$ -	0	
Large User Class	1.70%	$ 20,222.42	82,754,178	$ 0.0001
Unmetered Scattered Loads	0.02%	$ 252.17	1,031,949	$ 0.0001
Sentinel Lights	1.25%	$ 14,837.58	60,718,311	$ 0.0001
Street Lighting	0.00%	$ 17.40	71,218	$ 0.0001
Total	100.00%	$ 1,188,351.37	4,862,970,248	
		$ -		

DEFERRAL AND VARIANCE ACCOUNTS REQUESTED

PowerStream proposes to clear balances in accounts 1508 IFRS Transition Costs, 1592 HST/OVAT ITCs, 1592 HST/OVAT Contra and 2425 Other Deferred Credits on the basis of estimates to the end of 2012. Account 2425 contains the 50% of HST/PST savings to be shared with customers.

Per the December 2010 FAQ, the amounts recorded in 1592 for HST/PST are based on a proxy and the amounts for 2012 can be reliably determined. PowerStream proposes that the clearing of the HST amounts be final and these accounts be closed.

PowerStream proposes that account 1508 IFRS Transition Costs be kept open to track any variance between the approved amounts and the actual. While the amount in revenue for IFRS is known, the costs are estimated and may vary.

PowerStream proposed the following deferral and variance accounts related to IFRS:

- a variance account to track the difference between the estimated PP&E derecognition expense included in the approved 2013 rates and the actual costs in each year until the next setting of cost of service rates; and
- a deferral account for the changes in the post retirement employee benefits liability and costs under MIFRS compared to CGAAP up to this cost of service rebasing; and
- A variance account for changes in the post retirement employee benefits expense included in the approved 2013 rates and the actual costs in each year until the next setting of cost of service rates.

The need for these IFRS deferral and variance accounts is discussed in Exhibit A3, Tab 1, Schedule 5.

V.1.2

Ontario Energy Board

Deferral / Variance Account Work Form

Choose Your Utility:

Peterborough Distribution Incorporated
PowerStream Inc. - Barrie
PowerStream Inc. - South

File Number: EB-2012-0161

Rate Year: 2013

Application Contact Information

Name:	Tom Barrett
Title:	Manager, Rate Applications
Phone Number:	905-532-4640
Email Address:	tom.barrett@powerstream.ca

General Notes

1. Please ensure that your macros have been enabled. (Tools -> Macro -> Security)

2. Due to the time lag of deferral/variance account dispositions, this model assumes that all opening balances include previously disposed of amounts. Accordingly, all "Board Approved Dispositions" are deducted from the opening balance.

3. Please provide information in this model since the last time your balances were disposed.

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

Copyright

Ontario Energy Board

Deferral / Variance Account Work Form
PowerStream Inc.- South

Account Descriptions	Account Number	2005 Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
Group 1 Accounts											
LV Variance Account	1550					$ -					$ -
RSVA - Wholesale Market Service Charge	1580					$ -					$ -
RSVA - Retail Transmission Network Charge	1584					$ -					$ -
RSVA - Retail Transmission Connection Charge	1586					$ -					$ -
RSVA - Power (excluding Global Adjustment)	1588					$ -					$ -
RSVA - Power - Sub-account - Global Adjustment	1588					$ -					$ -
Recovery of Regulatory Asset Balances	1590					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595					$ -					$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508					$ -					$ -
Retail Cost Variance Account - Retail	1518					$ -					$ -
Misc. Deferred Debits	1525					$ -					$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548					$ -					$ -
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572					$ -					$ -
Deferred Rate Impact Amounts	1574					$ -					$ -
RSVA - One-time	1582					$ -					$ -
Other Deferred Credits	2425					$ -					$ -
Group 2 Sub-Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Payments in Lieu of Taxes	1562					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$ -					$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Account Descriptions	Account Number	2005 Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
Special Purpose Charge Assessment Variance Account[9]	1521										
Total including Account 1521		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555					$ -					$ -
Smart Meter OM&A Variance[11]	1556					$ -					$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563					$ -					$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$ -					$ -
Disposition and Recovery of Regulatory Balances[7]	1595					$ -					$ -

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

[1] Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, etc.

[1A] Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 2006 EDR and account 1595 during the 2008 EDR and subsequent years as ordered by the Board.

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

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

[4] Please describe "other" components of 1508 and add more component lines if necessary.

[5] 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.

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

[7] Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, include the balances in Account 1595 on a memo basis only (line 85).

[8] As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1, 2011 will require a variance account for OCEB purposes... The Board expects that any principal balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be addressed through the monthly settlement process with the IESO or the host distributor, as applicable.

[9] The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would have resulted in non-compliance with the timeline set out in section 8 of the SPC regulation.

[10] Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be cleared as an adjustment to the distributor's revenue requirement.

[11] Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Account rate rider. For details on how to dispose of balances in Smart Meter accounts see the Board's Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form
PowerStream Inc.- South

2006

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ -				$ -	$ -				$ -
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534					$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535					$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536					$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -				$ -
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Payments in Lieu of Taxes	1562	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Account Descriptions	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
Special Purpose Charge Assessment Variance Account[9]	**1521**										
Total including Account 1521		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wri

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

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

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If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fro
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refunc

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the pro
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form
PowerStream Inc.- South

2007

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Interest Amounts as of Dec-31-07
Group 1 Accounts											
LV Variance Account	1550	$ -			-$ 351,929	-$ 351,929	$ -			-$ 5,973	-$ 5,973
RSVA - Wholesale Market Service Charge	1580	$ -			-$ 11,351,970	-$ 11,351,970	$ -			-$ 80,971	-$ 80,971
RSVA - Retail Transmission Network Charge	1584	$ -			-$ 806,981	-$ 806,981	$ -			$ 81,190	$ 81,190
RSVA - Retail Transmission Connection Charge	1586	$ -			-$ 7,654,478	-$ 7,654,478	$ -			-$ 911,997	-$ 911,997
RSVA - Power (excluding Global Adjustment)	1588	$ -			-$ 12,626,445	-$ 12,626,445	$ -			-$ 549,524	-$ 549,524
RSVA - Power - Sub-account - Global Adjustment	1588	$ -			$ 9,819,109	$ 9,819,109	$ -			$ 201,949	$ 201,949
Recovery of Regulatory Asset Balances	1590	$ -			$ 712,435	$ 712,435	$ -			$ 1,730,590	$ 1,730,590
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	-$ 22,260,259	-$ 22,260,259	$ -	$ -	$ -	$ 465,264	$ 465,264
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	-$ 32,079,368	-$ 32,079,368	$ -	$ -	$ -	$ 263,315	$ 263,315
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ 9,819,109	$ 9,819,109	$ -	$ -	$ -	$ 201,949	$ 201,949
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -			$ 869,638	$ 869,638	$ -			$ 114,365	$ 114,365
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -			$ 2,164,832	$ 2,164,832	$ -			$ 209,565	$ 209,565
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ -			$ 100,872	$ 100,872	$ -			$ 3,482	$ 3,482
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -				$ -
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -			$ 347,152	$ 347,152	$ -			$ 43,123	$ 43,123
Other Deferred Credits	2425	$ -			$ 33,937	$ 33,937	$ -			-$ 184,024	-$ 184,024
Group 2 Sub-Total		$ -	$ -	$ -	$ 3,516,430	$ 3,516,430	$ -	$ -	$ -	$ 186,511	$ 186,511
Deferred Payments in Lieu of Taxes	1562	$ -			-$ 2,211,040	-$ 2,211,040	$ -			$ 88,846	$ 88,846
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -			-$ 633,969	-$ 633,969	$ -			-$ 31,187	-$ 31,187
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	$ -	-$ 21,588,838	-$ 21,588,838	$ -	$ -	$ -	$ 709,434	$ 709,434

Account Descriptions	Account Number	2007 Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Interest Amounts as of Dec-31-07
Special Purpose Charge Assessment Variance Account[9]	**1521**										
Total including Account 1521		$ -	$ -	$ -	-$ 21,588,838	-$ 21,588,838	$ -	$ -	$ -	$ 709,434	$ 709,434
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wri

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disp

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

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the oblig
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fror
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refunc

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the pro
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form
PowerStream Inc.- South

2008

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Interest Amounts as of Dec-31-08
Group 1 Accounts											
LV Variance Account	1550	-$ 351,929	$ 39,613			-$ 312,316	-$ 5,973	-$ 16,692			-$ 22,665
RSVA - Wholesale Market Service Charge	1580	-$ 11,351,970	-$ 3,867,640			-$ 15,219,610	-$ 80,971	-$ 533,071			-$ 614,042
RSVA - Retail Transmission Network Charge	1584	-$ 806,981	-$ 3,823,999			-$ 4,630,980	$ 81,190	-$ 133,883			-$ 52,693
RSVA - Retail Transmission Connection Charge	1586	-$ 7,654,478	-$ 2,562,496			-$ 10,216,974	-$ 911,997	-$ 367,509			-$ 1,279,506
RSVA - Power (excluding Global Adjustment)	1588	-$ 12,626,445	$ 6,343,595			-$ 6,282,850	-$ 549,524	-$ 217,596			-$ 767,120
RSVA - Power - Sub-account - Global Adjustment	1588	$ 9,819,109	-$ 5,956,240			$ 3,862,869	$ 201,949	$ 54,385			$ 256,334
Recovery of Regulatory Asset Balances	1590	$ 712,435	$ 1,761,410			$ 2,473,845	$ 1,730,590	-$ 65,485			$ 1,665,105
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -	$ -			$ -	$ -	$ -			$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 22,260,259	-$ 8,065,757	$ -	$ -	-$ 30,326,016	$ 465,264	-$ 1,279,851	$ -	$ -	-$ 814,587
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 32,079,368	-$ 2,109,517	$ -	$ -	-$ 34,188,885	$ 263,315	-$ 1,334,236	$ -	$ -	-$ 1,070,921
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 9,819,109	-$ 5,956,240	$ -	$ -	$ 3,862,869	$ 201,949	$ 54,385	$ -	$ -	$ 256,334
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 869,638				$ 869,638	$ 114,365	$ 34,582			$ 148,947
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 2,164,832				$ 2,164,832	$ 209,565	$ 86,086			$ 295,651
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 100,872	$ 12,361			$ 113,233	$ 3,482	$ 6,001			$ 9,483
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -				$ -
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ 347,152				$ 347,152	$ 43,123	$ 13,804			$ 56,927
Other Deferred Credits	2425	$ 33,937	$ 63,416			$ 97,353	-$ 184,024	$ 195,427			$ 11,403
Group 2 Sub-Total		$ 3,516,430	$ 75,777	$ -	$ -	$ 3,592,207	$ 186,511	$ 335,900	$ -	$ -	$ 522,411
Deferred Payments in Lieu of Taxes	1562	-$ 2,211,040	-$ 668,632			-$ 2,879,672	$ 88,846	-$ 111,557			-$ 22,711
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 633,969				-$ 633,969	-$ 31,187	-$ 25,210			-$ 56,397
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 21,588,838	-$ 8,658,612	$ -	$ -	-$ 30,247,450	$ 709,434	-$ 1,080,718	$ -	$ -	-$ 371,285

Account Descriptions	Account Number	2008 Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Interest Amounts as of Dec-31-08
Special Purpose Charge Assessment Variance Account[9]	**1521**										
Total including Account 1521		-$ 21,588,838	-$ 8,658,612	$ -	$ -	-$ 30,247,450	$ 709,434	-$ 1,080,718	$ -	$ -	-$ 371,285
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wri

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

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Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form
PowerStream Inc.- South

2009

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Interest Amounts as of Dec-31-09
Group 1 Accounts											
LV Variance Account	1550	-$ 312,316	-$ 538,141	-$ 351,929		-$ 498,528	-$ 22,665	-$ 5,426	-$ 23,494		-$ 4,597
RSVA - Wholesale Market Service Charge	1580	-$ 15,219,610	-$ 1,007,140	-$ 11,351,970		-$ 4,874,780	-$ 614,042	-$ 160,224	-$ 646,244		-$ 128,022
RSVA - Retail Transmission Network Charge	1584	-$ 4,630,980	$ 1,021,721	-$ 806,981		-$ 2,802,278	-$ 52,693	-$ 47,345	$ 41,007		-$ 141,045
RSVA - Retail Transmission Connection Charge	1586	-$ 10,216,974	-$ 258,458	-$ 7,654,478		-$ 2,820,954	-$ 1,279,506	-$ 106,019	-$ 1,293,154		-$ 92,371
RSVA - Power (excluding Global Adjustment)	1588	-$ 6,282,850	-$ 3,882,084	-$ 12,626,445		$ 2,461,511	-$ 767,120	-$ 60,289	-$ 1,178,257		$ 350,848
RSVA - Power - Sub-account - Global Adjustment	1588	$ 3,862,869	$ 8,021,076	$ -		$ 11,883,945	$ 256,334	$ 72,612	$ -		$ 328,946
Recovery of Regulatory Asset Balances	1590	$ 2,473,845	$ 2,491	$ 2,473,079		$ 3,257	$ 1,665,105	-$ 540,457	$ 1,121,399		$ 3,249
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -	$ 5,424,856	$ 26,738,878		-$ 21,314,022	$ -	-$ 115,038	$ 1,350,023		-$ 1,465,061
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 30,326,016	$ 8,784,321	-$ 3,579,846	$ -	-$ 17,961,849	-$ 814,587	-$ 962,186	-$ 628,720	$ -	-$ 1,148,053
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 34,188,885	$ 763,245	-$ 3,579,846	$ -	-$ 29,845,794	-$ 1,070,921	-$ 1,034,798	-$ 628,720	$ -	-$ 1,476,999
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 3,862,869	$ 8,021,076	$ -	$ -	$ 11,883,945	$ 256,334	$ 72,612	$ -	$ -	$ 328,946
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 869,638		$ 869,638		$ -	$ 148,947	$ 6,051	$ 157,668		-$ 2,671
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 2,164,832		$ 2,164,832		$ -	$ 295,651	$ 15,064	$ 317,364		-$ 6,649
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -	$ 369,780			$ 369,780	$ -	$ 2,256			$ 2,256
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 113,233		$ 100,872		$ 12,361	$ 9,483	$ 1,103	$ 8,505		$ 2,082
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534					$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535					$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536					$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -				$ -
Board-Approved CDM Variance Account	1567										$ -
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ 347,152		$ 347,152		-$ 0	$ 56,927	$ 3,312	$ 60,409		-$ 170
Other Deferred Credits	2425	$ 97,353		$ 97,353		-$ 0	$ 11,403	$ 929	$ 3,020		$ 9,312
Group 2 Sub-Total		$ 3,592,207	$ 369,780	$ 3,579,847	$ -	$ 382,140	$ 522,411	$ 28,715	$ 546,966	$ -	$ 4,160
Deferred Payments in Lieu of Taxes	1562	-$ 2,879,672	-$ 83,745			-$ 2,963,417	-$ 22,711	-$ 32,560			-$ 55,271
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 633,969				-$ 633,969	-$ 56,397	-$ 7,211			-$ 63,609
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 30,247,450	$ 9,070,356	$ 1	$ -	-$ 21,177,095	-$ 371,285	-$ 973,242	-$ 81,754	$ -	-$ 1,262,773

Account Descriptions	Account Number	2009: Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Interest Amounts as of Dec-31-09
Special Purpose Charge Assessment Variance Account[9]	**1521**										
Total including Account 1521		-$ 30,247,450	$ 9,070,356	$ 1	$ -	-$ 21,177,095	-$ 371,285	-$ 973,242	-$ 81,754	$ -	-$ 1,262,773
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wri

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

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Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form PowerStream Inc.- South

2010

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
Group 1 Accounts											
LV Variance Account	1550	-$ 498,528				-$ 498,528	-$ 4,597	-$ 3,986			-$ 8,583
RSVA - Wholesale Market Service Charge	1580	-$ 4,874,780				-$ 4,874,780	-$ 128,022	-$ 38,976			-$ 166,998
RSVA - Retail Transmission Network Charge	1584	-$ 2,802,278				-$ 2,802,278	-$ 141,045	-$ 22,405			-$ 163,450
RSVA - Retail Transmission Connection Charge	1586	-$ 2,820,954				-$ 2,820,954	-$ 92,371	-$ 22,554			-$ 114,925
RSVA - Power (excluding Global Adjustment)	1588	$ 2,461,511				$ 2,461,511	$ 350,848	$ 19,681			$ 370,529
RSVA - Power - Sub-account - Global Adjustment	1588	$ 11,883,945				$ 11,883,945	$ 328,946	$ 95,016			$ 423,962
Recovery of Regulatory Asset Balances	1590	$ 3,257				$ 3,257	$ 3,249	$ 15			$ 3,264
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	-$ 21,314,022				-$ 21,314,022	-$ 1,465,061				-$ 1,465,061
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -	$ 17,251,231			$ 17,251,231	$ -	-$ 94,571			-$ 94,571
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 17,961,849	$ 17,251,231	$ -	$ -	-$ 710,618	-$ 1,148,053	-$ 67,780	$ -	$ -	-$ 1,215,833
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 29,845,794	$ 17,251,231	$ -	$ -	-$ 12,594,563	-$ 1,476,999	-$ 162,796	$ -	$ -	-$ 1,639,795
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 11,883,945	$ -	$ -	$ -	$ 11,883,945	$ 328,946	$ 95,016	$ -	$ -	$ 423,962
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	-$ 2,671				-$ 2,671
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	-$ 6,649				-$ 6,649
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ 369,780	-$ 464,456			-$ 94,676	$ 2,256	$ 763			$ 3,019
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 12,361				$ 12,361	$ 2,082	$ 99			$ 2,180
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531	$ -				$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532	$ -				$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -				$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534	$ -				$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535	$ -				$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536	$ -				$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -				$ -
Board-Approved CDM Variance Account	1567					$ -	$ -				$ -
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	-$ 0				-$ 0	-$ 170	$ -			-$ 170
Other Deferred Credits	2425	-$ 0				-$ 0	$ 9,312				$ 9,312
Group 2 Sub-Total		$ 382,140	-$ 464,456	$ -	$ -	-$ 82,316	$ 4,160	$ 862	$ -	$ -	$ 5,022
Deferred Payments in Lieu of Taxes	1562	-$ 2,963,417	$ -			-$ 2,963,417	-$ 55,271	-$ 23,694			-$ 78,965
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 633,969				-$ 633,969	-$ 63,609	-$ 5,056			-$ 68,665
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 21,177,095	$ 16,786,775	$ -	$ -	-$ 4,390,320	-$ 1,262,773	-$ 95,668	$ -	$ -	-$ 1,358,441

Account Descriptions	Account Number	2010 Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
Special Purpose Charge Assessment Variance Account[9]	**1521**					$ -	-$ 63,609				-$ 63,609
Total including Account 1521		-$ 21,177,095	$ 16,786,775	$ -	$ -	-$ 4,390,320	-$ 1,326,381	-$ 95,668	$ -	$ -	-$ 1,422,050
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -			-$ 4,701,320	-$ 4,701,320	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -			$ 11,390,659	$ 11,390,659	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -			$ 10,347,694	$ 10,347,694	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -			$ 985,715	$ 985,715	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

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Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form
PowerStream Inc.- South

2011

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Other [2] Adjustments during Q1 2011	Other [2] Adjustments during Q2 2011	Other [2] Adjustments during Q3 2011	Other [2] Adjustments during Q4 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11
Group 1 Accounts														
LV Variance Account	1550	-$ 498,528							-$ 498,528	-$ 8,583	-$ 7,328			-$ 15,911
RSVA - Wholesale Market Service Charge	1580	-$ 4,874,780							-$ 4,874,780	-$ 166,998	-$ 71,659			-$ 238,657
RSVA - Retail Transmission Network Charge	1584	-$ 2,802,278							-$ 2,802,278	-$ 163,450	-$ 41,193			-$ 204,643
RSVA - Retail Transmission Connection Charge	1586	-$ 2,820,954							-$ 2,820,954	-$ 114,925	-$ 41,468			-$ 156,393
RSVA - Power (excluding Global Adjustment)	1588	$ 2,461,511							$ 2,461,511	$ 370,529	$ 36,184			$ 406,713
RSVA - Power - Sub-account - Global Adjustment	1588	$ 11,883,945							$ 11,883,945	$ 423,962	$ 174,694			$ 598,656
Recovery of Regulatory Asset Balances	1590	$ 3,257							$ 3,257	$ 3,264	$ 48			$ 3,312
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -							$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	-$ 21,314,022							-$ 21,314,022	-$ 1,465,061				-$ 1,465,061
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ 17,251,231	$ 5,894,847						$ 23,146,078	-$ 94,571	$ 9,977			-$ 84,594
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 710,618	$ 5,894,847	$ -	$ -	$ -	$ -	$ -	$ 5,184,229	-$ 1,215,833	$ 59,254	$ -	$ -	-$ 1,156,579
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 12,594,563	$ 5,894,847	$ -	$ -	$ -	$ -	$ -	-$ 6,699,716	-$ 1,639,795	-$ 115,440	$ -	$ -	-$ 1,755,235
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 11,883,945	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,883,945	$ 423,962	$ 174,694	$ -	$ -	$ 598,656
Group 2 Accounts														
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -							$ -	-$ 2,671				-$ 2,671
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -							$ -	-$ 6,649				-$ 6,649
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	-$ 94,676	-$ 393,801						-$ 488,477	$ 3,019	-$ 4,235			-$ 1,216
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -							$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 12,361							$ 12,361	$ 2,180	$ 182			$ 2,362
Misc. Deferred Debits	1525	$ -							$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531	$ -							$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532	$ -							$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -							$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534	$ -							$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535	$ -							$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536	$ -							$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -							$ -	$ -				$ -
Board-Approved CDM Variance Account	1567	$ -							$ -	$ -				$ -
Extra-Ordinary Event Costs	1572	$ -							$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -							$ -	$ -				$ -
RSVA - One-time	1582	-$ 0							-$ 0	-$ 170	$ -			-$ 170
Other Deferred Credits	2425	-$ 0							-$ 0	$ 9,312				$ 9,312
Group 2 Sub-Total		-$ 82,316	-$ 393,801	$ -	$ -	$ -	$ -	$ -	-$ 476,117	$ 5,022	-$ 4,053	$ -	$ -	$ 969
Deferred Payments in Lieu of Taxes	1562	-$ 2,963,417	-$ 827,897						-$ 3,791,314	-$ 78,965	-$ 158,402			-$ 237,367
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 633,969							-$ 633,969	-$ 68,665	-$ 9,319			-$ 77,984
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -							$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 4,390,320	$ 4,673,149	$ -	$ -	$ -	$ -	$ -	$ 282,829	-$ 1,358,441	-$ 112,521	$ -	$ -	-$ 1,470,962

Account Descriptions	Account Number	2011 Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Other [2] Adjustments during Q1 2011	Other [2] Adjustments during Q2 2011	Other [2] Adjustments during Q3 2011	Other [2] Adjustments during Q4 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11
Special Purpose Charge Assessment Variance Account[9]	**1521**	$ -							$ -	-$ 68,665				-$ 68,665
Total including Account 1521		-$ 4,390,320	$ 4,673,149	$ -	$ -	$ -	$ -	$ -	$ 282,829	-$ 1,427,106	-$ 112,521	$ -	$ -	-$ 1,539,626
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	-$ 4,701,320	-$ 17,242	-$ 4,718,562					$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ 11,390,659	-$ 1,171,279	$ 10,219,380					$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ 10,347,694	-$ 604,500						$ 9,743,194	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ 985,715	$ 927,637	$ 1,824,713					$ 88,639	$ -				$ -
The following is not included in the total claim but are included on a memo basis:														
Deferred PILs Contra Account [5]	1563	$ -							$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -							$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -							$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -							$ -	$ -				$ -

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Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form
PowerStream Inc.- South

Account Descriptions	Account Number	2012: Principal Disposition during 2012 - instructed by Board	2012: Interest Disposition during 2012 - instructed by Board	2012: Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012	2012: Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest on Dec-31-11 Balances: Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Projected Interest on Dec-31-11 Balances: Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Total Claim	2.1.7 RRR: As of Dec 31-11	Variance RRR vs. 2011 Balance *(Principal + Interest)*
Group 1 Accounts										
LV Variance Account	1550			-$ 498,528	-$ 15,911			-$ 514,439		$ 514,439
RSVA - Wholesale Market Service Charge	1580			-$ 4,874,780	-$ 238,657			-$ 5,113,437		$ 5,113,437
RSVA - Retail Transmission Network Charge	1584			-$ 2,802,278	-$ 204,643			-$ 3,006,921		$ 3,006,921
RSVA - Retail Transmission Connection Charge	1586			-$ 2,820,954	-$ 156,393			-$ 2,977,347		$ 2,977,347
RSVA - Power (excluding Global Adjustment)	1588			$ 2,461,511	$ 406,713			$ 2,868,224		-$ 2,868,224
RSVA - Power - Sub-account - Global Adjustment	1588			$ 11,883,945	$ 598,656			$ 12,482,601		-$ 12,482,601
Recovery of Regulatory Asset Balances	1590			$ 3,257	$ 3,312			$ 6,569		-$ 6,569
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595			$ -	$ -			$ -		$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595			-$ 21,314,022	-$ 1,465,061			-$ 22,779,083		$ 22,779,083
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595			$ 23,146,078	-$ 84,594			$ 23,061,484		-$ 23,061,484
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ 5,184,229	-$ 1,156,579	$ -	$ -	$ 4,027,650	$ -	-$ 4,027,650
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	-$ 6,699,716	-$ 1,755,235	$ -	$ -	-$ 8,454,951	$ -	$ 8,454,951
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ 11,883,945	$ 598,656	$ -	$ -	$ 12,482,601	$ -	-$ 12,482,601
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508			$ -	-$ 2,671			-$ 2,671		$ 2,671
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			$ -	-$ 6,649			-$ 6,649		$ 6,649
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			-$ 488,477	-$ 1,216			-$ 489,693		$ 489,693
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508			$ -	$ -			$ -		$ -
Retail Cost Variance Account - Retail	1518			$ 12,361	$ 2,362			$ 14,723		-$ 14,723
Misc. Deferred Debits	1525			$ -	$ -			$ -		$ -
Renewable Generation Connection Capital Deferral Account	1531			$ -	$ -			$ -		$ -
Renewable Generation Connection OM&A Deferral Account	1532			$ -	$ -			$ -		$ -
Renewable Generation Connection Funding Adder Deferral Account	1533			$ -	$ -			$ -		$ -
Smart Grid Capital Deferral Account	1534			$ -	$ -			$ -		$ -
Smart Grid OM&A Deferral Account	1535			$ -	$ -			$ -		$ -
Smart Grid Funding Adder Deferral Account	1536			$ -	$ -			$ -		$ -
Retail Cost Variance Account - STR	1548			$ -	$ -			$ -		$ -
Board-Approved CDM Variance Account	1567			$ -	$ -			$ -		$ -
Extra-Ordinary Event Costs	1572			$ -	$ -			$ -		$ -
Deferred Rate Impact Amounts	1574			$ -	$ -			$ -		$ -
RSVA - One-time	1582			-$ 0	-$ 170			-$ 170		$ 170
Other Deferred Credits	2425			-$ 0	$ 9,312			$ 9,312		-$ 9,312
Group 2 Sub-Total		$ -	$ -	-$ 476,117	$ 969	$ -	$ -	-$ 475,149	$ -	$ 475,149
Deferred Payments in Lieu of Taxes	1562			-$ 3,791,314	-$ 237,367			-$ 4,028,681		$ 4,028,681
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			-$ 633,969	-$ 77,984			-$ 711,953		$ 711,953
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			$ -	$ -			$ -		$ -
										$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	$ 282,829	-$ 1,470,962	$ -	$ -	-$ 1,188,133	$ -	$ 1,188,133

Account Descriptions	Account Number	2012 Principal Disposition during 2012 - instructed by Board	2012 Interest Disposition during 2012 - instructed by Board	2012 Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012	2012 Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest on Dec-31-11 Balances: Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Projected Interest on Dec-31-11 Balances: Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Total Claim	2.1.7 RRR As of Dec 31-11	Variance RRR vs. 2011 Balance *(Principal + Interest)*
Special Purpose Charge Assessment Variance Account[9]	**1521**			$ -	-$ 68,665			-$ 68,665		$ 68,665
										$ -
										$ -
Total including Account 1521		$ -	$ -	$ 282,829	-$ 1,539,626	$ -	$ -	-$ 1,256,797	$ -	$ 1,256,797
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555			$ -	$ -			$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555			$ -	$ -			$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555			$ 9,743,194	$ -			$ 9,743,194		-$ 9,743,194
Smart Meter OM&A Variance[11]	1556			$ 88,639	$ -			$ 88,639		-$ 88,639
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [5]	1563			$ -	$ -			$ -		$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575			$ -	$ -			$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592			$ -	$ -			$ -		$ -
Disposition and Recovery of Regulatory Balances[7]	1595			$ -	$ -			$ -		$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wri

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disp

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

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the oblig
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fror
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refunc

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the pro
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form

Variance Explanations

#N/A

Accounts that produced a variance on the 2013 continuity schedule are listed below.

Account Descriptions	Account Number	Variance RRR vs. 2011 Balance (Principal + Interest)	Explanation
Group 1 Accounts			
LV Variance Account	1550	$ 514,439.36	
RSVA - Wholesale Market Service Charge	1580	$ 5,113,437.27	
RSVA - Retail Transmission Network Charge	1584	$ 3,006,921.49	
RSVA - Retail Transmission Connection Charge	1586	$ 2,977,347.02	
RSVA - Power	1588	$ (2,868,224.21)	
RSVA - Power - Sub-account - Global Adjustment	1588	$ (12,482,600.99)	
Recovery of Regulatory Asset Balances	1590	$ (6,568.88)	
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ 22,779,082.81	
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ 22,779,082.81	
Group 2 Accounts			
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 2,670.61	
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 6,648.74	
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ 489,693.41	
Retail Cost Variance Account - Retail	1518	$ (14,722.52)	
RSVA - One-time	1582	$ 170.16	
Other Deferred Credits	2425	$ (9,311.68)	
Deferred Payments in Lieu of Taxes	1562	$ 4,028,681.26	
PILs and Tax Variance for 2006 and Subsequent Years	1592	$ 711,952.95	
Special Purpose Charge Assessment Variance Account[9]	1521	$ 68,664.61	
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ (9,743,194.00)	
Smart Meter OM&A Variance[11]	1556	$ (88,639.00)	

V.1.2

Ontario Energy Board

Deferral / Variance Account Work Form

Choose Your Utility:

Peterborough Distribution Incorporated
PowerStream Inc. - Barrie
PowerStream Inc. - South

File Number: EB-2012-xxxx

Rate Year: 2013

Application Contact Information

Name:	Tom Barrett
Title:	Manager, Rate Applications
Phone Number:	905-532-4640
Email Address:	tom.barrett@powerstream.ca

General Notes

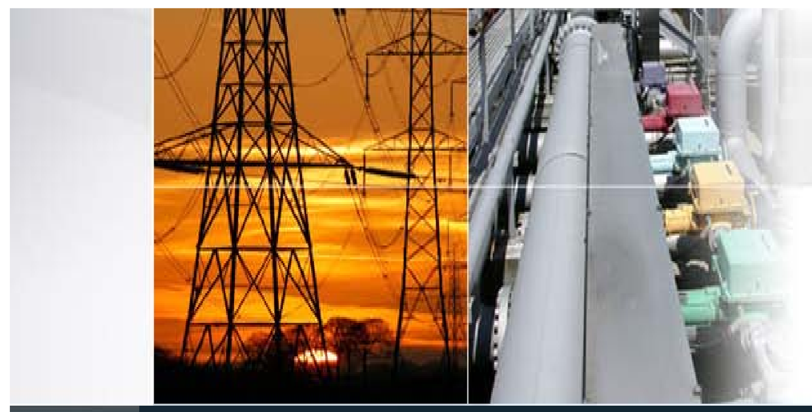
1. Please ensure that your macros have been enabled. (Tools -> Macro -> Security)

2. Due to the time lag of deferral/variance account dispositions, this model assumes that all opening balances include previously disposed of amounts. Accordingly, all "Board Approved Dispositions" are deducted from the opening balance.

3. Please provide information in this model since the last time your balances were disposed.

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

Copyright



Ontario Energy Board

Deferral / Variance Account Work Form PowerStream Inc.- Barrie

#N/A

2005

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
Group 1 Accounts											
LV Variance Account	1550					$ -					$ -
RSVA - Wholesale Market Service Charge	1580					$ -					$ -
RSVA - Retail Transmission Network Charge	1584					$ -					$ -
RSVA - Retail Transmission Connection Charge	1586					$ -					$ -
RSVA - Power (excluding Global Adjustment)	1588					$ -					$ -
RSVA - Power - Sub-account - Global Adjustment	1588					$ -					$ -
Recovery of Regulatory Asset Balances	1590					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595					$ -					$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508					$ -					$ -
Retail Cost Variance Account - Retail	1518					$ -					$ -
Misc. Deferred Debits	1525					$ -					$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548					$ -					$ -
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572					$ -					$ -
Deferred Rate Impact Amounts	1574					$ -					$ -
RSVA - One-time	1582					$ -					$ -
Other Deferred Credits	2425					$ -					$ -
Group 2 Sub-Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Payments in Lieu of Taxes	1562					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$ -					$ -

Account Descriptions	Account Number	2005 Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account[9]	**1521**										
Total including Account 1521		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555					$ -					$ -
Smart Meter OM&A Variance[11]	1556					$ -					$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563					$ -					$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$ -					$ -
Disposition and Recovery of Regulatory Balances[7]	1595					$ -					$ -

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

1 Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, etc.

1A Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 2006 EDR and account 1595 during the 2008 EDR and subsequent years as ordered by the Board.

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

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

4 Please describe "other" components of 1508 and add more component lines if necessary.

5 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.

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

7 Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, include the balances in Account 1595 on a memo basis only (line 85).

8 As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1, 2011 will require a variance account for OCEB purposes... The Board expects that any principal balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be addressed through the monthly settlement process with the IESO or the host distributor, as applicable.

9 The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would have resulted in non-compliance with the timeline set out in section 8 of the SPC regulation.

10 Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be cleared as an adjustment to the distributor's revenue requirement.

11 Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Account rate rider. For details on how to dispose of balances in Smart Meter accounts see the Board's Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
Group 1 Accounts											
LV Variance Account	1550	$ -			$ 19,202	$ 19,202	$ -			-$ 780	-$ 780
RSVA - Wholesale Market Service Charge	1580	$ -			-$ 497,731	-$ 497,731	$ -			$ 58,008	$ 58,008
RSVA - Retail Transmission Network Charge	1584	$ -			$ 299,234	$ 299,234	$ -			$ 8,058	$ 8,058
RSVA - Retail Transmission Connection Charge	1586	$ -			-$ 34,373	-$ 34,373	$ -			-$ 4,083	-$ 4,083
RSVA - Power (excluding Global Adjustment)	1588	$ -			-$ 2,053,441	-$ 2,053,441	$ -			-$ 51,653	-$ 51,653
RSVA - Power - Sub-account - Global Adjustment	1588	$ -			$ 656,625	$ 656,625	$ -			-$ 24,270	-$ 24,270
Recovery of Regulatory Asset Balances	1590	$ -			$ 3,273,936	$ 3,273,936	$ -			$ 858,985	$ 858,985
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ 1,663,452	$ 1,663,452	$ -	$ -	$ -	$ 844,265	$ 844,265
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ 1,006,827	$ 1,006,827	$ -	$ -	$ -	$ 868,535	$ 868,535
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ 656,625	$ 656,625	$ -	$ -	$ -	-$ 24,270	-$ 24,270
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -			$ 796,577	$ 796,577	$ -			$ 44,778	$ 44,778
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ -			$ 47,121	$ 47,121	$ -			$ 3,871	$ 3,871
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534					$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535					$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536					$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -			-$ 10,371	-$ 10,371	$ -			-$ 501	-$ 501
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -			$ 80,600	$ 80,600	$ -			$ 7,197	$ 7,197
Other Deferred Credits	2425	$ -			$ -	$ -	$ -			$ -	$ -
Group 2 Sub-Total		$ -	$ -	$ -	$ 913,927	$ 913,927	$ -	$ -	$ -	$ 55,345	$ 55,345
Deferred Payments in Lieu of Taxes	1562	$ -			-$ 318,764	-$ 318,764	$ -			$ 275,623	$ 275,623
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -			$ -	$ -	$ -			$ -	$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -

2006

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	$ -	$ 2,258,615	$ 2,258,615	$ -	$ -	$ -	$ 1,175,233	$ 1,175,233
Special Purpose Charge Assessment Variance Account[9]	**1521**										
Total including Account 1521		$ -	$ -	$ -	$ 2,258,615	$ 2,258,615	$ -	$ -	$ -	$ 1,175,233	$ 1,175,233
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -			$ -	$ -	$ -			$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -			$ -	$ -	$ -			$ -	$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 20

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dispos

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

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligat
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31
Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from Janu
balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund)

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1, 2
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the procee
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be cl

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Ac
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form PowerStream Inc.- Barrie

#N/A

2007

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Interest Amounts as of Dec-31-07
Group 1 Accounts											
LV Variance Account	1550	$ 19,202	-$ 10,577			$ 8,625	-$ 780	-$ 1,181			-$ 1,961
RSVA - Wholesale Market Service Charge	1580	-$ 497,731	-$ 1,907,889			-$ 2,405,620	$ 58,008	-$ 62,409			-$ 4,401
RSVA - Retail Transmission Network Charge	1584	$ 299,234	$ 250,008			$ 549,242	$ 8,058	$ 24,254			$ 32,312
RSVA - Retail Transmission Connection Charge	1586	-$ 34,373	$ 261,056			$ 226,683	-$ 4,083	$ 908			-$ 3,175
RSVA - Power (excluding Global Adjustment)	1588	-$ 2,053,441	-$ 1,269,935			-$ 3,323,376	-$ 51,653	-$ 120,880			-$ 172,533
RSVA - Power - Sub-account - Global Adjustment	1588	$ 656,625	-$ 406,573			$ 250,052	-$ 24,270	$ 1,923			-$ 22,347
Recovery of Regulatory Asset Balances	1590	$ 3,273,936	-$ 3,535,476			-$ 261,540	$ 858,985	$ 75,596			$ 934,581
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -	$ -			$ -	$ -	$ -			$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ 1,663,452	-$ 6,619,386	$ -	$ -	-$ 4,955,934	$ 844,265	-$ 81,789	$ -	$ -	$ 762,476
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ 1,006,827	-$ 6,212,813	$ -	$ -	-$ 5,205,986	$ 868,535	-$ 83,712	$ -	$ -	$ 784,823
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 656,625	-$ 406,573	$ -	$ -	$ 250,052	-$ 24,270	$ 1,923	$ -	$ -	-$ 22,347
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 796,577				$ 796,577	$ 44,778	$ 37,658			$ 82,436
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 47,121	-$ 5,821			$ 41,300	$ 3,871	$ 1,951			$ 5,822
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548	-$ 10,371	-$ 8,604			-$ 18,975	-$ 501	-$ 497			-$ 998
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ 80,600				$ 80,600	$ 7,197	$ 3,811			$ 11,008
Other Deferred Credits	2425	$ -			$ -	$ -	$ -			$ -	$ -
Group 2 Sub-Total		$ 913,927	-$ 14,425	$ -	$ -	$ 899,502	$ 55,345	$ 42,923	$ -	$ -	$ 98,268
Deferred Payments in Lieu of Taxes	1562	-$ 318,764	$ -			-$ 318,764	$ 275,623	-$ 7,608			$ 268,015
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -	-$ 54,576			-$ 54,576	$ -	-$ 2,707			-$ 2,707
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -

Account Descriptions	Account Number	2007 Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Interest Amounts as of Dec-31-07
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ 2,258,615	-$ 6,688,387	$ -	$ -	-$ 4,429,772	$ 1,175,233	-$ 49,181	$ -	$ -	$ 1,126,052
Special Purpose Charge Assessment Variance Account[9]	**1521**										
Total including Account 1521		$ 2,258,615	-$ 6,688,387	$ -	$ -	-$ 4,429,772	$ 1,175,233	-$ 49,181	$ -	$ -	$ 1,126,052
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e
a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 20

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dispos

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

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligat
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31
Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from Janu
balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund)

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1, 2
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the procee
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be cle

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Ac
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form PowerStream Inc.-Barrie

#N/A

2008

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Interest Amounts as of Dec-31-08
Group 1 Accounts											
LV Variance Account	1550	$ 8,625	$ 96,216	$ 19,202		$ 85,639	-$ 1,961	$ 984	$ 397		-$ 1,374
RSVA - Wholesale Market Service Charge	1580	-$ 2,405,620	-$ 723,683			-$ 3,129,303	-$ 4,401	-$ 112,506			-$ 116,907
RSVA - Retail Transmission Network Charge	1584	$ 549,242	-$ 857,763			-$ 308,521	$ 32,312	$ 2,383			$ 34,695
RSVA - Retail Transmission Connection Charge	1586	$ 226,683	-$ 601,658			-$ 374,975	-$ 3,175	-$ 1,238			-$ 4,413
RSVA - Power (excluding Global Adjustment)	1588	-$ 3,323,376	$ 430,641			-$ 2,892,735	-$ 172,533	-$ 122,626			-$ 295,159
RSVA - Power - Sub-account - Global Adjustment	1588	$ 250,052	$ 927,758			$ 1,177,810	-$ 22,347	$ 10,237			-$ 12,110
Recovery of Regulatory Asset Balances	1590	-$ 261,540	-$ 277,581			-$ 539,121	$ 934,581	-$ 948,120			-$ 13,539
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -	$ -			$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 4,955,934	-$ 1,006,070	$ 19,202	$ -	-$ 5,981,206	$ 762,476	-$ 1,170,886	$ 397	$ -	-$ 408,807
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 5,205,986	-$ 1,933,828	$ 19,202	$ -	-$ 7,159,016	$ 784,823	-$ 1,181,123	$ 397	$ -	-$ 396,697
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 250,052	$ 927,758	$ -	$ -	$ 1,177,810	-$ 22,347	$ 10,237	$ -	$ -	-$ 12,110
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 796,577		$ 796,577		$ -	$ 82,436		$ 82,436		$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 41,300	$ 8,937			$ 50,237	$ 5,822	$ 1,817			$ 7,639
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548	-$ 18,975	-$ 5,274			-$ 24,249	-$ 998	-$ 1,014			-$ 2,012
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ 80,600				$ 80,600	$ 11,008	$ 3,208			$ 14,216
Other Deferred Credits	2425	$ -	$ -			$ -	$ -	$ -			$ -
Group 2 Sub-Total		$ 899,502	$ 3,663	$ 796,577	$ -	$ 106,588	$ 98,268	$ 4,011	$ 82,436	$ -	$ 19,843
Deferred Payments in Lieu of Taxes	1562	-$ 318,764				-$ 318,764	$ 268,015	-$ 13,162			$ 254,853
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 54,576	$ -			-$ 54,576	-$ 2,707	-$ 2,253			-$ 4,960
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -

Account Descriptions	Account Number	2008 Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Interest Amounts as of Dec-31-08
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 4,429,772	-$ 1,002,407	$ 815,779	$ -	-$ 6,247,958	$ 1,126,052	-$ 1,182,290	$ 82,833	$ -	-$ 139,071
Special Purpose Charge Assessment Variance Account[9]	**1521**										
Total including Account 1521		-$ 4,429,772	-$ 1,002,407	$ 815,779	$ -	-$ 6,247,958	$ 1,126,052	-$ 1,182,290	$ 82,833	$ -	-$ 139,071
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 20

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dispos

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

Please describe "other" components of 1508 and add more component lines if necessary.

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If the LDC’s 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31
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Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund)

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As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
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balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be a

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the procee
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be cle

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Acc
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form PowerStream Inc.- Barrie

#N/A

Account Descriptions	Account Number	2009: Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Interest Amounts as of Dec-31-09
Group 1 Accounts											
LV Variance Account	1550	$ 85,639	-$ 150,811			-$ 65,172	-$ 1,374	$ 893			-$ 481
RSVA - Wholesale Market Service Charge	1580	-$ 3,129,303	-$ 267,069			-$ 3,396,372	-$ 116,907	-$ 35,983			-$ 152,890
RSVA - Retail Transmission Network Charge	1584	-$ 308,521	$ 286,232			-$ 22,289	$ 34,695	-$ 4,240			$ 30,455
RSVA - Retail Transmission Connection Charge	1586	-$ 374,975	-$ 103,340			-$ 478,315	-$ 4,413	-$ 5,160			-$ 9,573
RSVA - Power (excluding Global Adjustment)	1588	-$ 2,892,735	-$ 3,062,075			-$ 5,954,810	-$ 295,159	-$ 44,102			-$ 339,261
RSVA - Power - Sub-account - Global Adjustment	1588	$ 1,177,810	$ 4,424,023			$ 5,601,833	-$ 12,110	$ 31,130			$ 19,020
Recovery of Regulatory Asset Balances	1590	-$ 539,121	$ -			-$ 539,121	-$ 13,539	-$ 6,190			-$ 19,729
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -	-$ 519,551	-$ 815,779		$ 296,228	$ -	$ 26,591	-$ 93,924		$ 120,515
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 5,981,206	$ 607,409	-$ 815,779	$ -	-$ 4,558,018	-$ 408,807	-$ 37,061	-$ 93,924	$ -	-$ 351,944
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 7,159,016	-$ 3,816,614	-$ 815,779	$ -	-$ 10,159,851	-$ 396,697	-$ 68,191	-$ 93,924	$ -	-$ 370,964
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 1,177,810	$ 4,424,023	$ -	$ -	$ 5,601,833	-$ 12,110	$ 31,130	$ -	$ -	$ 19,020
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -	$ 242,444			$ 242,444	$ -	$ 862			$ 862
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 50,237				$ 50,237	$ 7,639	$ 571			$ 8,210
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534					$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535					$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536					$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	-$ 24,249				-$ 24,249	-$ 2,012	-$ 276			-$ 2,288
Board-Approved CDM Variance Account	1567										$ -
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ 80,600				$ 80,600	$ 14,216	$ 917			$ 15,133
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ 106,588	$ 242,444	$ -	$ -	$ 349,032	$ 19,843	$ 2,074	$ -	$ -	$ 21,917
Deferred Payments in Lieu of Taxes	1562	-$ 318,764	-$ 51,565			-$ 370,329	$ 254,853	-$ 10,781			$ 244,072
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 54,576				-$ 54,576	-$ 4,960	-$ 621			-$ 5,581
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -

Account Descriptions	Account Number	2009 Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Interest Amounts as of Dec-31-09
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 6,247,958	$ 798,288	-$ 815,779	$ -	-$ 4,633,891	-$ 139,071	-$ 46,388	-$ 93,924	$ -	-$ 91,535
Special Purpose Charge Assessment Variance Account[9]	**1521**										
Total including Account 1521		-$ 6,247,958	$ 798,288	-$ 815,779	$ -	-$ 4,633,891	-$ 139,071	-$ 46,388	-$ 93,924	$ -	-$ 91,535
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

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Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund)

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Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form PowerStream Inc.- Barrie

#N/A

2010

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
Group 1 Accounts											
LV Variance Account	1550	-$ 65,172		$ 85,639		-$ 150,811	-$ 481	-$ 1,051	-$ 246		-$ 1,286
RSVA - Wholesale Market Service Charge	1580	-$ 3,396,372		-$ 3,129,303		-$ 267,069	-$ 152,890	-$ 7,794	-$ 158,128		-$ 2,556
RSVA - Retail Transmission Network Charge	1584	-$ 22,289		-$ 308,521		$ 286,232	$ 30,455	$ 1,731	$ 30,631		$ 1,555
RSVA - Retail Transmission Connection Charge	1586	-$ 478,315		-$ 374,975		-$ 103,340	-$ 9,573	-$ 1,504	-$ 9,352		-$ 1,725
RSVA - Power (excluding Global Adjustment)	1588	-$ 5,954,810		-$ 2,892,735		-$ 3,062,075	-$ 339,261	-$ 29,713	-$ 333,264		-$ 35,710
RSVA - Power - Sub-account - Global Adjustment	1588	$ 5,601,833		$ 1,177,810		$ 4,424,023	$ 19,020	$ 37,501	$ 3,405		$ 53,116
Recovery of Regulatory Asset Balances	1590	-$ 539,121		-$ 539,121		$ -	-$ 19,729	-$ 940	-$ 20,641		-$ 28
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ 296,228				$ 296,228	$ 120,515				$ 120,515
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -	$ 3,501,747	$ 5,981,206		-$ 2,479,459	$ -	-$ 23,310	$ 487,595		-$ 510,905
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 4,558,018	$ 3,501,747	$ -	$ -	-$ 1,056,271	-$ 351,944	-$ 25,080	$ -	$ -	-$ 377,024
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 10,159,851	$ 3,501,747	-$ 1,177,810	$ -	-$ 5,480,294	-$ 370,964	-$ 62,581	-$ 3,405	$ -	-$ 430,140
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 5,601,833	$ -	$ 1,177,810	$ -	$ 4,424,023	$ 19,020	$ 37,501	$ 3,405	$ -	$ 53,116
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ 242,444	$ 78,499			$ 320,943	$ 862	$ 2,241			$ 3,103
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 50,237				$ 50,237	$ 8,210	$ 401			$ 8,611
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531	$ -				$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532	$ -				$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -				$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534	$ -				$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535	$ -				$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536	$ -				$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	-$ 24,249				-$ 24,249	-$ 2,288	-$ 193			-$ 2,481
Board-Approved CDM Variance Account	1567					$ -	$ -				$ -
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ 80,600				$ 80,600	$ 15,133	$ 643			$ 15,776
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ 349,032	$ 78,499	$ -	$ -	$ 427,531	$ 21,917	$ 3,091	$ -	$ -	$ 25,009
Deferred Payments in Lieu of Taxes	1562	-$ 370,329	$ -			-$ 370,329	$ 244,072	-$ 2,961			$ 241,111
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 54,576				-$ 54,576	-$ 5,581	-$ 435			-$ 6,016
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -

Account Descriptions	Account Number	2010 Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 4,633,891	$ 3,580,246	$ -	$ -	-$ 1,053,645	-$ 91,535	-$ 25,385	$ -	$ -	-$ 116,920
Special Purpose Charge Assessment Variance Account[9]	**1521**					$ -	-$ 5,581				-$ 5,581
Total including Account 1521		-$ 4,633,891	$ 3,580,246	$ -	$ -	-$ 1,053,645	-$ 97,116	-$ 25,385	$ -	$ -	-$ 122,501
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -			-$ 2,346,843	-$ 2,346,843	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -			$ 9,640,354	$ 9,640,354	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -			$ 3,149,265	$ 3,149,265	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -			$ 691,960	$ 691,960	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 20

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dispose

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

Please describe "other" components of 1508 and add more component lines if necessary.

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If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31
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Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund)

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balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the procee
non-compliance with the timeline set out in section 8 of the SPC regulation.

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Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Ac
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form PowerStream Inc.- Barrie

#N/A

Account Descriptions	Account Number	2011 Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Other [2] Adjustments during Q1 2011	Other [2] Adjustments during Q2 2011	Other [2] Adjustments during Q3 2011	Other [2] Adjustments during Q4 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11
Group 1 Accounts														
LV Variance Account	1550	-$ 150,811							-$ 150,811	-$ 1,286	-$ 2,217			-$ 3,503
RSVA - Wholesale Market Service Charge	1580	-$ 267,069							-$ 267,069	-$ 2,556	-$ 3,926			-$ 6,482
RSVA - Retail Transmission Network Charge	1584	$ 286,232							$ 286,232	$ 1,555	$ 4,208			$ 5,763
RSVA - Retail Transmission Connection Charge	1586	-$ 103,340							-$ 103,340	-$ 1,725	-$ 1,519			-$ 3,244
RSVA - Power (excluding Global Adjustment)	1588	-$ 3,062,075							-$ 3,062,075	-$ 35,710	-$ 45,013			-$ 80,723
RSVA - Power - Sub-account - Global Adjustment	1588	$ 4,424,023							$ 4,424,023	$ 53,116	$ 65,033			$ 118,149
Recovery of Regulatory Asset Balances	1590	$ -							$ -	-$ 28	$ -			-$ 28
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -							$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ 296,228							$ 296,228	$ 120,515				$ 120,515
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	-$ 2,479,459	$ 2,584,307						$ 104,848	-$ 510,905	-$ 3,645			-$ 514,550
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 1,056,271	$ 2,584,307	$ -	$ -	$ -	$ -	$ -	$ 1,528,036	-$ 377,024	$ 12,921	$ -	$ -	-$ 364,103
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 5,480,294	$ 2,584,307	$ -	$ -	$ -	$ -	$ -	-$ 2,895,987	-$ 430,140	-$ 52,112	$ -	$ -	-$ 482,252
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ 4,424,023	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,424,023	$ 53,116	$ 65,033	$ -	$ -	$ 118,149
Group 2 Accounts														
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ 320,943	$ 98,270						$ 419,213	$ 3,103	$ 5,332			$ 8,435
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -							$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 50,237							$ 50,237	$ 8,611	$ 738			$ 9,350
Misc. Deferred Debits	1525	$ -							$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531	$ -							$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532	$ -							$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -							$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534	$ -							$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535	$ -							$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536	$ -							$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	-$ 24,249							-$ 24,249	-$ 2,481	-$ 356			-$ 2,838
Board-Approved CDM Variance Account	1567	$ -							$ -	$ -				$ -
Extra-Ordinary Event Costs	1572	$ -							$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -							$ -	$ -				$ -
RSVA - One-time	1582	$ 80,600							$ 80,600	$ 15,776	$ 1,185			$ 16,960
Other Deferred Credits	2425	$ -							$ -	$ -				$ -
Group 2 Sub-Total		$ 427,531	$ 98,270	$ -	$ -	$ -	$ -	$ -	$ 525,801	$ 25,009	$ 6,899	$ -	$ -	$ 31,907
Deferred Payments in Lieu of Taxes	1562	-$ 370,329	-$ 350,906						-$ 721,235	$ 241,111	-$ 82,819			$ 158,292
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 54,576							-$ 54,576	-$ 6,016	-$ 802			-$ 6,818
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -							$ -	$ -				$ -

Account Descriptions	Account Number	2011 Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Other [2] Adjustments during Q1 2011	Other [2] Adjustments during Q2 2011	Other [2] Adjustments during Q3 2011	Other [2] Adjustments during Q4 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 1,053,645	$ 2,331,671	$ -	$ -	$ -	$ -	$ -	$ 1,278,026	-$ 116,920	-$ 63,801	$ -	$ -	-$ 180,721
Special Purpose Charge Assessment Variance Account[9]	**1521**	$ -							$ -	-$ 6,016				-$ 6,016
Total including Account 1521		-$ 1,053,645	$ 2,331,671	$ -	$ -	$ -	$ -	$ -	$ 1,278,026	-$ 122,936	-$ 63,801	$ -	$ -	-$ 186,737
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	-$ 2,346,843	-$ 454,579	-$ 2,801,422					$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ 9,640,354	$ 47,020	$ 9,687,374					$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ 3,149,265	-$ 103,675						$ 3,045,590	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ 691,960	$ 1,417,356	$ 1,957,148					$ 152,168	$ -				$ -
The following is not included in the total claim but are included on a memo basis:														
Deferred PILs Contra Account [5]	1563	$ -							$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -							$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -							$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -							$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 20

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dispos

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

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligat

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31 Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from Janu balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund)

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
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The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the procee non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be cl

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Ac Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2012: Principal Disposition during 2012 - instructed by Board	2012: Interest Disposition during 2012 - instructed by Board	2012: Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012	2012: Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest on Dec-31-11 Balances: Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Projected Interest on Dec-31-11 Balances: Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Total Claim	2.1.7 RRR: As of Dec 31-11	Variance RRR vs. 2011 Balance (Principal + Interest)
Group 1 Accounts										
LV Variance Account	1550			-$ 150,811	-$ 3,503			-$ 154,314		$ 154,314
RSVA - Wholesale Market Service Charge	1580			-$ 267,069	-$ 6,482			-$ 273,551		$ 273,551
RSVA - Retail Transmission Network Charge	1584			$ 286,232	$ 5,763			$ 291,995		-$ 291,995
RSVA - Retail Transmission Connection Charge	1586			-$ 103,340	-$ 3,244			-$ 106,584		$ 106,584
RSVA - Power (excluding Global Adjustment)	1588			-$ 3,062,075	-$ 80,723			-$ 3,142,798		$ 3,142,798
RSVA - Power - Sub-account - Global Adjustment	1588			$ 4,424,023	$ 118,149			$ 4,542,172		-$ 4,542,172
Recovery of Regulatory Asset Balances	1590			$ -	-$ 28			-$ 28		$ 28
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595			$ -	$ -			$ -		$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595			$ 296,228	$ 120,515			$ 416,743		-$ 416,743
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595			$ 104,848	-$ 514,550			-$ 409,702		$ 409,702
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ 1,528,036	-$ 364,103	$ -	$ -	$ 1,163,933	$ -	-$ 1,163,933
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	-$ 2,895,987	-$ 482,252	$ -	$ -	-$ 3,378,239	$ -	$ 3,378,239
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ 4,424,023	$ 118,149	$ -	$ -	$ 4,542,172	$ -	-$ 4,542,172
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			$ 419,213	$ 8,435			$ 427,648		-$ 427,648
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508			$ -	$ -			$ -		$ -
Retail Cost Variance Account - Retail	1518			$ 50,237	$ 9,350			$ 59,587		-$ 59,587
Misc. Deferred Debits	1525			$ -	$ -			$ -		$ -
Renewable Generation Connection Capital Deferral Account	1531			$ -	$ -			$ -		$ -
Renewable Generation Connection OM&A Deferral Account	1532			$ -	$ -			$ -		$ -
Renewable Generation Connection Funding Adder Deferral Account	1533			$ -	$ -			$ -		$ -
Smart Grid Capital Deferral Account	1534			$ -	$ -			$ -		$ -
Smart Grid OM&A Deferral Account	1535			$ -	$ -			$ -		$ -
Smart Grid Funding Adder Deferral Account	1536			$ -	$ -			$ -		$ -
Retail Cost Variance Account - STR	1548			-$ 24,249	-$ 2,838			-$ 27,087		$ 27,087
Board-Approved CDM Variance Account	1567			$ -	$ -			$ -		$ -
Extra-Ordinary Event Costs	1572			$ -	$ -			$ -		$ -
Deferred Rate Impact Amounts	1574			$ -	$ -			$ -		$ -
RSVA - One-time	1582			$ 80,600	$ 16,960			$ 97,560		-$ 97,560
Other Deferred Credits	2425			$ -	$ -			$ -		$ -
Group 2 Sub-Total		$ -	$ -	$ 525,801	$ 31,907	$ -	$ -	$ 557,708	$ -	-$ 557,708
Deferred Payments in Lieu of Taxes	1562			-$ 721,235	$ 158,292			-$ 562,943		$ 562,943
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			-$ 54,576	-$ 6,818			-$ 61,394		$ 61,394
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			$ -	$ -			$ -		$ -
										$ -

Account Descriptions	Account Number	2012 Principal Disposition during 2012 - instructed by Board	Interest Disposition during 2012 - instructed by Board	Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest on Dec-31-11 Balances: Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Total Claim	2.1.7 RRR As of Dec 31-11	Variance RRR vs. 2011 Balance *(Principal + Interest)*
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	$ 1,278,026	-$ 180,721	$ -	$ -	$ 1,097,305	$ -	-$ 1,097,305
Special Purpose Charge Assessment Variance Account[9]	**1521**			$ -	-$ 6,016			-$ 6,016		$ 6,016
										$ -
										$ -
Total including Account 1521		$ -	$ -	$ 1,278,026	-$ 186,737	$ -	$ -	$ 1,091,289	$ -	-$ 1,091,289
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555			$ -	$ -			$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555			$ -	$ -			$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555			$ 3,045,590	$ -			$ 3,045,590		-$ 3,045,590
Smart Meter OM&A Variance[11]	1556			$ 152,168	$ -			$ 152,168		-$ 152,168
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [5]	1563			$ -	$ -			$ -		$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575			$ -	$ -			$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592			$ -	$ -			$ -		$ -
Disposition and Recovery of Regulatory Balances[7]	1595			$ -	$ -			$ -		$ -

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Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form

Variance Explanations

#N/A

Accounts that produced a variance on the 2013 continuity schedule are listed below.

Account Descriptions	Account Number	Variance RRR vs. 2011 Balance *(Principal + Interest)*	Explanation
Group 1 Accounts			
LV Variance Account	1550	$ 154,313.92	
RSVA - Wholesale Market Service Charge	1580	$ 273,550.91	
RSVA - Retail Transmission Network Charge	1584	$ (291,994.61)	
RSVA - Retail Transmission Connection Charge	1586	$ 106,584.10	
RSVA - Power	1588	$ 3,142,797.50	
RSVA - Power - Sub-account - Global Adjustment	1588	$ (4,542,172.14)	
Recovery of Regulatory Asset Balances	1590	$ 28.00	
Group 2 Accounts			
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -	
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ (427,648.38)	

V.1.2

Ontario Energy Board

Deferral / Variance Account Work Form

Choose Your Utility:

Peterborough Distribution Incorporated
PowerStream Inc. - Barrie
PowerStream Inc. - South

File Number: EB-2012-0161

Rate Year: 2013

Application Contact Information

Name:	Tom Barrett
Title:	Manager, Rate Applications
Phone Number:	905-532-4640
Email Address:	tom.barrett@powerstream.ca

General Notes

1. Please ensure that your macros have been enabled. (Tools -> Macro -> Security)

2. Due to the time lag of deferral/variance account dispositions, this model assumes that all opening balances include previously disposed of amounts. Accordingly, all "Board Approved Dispositions" are deducted from the opening balance.

3. Please provide information in this model since the last time your balances were disposed.

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

Copyright

Deferral / Variance Account Work Form PowerStream Inc.- Shared

Account Descriptions	Account Number	2005 Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
Group 1 Accounts											
LV Variance Account	1550					$ -					$ -
RSVA - Wholesale Market Service Charge	1580					$ -					$ -
RSVA - Retail Transmission Network Charge	1584					$ -					$ -
RSVA - Retail Transmission Connection Charge	1586					$ -					$ -
RSVA - Power (excluding Global Adjustment)	1588					$ -					$ -
RSVA - Power - Sub-account - Global Adjustment	1588					$ -					$ -
Recovery of Regulatory Asset Balances	1590					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595					$ -					$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595					$ -					$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508					$ -					$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508					$ -					$ -
Retail Cost Variance Account - Retail	1518					$ -					$ -
Misc. Deferred Debits	1525					$ -					$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548					$ -					$ -
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572					$ -					$ -
Deferred Rate Impact Amounts	1574					$ -					$ -
RSVA - One-time	1582					$ -					$ -
Other Deferred Credits	2425					$ -					$ -
Group 2 Sub-Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Payments in Lieu of Taxes	1562					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					$ -					$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Account Descriptions	Account Number	2005									
		Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [3]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
Special Purpose Charge Assessment Variance Account[9]	**1521**										
Total including Account 1521		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555					$ -					$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555					$ -					$ -
Smart Meter OM&A Variance[11]	1556					$ -					$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563					$ -					$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575					$ -					$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$ -					$ -
Disposition and Recovery of Regulatory Balances[7]	1595					$ -					$ -

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

1 Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, etc.

1A Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 2006 EDR and account 1595 during the 2008 EDR and subsequent years as ordered by the Board.

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

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

4 Please describe "other" components of 1508 and add more component lines if necessary.

5 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.

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

7 Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, include the balances in Account 1595 on a memo basis only (line 85).

8 As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1, 2011 will require a variance account for OCEB purposes... The Board expects that any principal balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be addressed through the monthly settlement process with the IESO or the host distributor, as applicable.

9 The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would have resulted in non-compliance with the timeline set out in section 8 of the SPC regulation.

10 Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be cleared as an adjustment to the distributor's revenue requirement.

11 Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Account rate rider. For details on how to dispose of balances in Smart Meter accounts see the Board's Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form PowerStream Inc.- Shared

2006

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ -				$ -	$ -				$ -
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534					$ -	$ -				$ -
Smart Grid OM&A Deferral Account	1535					$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536					$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -				$ -
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Payments in Lieu of Taxes	1562	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Account Descriptions	Account Number	2006									
		Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [3]	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1, 1A]	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06
Special Purpose Charge Assessment Variance Account[9]	**1521**										
Total including Account 1521		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wr

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disp

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

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obl
If the LDC’s 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December
the Board in the 2012 rate decision. If the LDC’s 2013 rate year begins May 1, 2013 the projected interest is recorded fror
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refun

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will b

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the pro
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form PowerStream Inc.- Shared

Account Descriptions	Account Number	2007 Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Interest Amounts as of Dec-31-07
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ -				$ -	$ -				$ -
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -				$ -
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Payments in Lieu of Taxes	1562	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Account Descriptions	Account Number	2007									
		Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [3]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [2]	Closing Interest Amounts as of Dec-31-07
Special Purpose Charge Assessment Variance Account[9]	**1521**										
Total including Account 1521		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig
have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wr

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disp

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

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obl
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fror
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refun

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will b

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the pro
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form PowerStream Inc.- Shared

2008

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Interest Amounts as of Dec-31-08
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508										
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ -				$ -	$ -				$ -
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -					$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -					$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -					$ -
Smart Grid Capital Deferral Account	1534					$ -					$ -
Smart Grid OM&A Deferral Account	1535					$ -					$ -
Smart Grid Funding Adder Deferral Account	1536					$ -					$ -
Retail Cost Variance Account - STR	1548	$ -				$ -	$ -				$ -
Board-Approved CDM Variance Account	1567										
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -				$ -
Other Deferred Credits	2425	$ -				$ -	$ -				$ -
Group 2 Sub-Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Payments in Lieu of Taxes	1562	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Account Descriptions	Account Number	2008									
		Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [3]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [2]	Closing Interest Amounts as of Dec-31-08
Special Purpose Charge Assessment Variance Account[9]	1521										
Total including Account 1521		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wr

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disp

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

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obl
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fror
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refun

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will b

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the pro
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form PowerStream Inc.- Shared

Account Descriptions	Account Number	2009 Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Interest Amounts as of Dec-31-09
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -	$ -			$ -	$ -	$ 2,576			$ 2,576
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	$ -			$ -	$ -	$ 6,558			$ 6,558
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ -	$ 44,152			$ 44,152	$ -	$ 18			$ 18
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508					$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ -	$ 1,449			$ 1,449	$ -	$ 108			$ 108
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531					$ -	$ -				$ -
Renewable Generation Connection OM&A Deferral Account	1532					$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533					$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534		$ 5,009			$ 5,009	$ -	$ 2			$ 2
Smart Grid OM&A Deferral Account	1535					$ -	$ -				$ -
Smart Grid Funding Adder Deferral Account	1536					$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -	-$ 1,880			-$ 1,880	$ -	-$ 4			-$ 4
Board-Approved CDM Variance Account	1567										$ -
Extra-Ordinary Event Costs	1572	$ -				$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -				$ -	$ -	$ 125			$ 125
Other Deferred Credits	2425	$ -	$ 7			$ 7	$ -	$ 29			$ 29
Group 2 Sub-Total		$ -	$ 48,737	$ -	$ -	$ 48,737	$ -	$ 9,411	$ -	$ -	$ 9,411
Deferred Payments in Lieu of Taxes	1562	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$ -	-$ 105,305			-$ 105,305	$ -	-$ 2			-$ 2
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -				$ -	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	-$ 56,568	$ -	$ -	-$ 56,568	$ -	$ 9,409	$ -	$ -	$ 9,409

Account Descriptions	Account Number	2009 Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [3]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [2]	Closing Interest Amounts as of Dec-31-09
Special Purpose Charge Assessment Variance Account[9]	**1521**										
Total including Account 1521		$ -	-$ 56,568	$ -	$ -	-$ 56,568	$ -	$ 9,409	$ -	$ -	$ 9,409
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wr

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disp

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

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obl
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December
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disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refun

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
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balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will b

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the pro
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Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance A
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form PowerStream Inc.- Shared

2010

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
Group 1 Accounts											
LV Variance Account	1550	$ -	-$ 325,044			-$ 325,044	$ -	-$ 1,518			-$ 1,518
RSVA - Wholesale Market Service Charge	1580	$ -	-$ 8,512,333			-$ 8,512,333	$ -	-$ 33,372			-$ 33,372
RSVA - Retail Transmission Network Charge	1584	$ -	$ 3,095,654			$ 3,095,654	$ -	$ 15,079			$ 15,079
RSVA - Retail Transmission Connection Charge	1586	$ -	$ 28,790			$ 28,790	$ -	$ 719			$ 719
RSVA - Power (excluding Global Adjustment)	1588	$ -	$ 712,267			$ 712,267	$ -	$ 9,552			$ 9,552
RSVA - Power - Sub-account - Global Adjustment	1588	$ -	-$ 994,699			-$ 994,699	$ -	-$ 32,314			-$ 32,314
Recovery of Regulatory Asset Balances	1590	$ -	-$ 3,876			-$ 3,876	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	-$ 5,999,241	$ -	$ -	-$ 5,999,241	$ -	-$ 41,854	$ -	$ -	-$ 41,854
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	-$ 5,004,542	$ -	$ -	-$ 5,004,542	$ -	-$ 9,540	$ -	$ -	-$ 9,540
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	-$ 994,699	$ -	$ -	-$ 994,699	$ -	-$ 32,314	$ -	$ -	-$ 32,314
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -				$ -	$ 2,576				$ 2,576
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -				$ -	$ 6,558				$ 6,558
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ 44,152	$ 21,118			$ 65,270	$ 18	$ 490			$ 508
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -				$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -				$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	$ 1,449	-$ 39,188			-$ 37,739	$ 108	$ 4			$ 111
Misc. Deferred Debits	1525	$ -				$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531	$ -	$ 84,798			$ 84,798	$ -	$ 296			$ 296
Renewable Generation Connection OM&A Deferral Account	1532	$ -				$ -	$ -				$ -
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -				$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534	$ 5,009	$ 186,887			$ 191,896	$ 2	$ 367			$ 369
Smart Grid OM&A Deferral Account	1535	$ -	$ 206,380			$ 206,380	$ -	$ 393			$ 393
Smart Grid Funding Adder Deferral Account	1536	$ -				$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	-$ 1,880				-$ 1,880	-$ 4	-$ 16			-$ 20
Board-Approved CDM Variance Account	1567					$ -	$ -				$ -
Extra-Ordinary Event Costs	1572	$ -	$ 1,024,433			$ 1,024,433	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -				$ -	$ -				$ -
RSVA - One-time	1582	$ -	-$ 45,640			-$ 45,640	$ 125	-$ 90			$ 35
Other Deferred Credits	2425	$ 7	-$ 145,939			-$ 145,932	$ 29	-$ 9,689			-$ 9,660
Group 2 Sub-Total		$ 48,737	$ 1,292,849	$ -	$ -	$ 1,341,586	$ 9,411	-$ 8,245	$ -	$ -	$ 1,166
Deferred Payments in Lieu of Taxes	1562	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 105,305	-$ 68,155			-$ 173,460	-$ 2	-$ 1,152			-$ 1,154
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ -	-$ 291,859			-$ 291,859	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 56,568	-$ 5,066,406	$ -	$ -	-$ 5,122,974	$ 9,409	-$ 51,251	$ -	$ -	-$ 41,841

Account Descriptions	Account Number	2010 Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [3]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
Special Purpose Charge Assessment Variance Account[9]	**1521**		$ 1,094,729			$ 1,094,729	-$ 2	$ 7,756			$ 7,754
Total including Account 1521		-$ 56,568	-$ 3,971,677	$ -	$ -	-$ 4,028,245	$ 9,408	-$ 43,495	$ -	$ -	-$ 34,087
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -				$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -				$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -				$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account [5]	1563	$ -				$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -				$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -	$ 291,859			$ 291,859	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wr

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disp

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

Please describe "other" components of 1508 and add more component lines if necessary.

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Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refun

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Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance A
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

2011

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Other [2] Adjustments during Q1 2011	Other [2] Adjustments during Q2 2011	Other [2] Adjustments during Q3 2011	Other [2] Adjustments during Q4 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11
Group 1 Accounts														
LV Variance Account	1550	-$ 325,044	$ 293,576						-$ 31,468	-$ 1,518	-$ 4,342			-$ 5,860
RSVA - Wholesale Market Service Charge	1580	-$ 8,512,333	-$ 8,506,527						-$ 17,018,860	-$ 33,372	-$ 175,081			-$ 208,453
RSVA - Retail Transmission Network Charge	1584	$ 3,095,654	$ 2,093,688						$ 5,189,342	$ 15,079	$ 67,394			$ 82,473
RSVA - Retail Transmission Connection Charge	1586	$ 28,790	-$ 332,380						-$ 303,590	$ 719	$ 1,966			$ 2,685
RSVA - Power (excluding Global Adjustment)	1588	$ 712,267	$ 1,990,599						$ 2,702,866	$ 9,552	$ 64,512			$ 74,064
RSVA - Power - Sub-account - Global Adjustment	1588	-$ 994,699	$ 2,213,095						$ 1,218,396	-$ 32,314	-$ 15,690			-$ 48,004
Recovery of Regulatory Asset Balances	1590	-$ 3,876	-$ 423						-$ 4,299	$ -	-$ 61			-$ 61
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595	$ -							$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595	$ -							$ -	$ -				$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595	$ -							$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 5,999,241	-$ 2,248,372	$ -	$ -	$ -	$ -	$ -	-$ 8,247,613	-$ 41,854	-$ 61,301	$ -	$ -	-$ 103,155
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 5,004,542	-$ 4,461,467	$ -	$ -	$ -	$ -	$ -	-$ 9,466,009	-$ 9,540	-$ 45,611	$ -	$ -	-$ 55,151
RSVA - Power - Sub-account - Global Adjustment	**1588**	-$ 994,699	$ 2,213,095	$ -	$ -	$ -	$ -	$ -	$ 1,218,396	-$ 32,314	-$ 15,690	$ -	$ -	-$ 48,004
Group 2 Accounts														
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -	$ -						$ -	$ 2,576	$ -			$ 2,576
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	$ -						$ -	$ 6,558	$ -			$ 6,558
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ 65,270	$ 571						$ 65,840	$ 508	$ 959			$ 1,467
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$ -							$ -	$ -				$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508	$ -							$ -	$ -				$ -
Retail Cost Variance Account - Retail	1518	-$ 37,739	-$ 25,533						-$ 63,272	$ 111	-$ 497			-$ 386
Misc. Deferred Debits	1525	$ -							$ -	$ -				$ -
Renewable Generation Connection Capital Deferral Account	1531	$ 84,798	$ 440,019						$ 524,817	$ 296	$ 2,425			$ 2,721
Renewable Generation Connection OM&A Deferral Account	1532	$ -	$ 142,559						$ 142,559	$ -	$ 570			$ 570
Renewable Generation Connection Funding Adder Deferral Account	1533	$ -							$ -	$ -				$ -
Smart Grid Capital Deferral Account	1534	$ 191,896	$ 297,025						$ 488,921	$ 369	$ 4,029			$ 4,398
Smart Grid OM&A Deferral Account	1535	$ 206,380	$ 243,724						$ 450,104	$ 393	$ 4,685			$ 5,078
Smart Grid Funding Adder Deferral Account	1536	$ -							$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	-$ 1,880							-$ 1,880	-$ 20	-$ 28			-$ 47
Board-Approved CDM Variance Account	1567	$ -							$ -	$ -				$ -
Extra-Ordinary Event Costs	1572	$ 1,024,433	-$ 1,024,433						$ -	$ -				$ -
Deferred Rate Impact Amounts	1574	$ -							$ -	$ -				$ -
RSVA - One-time	1582	-$ 45,640							-$ 45,640	$ 35	-$ 672			-$ 637
Other Deferred Credits	2425	-$ 145,932	-$ 172,490						-$ 318,422	-$ 9,660	-$ 3,487			-$ 13,147
Group 2 Sub-Total		$ 1,341,586	-$ 98,558	$ -	$ -	$ -	$ -	$ -	$ 1,243,027	$ 1,166	$ 7,985	$ -	$ -	$ 9,151
Deferred Payments in Lieu of Taxes	1562	$ -							$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 173,460	$ 20,823						-$ 152,637	-$ 1,154	-$ 2,555			-$ 3,709
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$ 291,859	-$ 344,981						-$ 636,840	$ -				$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$ 5,122,974	-$ 2,671,088	$ -	$ -	$ -	$ -	$ -	-$ 7,794,063	-$ 41,841	-$ 55,872	$ -	$ -	-$ 97,714

2011

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [3]	Board-Approved Disposition during 2011	Other [2] Adjustments during Q1 2011	Other [2] Adjustments during Q2 2011	Other [2] Adjustments during Q3 2011	Other [2] Adjustments during Q4 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [2]	Closing Interest Amounts as of Dec-31-11
Special Purpose Charge Assessment Variance Account[9]	**1521**	$ 1,094,729	-$ 1,119,584						-$ 24,855	-$ 1,154	$ 3,123			$ 1,969
Total including Account 1521		-$ 4,028,245	-$ 3,790,672	$ -	$ -	$ -	$ -	$ -	-$ 7,818,918	-$ 42,995	-$ 52,749	$ -	$ -	-$ 95,744
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555	$ -							$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555	$ -							$ -	$ -				$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555	$ -							$ -	$ -				$ -
Smart Meter OM&A Variance[11]	1556	$ -							$ -	$ -				$ -
The following is not included in the total claim but are included on a memo basis:														
Deferred PILs Contra Account [5]	1563	$ -							$ -	$ -				$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575	$ -							$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ 291,859	$ 344,981						$ 636,840	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -							$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig
have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wr

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disp

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

Please describe "other" components of 1508 and add more component lines if necessary.

1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obl
If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December
the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded fror
disposed balances approved by the Board in the 2012 rate decision.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refun

balances in Account 1595 on a memo basis only (line 85).

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:
"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1
balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will b

The Board expected that requests for disposition of the balances in Account 1521 were to be addressed as part of the pro
non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance A
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Account Descriptions	Account Number	2012: Principal Disposition during 2012 - instructed by Board	2012: Interest Disposition during 2012 - instructed by Board	2012: Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012	2012: Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest on Dec-31-11 Balances: Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Projected Interest on Dec-31-11 Balances: Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Total Claim	2.1.7 RRR: As of Dec 31-11	Variance RRR vs. 2011 Balance *(Principal + Interest)*
Group 1 Accounts										
LV Variance Account	1550			-$ 31,468	-$ 5,860			-$ 37,328		$ 37,328
RSVA - Wholesale Market Service Charge	1580			-$ 17,018,860	-$ 208,453			-$ 17,227,313		$ 17,227,313
RSVA - Retail Transmission Network Charge	1584			$ 5,189,342	$ 82,473			$ 5,271,815		-$ 5,271,815
RSVA - Retail Transmission Connection Charge	1586			-$ 303,590	$ 2,685			-$ 300,905		$ 300,905
RSVA - Power (excluding Global Adjustment)	1588			$ 2,702,866	$ 74,064			$ 2,776,930		-$ 2,776,930
RSVA - Power - Sub-account - Global Adjustment	1588			$ 1,218,396	-$ 48,004			$ 1,170,392		-$ 1,170,392
Recovery of Regulatory Asset Balances	1590			-$ 4,299	-$ 61			-$ 4,360		$ 4,360
Disposition and Recovery/Refund of Regulatory Balances (2008)[7]	1595			$ -	$ -			$ -		$ -
Disposition and Recovery/Refund of Regulatory Balances (2009)[7]	1595			$ -	$ -			$ -		$ -
Disposition and Recovery/Refund of Regulatory Balances (2010)[7]	1595			$ -	$ -			$ -		$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	-$ 8,247,613	-$ 103,155	$ -	$ -	-$ 8,350,768	$ -	$ 8,350,768
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	-$ 9,466,009	-$ 55,151	$ -	$ -	-$ 9,521,160	$ -	$ 9,521,160
RSVA - Power - Sub-account - Global Adjustment	**1588**	$ -	$ -	$ 1,218,396	-$ 48,004	$ -	$ -	$ 1,170,392	$ -	-$ 1,170,392
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508			$ -	$ 2,576			$ 2,576		-$ 2,576
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			$ -	$ 6,558			$ 6,558		-$ 6,558
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$ 65,840	$ 1,467			$ 67,307		-$ 67,307
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508			$ -	$ -			$ -		$ -
Other Regulatory Assets - Sub-Account - Other [4]	1508			$ -	$ -			$ -		$ -
Retail Cost Variance Account - Retail	1518			-$ 63,272	-$ 386			-$ 63,658		$ 63,658
Misc. Deferred Debits	1525			$ -	$ -			$ -		$ -
Renewable Generation Connection Capital Deferral Account	1531			$ 524,817	$ 2,721			$ 527,538		-$ 527,538
Renewable Generation Connection OM&A Deferral Account	1532			$ 142,559	$ 570			$ 143,129		-$ 143,129
Renewable Generation Connection Funding Adder Deferral Account	1533			$ -	$ -			$ -		$ -
Smart Grid Capital Deferral Account	1534			$ 488,921	$ 4,398			$ 493,319		-$ 493,319
Smart Grid OM&A Deferral Account	1535			$ 450,104	$ 5,078			$ 455,182		-$ 455,182
Smart Grid Funding Adder Deferral Account	1536			$ -	$ -			$ -		$ -
Retail Cost Variance Account - STR	1548			-$ 1,880	-$ 47			-$ 1,927		$ 1,927
Board-Approved CDM Variance Account	1567			$ -	$ -			$ -		$ -
Extra-Ordinary Event Costs	1572			$ -	$ -			$ -		$ -
Deferred Rate Impact Amounts	1574			$ -	$ -			$ -		$ -
RSVA - One-time	1582			-$ 45,640	-$ 637			-$ 46,277		$ 46,277
Other Deferred Credits	2425			-$ 318,422	-$ 13,147			-$ 331,569		$ 331,569
Group 2 Sub-Total		$ -	$ -	$ 1,243,027	$ 9,151	$ -	$ -	$ 1,252,178	$ -	-$ 1,252,178
Deferred Payments in Lieu of Taxes	1562			$ -	$ -			$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			-$ 152,637	-$ 3,709			-$ 156,346		$ 156,346
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			-$ 636,840	$ -			-$ 636,840		$ 636,840
										$ -
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$ -	$ -	-$ 7,794,063	-$ 97,714	$ -	$ -	-$ 7,891,776	$ -	$ 7,891,776

Account Descriptions	Account Number	2012 Principal Disposition during 2012 - instructed by Board	Interest Disposition during 2012 - instructed by Board	Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012	Projected Interest on Dec-31-11 Balances Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [6]	Total Claim	2.1.7 RRR As of Dec 31-11	Variance RRR vs. 2011 Balance *(Principal + Interest)*
Special Purpose Charge Assessment Variance Account[9]	**1521**			-$ 24,855	$ 1,969			-$ 22,886		$ 22,886
										$ -
										$ -
Total including Account 1521		$ -	$ -	-$ 7,818,918	-$ 95,744	$ -	$ -	-$ 7,914,662	$ -	$ 7,914,662
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[11]	1555			$ -	$ -			$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[11]	1555			$ -	$ -			$ -		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[11]	1555			$ -	$ -			$ -		$ -
Smart Meter OM&A Variance[11]	1556			$ -	$ -			$ -		$ -
The following is not included in the total claim but are included on a memo basis:										
Deferred PILs Contra Account [5]	1563			$ -	$ -			$ -		$ -
IFRS-CGAAP Transition PP&E Amounts[10]	1575			$ -	$ -			$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592			$ 636,840	$ -			$ 636,840		-$ 636,840
Disposition and Recovery of Regulatory Balances[7]	1595			$ -	$ -			$ -		$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig
have a negative figure) as per the related Board decision.

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wr

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

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Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refun

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balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will b

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non-compliance with the timeline set out in section 8 of the SPC regulation.

Account 1575 shall not be cleared through the distributor's deferral and variance account rate rider. Account 1575 shall be

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance
Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

Ontario Energy Board

Deferral / Variance Account Work Form

Variance Explanations

#N/A

Accounts that produced a variance on the 2013 continuity schedule are listed below.

Account Descriptions	Account Number	Variance RRR vs. 2011 Balance *(Principal + Interest)*	Explanation
Group 1 Accounts			
LV Variance Account	1550	$ 37,327.72	
RSVA - Wholesale Market Service Charge	1580	$ 17,227,312.82	
RSVA - Retail Transmission Network Charge	1584	$ (5,271,814.88)	
RSVA - Retail Transmission Connection Charge	1586	$ 300,904.88	
RSVA - Power	1588	$ (2,776,930.29)	
RSVA - Power - Sub-account - Global Adjustment	1588	$ (1,170,391.87)	
Recovery of Regulatory Asset Balances	1590	$ 4,359.88	
Group 2 Accounts			
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ (2,575.70)	
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ (6,557.77)	
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ -	

SMART METER DEFERRAL ACCOUNTS

In 2011 PowerStream filed and received approval for its "final" smart meter cost recovery (EB-2011-0128). In that application PowerStream proposed to defer disposition of the stranded meter cost until its next Cost of Service ("COS") rate filing in 2013. PowerStream was also directed to remove customer premise costs that it estimated in its 2011 smart meter application. Table 1 below shows the December 31, 2011 balance in account 1555 and Table 2 the 2011 balance in account 1556. As PowerStream has completed its smart meter implementation program, this application is requesting disposition and recovery of both of these remaining balances.

Table 1 Account 1555 Smart Meter Capital and Recovery Account as at December 31, 2011 ($000's)

Description	Jan 1/11 Open	Additions	Adjustments	Dec 31/11 Close
Smart Meter capital at Cost	21,820	2,026	(23,843)	4
Smart Meter Capital - accumulated depreciation	(789)	0	789	0
Smart Meter Capital – Net Book Value	21,031	2,026	(23,054)	4
Stranded meters at Cost	30,976	2,394	0	33,370
Stranded meters- accumulated depreciation	(17,479)	(3,102)	0	(20,581)
Stranded meters -Net Book Value	13,497	(708)	0	12,789
Smart Meter Adder Billed	(7,048)	(475)	7,520	(4)
TOTAL	27,480	843	(15,534)	12,789

The residual $12,789,000 balance in account 1555 consists solely of the net book value ("NBV") of stranded meters, less proceeds of disposition. These stranded meters were recorded in account 1555 as they were removed from service and accounted for in accordance with OEB guideline G2008-002 and appendix B attachment to Board letter of January 16, 2007.

Ontario regulation 441/07 states: "…..Subject to Board order,…. distributors may recover the costs associated with meters owned before, on or after January 1, 2006 being replaced because of the smart metering initiative …..".

PowerStream replaced 284,000 conventional meters with smart meters. The NBV of these 'stranded" meters is all that remains in this account for disposition and recovery. No interest is included in the balance of $12,789,000. PowerStream has continued to "depreciate" these stranded meters and charge the related expense to account 5695. PowerStream has adjusted the balance claimed for estimated 2012 depreciation of $988,860 for the South and $251,140 for Barrie.

Chapter 2, section 2.5.1.5, *"Treatment of Stranded Assets Related to Smart Meter Deployment"* of the *OEB Filing Requirements for Transmission and Distribution Applications* states that distributors are to file a proposed treatment for the recovery of stranded meters. This treatment should be consistent with the two decisions issued by the Board in 2011. In this application PowerStream proposes to include the stranded meter amount in the deferral and variance account rate rider calculation.

The remaining balance in smart meter account 1556, per table 2 below, is attributed to incremental customer premises expenditures that PowerStream incurred to retrofit smart meters. As stated in PowerStream' s June 2011 smart meter application (EB-2011-028) these were additional costs incurred as a result of difficulties in converting older meters to smart meters.

Table 2 Account 1556 Smart Meter OM&A Costs as at December 31, 2011 ($000's)

Description	Jan 1/11 Open	2011 Additions	2011 Adjustments	Dec 31/11 Close
SM OM&A Costs	889	1,215	(1,863)	241
Smart meter depreciation	789	0	(789)	0
TOTAL	1,678	1,215	(2,652)	241

This majority of this work was completed by 2011. Therefore, PowerStream is requesting recovery of these expenditures and to apply the same approach as indicated for account 1555. Any additional costs incurred in 2012 will not be recorded in the smart meter deferral account but will be treated as a normal operating expense.

The costs for each rate zone have been entered on the respective deferral and variance account continuity schedule. Within each rate zone the amount is allocated to each rate class based on the 2011 number of metered customers.

PAYMENTS IN LIEU OF TAXES (“PILs”) VARIANCE ACCOUNTS

PowerStream and its predecessor utilities made and continue to make PILs payments to the Ontario Electrical Financial Corporation (“OEFC”), part of the legal continuation of Ontario Hydro. These payments are used to reduce the “stranded debt” of Ontario Hydro, now held by OEFC. The PILs payable by PowerStream are calculated based on Federal and Ontario tax rates and regulations using the same tax returns as other corporations who pay regular taxes.

The OEB established accounts 1562 and 1592 to track specific differences between the PILs Proxy incorporated into rates and changes in actual taxes rates and rules. The PILs variances accounts at December 31, 2011 are summarized in Table 1 below.

Table 1: Summary of PILs Variances Accounts at December 31, 2011

Account	Barrie	South	Shared	Total
1562	$ (562,943)	$ (4,028,681)	$ -	$ (4,591,624)
1592	$ (61,350)	$ (711,953)	$ (156,376)	$ (929,679)
Total	**$ (624,293)**	**$ (4,740,634)**	**$ (156,376)**	**$ (5,521,303)**

Each of these accounts is discussed below.

Deferred PILs Account 1562:

Account 1562 was used to track specific differences between the PILs Proxy in rates and actual tax rates for the 2001 through 2005 rate years. The differences to be recorded in account 1562 were monthly differences between the PILs proxy amount used to set rates and the actual amount of PILs collected from customers, plus an annual difference calculated using an OEB supplied “SIMPILs” model.

Account 1562 was the subject of a combined proceeding (EB-2008-0381), in which Barrie Hydro was one of the three applicants. In this proceeding the Board reviewed and approved an amount of $565,583 credit for Barrie Hydro to be refunded to customers. The approved amount contains interest to April 30, 2012 which results in a small difference compared to the amount recorded at December 31, 2011, which does not include the January 2012 to April 30, 2012 interest.

As directed by the Board, PowerStream Barrie included the approved amount in its 2012 IRM rate application (EB-2011-0005). On March 22, 2012, the Board issued its Decision and Order approving the account 1562 balance and the rate riders to refund this over the period May 1, 2012 to April 30, 2013.

As the Barrie account 1562 balance has already been approved for disposition, it must be removed from the balances being considered for disposition in this Application.

In the Decision in the combined proceeding on account 1562 (EB-2008-0381), the Board directed other utilities to file for disposition of account 1562 as part of their 2012 IRM rate application, using models that exclude known errors, stating a preference for the "updated models" filed by Halton Hills. In its letter of August 25, 2011 to the Board, PowerStream explained it would not be filing for disposition of account 1562 in the 2012 IRM for the PowerStream South rate zone, as its situation requires it to file for disposition "on a basis which differs from that contemplated by the decisions in this proceeding". In a reply letter of October 12, 2011, the Board accepted PowerStream's proposal and directed it to file for disposition of account 1562 for the PowerStream South rate zone in its 2013 cost of service rate application.

PowerStream has updated its calculation of the account 1562 Deferred PILs balance for the South rate zone (i.e. PowerStream prior to the merger with Barrie Hydro). This includes the predecessor utilities (Markham Hydro, Richmond Hill Hydro and Hydro Vaughan) which were amalgamated on June 1, 2004 to create PowerStream, and Aurora Hydro which was purchased and amalgamated with PowerStream effective November 1, 2005.

In updating the account 1562 balance, PowerStream prepared the "updated models" referred to in the Decision for EB-2008-0381 in accordance with the Decision and approved Settlement of Issues. PowerStream has some issues that were not fully addressed in EB-2008-0381 which required further steps not contemplated in that proceeding:

- PowerStream has calculated the "interest adjustment for tax purposes" taking into account all relevant factors. PowerStream has provided details of its interest calculations.

- Due to the amalgamations, it was necessary to prepare SIMPILs models for short tax years that did not match the full year PILs proxy. PowerStream has made the necessary pro-rations to match the shorter tax year.

Appendix 5 to this application contains the account 1562 continuity schedules showing the details making up the credit balance of $3,791,314 principal and accrued interest credit of $237,367 for a total credit of $4,028,681 at December 31, 2011. This appendix also contains the updated models, calculations regarding the "interest adjustment for tax purposes" and other supporting documentation.

Account 1592 PILs and Tax Variances for 2006 and Subsequent Years:

The balance in account 1592 as at December 31, 2011 is summarized in Table 2 below.

Table 2: Summary of Account 1592 Account Amounts

	Barrie	South	Shared	Total
Large Corporations Tax (LCT)	$ (54,575)	$ (633,969)	$ -	$ (688,544)
HST Savings			$ (636,640)	$ (636,640)
HST Savings Contra			$ 636,640	$ 636,640
HONI Rate Rider 3A			$ (152,623)	$ (152,623)
Interest	$ (6,775)	$ (77,984)	$ (3,753)	$ (88,512)
Total	**$ (61,350)**	**$ (711,953)**	**$ 156,376)**	**$ (929,679)**

The Large Corporations Tax ("LCT") amount represents the LCT that remained in rates for the 2006 rate year, as the 2006 rates were approved prior to the Federal budget which abolished the LCT effective January 1, 2006.

Harmonizes Sales Tax ("HST") savings represents the amounts that PowerStream and other utilities were directed to record in the Decisions on 2010 IRM rates. These amounts are tracked in the HST/OVAT Input Tax Credits (ITC) sub-accounts of 1592. See Exhibit I, Tab 1, Schedule 12, for a discussion of the amounts that PowerStream has recorded as a result of the Board's direction concerning the implementation of HST effective July 1, 2010.

HONI Rate Rider 3A represents credits received from Hydro One Networks Inc. ("HONI"). PowerStream has a number of embedded supply points where PowerStream is billed by Hydro One for the transmission charges related to these points and is charged the applicable

HONI OEB approved rate riders for deferral and variance disposition. This particular rate rider applies to PILs variances and so PowerStream has included in its PILs variance account.

IFRS TRANSITION COST VARIANCE

PowerStream has recorded the one-time non-capital transition costs to implement International Financial Reporting Standards ("IFRS") for accounting and financial reporting in the sub-account of account 1508 Other Regulatory Assets. In its 2009 Cost of Service ("COS") rate application, PowerStream included an amount for IFRS transition costs. Barrie did not include an amount for IFRS transition costs in its 2008 COS rate application. The amount deemed to be included in the South rates has also been recorded in this variance account. Table 1 summarizes the amounts recorded to December 31, 2011, the forecast amounts for 2012 and the projected total as at December 31, 2012.

Table 1: Summary of IFRS Transition Cost Variance

	Actual to Dec. 31, 2011	Forecast 2012	Projected Dec. 31, 2012
Costs	$ 1,917,398	$ 594,347	$ 2,511,745
Interest	$ 7,218	$ (578)	$ 6,640
Collected in Rates	$ (1,986,660)	$ (745,000)	$ (2,731,660)
Net balance	**$ (62,044)**	**$ (151,230)**	**$ (213,274)**

See Exhibit A3, Tab 1, Schedule 5 for more details on the transition to IFRS and related costs.

PowerStream has included the projected amount as of December 31, 2012 for recovery, to capture the remaining revenue and cost amounts. PowerStream proposes that the account should remain open so that any variance between the actual and approved amounts can be reviewed by the Board for disposition in a future application.

PowerStream notes that the costs incurred to adopt IFRS are of the same benefit to all ratepayers but the offsetting amounts have only been collected from the South rate zone customers. In determining the amounts to be recovered from each rate zone, PowerStream has allocated the costs based on the actual number of customers in each rate zone as at December 31, 2011. The amount collected in rates has been allocated entirely to the South rate zone. The allocation is summarized in Table 2 below.

Table 2: Allocation of IFRS Variance Between Rate Zones

	Barrie	South	Total
Number of customers	73,448	262,487	335,935
Costs	$ 549,162	$ 1,962,584	$ 2,511,745
Collected in Rates		$ (2,731,660)	$ (2,731,660)
Subtotal	**$ 549,162**	**$ (769,076)**	**$ (219,915)**
Interest - billings		$ (65,697)	$ (65,697)
Interest - costs	$ 15,816	$ 56,522	$ 72,337
Subtotal - Interest	**$ 15,816**	**$ (9,175)**	**$ 6,640**
Net total	**$ 564,978**	**$ (778,252)**	**$ (213,274)**

The amounts, up to December 31, 2011, for each rate zone, have been included in the continuity schedule for the rate zone. The 2012 amounts have been added as an adjustment in arriving at the amounts to be allocated to rate classes and used to derive the rate riders.

GREEN ENERGY DEFERRAL ACCOUNTS

On September 9, 2009, the *Green Energy and Green Economy Act, 2009* ("GEA") was enacted. The GEA amended a number of Acts and regulations including the *Ontario Energy Board Act, 1998* (the "OEB Act") and the *Electricity Act 1998* ("Electricity Act") to enable distributors to do renewable generation connections and smart grid development.

Exhibit B2, Tab 1, Schedules 1 and 2 contain more information regarding PowerStream's GEA plan, actual and planned spending, calculation of direct benefits attributable to PowerStream's customers and the portion to be provincially funded; it should be read in conjunction with this section.

The OEB authorized several deferral accounts to record GEA related spending, as these costs were not incorporated in the distribution rates of LDCs. Table 1 below provides a summary of the GEA accounts and the costs to December 31, 2011.

Table 1: GEA Deferral Account Balances – December 31, 2011 ($000)

Account	Principal	Interest	Balance
1531 Renewable Connection Capital Deferral	$ 525	$ 3	$ 528
1534 Smart Grid Capital Deferral	$ 477	$ 4	$ 481
Total Capital	**$ 1,002**	**$ 7**	**$ 1,009**
1532 Renewable Connection OM&A Deferral	$ 143	$ -	$ 143
1535 Smart Grid OM&A Deferral	$ 462	$ 5	$ 467
Total OM&A	**$ 605**	**$ 5**	**$ 610**
Total Expenditures	**$ 1,607**	**$ 12**	**$ 1,619**

PowerStream is seeking to dispose of the actual balances in the GEA account as at December 31, 2011. PowerStream is also seeking a funding adder of $0.20 per customer per month for the planned GEA spending over the years 2012 to 2016. The funding adder requirement and calculation discussed in Exhibit B2, Tab 1, Schedule 1.

Disposition of Actual Costs to December 31, 2011

PowerStream has added the net book value of the capital additions to December 31, 2011, as at December 31, 2012 in the amount of $463,000 to 2013 rate base in calculating the 2013 revenue requirement. This net book value ("NBV") was determined as shown in Table 2.

Table 2: NBV of GEA Capital at December 31, 2012 ($000)

Description	Amount
GEA Capital Costs to December 31, 2011	$ 1,002
Less Provincial funded portion Account 1531*	$ (493)
Net capital for rate base	**$ 509**
Accumulated depreciation to Dec. 31, 2012	$ (46)
NBV as at Dec. 31, 2012	**$ 463**

* See Exhibit B2, Tab 1, Schedule 1, Table 2

PowerStream has included a balance of $663,000 in the Variance and Deferral Account continuity schedule for recovery. The derivation of this amount is shown in Table 3:

Table 3: GEA Amount for Recovery through D&V Rate Riders ($000)

Description	Amount
Total Spending to Dec. 31, 2011	$ 1,619
Less Provincial funded portion Account 1531	$ (493)
less added to rate base	$ (463)
Remaining costs for recovery	**$ 663**
Consisting of:	
OM&A (Table 1)	$ 605
Depreciation Expense (Table 2)	$ 46
Subtotal - Principal	$ 651
Interest to Dec. 31, 2011	$ 12
Total costs for recovery	**$ 663**

These amounts occurred after January 1, 2009 and not identifiable by rate zone. These have been added to the combined continuity schedule.

GEA Funding Adder:

PowerStream is also seeking a funding adder of $0.20 per customer per month for the planned GEA spending over the years 2012 to 2016. The funding adder requirement and calculation discussed in Exhibit B2, Tab 1, Schedule 1. The calculation of the funding adder is on the following pages.

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Assumptions and Data

Deemed Debt	60%
Deemed Equity	40%
Weighted Debt Rate (from 2013 PowerStream EDR)	4.77%
Proposed ROE (from 2013 PowerStream EDR)	9.12%
Weighted Average Cost of Capital	6.51%
Working Capital Allowance %	13.00%

2013 EDR Total Customers

Residential	308,309
General Service Less Than 50 kW	31,199
General Service Greater Than 50 kW	4,662
Large Users	2
USL	2,814
Sentinel	120
Total customers	347,105

	2010	2011	2012	2013	2014	2015	2016
Corporate Income Tax Rate	31.00%	28.25%	26.25%	25.50%	25.00%	25.00%	25.00%

Capital Data:	2010	2011	2012	2013	2014	2015	2016
Smart Grid Distribution Assets			$ 800,000	$ 300,000	$ 200,000	$ 200,000	$ 200,000
Computer Hardware			$ 50,000				
Computer Software			$ 400,000	$ 350,000	$ 150,000	$ 150,000	$ 150,000
Vehicles							
Total Capital Costs	$ -	$ -	$ 1,250,000	$ 650,000	$ 350,000	$ 350,000	$ 350,000

Amortization Policy:	Amortization		CCA Class	CCA Rate	
Distribution Assets Amortization Rate	40.00	Years	47	8	%
Computer Hardware Amortization Rate	5.00	Years	50	55	%
Computer Software Amortization Rate	4.00	Years	12	100	%
Vehicles Amortization Rate	7.00	Years	10	30	%

Operating Expense Data:	2010	2011	2012	2013	2014	2015	2016
Smart Grid			$ 207,000	$ 230,000	$ 200,000	$ 200,000	$ 200,000
	$ -	$ -	$ 153,738	$ 158,350	$ 149,716	$ 131,675	$ 135,625
Total O M & A Costs	$ -	$ -	$ 360,738	$ 388,350	$ 349,716	$ 331,675	$ 335,625

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Average Net Fixed Assets

Net Fixed Assets

	2011	2012	2013	2014	2015	2016
Opening Capital Investment	$ -	$ -	$ 800,000.00	$ 1,100,000.00	$ 1,300,000.00	$ 1,500,000.00
Capital Investment	$ -	$ 800,000.00	$ 300,000.00	$ 200,000.00	$ 200,000.00	$ 200,000.00
Closing Capital Investment	$ -	$ 800,000.00	$ 1,100,000.00	$ 1,300,000.00	$ 1,500,000.00	$ 1,700,000.00
Opening Accumulated Amortization	$ -	$ -	$ 10,000.00	$ 33,750.00	$ 63,750.00	$ 98,750.00
Amortization Year 1 (40 Years Straight Line)	$ -	$ 10,000.00	$ 23,750.00	$ 30,000.00	$ 35,000.00	$ 40,000.00
Closing Accumulated Amortization	$ -	$ 10,000.00	$ 33,750.00	$ 63,750.00	$ 98,750.00	$ 138,750.00
Opening Net Fixed Assets	$ -	$ -	$ 790,000.00	$ 1,066,250.00	$ 1,236,250.00	$ 1,401,250.00
Closing Net Fixed Assets	$ -	$ 790,000.00	$ 1,066,250.00	$ 1,236,250.00	$ 1,401,250.00	$ 1,561,250.00
Average Net Fixed Assets	$ -	$ 395,000.00	$ 928,125.00	$ 1,151,250.00	$ 1,318,750.00	$ 1,481,250.00

Net Fixed Assets - Computer Hardware

	2011	2012	2013	2014	2015	2016
Opening Capital Investment	$ -	$ -	$ 50,000.00	$ 50,000.00	$ 50,000.00	$ 50,000.00
Capital Investment	$ -	$ 50,000.00	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ 50,000.00	$ 50,000.00	$ 50,000.00	$ 50,000.00	$ 50,000.00
Opening Accumulated Amortization	$ -	$ -	$ 5,000.00	$ 15,000.00	$ 25,000.00	$ 35,000.00
Amortization Year 1 (5 Years Straight Line)	$ -	$ 5,000.00	$ 10,000.00	$ 10,000.00	$ 10,000.00	$ 10,000.00
Closing Accumulated Amortization	$ -	$ 5,000.00	$ 15,000.00	$ 25,000.00	$ 35,000.00	$ 45,000.00
Opening Net Fixed Assets	$ -	$ -	$ 45,000.00	$ 35,000.00	$ 25,000.00	$ 15,000.00
Closing Net Fixed Assets	$ -	$ 45,000.00	$ 35,000.00	$ 25,000.00	$ 15,000.00	$ 5,000.00
Average Net Fixed Assets	$ -	$ 22,500.00	$ 40,000.00	$ 30,000.00	$ 20,000.00	$ 10,000.00

Net Fixed Assets - Computer Software

	2011	2012	2013	2014	2015	2016
Opening Capital Investment	$ -	$ -	$ 400,000.00	$ 750,000.00	$ 900,000.00	$ 1,050,000.00
Capital Investment	$ -	$ 400,000.00	$ 350,000.00	$ 150,000.00	$ 150,000.00	$ 150,000.00
Closing Capital Investment	$ -	$ 400,000.00	$ 750,000.00	$ 900,000.00	$ 1,050,000.00	$ 1,200,000.00
Opening Accumulated Amortization	$ -	$ -	$ 50,000.00	$ 193,750.00	$ 400,000.00	$ 643,750.00
Amortization Year 1 (4 Years Straight Line)	$ -	$ 50,000.00	$ 143,750.00	$ 206,250.00	$ 243,750.00	$ 281,250.00
Closing Accumulated Amortization	$ -	$ 50,000.00	$ 193,750.00	$ 400,000.00	$ 643,750.00	$ 925,000.00
Opening Net Fixed Assets	$ -	$ -	$ 350,000.00	$ 556,250.00	$ 500,000.00	$ 406,250.00
Closing Net Fixed Assets	$ -	$ 350,000.00	$ 556,250.00	$ 500,000.00	$ 406,250.00	$ 275,000.00
Average Net Fixed Assets	$ -	$ 175,000.00	$ 453,125.00	$ 528,125.00	$ 453,125.00	$ 340,625.00

Net Fixed Assets - Vehicles

	2011	2012	2013	2014	2015	2016
Opening Capital Investment	$ -	$ -	$ -	$ -	$ -	$ -
Capital Investment	$ -	$ -	$ -	$ -	$ -	$ -
Closing Capital Investment	$ -	$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -	$ -	$ -	$ -
Amortization Year 1 (7 Years Straight Line)	$ -	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -

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For PILs Calculation

UCC - Distribution Assets

CCA Class 47 (8%)	2011	2012	2013	2014	2015	2016
Opening UCC	$ -	$ -	$ 768,000.00	$ 994,560.00	$ 1,106,995.20	$ 1,210,435.58
Capital Additions	$ -	$ 800,000.00	$ 300,000.00	$ 200,000.00	$ 200,000.00	$ 200,000.00
UCC Before Half Year Rule	$ -	$ 800,000.00	$ 1,068,000.00	$ 1,194,560.00	$ 1,306,995.20	$ 1,410,435.58
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 400,000.00	$ 150,000.00	$ 100,000.00	$ 100,000.00	$ 100,000.00
Reduced UCC	$ -	$ 400,000.00	$ 918,000.00	$ 1,094,560.00	$ 1,206,995.20	$ 1,310,435.58
CCA Class 47 (8%)	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
CCA	$ -	$ 32,000.00	$ 73,440.00	$ 87,564.80	$ 96,559.62	$ 104,834.85
Closing UCC	$ -	$ 768,000.00	$ 994,560.00	$ 1,106,995.20	$ 1,210,435.58	$ 1,305,600.74

UCC - Computer Software

CCA Class 12 (100%)	2011	2012	2013	2014	2015	2016
Opening UCC	$ -	$ -	$ 200,000.00	$ 175,000.00	$ 75,000.00	$ 75,000.00
Capital Additions Computer Software	$ -	$ 400,000.00	$ 350,000.00	$ 150,000.00	$ 150,000.00	$ 150,000.00
UCC Before Half Year Rule	$ -	$ 400,000.00	$ 550,000.00	$ 325,000.00	$ 225,000.00	$ 225,000.00
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 200,000.00	$ 175,000.00	$ 75,000.00	$ 75,000.00	$ 75,000.00
Reduced UCC	$ -	$ 200,000.00	$ 375,000.00	$ 250,000.00	$ 150,000.00	$ 150,000.00
CCA Class 12 (100%)	100%	100%	100%	100%	100%	100%
CCA	$ -	$ 200,000.00	$ 375,000.00	$ 250,000.00	$ 150,000.00	$ 150,000.00
Closing UCC	$ -	$ 200,000.00	$ 175,000.00	$ 75,000.00	$ 75,000.00	$ 75,000.00

UCC - Computer Hardware

CCA Class 50 (55%)	2011	2012	2013	2014	2015	2016
Opening UCC	$ -	$ -	$ 36,250.00	$ 16,312.50	$ 7,340.63	$ 3,303.28
Capital Additions Computer Hardware	$ -	$ 50,000.00	$ -	$ -	$ -	$ -
Capital Additions Computer Software						
UCC Before Half Year Rule	$ -	$ 50,000.00	$ 36,250.00	$ 16,312.50	$ 7,340.63	$ 3,303.28
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 25,000.00	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ 25,000.00	$ 36,250.00	$ 16,312.50	$ 7,340.63	$ 3,303.28
CCA Class 50 (55%)	55%	55%	55%	55%	55%	55%
CCA	$ -	$ 13,750.00	$ 19,937.50	$ 8,971.88	$ 4,037.34	$ 1,816.80
Closing UCC	$ -	$ 36,250.00	$ 16,312.50	$ 7,340.63	$ 3,303.28	$ 1,486.48

UCC - Vehicles

CCA Class 10 (30%)	2011	2012	2013	2014	2015	2016
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Software	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -
CCA Class 10 (30%)	30%	30%	30%	30%	30%	30%
CCA	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -

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Rate Calculation

	2010			2011			2012		
Average Asset Values									
Net Fixed Assets Smart Grid Distribution Assets	$ -			$ -			$ 395,000		
Net Fixed Assets Computer Hardware	$ -			$ -			$ 22,500		
Net Fixed Assets Computer Software	$ -			$ -			$ 175,000		
Net Fixed Assets Vehicles	$ -			$ -			$ -		
Total Net Fixed Assets	$ -	$ -		$ -	$ -		$ 592,500	$ 592,500	
Working Capital									
Operation Expense	$ -			$ -			$ 360,738		
Working Capital 13 %	$ -	$ -		$ -	$ -		$ 46,896	$ 46,896	
Assets to be included in Rate Base		$ -			$ -			$ 639,396	
Return on Rate Base									
Deemed Debt	60%	$ -		60%	$ -		60%	$ 383,638	
Deemed Equity	40%	$ -		40%	$ -		40%	$ 255,758	
		$ -			$ -			$ 639,396	
Weighted Debt Rate	4.77%	$ -		4.77%	$ -		4.77%	$ 18,292	
Proposed ROE	9.12%	$ -		9.12%	$ -		9.12%	$ 23,325	
Return on Rate Base		$ -	$ -		$ -	$ -		$ 41,617	$ 41,617
Operating Expenses									
Incremental Operating Expenses			$ -			$ -			$ 360,738
Amortization Expenses									
Amortization Expenses - Smart Grid Distribution Assets		$ -			$ -			$ 10,000	
Amortization Expenses - Computer Hardware		$ -			$ -			$ 5,000	
Amortization Expenses - Computer Software		$ -			$ -			$ 50,000	
Amortization Expenses - Vehicles		$ -			$ -			$ -	
Total Amortization Expenses			$ -			$ -			$ 65,000
Revenue Requirement Before PILs			$ -			$ -			$ 467,355
Calculation of Taxable Income									
Incremental Operating Expenses			$ -			$ -			-$ 360,738
Depreciation Expenses			$ -			$ -			-$ 65,000
Interest Expense			$ -			$ -			-$ 18,292
Taxable Income For PILs			$ -			$ -			$ 23,325
Grossed up PILs			$ -			$ -			$ 86,340
Revenue Requirement Before PILs			$ -			$ -			$ 467,355
Grossed up PILs			$ -			$ -			$ 86,340
Revenue Requirement			**$ -**			**$ -**			**$ 553,695**
Rate Adder									
Revenue Requirement									$ 553,695
Total Customers (EDR 2013)									347,105
Annualized amount required per customer									$ 1.60
Number of months in year									12
Rate Adder	**Average:**		**$ 0.20**						**$ 0.13**

	2013			2014			2015			2016		
Average Asset Values												
Net Fixed Assets Smart Grid Distribution Assets	$ 928,125			$ 1,151,250			$ 1,318,750			$ 1,481,250		
Net Fixed Assets Computer Hardware	$ 40,000			$ 30,000			$ 20,000			$ 10,000		
Net Fixed Assets Computer Software	$ 453,125			$ 528,125			$ 453,125			$ 340,625		
Net Fixed Assets Vehicles	$ -			$ -			$ -			$ -		
Total Net Fixed Assets	$ 1,421,250	$ 1,421,250		$ 1,709,375	$ 1,709,375		$ 1,791,875	$ 1,791,875		$ 1,831,875	$ 1,831,875	
Working Capital												
Operation Expense	$ 388,350			$ 349,716			$ 331,675			$ 335,625		
Working Capital 13 %	$ 50,486	$ 50,486		$ 45,463	$ 45,463		$ 43,118	$ 43,118		$ 43,631	$ 43,631	
Assets to be included in Rate Base		$ 1,471,736			$ 1,754,838			$ 1,834,993			$ 1,875,506	
Return on Rate Base												
Deemed Debt	60%	$ 883,041		60%	$ 1,052,903		60%	$ 1,100,996		60%	$ 1,125,304	
Deemed Equity	40%	$ 588,694		40%	$ 701,935		40%	$ 733,997		40%	$ 750,203	
		$ 1,471,736			$ 1,754,838			$ 1,834,993			$ 1,875,506	
Weighted Debt Rate	4.77%	$ 42,103		4.77%	$ 50,202		4.77%	$ 52,495		4.77%	$ 53,654	
Proposed ROE	9.12%	$ 53,689		9.12%	$ 64,016		9.12%	$ 66,941		9.12%	$ 68,418	
Return on Rate Base		$ 95,792	$ 95,792		$ 114,219	$ 114,219		$ 119,436	$ 119,436		$ 122,073	$ 122,073
Operating Expenses												
Incremental Operating Expenses			$ 388,350			$ 349,716			$ 331,675			$ 335,625
Amortization Expenses												
Amortization Expenses - Smart Grid Distribution Assets		$ 23,750			$ 30,000			$ 35,000			$ 40,000	
Amortization Expenses - Computer Hardware		$ 10,000			$ 10,000			$ 10,000			$ 10,000	
Amortization Expenses - Computer Software		$ 143,750			$ 206,250			$ 243,750			$ 281,250	
Amortization Expenses - Vehicles		$ -			$ -			$ -			$ -	
Total Amortization Expenses			$ 177,500			$ 246,250			$ 288,750			$ 331,250
Revenue Requirement Before PILs			$ 661,642			$ 710,185			$ 739,861			$ 788,948
Calculation of Taxable Income												
Incremental Operating Expenses			-$ 388,350			-$ 349,716			-$ 331,675			-$ 335,625
Depreciation Expenses			-$ 177,500			-$ 246,250			-$ 288,750			-$ 331,250
Interest Expense			-$ 42,103			-$ 50,202			-$ 52,495			-$ 53,654
Taxable Income For PILs			$ 53,689			$ 64,016			$ 66,941			$ 68,418
Grossed up PILs			$ 175,526			$ 154,577			$ 135,031			$ 147,672
Revenue Requirement Before PILs			$ 661,642			$ 710,185			$ 739,861			$ 788,948
Grossed up PILs			$ 175,526			$ 154,577			$ 135,031			$ 147,672
Revenue Requirement			**$ 837,168**			**$ 864,762**			**$ 874,892**			**$ 936,620**
Rate Adder												
Revenue Requirement			$ 837,168			$ 864,762			$ 874,892			$ 936,620
Total Customers (EDR 2013)			347,105			347,105			347,105			347,105
Annualized amount required per customer			$ 2.41			$ 2.49			$ 2.52			$ 2.70
Number of months in year			12			12			12			12
Rate Adder			**$ 0.20**			**$ 0.21**			**$ 0.21**			**$ 0.22**

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PILs Calculation

	2010	2011	2012	2013	2014	2015	2016
INCOME TAX							
Net Income	$ -	$ -	$ 23,325	$ 53,689	$ 64,016	$ 66,941	$ 68,418
Amortization	$ -	$ -	$ 65,000	$ 177,500	$ 246,250	$ 288,750	$ 331,250
CCA - Class 47 (8%) Distribution Assets	$ -	$ -	-$ 32,000	-$ 73,440	-$ 87,565	-$ 96,560	-$ 104,835
CCA - Class 12(100%) Software	$ -	$ -	$ 200,000	$ 375,000	$ 250,000	$ 150,000	$ 150,000
CCA - Class 50 (55%) Computers	$ -	$ -	-$ 13,750	-$ 19,938	-$ 8,972	-$ 4,037	-$ 1,817
CCA - Class 10 (30%) Vehicles	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxable income	$ -	$ -	$ 242,575	$ 512,811	$ 463,730	$ 405,094	$ 443,017
Tax Rate	31.00%	28.25%	26.25%	25.50%	25.00%	25.00%	25.00%
Income Taxes Payable	$ -	$ -	$ 63,676	$ 130,767	$ 115,932	$ 101,273	$ 110,754

Gross Up

	PILs Payable	PILs Payable	PILs Payable	PILs Payable	PILs Payable	PILs Payable	PILs Payable
Change in Income Taxes Payable	$ -	$ -	$ 63,676	$ 130,767	$ 115,932	$ 101,273	$ 110,754
Change in OCT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PIL's	$ -	$ -	$ 63,676	$ 130,767	$ 115,932	$ 101,273	$ 110,754
	Gross Up	Gross Up	Gross Up	Gross Up	Gross Up	Gross Up	Gross Up
	31.00%	28.25%	26.25%	25.50%	25.00%	25.00%	25.00%
	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs
Change in Income Taxes Payable	$ -	$ -	$ 86,340	$ 175,526	$ 154,577	$ 135,031	$ 147,672
Change in OCT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PIL's	**$ -**	**$ -**	**$ 86,340**	**$ 175,526**	**$ 154,577**	**$ 135,031**	**$ 147,672**

HST SAVINGS AMOUNTS

In the Decision on PowerStream's 2010 IRM rates (EB-2009-0245/0246) dated April 6, 2010, the Board addressed the replacement of the Ontario Provincial Sales Tax ("PST") with the Harmonized Sales Tax ("HST") effective July 1, 2010.

The Board determined that cost reductions arising from the implementation of HST should be shared equally between ratepayers and the shareholders. The Board directed PowerStream to record the incremental savings in account 1592, PILs and Tax Variances, sub-account HST/OVAT Input Tax Credits ("ITC"s) and stated that fifty percent (50%) of the confirmed balances in the account shall be returnable to the ratepayers. It was indicated that further guidance may be forthcoming.

The Board provided further guidance on the recording of amounts into account 1592 in OEB Accounting Procedures Handbook Frequently Asked Questions dated December 2010, in Q.1 to Q.5.

In Q.1, it is indicated that the offsetting entry to account 1592, sub-account HST/OVAT Input Tax Credits ("1592 HST") should be made to account 1592, sub-account HST/OVAT Contra Account ("1592 Contra"), such that the sum of these two sub-accounts should be $0. PowerStream has followed this accounting treatment.

In Q.2, it is indicated that ITCs received on items not previous subject to PST should not be recorded in account 1592. PowerStream has followed this accounting treatment.

In Q.3, it is indicated that the incremental HST on items not previously subject to PST, such as natural gas and electricity utility costs, that became subject to the HST but are subject to restricted ITCs such that no OVAT ITC is received, should not be recorded in account 1592. PowerStream agrees that there is no cost reduction to be recorded. However it is clear that there is a cost increment in this case. PowerStream is now paying an additional 8% sales tax to Ontario that is non-refundable, where previously there was no PST. PowerStream has included this additional cost resulting from the implementation of HST in account 1592 as a reduction to arrive at the incremental savings.

In Q.4, the Board addresses the practicality of trying to identify which ITCs represent savings to be recorded in account 1592 and suggests a proxy method to determine the amounts to be recorded in account 1592.

The proxy method alternative discusses how to derive the PST savings on OM&A and capital items for the 2009 historic year to use as a proxy for the amounts to be recorded from July 2010 until the next rebasing.

PowerStream has used this proxy method to identify the amount of PST savings based on a detailed analysis of 2009 actual OM&A costs and the PST embedded in those costs. The results of this analysis are summarized in Table 1 below.

Table 1: PST Savings on OM&A based on 2009 Historic Year

Description	**Amount**	**Notes**
PST included in 2009 OM&A Costs	$ 709,766	
Less PST remaining on insurance	$ (217,887)	1
Less new sales tax due to Ontario restricted ITC	$ (55,316)	2
Subtotal	$ 436,563	
Less transition costs	$ (12,000)	3
Annual PST savings on OM&A	**$ 424,563**	

Notes

1. Insurance is not subject to HST but remains subject to an 8% Ontario Sales Tax.
2. This represents new sales tax costs as a result of HST with restricted OVAT ITCs that needs to be deducted to arrive at the incremental savings.
3. PowerStream spent $30,000 on consulting and training to make the change from PST & GST to HST that needs to be deducted to arrive at the incremental savings. This has been “amortized” over the two and one-half year period from July 1, 2010 to December 31, 2012, assuming rebasing as of January 1, 2013, resulting in an annual amount of $12,000.

Starting in July 2010, PowerStream has booked 1/12 of the annual OM&A PST savings, (i.e. $35,380 per month) each month into account 1592 HST with an offsetting entry to 1592 Contra. In the eighteen (18) months, from July 1, 2010 to December 31, 2011, this has resulted in a credit balance of $636,840 in 1592 HST and a debit balance of $636,840 in 1592 Contra.

Additionally PowerStream has recorded fifty percent (50%) of the 1592 HST amount in account 2425, representing the balance to be returned to ratepayers, along with interest at the OEB prescribed rate.

Due to the use of the proxy method alternative in Q.4, it is a simple matter to determine the projected December 31, 2012 balance for HST savings on OM&A. The amounts recorded to December 31, 2011 and the projected amounts to December 31, 2012 are summarized in Table 2 below:

Table 2: Projected 1592 HST Balance as of December 31, 2012

Description	**1592 HST 100%**	**AC# 2425 50%**
Balance June 30, 2010	$ -	$ -
Transactions July to December 2010	$ (212,282)	$ (106,141)
Balance December 31, 2010	$ (212,282)	$ (106,141)
Transactions January to December 2011	$ (424,563)	$ (212,282)
Balance December 31, 2011	**$ (636,845)**	**$ (318,422)**
Transactions January to December 2012	$ (424,563)	$ (212,282)
Balance December 31, 2012	**$ (1,061,408)**	**$ (530,704)**

PowerStream seeks to dispose of 50% of the incremental HST savings on OM&A to December 31, 2012, in the amount of $530,704 credit plus accrued interest, in this Application.

Q.4 also discusses whether there are any savings from HST related to capital and depreciation that are to be recorded in 1592 HST.

In Q.4 it is recognized that any savings on capital purchases on or after July 1, 2010 will be reflected in the cost when these assets are included in rate base at the next cost of service application. Any savings in cost due to the elimination of PST will flow to ratepayers at that time and there is no savings to be recorded in 1592 HST.

In Q.4 there is further discussion and examples regarding the depreciation on capital additions on or after July 1, 2010, that imply there are savings on depreciation to be recorded in 1592 HST. There is no explanation as to why there would be an assumption of savings related to depreciation on assets that have yet to be rebased and become part of rates. Furthermore, the Board’s Decision talks about incremental ITCs which do not apply to depreciation, only to the capital cost of the asset addition.

With no clear rationale for the savings on depreciation, PowerStream contacted Board Staff for an explanation. The explanation offered was that since depreciation is an annual expense, it was felt that this should be treated similar to OM&A.

PowerStream questions this rationale. Unlike OM&A which represents current expenditures, depreciation represents the recovery of the original cost of fixed assets over the useful lives. The depreciation in current rates is recovering the original cost of assets acquired at or before PowerStream's last cost of service rebasing (Barrie 2008, PowerStream 2009) on which PowerStream has paid PST. Accordingly there can be no savings from the implementation of HST in 2010.

PowerStream considered if there was any way that there could a realization of savings on depreciation resulting from the implementation of HST during the current Incentive Regulation Mechanism ("IRM") period. This could only occur if there was depreciation in current rates that could be considered to be depreciation on additions after June 30, 2010 and if this depreciation was greater than the actual depreciation on the new additions.

PowerStream considered the mechanics of IRM rate setting, the nature of capital investment and recovery of capital costs through rates. PowerStream's current rates are based on the capital assets in service in 2009 (Barrie 2008) or earlier. As indicated above, the additions after June 30, 2010 (which are subject to HST rather than PST) will not be added to the rate base until PowerStream's next cost of service rebasing for 2013 rates.

The only way that there is depreciation in rates on additions after 2009, is the extent of depreciation on assets included in the last cost of service rebasing that become fully depreciated. This would provide some depreciation expense in rates available to fund depreciation on new additions.

The savings calculated in FAQ Q.4 would only arise if the annual depreciation expense on additions were 8% lower than the amount of annual depreciation expense on fully amortized assets that is no longer required. The inherent assumption is that additions and related annual depreciation will be 8% lower than the amount of fully amortized assets and related annual depreciation expense. This is extremely unlikely. The historical cost and related depreciation on fully amortized assets is likely to be much lower than the cost of new additions and related depreciation, well in excess of any reduction due to HST, as explained below.

Distribution assets represent the vast majority of PowerStream's rate base and on average have a useful life of 25 years.

The materials cost of utility assets has increased by approximately 88.8% over the 25 year period since 1985 (refer to Table 3 below). An 8% cost reduction from PST, would reduce the material cost index to 155.3 and the estimated cost increase in materials being replaced in fiscal 2010 would be approximately 75.1% greater than the cost of the original capital that was included in current rates. Similarly the labour cost of constructed assets has increased by 74.7% over the same period.

The facts indicate that the cost of replacement capital assets and the corresponding depreciation expense generally will be much greater than the cost and associated depreciation of fully depreciated assets being replaced, well in excess of any reduction from the removal of PST.

Table 3: Electric Utility Price Construction Price Indexes

Table 327-0011 Electric utility construction price indexes (EUCPI), annual (index, 1992=100)
Survey or program details:
Electric Utility Construction Price Indexes - 2316
Geography Canada

YEAR	Materials	Annual Inflation	Labour	Annual Inflation
1979	60.3		47	
1980	70.6	17%	51.6	10%
1981	75	6%	57.5	11%
1982	79.9	7%	64.5	12%
1983	79.1	-1%	71	10%
1984	83	5%	73.6	4%
1985	88.7	7%	76	3%
1986	90.7	2%	78	3%
1987	93.3	3%	80.7	3%
1988	101.7	9%	83.6	4%
1989	105	3%	88	5%
1990	106.9	2%	91.3	4%
1991	98.5	-8%	96.9	6%
1992	100	2%	100	3%
1993	102.1	2%	102.7	3%
1994	112.5	10%	104.3	2%
1995	128.1	14%	106.1	2%
1996	126.1	-2%	106.6	0%
1997	125	-1%	110.1	3%
1998	125.4	0%	117.6	7%
1999	126	0%	123.6	5%
2000	128.6	2%	128.8	4%
2001	127.7	-1%	130.7	1%
2002	127.6	0%	132.3	1%
2003	127.8	0%	132.7	0%
2004	132.5	4%	127.2	-4%
2005	138.2	4%	125.3	-1%
2006	155	12%	127.5	2%
2007	165	6%	130.3	2%
2008	167.6	2%	127.7	-2%
2009	167.5	0%	127.2	0%
2010	168.8	1%	132.8	4%

	Materials		Labour	
1985 index	88.7	B	76.0	B
2010 index (Note 1)	155.3		132.8	
Change in index	66.6	A	56.8	A
A / B =	75.1%		74.7%	

Note 1: 2010 index for materials adjusted by 8% [168.8 x (1 - 8%)] to reflect removal of PST on material purchases; there is no PST on labour costs, so no adjustment is required.

PowerStream analyzed its 2009 additions and fully depreciated assets and the related depreciation expense. The results are summarized in Table 4 below:

Table 4: Summary Comparison of 2009 Additions and Fully Depreciated Assets and Associated Depreciation

	Fixed Asset Cost	Annual Depreciation Amount
2009 Fixed Assets Additions	$ 63,972,606	$ 2,051,982
2009 Fully Depreciated Assets	$ 18,179,992	$ 1,051,460
Excess of additions over fully depreciated	$ 45,792,614	$ 1,000,521

The analysis of 2009 additions and fully depreciated assets shows that there is a significant shortfall between the depreciation provided from fully depreciated assets and the depreciation expense on new additions. If we assumed the entire cost of fixed assets was subject to PST then an eight percent (8%) reduction in the cost of additions and associated annual depreciation cost would only narrow the shortfall from $1.0 million to $0.9 million. In actual fact, only about half the cost of assets was subject to PST, making this reduction even smaller. Clearly there is no excess depreciation in rates as a result of the replacement of PST with HST.

PowerStream concludes that no savings on depreciation was realized based on the implementation of HST, and no amounts have been recorded in the 1592 HST deferral account.

In Q.5, it is indicated that 100% of the savings are to be recorded in account 1592 and that the 50% to be refunded to ratepayers will be dealt with separately. As indicated above regarding Q.1, PowerStream has recorded 100% of the incremental savings in account 1592.

For financial reporting purposes, PowerStream has recorded the 50% to be refunded to ratepayers in account 2425, Other Regulatory Liabilities, and reduced distribution revenue by a corresponding amount. Interest has been accrued on this balance at OEB prescribed rates.